Direct Testimony and Schedules
Benjamin C. Halama

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-23___
Exhibit___(BCH-1)

Overall Revenue Requirements
Rate Base
Income Statement

December 29, 2023

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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 SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over eight 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, Statement of Qualifications.

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

A. I support the Company's financial data and our requests for a general base rate increase and interim rate increase for the State of North Dakota retail gas jurisdiction, specifically:

- the overall retail revenue requirement of $98.453 million and base rate revenue deficiency of $8.463 million, determined by the cost of service for the 2024 test year; and
- the interim increase of $7.889 million as discussed in our Alternative Petition for Interim Rates.

I relied on and incorporated information provided by other witnesses in this proceeding to develop many of the test year revenue requirement adjustments discussed in my testimony. My testimony includes several schedules with financial information related to the 2024 test year revenue requirements and deficiency. These schedules were prepared by me or under my supervision. Exhibit___(BCH-1), Schedule 2, provides an index of the schedules to my testimony.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into the following sections:

- Section II Case Overview
- Section III Supporting Information
- Section IV Rate Base Components
- Section V Income Statement
- Section VI Utility and Jurisdictional Allocations
- Section VII Annual Adjustments to the Test Year
- Section VIII Compliance Matters
- Section IX Conclusion

II. CASE OVERVIEW

A. Test Year Revenue Requirements and Deficiency

Q. WHAT IS THE AMOUNT OF THE TEST YEAR REVENUE REQUIREMENT FOR THE COMPANY'S GAS OPERATIONS IN ITS NORTH DAKOTA JURISDICTION?

A. The 2024 test year jurisdictional retail revenue requirement for North Dakota gas utility operations is $98.453 million based on forecasted average rate base and projected net operating income for the calendar year 2024 test year, based on a 7.52 percent overall Rate of Return (ROR) recommended by Company witness Joshua C. Nowak in Direct Testimony.

Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE TEST YEAR?

A. The base rate revenue deficiency for the test year is $8.463 million. A summary of the base rate revenue deficiency for 2024 is shown in Exhibit___(BCH-1), Schedule 7. The level of North Dakota retail gas rates must be increased by this amount in 2024 for the Company to have an opportunity to earn an overall return on rate base of 7.52 percent as shown in Exhibit___(BCH-1), Schedule 3A, 2024 Test Year Cost of Service Study.

Q. HOW DID YOU CALCULATE THE DEFICIENCY?

A. The 2024 revenue requirements for this filing are calculated by including all revenues and costs at the proposed capital structure, as well as any federal and state credits earned on a total company basis, then allocating those components to North Dakota based on the allocation methods discussed in Section VI.

Q. DID YOU PREPARE A COST OF SERVICE STUDY THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE TEST YEAR?

A. Yes. Under my direction, a cost of service study was prepared. Schedule 3A contains a copy of the jurisdictional cost of service study (JCOSS) for the test year.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CAPITAL STRUCTURE AND WHAT ARE THE VARIOUS COMPONENTS?

A. The capital structure employed in this case represents the Company's 2024 budgeted amounts. The costs and ratios associated with this capital structure are found in Schedule 3A, and are as follows:

	Rate	Ratio	Weighted Cost
Long Term Debt	4.54%	47.38%	2.15%
Short Term Debt	7.72%	0.12%	0.01%
Common Equity	10.20%	52.50%	5.36%
Weighted Cost			7.52%

Company witness Nowak discusses the Company's capital structure in further detail in his direct testimony.

B. Case Drivers

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

A. I discuss the drivers of this rate case when compared to existing rates. I first discuss capital related cost drivers, then amortizations driving the test year revenue requirement, then tax related cost drivers, then operation and maintenance (O&M) related cost drivers and conclude with other margin related drivers.

Q. HAVE YOU PREPARED A COMPARISON OF THE COSTS IN THE TEST YEAR FORECAST TO CURRENT RATES RESULTING FROM THE 2022 TEST YEAR?

A. Yes. Consistent with the analysis provided in prior rate cases, I provide an explanation of the detailed case drivers of the deficiency using a comparison of the 2024 test year with the base rates in effect as a result of Case No. PU-21-381, which used a test year based on the 2022 budget. I will refer to the comparison year as the 2022 test year. My analysis is done by FERC accounts and functional groupings and differs from the direct testimony of the Company's witnesses, who primarily discuss costs and cost changes in terms of actual costs and budgets (not revenue deficiencies). Therefore, my discussion of key cost drivers reflects dollar values that group costs differently from their discussions. I also use the 2022 test year as a comparison point rather than 2022 actual results. I note that I discuss these drivers at a high level for purposes of discussing the overall deficiency and rely on information provided by various business areas around the activities and changes giving rise to these drivers.

Q. WHAT ARE THE MAJOR DRIVERS OF THE COMPANY'S NEED FOR RATE RELIEF?

A. A summary of the cost elements to which the revenue deficiency can be attributed is provided in Exhibit___(BCH-1), Schedule 9, Detailed Case Drivers. The major cost elements driving the revenue deficiency are identified in Table 1 below.

Table 1
Net Deficiency ($ in millions)

	Increase (Decrease) 2024 TY to 2022 TY
Capital and Capital Related	$7.3
Amortizations	0.3
Taxes	1.7
Operating Expense	1.2
Other Margin Impacts (sales and customer growth)	(2.1)
Total Net Incremental Deficiency	$8.5

Q. SINCE THE LAST GAS RATE CASE, HAVE ANY OTHER FACTORS IMPACTED THE COMPANY'S GAS BUSINESS?

A. Yes. There are several notable factors that have impacted our gas business since the Company's last gas rate case – primarily, inflation and supply chain disruptions. Specifically, unprecedented inflation has affected the cost of our capital investments and operations, from the cost of materials and supplies to the cost of paying our employees and contractors. Labor shortages, coupled with wage increases and supply chain shortages and delays across industries, have also impacted how the Company must manage its operations and labor and plan its investments. The Company makes every effort to manage these economic conditions as they apply to our business and customers, but these issues continue to drive our costs up since the Company developed its future test year forecast for the last case in 2021.

Q. PLEASE PROVIDE A SPECIFIC EXAMPLE OF INFLATIONARY PRESSURES IDENTIFIED SINCE THE COMPANY'S LAST GAS RATE CASE.

A. The cost of fleet fuel has risen almost 100 percent from the forecast used in the Company's 2022 test year to the basis for the 2024 test year. An increase in fleet fuel prices could impact both capital and O&M costs when compared to the previous test year.

1. *Capital Related Cost Drivers*

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

A. Table 2 below compares the 2024 test year revenue requirements with the revenue requirements for the 2022 test year, by category, for capital plant related costs as shown on Schedule 9.

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

A. The 2024 test year revenue requirements include a $4.2 million increase due to the distribution business unit's capital investments in North Dakota compared to the 2022 test year. This increase is due to capital investments relating to new customer business, safety and reliability work, and mandatory relocations. Additional information regarding distribution's capital investments is provided in the direct testimony of Company witness Alicia E. Berger.

Table 2
Capital and Capital Related Revenue Requirements Changes
($ in millions)

		Increase (Decrease) 2024 TY to 2022 TY
Distribution Systems		$4.2
Intangible		0.9
Gas Peaking		0.8
ROE Change		0.5
Gas Storage		0.4
General		0.3
Other Rate Base		0.3
TOTAL Capital and Capital Related		$7.3

Q. PLEASE IDENTIFY THE PRINCIPAL CHANGES IN GENERAL AND INTANGIBLE CAPITAL COSTS.

A. The 2024 test year revenue requirements include a $1.2 million increase due to our investments in capital projects classified as general and intangible compared to the 2022 test year. This increase is due to capital investments relating to replacing aging information technology (IT) and enhancing the safety and reliability of our transportation fleet and operations centers. Company witnesses Al Krug and Allison M. Johnson discuss these investments further in direct testimony.

Q. PLEASE IDENTIFY THE PRINCIPAL CHANGES IN GAS PEAKING CAPITAL COSTS.

A. The 2024 test year revenue requirements include a $0.8 million increase due to our investments in capital projects for our Gas Peaking facilities compared to the 2022 test year. Company witness Berger discusses these investments further in her direct testimony.

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

A. The test year forecast revenue requirements include a $0.5 million increase related to the proposed change in the return on equity (ROE), compared to the ROE approved in the Company's last gas rate case. The total change in cost of capital is due to a requested 10.2 percent ROE and an increase in the cost of debt. However, the Company's interim rate request reflects the 9.8 percent ROE. Company witness Joshua C. Nowak of Concentric Energy Advisors, Inc. discusses the ROE.

2. Amortizations

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN AMORTIZATIONS.

A. The test year revenue requirements include a $0.3 million increase related to amortizations compared to the 2022 test year. This increase is primarily due to the Rate Case Expense amortization.

3. Taxes

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN PROPERTY TAXES.

A. The test year revenue requirements includes a $0.6 million increase in property taxes compared to the 2022 test year. This is driven by a general overall increase in North Dakota property tax valuations along with a shift in the North Dakota allocation percentage between electric and gas as the gas distribution plant percentage increased for the test year due to the Fargo capacity project going into service at the end of 2021.

4. *Operating and Maintenance Expenses (O&M)*

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN OPERATING AND MAINTENANCE EXPENSES.

A. Table 3 below compares the 2024 test year revenue requirements with the revenue requirements for the 2022 test year, by category, for operating expenses as shown on Schedule 9.

Table 3
O&M Expense Changes ($ in millions)

	Increase (Decrease) 2024 TY to 2022 TY
Admin & General	1.0
Gas Production and Storage	0.4
Distribution Systems	0.2
Transmission	(0.1)
Customer Accounting / Info / Service	(0.3)
TOTAL O&M	$1.2

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

A. The 2024 test year revenue requirements include a $0.2 million increase in distribution operating expenses compared to the 2022 test year. This increase is due to an increase in the cost of labor, due mainly to bargaining unit contract increases and increases in materials costs, primarily due to inflation. Additional information regarding 2024 test year distribution O&M relative to the 2022 actual year is discussed in the direct testimony of Company witness Berger.

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

A. The 2024 test year revenue requirements include a $1.0 million increase in A&G expense compared to the 2022 test year. This increase is also due to higher cost of labor, plus increased software maintenance and licensing cost increases necessary to support new applications and maintain existing applications to limit cyber security threats.

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

A. No. Although the cost of fuel is considered an operating expense, recovery occurs through the Company's separate gas adjustment mechanism and true-up process.

5. Other Margin

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT IMPACT FOR THE PRINCIPAL CHANGES IN OTHER MARGIN.

A. Table 4 below compares the 2024 test year revenue requirements with the revenue requirements for the 2022 test year, by category, for other margin as shown on Schedule 9.[1]

[1] Due to rounding, the totals in Table 4 do not sum to the total of the Sales Change and Other figures in Sch. 9.

Table 4
Net Deficiency ($ in millions)

		Increase (Decrease) 2024 TY to 2022 TY
Sales Change		($2.1)
Other		0.1
TOTAL Other Margin Impacts		($2.1)

Q. PLEASE DESCRIBE HOW CHANGES IN REVENUE IMPACT THE COMPANY'S REVENUE REQUIREMENTS.

A. Over the past 5 years, the Company's total number of natural gas customers in North Dakota has increased by 11 percent. Company witness John M. Goodenough supports the Company's customer growth, sales data, and sales forecast in direct testimony. Customer and sales growth over the past 5 years is approximately 2.1 percent and that trend is expected to continue for 2023 and 2024 which results in the increased revenue shown on Table 4 above.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2024 TEST YEAR FORECAST AND THOSE CONTAINED IN 2022 RATE CASE TEST YEAR?

A. Yes. Both categorizations conform to the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts.

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 Test Year

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

A. Financial data is provided for the most recent fiscal year (calendar year 2022), the current year (calendar year 2023 – forecasted from July 1, 2023), and the test year (calendar year 2024). Financial data for the most recent fiscal year, the current year, and the test year are adjusted for traditional regulatory adjustments (*e.g.*, advertising expenses, association dues, etc.).

Q. WHY DID THE COMPANY PROPOSE CALENDAR YEAR 2024 FOR THE TEST YEAR FOR THIS PROCEEDING?

A. Calendar year 2024 was selected as the test year because it uses the most recent available budget information and is a reasonable representation of the costs and expenses the Company will incur when interim and final rates take effect.

Q. DOES THE 2024 FUTURE TEST YEAR MEET THE COMMISSION'S REQUIREMENTS?

A. Yes. The use of a future test year is permitted by North Dakota Century Code (N.D.C.C.) § 49-05-04.1(1), which allows a utility to select a future test year. N.D.C.C. § 49-05-04.1(2) then requires the Company to present:

a) a comparison of forecast data to historical period data to demonstrate the reliability and accuracy of the utility's forecast, including a comparison of the prior years' forecast or budgeted data to actual data for those periods;

b) a statement that the test year budget data is reasonable, reliable, and made in good faith; and all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast; and

c) the accounting treatment applied to anticipated events and transactions in the budget is the same as the accounting treatment to be applied in recording the events once they have occurred.

Exhibit___(BCH-1), Schedule 10, Budgeting Accuracy, to my direct testimony provides a comparison of past budgets to actual costs from 2020-2022 in compliance with the first requirement of this statute. The 2024 Company budget data, after the adjustments I discuss below, is a reasonable and conservative representation of the costs and expenses the Company will incur to provide gas service in the State of North Dakota and complies with N.D.C.C. § 49-05-04.1(2). Thus, the 2024 test-year data is reasonable, reliable, and made in good faith, and is appropriate for setting rates in this proceeding. In addition, the accounting treatment applied to anticipated events and transactions in the budget is the same as the accounting treatment applied in recording the events once they have occurred.

Q. N.D.C.C. § 49-05-04.1(2)(c) REQUIRES A UTILITY TO FILE CERTAIN FINANCIAL DATA FOR COMPARISON WITH THE TEST YEAR DATA. IS THE COMPANY COMPLYING WITH THIS REQUIREMENT?

A. Yes. Exhibit___(BCH-1), Schedule 3C is the Company's 2022 actual JCOSS study. This information, providing the most recent calendar year of actual data, is consistent with the approach we took in our last two gas rate cases (Case No. PU-21-381 and Case No. PU-06-525), and with the financial statements in our May 1, 2023 jurisdictional annual report filed with the Commission in Case No. PU-23-167. Exhibit___(BCH-1), Schedule 3B provides the same information for the 2023 current year as required by the N.D.C.C.

B. Jurisdictional Cost of Service Study

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JCOSS FOR THE 2024 TEST YEAR.

A. The complete JCOSS for 2024 is provided in Schedule 3A, 2024 Test Year COSS, and includes all the adjustments discussed in my direct testimony. The JCOSS includes the following financial data input sections for both total Company and the North Dakota 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 computation.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SCHEDULES.

A. The JCOSS summary for the 2024 test year is included in Schedule 3A:

- The "Rate Base Summary" for total Company gas operations and the North Dakota jurisdiction is shown on Schedule 3A, page 1.
- An "Income Statement Summary" for total Company gas operations and the North Dakota jurisdiction is shown on Schedule 3A, page 2.
- The "Income Tax Summary" for total Company gas operations and the North Dakota jurisdiction is shown on Schedule 3A, page 3. The schedule shows adjustments to book income necessary to determine state and federal taxable income. The federal and state income tax calculations are carried back to the income statement on Schedule 3A, page 2.
- The "Revenue Requirement Summary" for total Company gas operations and the North Dakota jurisdiction is shown on Schedule 3A, page 3. Specifically, the schedule shows: (i) the earned overall rate of return on rate base; (ii) the earned return on equity (ROE); (iii) the base rate revenue deficiency that needs to be recovered to enable North Dakota jurisdiction gas operations to earn the requested ROE; and (iv) the total revenue requirements.

- The computation of cash working capital is shown on Exhibit___(BCH-1), Schedule 8, and is carried back to the rate base on Schedule 3A, page 1.

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

A. Yes. The revenue conversion factor is the incremental amount of gross revenue required to generate an additional dollar of operating income. See Table 5 below for the revenue conversion factor calculation.

Table 5
Revenue Conversion Factor Calculation

Gross Revenue Factor =	1 / (1 - Federal and ND Income Tax)
	1 / (1 - 0.24405)
	1.32284

Q. WHAT FEDERAL CORPORATE TAX RATE WAS USED TO CALCULATE THE REVENUE CONVERSION FACTOR?

A. Pursuant to the Tax Cuts and Jobs Act of 2017, the Company has used a federal corporate tax rate of 21 percent in the calculation of the revenue conversion factor. The revenue conversion factor and composite income tax rates are included in Schedule 3A, page 1.

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

A. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization." The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base.

Q. DESCRIBE THE SCHEDULE IN YOUR EXHIBITS THAT IS RELATED TO THE INCOME STATEMENT.

A. Exhibit___(BCH-1), Schedule 11, consists of comparative income statements for the test year. Schedule 11, page 1 is a comparative income statement for the 2024 test year, showing the income effect of present authorized rates and proposed rates. This comparative income statement was prepared from the results of the JCOSS and includes the revenue deficiency in the North Dakota jurisdiction gas utility operations. Schedule 11, page 2 shows a gas utility comparative income statement for the North Dakota jurisdiction for the 2024 test year, before and after making test period adjustments.

IV. RATE BASE COMPONENTS

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital investment made by a utility in plant, equipment, materials, supplies, and other assets necessary for the provision of utility service, reduced by accumulated depreciation and non-investor sources of capital, such as deferred taxes.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED TEST YEAR RATE BASE.

A. The test year rate base is generally composed of the following major items, which will be described in further detail later in my testimony:

- Net Utility Plant;
- Short-term Construction Work in Progress (CWIP);
- Accumulated Deferred Income Taxes (ADIT); and
- Other Rate Base Items.

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

A. Exhibit___(BCH-1), Schedule 15, page 1 of 3, shows a detailed statement of the Average Rate Base by component for the 2024 test year. Schedule 15, page 2 of 3, is a comparative statement of the 2024 test year average rate base for the North Dakota jurisdiction and total Company, before and after making proposed test period adjustments. Schedule 15, page 3 of 3 provides detailed information on CWIP and ADIT for the total Company and North Dakota jurisdiction. Schedule 3C, page 1 shows the Company's actual 2022 average rate base as provided in the May 1, 2023 jurisdictional annual report to the Commission. The annual jurisdictional report rate base provided in Schedule 3C has been modified to include the proposed ROE, cash working capital, and an adjustment to include the cost of gas. These modifications were made consistent with past practice to align with the 2024 test year cost of service.

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 gas 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 test year. Such treatment is consistent with the method employed in our most recent North Dakota gas rate case.

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

A. The historical base used was the Company's actual net investment (Plant-In-Service less Accumulated Depreciation) on the books and records of the Company as of June 30, 2023. The budget projections for July through December 2023 were then applied to the June 30, 2023 balance to arrive at a beginning test year net plant balance.

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

A. The ending net plant balances were determined by applying the data contained in the 2024 capital budget to the above-described beginning test year balances, adjusted for plant additions, retirements, depreciation, salvage, and removal costs projected to occur during the test year. The net plant balance in rate base reflects the simple average of projected net plant balances at the beginning and end of the 2024 test year. Such treatment is consistent with the method employed in the Company's most recent gas rate case.

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

A. The average net utility plant included in the test year rate base is $183.832 million, provided in Schedule 3A, page 1. As shown on this schedule, the average net utility plant is comprised of an average plant balance of $279.835 million minus an average depreciation reserve of $96.003 million.

B. Construction Work in Progress (CWIP)

Q. HAS CWIP BEEN INCLUDED IN THE TEST YEAR RATE BASE?

A. Yes. However, the only CWIP that is included in rate base are costs related to projects of a short duration (any capital project that is deemed routine and finishes work within a month) that do not accrue Allowance for Funds Used During Construction (AFUDC). I note the identification of short term CWIP ensures that no CWIP is recovered in base rates. Thus, there is no AFUDC offset added to operating income. The rate base amount reflects a simple average of projected short-term CWIP beginning and ending test year balances. This is consistent with the method employed in our last North Dakota gas rate case and matches the use of an average rate base.

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

A. The beginning test year balance for CWIP was the June 30, 2023 actual balance. Construction expenditures, and transfers to Plant-In-Service during the remaining months of 2023 were netted against the June 30, 2023 balance to derive a beginning test year balance. The beginning test year CWIP balance was adjusted to reflect projected construction expenditures, and transfers to Plant-In-Service during the 2024 test year to obtain the ending test year CWIP balance. These projections were developed from the Company's 2024 capital budget.

Q. WHAT WAS THE LEVEL OF SHORT-TERM CWIP INCLUDED IN THE TEST YEAR RATE BASE?

A. As shown in Schedule 3A, page 1, the average short-term CWIP included in rate base was $0.678 million.

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 IN THE PROJECTED TEST YEAR RATE BASE?

A. As shown on Schedule 3A, page 1, $22.872 million was deducted. This amount reflects a simple average of the projected beginning and ending 2024 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.

Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S ADIT AMORTIZATION REQUIREMENTS?

A. Yes. The Commission's adoption of the Settlement in Case No. PU-18-156 requires the Company to amortize its excess plant-related ADIT using the Average Rate Assumption Method (ARAM), and amortize unprotected, excess non-plant-related ADIT over a three-year period. Consistent with this requirement, the Company is amortizing the excess plant related ADIT using ARAM. The excess non-plant-related ADIT was amortized as ordered over three years and ended in 2020, therefore no impact remains in the 2024 test year.

D. Other Rate Base

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

A. Other rate base is comprised primarily of what is referred to as working capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations as discussed later 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 requirements, also referred to as cash working capital, is a separate line item on various schedules.

Q. HOW HAVE TEST YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS BEEN CALCULATED?

A. The materials and supplies and fuel inventory amounts shown on Schedule 3A, page 1, are based on the thirteen-month average balances projected during the test year. Materials and supplies average balance included in the test year rate base equals $0.306 million. The test year average rate base amount for fuel inventory is $6.008 million.

Q. HOW HAVE THE TEST YEAR NON-PLANT ASSETS AND LIABILITIES BEEN DETERMINED?

A. These balances as shown on Schedule 3A, page 1, represent the 2024 calendar year estimate 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. This group is primarily composed of assets that increase test year rate base by $1.049 million.

Q. HOW HAVE THE TEST YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS BEEN DETERMINED?

A. Prepayments and other working capital, such as customer advances and deposits, are based on the actual thirteen-month average balances during the period ended June 30, 2023, as a proxy for the test year. The unamortized balances included in this section are based on the amortization schedules as described later in my testimony. The net impact of these various items decreases the test year rate base by $1.294 million as shown on Schedule 3A, page 1.

Q. HOW HAVE TEST YEAR REGULATORY AMORTIZATIONS BEEN CALCULATED?

A. The rate base amount reflects a simple average of beginning and ending test year balances.

Q. How have the test year cash working capital requirements been determined?

A. Cash working capital requirements have been determined by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses.

Q. Have the components of the test year cash working capital been calculated consistent with methods used in the most recent North Dakota gas rate case?

A. Yes.

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 the Company's lead/lag study been updated since its last North Dakota gas rate case?

A. Yes. The Company has updated the study for the calculation of expense lead days and revenue lag days for the twelve months ending December 31, 2022. The methodology for calculating the lead/lag days is consistent with the methodology used in the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for gas operations were incorporated into the North Dakota jurisdiction cash working capital rate base component as shown on Schedule 3A, page 1.

Q. WHAT IS THE TEST YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in the average rate base is a negative $0.726 million. The detailed components and calculations associated with this amount are summarized in Schedule 8.

Q. WHAT IS INDICATED BY THE NEGATIVE CASH WORKING CAPITAL AMOUNT?

A. Negative cash working capital indicates overall revenue collections occur sooner than the date when the associated costs of service are paid. In the Company's circumstance, retail revenue collections comprise the largest source of cash working capital, being offset by operating expenses, fuel expense, and property taxes. The negative cash working capital decreases rate base to compensate customers for funds provided to meet cash working capital requirements.

Q. IS THE 2024 TEST YEAR RATE BASE FOR THE COMPANY'S NORTH DAKOTA JURISDICTION GAS OPERATIONS REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The test year rate base was developed on sound ratemaking principles in a manner similar to prior Company North Dakota gas rate cases.

V. INCOME STATEMENT

A. Revenues

Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES AND CUSTOMER GROWTH FOR THE TEST YEAR RECOGNIZED IN THE TEST YEAR REVENUE REQUIREMENT?

A. Yes. Test year retail sales levels assume normal weather. Customer counts are forecasted as described by Company witness Goodenough.

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

A. Yes. As Company witness Goodenough 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 test year includes items such as revenues from specific tariff charges including service activation fees, late payment fees, and others. In areas where the Company did not budget for the collection of these other operating revenues, a representative level was determined and included in revenues in the cost of service study.

B. Operating and Maintenance Expenses

Q. WHAT O&M COSTS IS THE COMPANY BUDGETING FOR IN THE TEST YEAR?

A. The test year cost of service represents all the Company's forecasted O&M expenses directly assigned or allocated to the North Dakota gas utility; the bulk of these costs are the O&M expenses incurred by our gas operations function. The direct testimony of Company witness Berger presents the budgeted O&M costs for gas operations. As she notes, actual gas operations O&M costs are expected to be flat through the 2024 test year in aggregate, due to the Company's ongoing cost-control efforts. Forecasted increases in some areas are offset by budgeted reductions in others. The allocation of these costs to the gas utility and then to the North Dakota jurisdiction is addressed in Section VI of my direct testimony.

C. Depreciation Expense

Q. WHAT DEPRECIATION EXPENSE IS USED IN THIS PROCEEDING?

A. In direct testimony, Company witness Johnson presents the test year depreciation expense. As she notes, the Company is proposing a reduction for the North Dakota jurisdiction, which is discussed in Section VII of my testimony.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE 2024 TEST YEAR INCOME STATEMENT?

A. We have line items for property tax; income taxes including deferred income tax; investment tax credits and federal and state income tax; and payroll tax. The state and federal income taxes are calculated in Schedule 3A, page 3.

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. DOES THE COST OF SERVICE REFLECT ANY POTENTIAL FEDERAL OR STATE CORPORATE TAX RATE CHANGES DURING THE TEST YEAR?

A. Not at this time. While it is possible that there will be state or federal legislation during the course of a rate case to change tax rates, no changes are known at this time.

Q. WHAT IMPACT WOULD A FEDERAL TAX RATE INCREASE HAVE ON THE COST OF SERVICE?

A. The specific impacts to the cost of service would depend on the actual legislation that is enacted, if any. However, at a high level, an increase in the corporate income tax rate is expected to increase current and deferred income tax expense and ADIT leading to a net increase in the cost of service. Similarly, a decrease in the corporate income tax rate is expected to decrease current and deferred income tax expense and ADIT leading to a net decrease in the cost of service, consistent with the TCJA impacts on the cost of service. If, or when, federal and/or state tax rates may change, the Company would likely need to work with the Commission to seek relief, or otherwise address the changes similarly to how the TCJA was addressed in 2018.

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

A. A NOL is created when taxable deductions exceed taxable revenue; when this occurs, the excess deductions are carried forward to future periods. NOLs require an adjustment that offsets the part of the ADIT rate base reduction that is associated with the accelerated depreciation deductions. 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 is required under federal income tax law as part of "normalization" for both accounting and ratemaking.

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, the remaining deductions are "carried forward" and can be used to reduce taxes in future years. To the extent the calculated income tax expense is negative 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, depreciation deductions that were carried forward are utilized to reduce the income tax expense by 80 percent for depreciation deductions. This utilization creates an increase in deferred tax expense, reducing the balance of the DTA. Once all depreciation deductions previously carried forward are utilized, the Company will have returned to a positive tax position. This is standard 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 are included with non-rider revenues and investments. This approach determines the extent to which the Company's Gas Utility North Dakota retail jurisdiction is in a tax loss position or in a position to utilize deductions carried forward from previous periods. This approach ensures that any reduction in revenue requirements resulting from the utilization of deductions carried forward from prior periods is returned to customers as soon as it is available in the form of a reduction to base rates.

These balances related to deductions are reported in the Company's May 1 Jurisdictional Annual Reports, including the most recent May 1, 2023 Jurisdictional Annual Report. By having these annual determinations made on an all-in basis, the 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 2024 TEST YEAR REVENUE REQUIREMENTS?

A. No. The Company's 2024 test year COSS does not include a DTA balance associated with a NOL or state and federal tax credits.

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.

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 Company's North Dakota Gas Retail jurisdiction. Taxable income is determined by total revenues less total deductions. Once base rates are set in this case for the 2024 test year, they will remain in place until changed in another gas rate case.

E. AFUDC

Q. WHAT IS AFUDC?

A. As previously noted, AFUDC is the cost of financing during the period a capital investment is constructed. Once an asset is placed in service, the total cost to construct, including accumulated AFUDC, is recovered through depreciation expense.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE COMPANY'S GAS UTILITY OPERATIONS.

A. The 2024 test year includes both costs incurred directly by the Company's gas operating business and costs assigned or allocated by the Service Company for corporate functions (*e.g.,* accounting, human resources, law, etc.). The Service Company cost allocation and billing process is subject to FERC jurisdiction and authorization under a Utility Services Agreement between the Service Company and the Company.

Cost allocation and assignment principles have not changed since our last North Dakota gas rate case. O&M cost assignments and allocations are also consistent with the Company's recent North Dakota gas rate case filed on September 1, 2021 (Case No. PU-21-381). Non-O&M costs include such items as book depreciation expense, deferred income taxes, and property taxes. All of the investments common to the electric and natural gas utilities, and their related costs (*e.g.*, software or other common investments and expenses), are evaluated as to whether the cost should be direct assigned to electric or natural gas; or allocated based on appropriate allocators such as: Customers, Customer Bills, Transportation Studies, or the three factor general allocator (the average of Revenue Ratio, Employee Ratio, and Asset Ratio).

Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM), which I have included as Exhibit___(BCH-1), Schedule 12. There have not been any changes since the last gas rate case that would significantly impact the percentage of costs that are assigned to North Dakota.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR THE COMPANY'S GAS UTILITY OPERATIONS IN NORTH DAKOTA.

A. O&M cost assignments and allocations are summarized on Exhibit___(BCH-1), Schedule 13. 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 North Dakota jurisdiction gas operations or allocated to the gas operations based on cost causation.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING THE COMPANY'S INVESTMENT IN GAS PLANT TO THE NORTH DAKOTA JURISDICTION.

A. A summary and description of the allocation factors used to allocate capital related items to the North Dakota jurisdictional gas operations income statement and rate base is contained in Exhibit___(BCH-1), Schedule 14. Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (*e.g.*, Production, Transmission, Distribution). 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 gas service in a particular jurisdiction and the underlying elements of cost causation. Customer count, design day, and load dispatch are three of the allocators used when costs cannot be directly assigned.

Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE NORTH DAKOTA JURISDICTION?

A. The Company's gas distribution plant investment amounts have been directly assigned, when possible, based upon the jurisdiction(s) served by each of the individual distribution facilities. Therefore, North Dakota distribution investments are generally assigned directly to North Dakota. However, if distribution investments include components that are common or general plant in nature they are allocated based on their functional class, consistent with the CAAM.

VII. ANNUAL ADJUSTMENTS TO THE TEST YEAR

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 2024 test year forecast revenue requirement. These adjustments were identified during our review of the 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 test year forecast.

Q. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS MADE TO THE 2024 TEST YEAR.

A. I present traditional adjustments consistent with treatment in prior cases and existing Commission Policy Statements (Precedential Adjustments) and rate case adjustments related to this particular case (Rate Case Adjustments). Next, I explain the various amortizations affecting the test year (Amortizations), and a group of adjustments that are the result of secondary dynamic calculations in the cost of service model (Secondary COS Calculations).

Q. PLEASE LIST THE 2024 TEST YEAR ADJUSTMENTS.

A. The following adjustments were made to rate base and the income statement where applicable. Rate base adjustments are shown on Exhibit___(BCH-1), Schedule 5, 2024 Test Year Bridge Schedule - Rate Base, and income statement (revenue requirement) adjustments are shown on Exhibit___(BCH-1), Schedule 6, 2024 Test Year Bridge Schedule - Income Statement. Column 5 of the Rate Base bridge schedule shows the 2024 unadjusted rate base by each component of rate base. Each adjustment to rate base is contained within a column that shows its effect on each rate base component. Likewise, Column 5 of the Income Statement bridge schedule shows the 2024 unadjusted income statement by each component of the income statement. As with rate base, each adjustment to the income statement is contained within a column that shows its effect on each income statement component. In addition, the Income Statement bridge schedule shows the impact of each rate base and income statement adjustment on the revenue requirement. Exhibit___(BCH-1), Schedule 4, List of Adjustments, provides adjustment amounts for the 2024 test year.

Rate Case Adjustments

1. Bad Debt
2. Depreciation Study: TD&G
3. Dues: Chamber of Commerce
4. Economic Development Donations
5. Foundation and Other Donations
6. Long Term Incentive (LTI) Compensation

Amortizations

1. Income Tax Tracker Amortization
2. NOL Tax Reform Regulatory Amortization
3. Rate Case Expense Amortization

Secondary Cost of Service Calculations

1. ADIT Pro-Rate – IRS Required
2. Cash Working Capital Adjustment
3. Change in Cost of Capital

Each of these adjustments is discussed in more detail in this section of my testimony.

Q. IS THE 2024 O&M EXPENSE FORECAST FOR THE COMPANY'S GAS UTILITY OPERATIONS AN ACCURATE AND RELIABLE PROJECTION?

A. Yes. With the adjustments I previously described, it is an accurate and reliable projection on which to base this rate request.

A. Precedential Adjustments

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

A. Schedule 4, List of Adjustments, provides a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent for the 2024 test year.

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 completed gas rate cases. 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 Schedule 4. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

B. Rate Case Adjustments

1. Aviation

Q. PLEASE DESCRIBE THE AVIATION ADJUSTMENT.

A. The aviation adjustment removes 100 percent of the aviation-related costs to the North Dakota gas jurisdiction. These costs are incurred in lieu of commercial aviation transportation and help to facilitate the efficient use of executive time. We are making this adjustment to reduce the number of disputed issues in this case.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, column 7,
- Schedule 4, page 1, row 10, column 5,
- Volume 3, Section VIII Adjustments, Tab A3.

2. Bad Debt

Q. PLEASE DESCRIBE THE BAD DEBT ADJUSTMENT.

A. The original calculation for 2024 bad debt expense was generated during the budget process and is a function of projected revenues multiplied by the bad debt ratio for NSPM. An analysis was performed to update the bad debt expense based upon the revenue deficiency in the 2024 test year. An adjustment is needed to incorporate into the revenue requirement the updated bad debt amount, which best reflects test year costs.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, column 8,
- Schedule 4, page 1, row 11, column 5,
- Volume 3, Section VIII Adjustments, Tab A7.

3. Depreciation Study - Transmission, Distribution, and General

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

A. This adjustment updates the 2024 test year to include the impact of the Company's 2022 depreciation study related to TD&G. This adjustment is further supported by Company witness Johnson in her direct testimony.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 46, column 6,
- Schedule 6, page 1, row 40, column 9,
- Schedule 4, page 1, row 12, column 5,
- Volume 3, Section VIII Adjustments, Tab A8.

4. Dues: Chamber of Commerce

Q. DOES THE COMPANY'S REQUEST INCLUDE RECOVERY OF ASSOCIATION DUES PAID TO CHAMBERS OF COMMERCE?

A. Yes. The Company has included membership dues paid to various Chambers of Commerce in North Dakota in the 2024 test year. Chambers of Commerce provide an essential link between the Company and the communities it serves, allowing for improved utility service. Because membership in these organizations provides benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is appropriate. Chamber of Commerce dues are initially recorded below the line; thus, an adjustment is necessary to include Chamber of Commerce dues in test year costs.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, column 10,
- Schedule 4, page 1, row 13, column 5,
- Volume 3, Section VIII Adjustments, Tab A9.

5. Economic Development Donations

Q. PLEASE IDENTIFY THE COMPANY'S ECONOMIC DEVELOPMENT PROGRAMS CURRENTLY AVAILABLE.

A. The Company makes contributions to a number of regional and local economic development organizations positioned to combine resources for the purpose of maintaining and improving the long-term economic health of communities in our service territory or retaining employment opportunities and expanding the state and local tax base.

The Company can, through a donation, provide communities or organizations involved in community and economic development with either an operating grant or a one-time investment in a special project that supports the community and economic development efforts of our communities.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, column 11,
- Schedule 4, page 1, row 14, column 5,
- Volume 3, Section VIII Adjustments, Tab A10.

6. Foundation and Other Donations

Q. PLEASE DESCRIBE THE CHARITABLE CONTRIBUTION ADJUSTMENT.

A. The Company is proposing to include 50 percent of corporate charitable contributions benefiting the State of North Dakota in the test year. An analysis was performed on contribution details to ensure that only amounts contributed to charities and institutions that could be associated with the Company's North Dakota jurisdiction were included in the cost of service.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, column 12,
- Schedule 4, page 1, row 15, column 5,
- Volume 3, Section VIII Adjustments, Tab A11.

7. Long Term Incentive (LTI) Compensation

Q. PLEASE DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT IN THE 2024 TEST YEAR.

A. We have adjusted test year costs to include the budgeted costs of the long-term incentive compensation related to Company achievement of environmental goals and time-based employee retention incentives. Company witness Krug discusses incentive compensation in his direct testimony.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, columns 13-14,
- Schedule 4, page 1, rows 16-17, column 5,
- Volume 3, Section VIII Adjustments, Tab A12-13.

C. Amortizations

1. 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. We proposed to collect this amount over the three years in Case No. PU-21-381 and this adjustment represents the last year of that amortization.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 46, column 7,
- Schedule 6, page 1, row 40, column 15,
- Schedule 4, page 1, row 20, column 5,
- Volume 3, Section VIII Adjustments, Tab A14.

2. NOL Tax Reform Regulatory Amortization

Q. PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.

A. The Commission's Order in Case No. PU-18-156 approved the Company's proposed amortization level included in the TCJA refund calculation. This is being amortized over 23 years. This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 46, column 8,
- Schedule 6, page 1, row 40, column 16,
- Schedule 4, page 1, row 21, column 5,
- Volume 3, Section VIII Adjustments, Tab A15.

3. Rate Case Expense Amortization

Q. PLEASE DESCRIBE THE 2024 RATE CASE EXPENSES AMORTIZATION.

A. The Company requests approval of $1.381 million of projected direct expenses associated with this rate case docket and a three-year amortization period. A three-year amortization period is consistent with our requested amortization period for other amortizations in prior rate cases.

Q. WHAT ELSE IS INCLUDED IN THE REQUESTED RATE CASE EXPENSE AMOUNT IN THE 2024 TEST YEAR?

A. Based on the Settlement Agreement in PU-21-381, rate case expense of $1.2 million was approved and amortized over a five -year period from 2022 to 2026. The Company has included an adjustment for the prior amortization to reflect the actual expense incurred and to account for the amortization periods that will not be completed prior to the 2024 test year.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, column 17,
- Schedule 4, page 1, row 22, column 5,
- Volume 3, Section VIII Adjustments, Tab A16.

D. Secondary Cost of Service Calculations

1. ADIT Prorate – IRS Required

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

A. In general, the IRS tax regulations in Sec. 1.167(l) define a prorated schedule for the extent average accumulated deferred income taxes can be used to reduce rate base to comply with the tax normalization requirements of the Code when forecast information is used to set rates. Given that the Company's filing utilizes forecast test year data, this condition applies. This has been supported by a number of Private Letter Rulings (PLRs) issued by the IRS.

This secondary calculation limits the ADIT deduction from rate base by applying the IRS defined prorate method to only the forecast entries to this balance.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 46, column 9,
- Schedule 6, page 1, row 40, column 18,
- Schedule 4, page 1, row 25, column 5,
- Volume 3, Section VIII Adjustments, Tab A17.

2. Cash Working Capital Adjustment

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

A. As discussed earlier in Section IV.D, 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.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 5, page 1, row 46, column 10,
- Schedule 6, page 1, row 40, column 19,
- Schedule 4, page 1, row 26, column 5,
- Volume 3, Section VIII Adjustments, Tab A18.

3. Change in the Cost of Capital

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

A. The revenue requirements associated with the above adjustments described in this section of my testimony are calculated using the approved cost of capital in our last rate case. We calculate the revenue requirement impact of each adjustment at our currently authorized overall ROR of 7.08 percent (which includes the currently authorized ROE of 9.8 percent) so that changes in the overall cost of capital that occur during the duration of the rate case do not affect the revenue requirements for each adjustment. The change in cost of capital adjustment reflects the impact of the change in the approved ROR (7.08 percent) and proposed ROR (7.52 percent with a 10.20 percent ROE) for all the rate base and income statement adjustments.

This adjustment impacts the 2024 test year revenue requirements by the amounts shown on:

- Schedule 6, page 1, row 40, column 20,
- Volume 3, Section VIII Adjustments, Tab A19.

VIII. COMPLIANCE MATTERS

Q. DID YOU REVIEW PRIOR COMMISSION ORDERS AS PART OF THE DEVELOPMENT OF THE TEST YEAR REVENUE REQUIREMENT?

A. Yes. I describe below the various Commission Orders that were reviewed and addressed in preparing the test year. I discussed required adjustments related to each of these items earlier in my testimony. The Filing Requirements Compliance Table included in the testimony of Company witness Krug, Exhibit___(ADK-1), Schedule 2, documents how our rate case filing includes information submitted in compliance with these prior Commission orders.

1. Long Term Incentive

Portions of long-term incentive have been excluded from the test year as part of our incentive adjustment, which is discussed in Section VII of my testimony. However, as discussed in the direct testimony of Company witness Krug, the Company is requesting recovery of the "environmental" and "time base" portion of its Long-Term Incentive Plan. I discuss the inclusion of these costs in our request above.

The Company has removed all expenses associated with the Company's Supplemental Executive Retirement Plan (SERP) from its base data, which is consistent with prior Commission practice.

2. Organizational Dues

Consistent with prior Commission orders, only organizational dues related to North Dakota gas operations were allowed recovery in gas rates. Any organizational dues not related to the gas operations supporting the State of North Dakota have been eliminated from the test year in our association dues adjustment.

3. Lobbying Expense

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

A. No. The Company moved all lobbying costs to below the line accounting, FERC account 426.4, Expenditures for certain civic, political, and related activities. Thus, no adjustment to the cost of service for lobbying is required, as these below-the-line amounts are not used in developing the cost of service.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission determine an overall retail revenue requirement of $98.453 million and 2024 revenue deficiency of $8.463 million for the Company's North Dakota jurisdictional gas operation, determined by the cost of service for the 2024 test year. I also recommend the Commission grant an interim rate increase of $7.889 million for the Company's North Dakota jurisdictional operation.

Q. DOES THIS CONCLUDE YOUR 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

Index of Schedules

2024 Test Year Cost of Service Study (COSS)

	2024 Test Year		
	Total	ND Gas	Other
Composite Income Tax Rate			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
Federal Effective Tax Rate	20.09%	20.09%	20.09%
Composite Tax Rate	**24.40%**	**24.40%**	**24.40%**
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Weighted Cost of Capital			
Active Rates and Ratios Version	Proposed	Proposed	Proposed
Cost of Short Term Debt	7.72%	7.72%	7.72%
Cost of Long Term Debt	4.54%	4.54%	4.54%
Cost of Common Equity	10.20%	10.20%	10.20%
Ratio of Short Term Debt	0.12%	0.12%	0.12%
Ratio of Long Term Debt	47.38%	47.38%	47.38%
Ratio of Common Equity	52.50%	52.50%	52.50%
Weighted Cost of STD	0.01%	0.01%	0.01%
Weighted Cost of LTD	2.15%	2.15%	2.15%
Weighted Cost of Debt	2.16%	2.16%	2.16%
Weighted Cost of Equity	5.36%	5.36%	5.36%
Required Rate of Return	**7.52%**	**7.52%**	**7.52%**
Rate Base			
Plant Investment	2,487,402	279,835	2,207,568
Depreciation Reserve	888,971	96,003	792,967
Net Utility Plant	1,598,432	183,832	1,414,600
CWIP	5,715	678	5,037
Accumulated Deferred Taxes	236,864	22,872	213,992
DTA - NOL Average Balance			
DTA - State Tax Credit Average Balance			
DTA - Federal Tax Credit Average Balance	-	-	-
Total Accum Deferred Taxes	236,864	22,872	213,992
Cash Working Capital	(13,777)	(726)	(13,052)
Materials and Supplies	2,624	306	2,318
Fuel Inventory	49,763	6,008	43,755
Non-plant Assets and Liabilities	9,017	1,049	7,968
Customer Advances	(1,755)	(1,560)	(195)
Customer Deposits	(173)	(20)	(153)
Prepaids and Other	2,455	287	2,168
Regulatory Amortizations	990	990	-
Total Other Rate Base Items	49,143	6,333	42,810
Total Rate Base	**1,416,425**	**167,970**	**1,248,455**
Operating Revenues			
Retail	700,993	89,990	611,003
Interdepartmental	7,410		7,410
Other Operating Rev - Non-Retail	4,064	469	3,594
Total Operating Revenues	**712,467**	**90,459**	**622,008**

2024 Test Year Cost of Service Study (COSS)

	2024 Test Year		
	Total	ND Gas	Other
Expenses			
Operating Expenses:			
Purchased Gas	408,589	58,155	350,434
Gas Production & Storage	10,228	2,300	7,927
Gas Transmission	2,464	295	2,169
Gas Distribution	44,728	5,282	39,446
Customer Accounting	12,680	1,354	11,326
Customer Service & Information	24,150	152	23,998
Sales, Econ Dvlp & Other	60	9	50
Administrative & General	31,211	3,474	27,738
Total Operating Expenses	**534,109**	**71,020**	**463,089**
Depreciation	79,142	9,370	69,772
Amortization	1,492	567	926
Taxes:			
Property Taxes	24,706	2,020	22,686
ITC Amortization	(107)	(0)	(106)
Deferred Taxes	8,985	1,277	7,708
Deferred Taxes - NOL			
Less State Tax Credits deferred			
Less Federal Tax Credits deferred			
Deferred Income Tax & ITC	8,878	1,277	7,601
Payroll & Other Taxes	3,823	396	3,427
Total Taxes Other Than Income	**37,406**	**3,692**	**33,714**
Income Before Taxes			
Total Operating Revenues	712,467	90,459	622,008
less: Total Operating Expenses	534,109	71,020	463,089
Book Depreciation	79,142	9,370	69,772
Amortization	1,492	567	926
Taxes Other than Income	37,406	3,692	33,714
Total Before Tax Book Income	60,318	5,811	54,507
Tax Additions			
Book Depreciation	79,142	9,370	69,772
Deferred Income Taxes and ITC	8,878	1,277	7,601
Nuclear Fuel Burn (ex. D&D)			
Nuclear Outage Accounting			
Avoided Tax Interest	1,676	175	1,501
Other Book Additions	60	60	-
Total Tax Additions	89,756	10,881	78,875
Tax Deductions			
Total Rate Base	1,416,425	167,970	1,248,455
Weighted Cost of Debt	2.16%	2.16%	2.16%
Debt Interest Expense	30,595	3,628	26,967
Nuclear Outage Accounting			
Tax Depreciation and Removals	122,176	15,033	107,143
NOL Utilized / (Generated)			
Other Tax / Book Timing Differences	(3,429)	(396)	(3,033)
Total Tax Deductions	**149,342**	**18,265**	**131,077**

2024 Test Year Cost of Service Study (COSS)

	2024 Test Year		
	Total	ND Gas	Other
State Taxes			
State Taxable Income	732	(1,574)	2,305
State Income Tax Rate	4.31%	4.31%	4.31%
State Taxes before Credits	32	(68)	99
Less State Tax Credits applied	(61)	(8)	(53)
Total State Income Taxes	(29)	(76)	47
Federal Taxes			
Federal Sec 199 Production Deduction			
Federal Taxable Income	761	(1,498)	2,259
Federal Income Tax Rate	21.00%	21.00%	21.00%
Federal Tax before Credits	160	(315)	474
Less Federal Tax Credits	(249)	(33)	(216)
Total Federal Income Taxes	(89)	(347)	258
Total Taxes			
Total Taxes Other than Income	37,406	3,692	33,714
Total Federal and State Income Taxes	(118)	(423)	305
Total Taxes	37,288	3,269	34,019
Total Operating Revenues	**712,467**	**90,459**	**622,008**
Total Expenses	**652,032**	**84,226**	**567,806**
AFDC Debt			
AFDC Equity			
Net Income	**60,436**	**6,234**	**54,202**
Rate of Return (ROR)			
Total Operating Income	60,436	6,234	54,202
Total Rate Base	1,416,425	167,970	1,248,455
ROR (Operating Income / Rate Base)	4.27%	3.71%	4.34%
Return on Equity (ROE)			
Net Operating Income	60,436	6,234	54,202
Debt Interest (Rate Base * Weighted Cost of Debt)	(30,595)	(3,628)	(26,967)
Earnings Available for Common	29,841	2,606	27,235
Equity Rate Base (Rate Base * Equity Ratio)	743,623	88,184	655,439
ROE (earnings for Common / Equity)	**4.01%**	**2.95%**	**4.16%**
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	106,515	12,631	93,884
Net Operating Income	60,436	6,234	54,202
Operating Income Deficiency	46,079	6,398	39,682
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Revenue Deficiency (Income Deficiency * Conversion Factor)	**60,955**	**8,463**	**52,493**
Total Revenue Requirements			
Total Retail Revenues	708,404	89,990	618,414
Revenue Deficiency	60,955	8,463	52,493
Total Revenue Requirements	769,359	98,453	670,906

2023 Current Cost of Service Study (COSS)

	2023 Current Year		
	Total	ND Gas	Other
Composite Income Tax Rate			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
Federal Effective Tax Rate	20.09%	20.09%	20.09%
Composite Tax Rate	**24.40%**	**24.40%**	**24.40%**
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Weighted Cost of Capital			
Active Rates and Ratios Version	Proposed	Proposed	Proposed
Cost of Short Term Debt	5.56%	5.56%	5.56%
Cost of Long Term Debt	4.34%	4.34%	4.34%
Cost of Common Equity	10.20%	10.20%	10.20%
Ratio of Short Term Debt	0.82%	0.82%	0.82%
Ratio of Long Term Debt	46.68%	46.68%	46.68%
Ratio of Common Equity	52.50%	52.50%	52.50%
Weighted Cost of STD	0.05%	0.05%	0.05%
Weighted Cost of LTD	2.03%	2.03%	2.03%
Weighted Cost of Debt	2.08%	2.08%	2.08%
Weighted Cost of Equity	5.36%	5.36%	5.36%
Required Rate of Return	**7.44%**	**7.44%**	**7.44%**
Rate Base			
Plant Investment	2,270,714	248,221	2,022,493
Depreciation Reserve	830,599	89,221	741,378
Net Utility Plant	1,440,116	159,001	1,281,115
CWIP	4,551	544	4,007
Accumulated Deferred Taxes	229,021	21,675	207,345
DTA - NOL Average Balance			
DTA - State Tax Credit Average Balance			
DTA - Federal Tax Credit Average Balance	-	-	-
Total Accum Deferred Taxes	229,021	21,675	207,345
Cash Working Capital	(7,640)	10	(7,650)
Materials and Supplies	2,624	306	2,318
Fuel Inventory	49,763	6,008	43,755
Non-plant Assets and Liabilities	9,223	1,071	8,153
Customer Advances	(1,755)	(1,560)	(195)
Customer Deposits	(173)	(20)	(153)
Prepaids and Other	2,455	287	2,168
Regulatory Amortizations	1,059	1,059	-
Total Other Rate Base Items	55,556	7,160	48,396
Total Rate Base	**1,271,201**	**145,029**	**1,126,172**
Operating Revenues			
Retail	817,279	110,404	706,875
Interdepartmental	943		943
Other Operating Rev - Non-Retail	733	371	362
Total Operating Revenues	**818,955**	**110,774**	**708,181**

2023 Current Cost of Service Study (COSS)

	2023 Current Year		
	Total	ND Gas	Other
Expenses			
Operating Expenses:			
Purchased Gas	525,939	78,204	447,735
Gas Production & Storage	11,473	2,524	8,949
Gas Transmission	1,475	177	1,299
Gas Distribution	46,710	5,457	41,252
Customer Accounting	13,379	1,509	11,870
Customer Service & Information	23,187	129	23,058
Sales, Econ Dvlp & Other	(49)	(3)	(45)
Administrative & General	28,252	3,391	24,861
Total Operating Expenses	**650,367**	**91,388**	**558,979**
Depreciation	70,749	7,953	62,797
Amortization	36	191	(156)
Taxes:			
Property Taxes	22,121	1,791	20,330
ITC Amortization	(107)	(0)	(107)
Deferred Taxes	6,879	1,130	5,749
Deferred Taxes - NOL			
Less State Tax Credits deferred			
Less Federal Tax Credits deferred			
Deferred Income Tax & ITC	6,772	1,130	5,642
Payroll & Other Taxes	3,459	395	3,065
Total Taxes Other Than Income	**32,352**	**3,316**	**29,037**
Income Before Taxes			
Total Operating Revenues	818,955	110,774	708,181
less: Total Operating Expenses	650,367	91,388	558,979
Book Depreciation	70,749	7,953	62,797
Amortization	36	191	(156)
Taxes Other than Income	32,352	3,316	29,037
Total Before Tax Book Income	65,450	7,926	57,524
Tax Additions			
Book Depreciation	70,749	7,953	62,797
Deferred Income Taxes and ITC	6,772	1,130	5,642
Nuclear Fuel Burn (ex. D&D)			
Nuclear Outage Accounting			
Avoided Tax Interest	1,478	217	1,260
Other Book Additions	60	60	-
Total Tax Additions	79,059	9,360	69,699
Tax Deductions			
Total Rate Base	1,271,201	145,029	1,126,172
Weighted Cost of Debt	2.08%	2.08%	2.08%
Debt Interest Expense	26,441	3,017	23,424
Nuclear Outage Accounting			
Tax Depreciation and Removals	106,603	13,008	93,595
NOL Utilized / (Generated)			
Other Tax / Book Timing Differences	(2,945)	(342)	(2,602)
Total Tax Deductions	**130,099**	**15,683**	**114,416**

2023 Current Cost of Service Study (COSS)

	2023 Current Year		
	Total	ND Gas	Other
State Taxes			
State Taxable Income	14,410	1,603	12,807
State Income Tax Rate	4.31%	4.31%	4.31%
State Taxes before Credits	621	69	552
Less State Tax Credits applied	(61)	(8)	(53)
Total State Income Taxes	560	61	499
Federal Taxes			
Federal Sec 199 Production Deduction			
Federal Taxable Income	13,850	1,542	12,307
Federal Income Tax Rate	21.00%	21.00%	21.00%
Federal Tax before Credits	2,908	324	2,585
Less Federal Tax Credits	(249)	(33)	(216)
Total Federal Income Taxes	2,660	291	2,369
Total Taxes			
Total Taxes Other than Income	32,352	3,316	29,037
Total Federal and State Income Taxes	3,220	352	2,868
Total Taxes	35,572	3,668	31,904
Total Operating Revenues	**818,955**	**110,774**	**708,181**
Total Expenses	**756,725**	**103,200**	**653,524**
AFDC Debt			
AFDC Equity			
Net Income	**62,230**	**7,574**	**54,656**
Rate of Return (ROR)			
Total Operating Income	62,230	7,574	54,656
Total Rate Base	1,271,201	145,029	1,126,172
ROR (Operating Income / Rate Base)	4.90%	5.22%	4.85%
Return on Equity (ROE)			
Net Operating Income	62,230	7,574	54,656
Debt Interest (Rate Base * Weighted Cost of Debt)	(26,441)	(3,017)	(23,424)
Earnings Available for Common	35,789	4,557	31,232
Equity Rate Base (Rate Base * Equity Ratio)	667,381	76,140	591,240
ROE (earnings for Common / Equity)	**5.36%**	**5.99%**	**5.28%**
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	94,577	10,790	83,787
Net Operating Income	62,230	7,574	54,656
Operating Income Deficiency	32,347	3,216	29,131
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Revenue Deficiency (Income Deficiency * Conversion Factor)	**42,790**	**4,254**	**38,535**
Total Revenue Requirements			
Total Retail Revenues	818,222	110,404	707,818
Revenue Deficiency	42,790	4,254	38,535
Total Revenue Requirements	861,012	114,658	746,354

2022 Actual Cost of Service Study (COSS)

	2022 Actual WN Year		
	Total	ND Gas	Other
Composite Income Tax Rate			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
Federal Effective Tax Rate	20.09%	20.09%	20.09%
Composite Tax Rate	**24.40%**	**24.40%**	**24.40%**
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Weighted Cost of Capital			
Active Rates and Ratios Version	Proposed	Proposed	Proposed
Cost of Short Term Debt	6.92%	6.92%	6.92%
Cost of Long Term Debt	4.18%	4.18%	4.18%
Cost of Common Equity	10.20%	10.20%	10.20%
Ratio of Short Term Debt	0.22%	0.22%	0.22%
Ratio of Long Term Debt	47.16%	47.16%	47.16%
Ratio of Common Equity	52.62%	52.62%	52.62%
Weighted Cost of STD	0.02%	0.02%	0.02%
Weighted Cost of LTD	1.97%	1.97%	1.97%
Weighted Cost of Debt	1.99%	1.99%	1.99%
Weighted Cost of Equity	5.37%	5.37%	5.37%
Required Rate of Return	**7.36%**	**7.36%**	**7.36%**
Rate Base			
Plant Investment	2,029,719	216,080	1,813,639
Depreciation Reserve	779,468	82,880	696,588
Net Utility Plant	1,250,251	133,200	1,117,051
CWIP	4,683	529	4,153
Accumulated Deferred Taxes	225,445	20,825	204,620
DTA - NOL Average Balance	(287)	(139)	(148)
DTA - State Tax Credit Average Balance	(2)	(2)	
DTA - Federal Tax Credit Average Balance	(48)	(5)	(42)
Total Accum Deferred Taxes	225,109	20,679	204,430
Cash Working Capital	(13,810)	(820)	(12,990)
Materials and Supplies	2,017	231	1,786
Fuel Inventory	50,382	6,202	44,180
Non-plant Assets and Liabilities	11,347	1,295	10,052
Customer Advances	(1,394)	(1,465)	71
Customer Deposits	(182)	(21)	(161)
Prepaids and Other	2,603	304	2,299
Regulatory Amortizations	1,128	1,128	-
Total Other Rate Base Items	52,092	6,854	45,238
Total Rate Base	**1,081,916**	**119,904**	**962,012**
Operating Revenues			
Retail	1,007,105	138,308	868,797
Interdepartmental	1,468		1,468
Other Operating Rev - Non-Retail	3,868	2,249	1,619
Total Operating Revenues	**1,012,441**	**140,557**	**871,883**

2022 Actual Cost of Service Study (COSS)

	2022 Actual WN Year		
	Total	ND Gas	Other
Expenses			
Operating Expenses:			
Purchased Gas	730,004	109,799	620,205
Gas Production & Storage	10,223	1,630	8,594
Gas Transmission	1,164	143	1,021
Gas Distribution	41,017	5,260	35,757
Customer Accounting	13,350	1,441	11,909
Customer Service & Information	25,008	140	24,867
Sales, Econ Dvlp & Other	68	10	57
Administrative & General	26,961	3,172	23,789
Total Operating Expenses	**847,795**	**121,595**	**726,200**
Depreciation	58,677	6,460	52,217
Amortization	(9,569)	69	(9,638)
Taxes:			
Property Taxes	21,259	1,490	19,769
ITC Amortization	(107)	(0)	(107)
Deferred Taxes	3,443	471	2,971
Deferred Taxes - NOL	1,882	651	1,231
Less State Tax Credits deferred	4	4	
Less Federal Tax Credits deferred	95	11	84
Deferred Income Tax & ITC	5,317	1,137	4,180
Payroll & Other Taxes	2,920	339	2,581
Total Taxes Other Than Income	**29,496**	**2,966**	**26,531**
Income Before Taxes			
Total Operating Revenues	1,012,441	140,557	871,883
less: Total Operating Expenses	847,795	121,595	726,200
Book Depreciation	58,677	6,460	52,217
Amortization	(9,569)	69	(9,638)
Taxes Other than Income	29,496	2,966	26,531
Total Before Tax Book Income	86,041	9,468	76,573
Tax Additions			
Book Depreciation	58,677	6,460	52,217
Deferred Income Taxes and ITC	5,317	1,137	4,180
Nuclear Fuel Burn (ex. D&D)			
Nuclear Outage Accounting			
Avoided Tax Interest	1,743	118	1,625
Other Book Additions	60	60	-
Total Tax Additions	65,797	7,774	58,023
Tax Deductions			
Total Rate Base	1,081,916	119,904	962,012
Weighted Cost of Debt	1.99%	1.99%	1.99%
Debt Interest Expense	21,530	2,386	19,144
Nuclear Outage Accounting			
Tax Depreciation and Removals	85,866	9,718	76,149
NOL Utilized / (Generated)	6,730	2,329	4,401
Other Tax / Book Timing Differences	(7,451)	(856)	(6,595)
Total Tax Deductions	**106,675**	**13,576**	**93,099**

2022 Actual Cost of Service Study (COSS)

	2022 Actual WN Year		
	Total	ND Gas	Other
State Taxes			
State Taxable Income	45,162	3,666	41,497
State Income Tax Rate	4.31%	4.31%	4.31%
State Taxes before Credits	1,947	158	1,789
Less State Tax Credits applied	(52)	(10)	(43)
Total State Income Taxes	1,894	148	1,746
Federal Taxes			
Federal Sec 199 Production Deduction			
Federal Taxable Income	43,268	3,518	39,751
Federal Income Tax Rate	21.00%	21.00%	21.00%
Federal Tax before Credits	9,086	739	8,348
Less Federal Tax Credits	(344)	(42)	(302)
Total Federal Income Taxes	8,742	697	8,046
Total Taxes			
Total Taxes Other than Income	29,496	2,966	26,531
Total Federal and State Income Taxes	10,637	845	9,792
Total Taxes	40,133	3,810	36,323
Total Operating Revenues	**1,012,441**	**140,557**	**871,883**
Total Expenses	**937,036**	**131,934**	**805,102**
AFDC Debt			
AFDC Equity			
Net Income	**75,404**	**8,623**	**66,781**
Rate of Return (ROR)			
Total Operating Income	75,404	8,623	66,781
Total Rate Base	1,081,916	119,904	962,012
ROR (Operating Income / Rate Base)	6.97%	7.19%	6.94%
Return on Equity (ROE)			
Net Operating Income	75,404	8,623	66,781
Debt Interest (Rate Base * Weighted Cost of Debt)	(21,530)	(2,386)	(19,144)
Earnings Available for Common	53,874	6,237	47,637
Equity Rate Base (Rate Base * Equity Ratio)	569,304	63,094	506,211
ROE (earnings for Common / Equity)	**9.46%**	**9.88%**	**9.41%**
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	79,629	8,825	70,804
Net Operating Income	75,404	8,623	66,781
Operating Income Deficiency	4,225	202	4,023
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Revenue Deficiency (Income Deficiency * Conversion Factor)	**5,589**	**267**	**5,321**
Total Revenue Requirements			
Total Retail Revenues	1,008,573	138,308	870,265
Revenue Deficiency	5,589	267	5,321
Total Revenue Requirements	1,014,162	138,576	875,586

2024 Test Year - List of Adjustments
$000

(1) Line No.	(2) Record Category	(3) Report Label	(4) Record Type	(5) ND Gas 2024 Test Year	(6) Workpaper Reference
1	Unadjusted	Unadjusted	**Total Unadjusted**	**8,118**	
2					
3	Precedential	Precedential Adjustments	NSPM-Advertising (Trad)	(74)	A1
4	Precedential	Precedential Adjustments	NSPM-Assn Dues (Trad)	(3)	A2
5	Precedential	Precedential Adjustments	NSPM-Incentive Pay	(20)	A4
6	Precedential	Precedential Adjustments	NSPM-Incentive Pay_Remove Long Term	(130)	A5
7	Precedential	Precedential Adjustments	NSPM-Pension Non-Qual SERP Removal	(0)	A6
8	Precedential		**Sub-Total Precedential**	**(228)**	
9					
10	Adjustment	Aviation	NSPM-Aviation	(35)	A3
11	Adjustment	Bad Debt	NSPM-Bad Debt	35	A7
12	Adjustment	Depreciation Study: TD&G	NSPM-ND Gas Depreciation Study TD&G	(150)	A8
13	Adjustment	Dues: Chamber of Commerce	NSPM-Chamber of Commerce Dues	3	A9
14	Adjustment	Economic Development Donations	NSPM-Econ Dev Donations (Trad)	4	A10
15	Adjustment	Foundation and Other Donations	NSPM-Donations (Trad)	22	A11
16	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Environmental LTI	16	A12
17	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Time Based LTI	62	A13
18	Adjustment		**Sub-Total Adjustment**	**(43)**	
19					
20	Amortization	Income Tax Tracker	NSPM-Income Tax Tracker	10	A14
21	Amortization	NOL ADIT ARAM	NSPM-NOL Tax Reform ADIT ARAM	170	A15
22	Amortization	Rate Case Expenses	NSPM-Amortization Rate Case Expense	498	A16
23	Amortization		**Sub-Total Amortization**	**678**	
24					
25	Secondary Calculations	ADIT Prorate for IRS	NSPM-ADIT Prorate for IRS	4	A17
26	Secondary Calculations	Cash Working Capital	NSPM-Cash Working Capital	(67)	A18
27	Secondary Calculations		**Sub-Total Secondary Calculations**	**(63)**	
28					
29			**Total Revenue Deficiency**	**8,463**	

2024 Test Year Bridge Schedule - Rate Base ($000s)
Unadjusted at Last Authorized walkforward to Adjusted at Proposed

	1	2	3	4	5	6	7	8	9	10	11
		Bridge - Unadjusted					Amortization		Secondary Calculations		
Line No.		ADIT Prorate for IRS	Cash Working Capital	Base	Total Unadjusted	Depreciation Study: TD&G	Income Tax Tracker	NOL ADIT ARAM	ADIT Prorate for IRS	Cash Working Capital	Total
1						WP-A8	WP-A14	WP-A15	WP-A17	WP-A18	
2	Plant as booked										
3	Gas Manufactured Plant			11,445	11,445						11,445
4	Gas Storage			14,311	14,311						14,311
5	Gas Transmission			4,006	4,006						4,006
6	Gas Distribution			214,184	214,184						214,184
7	General			19,609	19,609						19,609
8	Common			16,280	16,280						16,280
9	Total Utility Plant in Service			279,835	279,835						279,835
10											
11	Reserve for Depreciation										
12	Gas Manufactured Plant			2,944	2,944						2,944
13	Gas Storage			8,376	8,376						8,376
14	Gas Transmission			1,818	1,818	5					1,823
15	Gas Distribution			66,782	66,782	124					66,906
16	General			8,044	8,044	(166)					7,878
17	Common			8,126	8,126	(49)					8,077
18	Total Reserve for Depreciation			96,089	96,089	(86)					96,003
19											
20	Net Utility Plant										
21	Gas Manufactured Plant			8,501	8,501						8,501
22	Gas Storage			5,935	5,935						5,935
23	Gas Transmission			2,188	2,188	(5)					2,183
24	Gas Distribution			147,402	147,402	(124)					147,278
25	General			11,564	11,564	166					11,731
26	Common			8,155	8,155	49					8,204
27	Net Utility Plant in Service			183,746	183,746	86					183,832
28											
29	Utility Plant Held for Future Use										
30											
31	Construction Work in Progress			678	678						678
32											
33	Less: Accumulated Deferred Income Taxes	(46)		22,893	22,847	27			(2)		22,872
34											
35	Other Rate Base Items										
36	Cash Working Capital		(802)		(802)					77	(726)
37	Materials and Supplies			306	306						306
38	Fuel Inventory			6,008	6,008						6,008
39	Non Plant Assets and Liabilities			1,049	1,049						1,049
40	Customer Advances			(1,560)	(1,560)						(1,560)
41	Customer Deposits			(20)	(20)						(20)
42	Prepayments			287	287						287
43	Regulatory Amortizations						5	985			990
44	Total Other Rate Base		(802)	6,068	5,266		5	985		77	6,333
45											
46	Total Average Rate Base	46	(802)	167,599	166,843	59	5	985	2	77	167,970

2024 Test Year Bridge Schedule - Income Statement ($000s)
Unadjusted at Last Authorized walkforward to Adjusted at Proposed

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
		Bridge - Unadjusted				Precedential	Adjustment							
Line No.		ADIT Prorate for IRS	Cash Working Capital	Base	Total Unadjusted	Precedential Adjustments	Aviation	Bad Debt Expense	Depreciation Study: TD&G	Dues: Chamber of Commerce	Economic Development Donations	Foundation and Other Donations	LTI-Environmental	LTI-Time Based
1						WP A1,A2,A4-A6	WP-A3	WP-A7	WP-A8	WP-A9	WP-A10	WP-A11	WP-A12	WP-A13
2	Operating Revenues													
3	Retail Revenue			89,990	89,990									
4	Other Operating			469	469									
5	Total Revenue			90,459	90,459									
6														
7	Expenses													
8	Operating Expenses													
9	Base Cost of Gas			58,155	58,155									
10	Gas Production and Storage			2,300	2,300									
11	Gas Transmission			295	295									
12	Gas Distribution			5,282	5,282									
13	Customer Accounting			1,318	1,318			35						
14	Customer Service and Information			192	192	(40)								
15	Sales, Econ Dev, & Other			5	5						4			
16	Administrative and General			3,593	3,593	(188)	(35)			3		22	16	62
17	Total Operating Expenses			71,140	71,140	(228)	(35)	35		3	4	22	16	62
18														
19	Depreciation			9,541	9,541				(172)					
20	Amortization													
21														
22	Taxes													
23	Property			2,020	2,020									
24	Deferred Income Tax and ITC			1,222	1,222				55					
25	Federal and State Income Tax	(0)	4	(233)	(229)	56	9	(9)	(0)	(1)	(1)	(5)	(4)	(15)
26	Payroll and Other			396	396		(0)							
27	Total Taxes	(0)	4	3,405	3,409	56	8	(9)	54	(1)	(1)	(5)	(4)	(15)
28														
29	Total Expenses	(0)	4	84,087	84,090	(172)	(27)	27	(117)	2	3	17	12	47
30														
31	Allowance for Funds Used During Construct													
32														
33	Net Income	0	(4)	6,372	6,369	172	27	(27)	117	(2)	(3)	(17)	(12)	(47)
34														
35	Calculation of Revenue Requirements													
36	Rate Base	46	(802)	167,599	166,843				59					
37	Required Operating Income	3	(57)	11,866	11,812				4					
38	Operating Income	0	(4)	6,372	6,369	172	27	(27)	117	(2)	(3)	(17)	(12)	(47)
39	Income Deficiency	3	(53)	5,494	5,444	(172)	(27)	27	(113)	2	3	17	12	47
40	**Revenue Deficiency**	**4**	**(70)**	**7,267**	**7,201**	**(228)**	**(35)**	**35**	**(150)**	**3**	**4**	**22**	**16**	**62**

2024 Test Year Bridge Schedule - Income Statement
Unadjusted at Last Authorized walkforward to Adjust

	1	15	16	17	18	19	20	21
		Amortization			Secondary Calculations			
Line No.		Income Tax Tracker	NOL ADIT ARAM	Rate Case Expenses	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Total
1		WP-A14	WP-A15	WP-A16	WP-A17	WP-A18	WP-A19	
2	Operating Revenues							
3	Retail Revenue							89,990
4	Other Operating							469
5	Total Revenue							90,459
6								
7	Expenses							
8	Operating Expenses							
9	Base Cost of Gas							58,155
10	Gas Production and Storage							2,300
11	Gas Transmission							295
12	Gas Distribution							5,282
13	Customer Accounting							1,354
14	Customer Service and Information							152
15	Sales, Econ Dev, & Other							9
16	Administrative and General							3,474
17	Total Operating Expenses							71,020
18								
19	Depreciation							9,370
20	Amortization	9	60	498				567
21								
22	Taxes							
23	Property							2,020
24	Deferred Income Tax and ITC							1,277
25	Federal and State Income Tax	(2)	(5)	(121)	(0)	(0)	(94)	(423)
26	Payroll and Other							396
27	Total Taxes	(2)	(5)	(121)	(0)	(0)	(94)	3,269
28								
29	Total Expenses	7	55	376	(0)	(0)	(94)	84,226
30								
31	Allowance for Funds Used During Construct							
32								
33	Net Income	(7)	(55)	(376)	0	0	94	6,234
34								
35	Calculation of Revenue Requirements							
36	Rate Base	5	985		2	77		167,970
37	Required Operating Income	0	70		0	5	739	12,631
38	Operating Income	(7)	(55)	(376)	0	0	94	6,234
39	Income Deficiency	7	125	376	0	5	645	6,398
40	**Revenue Deficiency**	**10**	**165**	**498**	**0**	**7**	**853**	**8,463**

Summary of Revenue Requirments
($000's)

Line	Description	Adjusted Proposed Test Year 2024
1	Average Rate Base	$167,970
2	Operating Income (Before AFUDC)	$6,234
3	Allowance for Funds Used During Construction	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$6,234
5	Overall Rate of Return (Line 4 / Line 1)	3.71%
6	Required Rate of Return	7.52%
7	Operating Income Requirement (Line 1 x Line 6)	$12,631
8	Income Deficiency (Line 7 - Line 4)	$6,398
9	Gross Revenue Conversion Factor	1.32284
10	Revenue Deficiency (Line 8 x Line 9)	$8,463
11	Retail Related Revenue Under Present Rates	$89,990
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	9.40%

Northern States Power Company
State of North Dakota Gas Jurisdiction
Test Year Ending December 31, 2024
Cash Working Capital Summary

Line No.	Summary Cash Working Capital		Lead/Lag Days	Total Dollars	Total Dollar x Days	ND Gas Dollars	ND Gas Dollar x Days	Other Dollars	Other Dollar x Days
1	**Fuel Expenses**								
2	Gas for Generation		37.67	408,589	15,391,537	58,155	2,190,680	350,434	13,200,857
3	**Subtotal Fuel Expenses**			**408,589**	**15,391,537**	**58,155**	**2,190,680**	**350,434**	**13,200,857**
4									
5	**Labor and Related**								
6	Regular Payroll		12.11	44,316	536,666	5,110	61,879	39,206	474,787
7	Incentive		251.96	484	122,013	56	14,209	428	107,804
8	Pension and Benefits		37.29	9,827	366,467	1,002	37,364	8,825	329,103
9	**SubTotal Labor and Related**			**54,628**	**1,025,146**	**6,168**	**113,452**	**48,460**	**911,694**
10									
11	All Other Operating Expenses		30.71	70,893	2,177,123	6,698	205,683	64,195	1,971,439
12	Property taxes		354.81	24,706	8,765,794	2,020	716,668	22,686	8,049,126
13	Employer's Payroll Taxes		28.07	3,823	107,307	396	11,104	3,427	96,203
14	Gross Earnings Tax		38.60	14,233	549,379	1,662	64,136	12,571	485,243
15	Federal Income Tax		37.25	(89)	(3,314)	(347)	(12,939)	258	9,624
16	State Income Tax		37.25	(29)	(1,090)	(76)	(2,825)	47	1,735
17	State Sales Tax Customer Billings		-	16,213	742,250			16,213	742,250
18	**Total Expenses**	A		**592,966**	**28,754,131**	**74,674**	**3,285,960**	**518,292**	**25,468,171**
19	Net Annual Expense			48.49	78,778	44.00	9,003	49.14	69,776
20									
21	**Revenues**								
22	Retail Revenue		40.61	700,993	28,467,341	89,990	3,654,496	611,003	24,812,844
23	Late Payment		-	2,364		251		2,113	
24	Interdepartmental		-	7,410				7,410	
25	Misc Services		40.61	479	19,466	124	5,044	355	14,422
26	CIP Incentive		-						
27	Rentals		-	709		91		618	
28	Interchange		-						
29	Sales for Resale		-						
30	Retail Rev Lag Days		40.61	3	117	3	129	(0)	(11)
31	MISO		-						
32	Wholesale Lag Days		-						
33	**Total Revenues**	B		**711,959**	**28,486,924**	**90,459**	**3,659,669**	**621,500**	**24,827,255**
34	Net Annual Amount			40.01	78,046	40.46	10,026	39.95	68,020
35	Expense/Revenue Factor	C = A/B					82.55%		
36	Allocated Revenue Amount	D = B * C				-	8,277		
37	**Net Cash Working Capital**	E = D - A					**(726)**		

DETAILED CASE DRIVERS

Test Year Drivers - Revenue Requirements

Amounts in millions

	Increase (Decrease) 2024 TY to 2022 TY	Increase (Decrease) 2024 TY to 2022 Actual
Capital Related		
Distribution Systems	4.2	4.2
Intangible	0.9	0.8
Gas Peaking	0.8	0.7
ROE Change	0.5	0.5
Gas Storage	0.4	0.6
General	0.3	0.4
Other Rate Base	0.3	(0.1)
TOTAL Capital Related	7.3	7.0
Amortizations	0.3	0.5
Taxes		
Taxes - Other	1.0	0.8
Property Tax	0.6	0.5
Payroll Tax	0.1	0.1
TOTAL Taxes	1.7	1.4
Operating Expense		
Admin & General	1.0	0.3
Gas Production and Storage	0.4	(0.2)
Distribution Systems	0.2	0.0
Transmission	(0.1)	0.2
Customer Accounting / Info / Service	(0.3)	(0.1)
TOTAL O&M	1.2	0.2
Other Margin Impacts		
Customer, Sales Growth	(2.1)	(2.4)
Other	0.1	1.8
TOTAL Other Margin Impacts	(2.1)	(0.6)
TOTAL Net Incremental Deficiency	**8.5**	**8.5**

Budgeting Accuracy

NSPM Total Company Actual versus Budget O&M ($millions)

Year	Budget Amount	Actual Amount	$ Variance	% Variance
2022	$1,205	$1,228	$23	1.88%
2021	$1,189	$1,190	$1	0.11%
2020	$1,217	$1,191	($26)	-2.12%
Three-Year Total	$3,611	$3,609	($2)	-0.05%

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

Year	Budget Amount	Actual Amount	$ Variance	% Variance
2022	$89	$95	$6	6.24%
2021	$87	$92	$6	6.50%
2020	$94	$90	($4)	-4.67%
Three-Year Total	$270	$277	$7	2.52%

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
(000's)

Line No.	Description	Test Year Ending 12/31/2024 Present Rates	Final Increase	Test Year Ending 12/31/2024 Final Rates
		(A)	(B)	(C) = (B) + (A)
	Operating Revenues			
1	Retail	$89,990	$8,463	$98,453
2	Interdepartmental	0		0
3	Other Operating	469		469
4	Gross Earnings Tax	0		0
5	Total Operating Revenues	$90,459	$8,463	$98,923
	Expenses			
	Operating Expenses:			
6	Purchased Gas	$58,155		$58,155
7	Gas Production & Storage	2,300		2,300
8	Gas Transmission	295		295
9	Gas Distribution	5,282		5,282
10	Customer Accounting	1,354		1,354
11	Customer Service & Information	152		152
12	Sales, Econ Dvlp & Other	9		9
13	Administrative & General	3,474		3,474
14	Total Operating Expenses	$71,020	$0	$71,020
15	Depreciation	$9,370		$9,370
16	Amortizations	567		567
	Taxes:			
17	Property	$2,020		$2,020
18	Gross Earnings	0		0
19	Deferred Income Tax & ITC	1,277		1,277
20	Federal & State Income Tax	(423)	2,065	1,642
21	Payroll & Other	396		396
22	Total Taxes	$3,269	$2,065	$5,334
23	Total Expenses	$84,226	$2,065	$86,291
24	AFUDC	$0	$0	$0
25	Total Operating Income	$6,234	$6,398	$12,631

Statement of Operating Income
(000's)

Line No.	Description	2024 Test Year Unadjusted (A)	Adjustments (B)	2024 Test Year Adjusted (C) = (B) + (A)
	Operating Revenues			
1	Retail	$89,990	$0	$89,990
2	Interdepartmental	0	0	0
3	Other Operating	469	0	469
4	Gross Earnings Tax	0	0	0
5	Total Operating Revenues	$90,459	$0	$90,459
	Expenses			
	Operating Expenses:			
6	Purchased Gas	$58,155	$0	$58,155
7	Gas Production & Storage	2,300	0	2,300
8	Gas Transmission	295	0	295
9	Gas Distribution	5,282	0	5,282
10	Customer Accounting	1,318	35	1,354
11	Customer Service & Information	192	(40)	152
12	Sales, Econ Dvlp & Other	5	4	9
13	Administrative & General	3,593	(120)	3,474
14	Total Operating Expenses	$71,140	($120)	$71,020
15	Depreciation	$9,541	($172)	$9,370
16	Amortizations	$0	$567	$567
	Taxes:			
17	Property	$2,020	$0	$2,020
18	Gross Earnings	0	0	0
19	Deferred Income Tax & ITC	1,222	55	1,277
20	Federal & State Income Tax	(327)	(96)	(423)
21	Payroll & Other	396	(0)	396
22	Total Taxes	$3,311	($42)	$3,269
23	Total Expenses	$83,993	$233	$84,226
24	Allowance for Funds Used During Construction	$0	$0	$0
25	Total Operating Income	$6,467	($233)	$6,234

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
(000's)

Line No.	Description	Current Ending 12/31/2023 Present Rates	Final Increase	Current Ending 12/31/2023 Final Rates
		(A)	(B)	(C) = (B) + (A)
	Operating Revenues			
1	Retail	$110,404	$4,254	$114,658
2	Interdepartmental	$0		0
3	Other Operating	$371		371
4	Gross Earnings Tax	$0		0
5	Total Operating Revenues	$110,774	$4,254	$115,030
	Expenses			
	Operating Expenses:			
6	Purchased Gas	$78,204		$78,204
7	Gas Production & Storage	$2,524		2,524
8	Gas Transmission	$177		177
9	Gas Distribution	$5,457		5,457
10	Customer Accounting	$1,509		1,509
11	Customer Service & Information	$129		129
12	Sales, Econ Dvlp & Other	($3)		(3)
13	Administrative & General	$3,391		3,391
14	Total Operating Expenses	$91,388	$0	$91,388
15	Depreciation	$7,953		$7,953
16	Amortizations	$191		191
	Taxes:			
17	Property	$1,791		$1,791
18	Gross Earnings	$0		0
19	Deferred Income Tax & ITC	$1,130		1,130
20	Federal & State Income Tax	$352	1,038	1,390
21	Payroll & Other	$395		395
22	Total Taxes	$3,668	$1,038	$4,706
23	Total Expenses	$103,200	$1,038	$104,239
24	AFUDC	$0	$0	$0
25	Total Operating Income	$7,574	$3,216	$10,790

Statement of Operating Income
(000's)

Line No.	Description	2023 Current Yr Unadjusted (A)	Adjustments (B)	2023 Current Yr Adjusted (C) = (B) + (A)
	Operating Revenues			
1	Retail	$110,404	$0	$110,404
2	Interdepartmental	0	0	0
3	Other Operating	371	0	371
4	Gross Earnings Tax	0	0	0
5	Total Operating Revenues	$110,774	$0	$110,774
	Expenses			
	Operating Expenses:			
6	Purchased Gas	$78,204	$0	$78,204
7	Gas Production & Storage	2,524	0	2,524
8	Gas Transmission	177	0	177
9	Gas Distribution	5,457	0	5,457
10	Customer Accounting	1,509	0	1,509
11	Customer Service & Information	149	(20)	129
12	Sales, Econ Dvlp & Other	(6)	3	(3)
13	Administrative & General	3,486	(95)	3,391
14	Total Operating Expenses	$91,500	($112)	$91,388
15	Depreciation	$7,953	$0	$7,953
16	Amortizations	$0	$191	$191
	Taxes:			
17	Property	$1,791	$0	$1,791
18	Gross Earnings	0	0	0
19	Deferred Income Tax & ITC	1,130	0	1,130
20	Federal & State Income Tax	363	(10)	352
21	Payroll & Other	395	(0)	395
22	Total Taxes	$3,679	($11)	$3,668
23	Total Expenses	$103,131	$69	$103,200
24	Allowance for Funds Used During Construction	$0	$0	$0
25	Total Operating Income	$7,643	($69)	$7,574

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
(000's)

Line No.	Description	WN Actual Year Ending 12/31/22 Present Rates	Final Increase	WN Actual Year Ending 12/31/22 Final Rates
		(A)	(B)	(C) = (B) + (A)
	Operating Revenues			
1	Retail	$138,308	$267	$138,576
2	Interdepartmental	$0		0
3	Other Operating	$2,249		2,249
4	Gross Earnings Tax	$0		0
5	Total Operating Revenues	$140,557	$267	$140,826
	Expenses			
	Operating Expenses:			
6	Purchased Gas	$109,799		$109,799
7	Gas Production & Storage	$1,630		1,630
8	Gas Transmission	$143		143
9	Gas Distribution	$5,260		5,260
10	Customer Accounting	$1,441		1,441
11	Customer Service & Information	$140		140
12	Sales, Econ Dvlp & Other	$10		10
13	Administrative & General	$3,172		3,172
14	Total Operating Expenses	$121,595	$0	$121,595
15	Depreciation	$6,460		$6,460
16	Amortizations	$69		69
	Taxes:			
17	Property	$1,490		$1,490
18	Gross Earnings	$0		0
19	Deferred Income Tax & ITC	$1,137		1,137
20	Federal & State Income Tax	$845	65	910
21	Payroll & Other	$339		339
22	Total Taxes	$3,810	$65	$3,876
23	Total Expenses	$131,934	$65	$132,000
24	AFUDC	$0	$0	$0
25	Total Operating Income	$8,623	$202	$8,825

Statement of Operating Income
(000's)

Line No.	Description	2022 WN Actual Year Unadjusted (H)	Adjustments (I)	2022 WN Actual Ye: Adjusted (J) (Col F + G)
	Operating Revenues			
1	Retail	$138,308	$0	$138,308
2	Interdepartmental	0	0	0
3	Other Operating	2,249	0	2,249
4	Gross Earnings Tax	0	0	0
5	Total Operating Revenues	$140,557	$0	$140,557
	Expenses			
	Operating Expenses:			
6	Purchased Gas	$109,799	$0	$109,799
7	Gas Production & Storage	1,630	0	1,630
8	Gas Transmission	143	0	143
9	Gas Distribution	5,260	0	5,260
10	Customer Accounting	1,441	0	1,441
11	Customer Service & Information	141	(0)	140
12	Sales, Econ Dvlp & Other	10	0	10
13	Administrative & General	3,367	(194)	3,172
14	Total Operating Expenses	$121,790	($195)	$121,595
15	Depreciation	$6,460	$0	$6,460
16	Amortizations	$0	$69	$69
	Taxes:			
17	Property	$1,490	$0	$1,490
18	Gross Earnings	0	0	0
19	Deferred Income Tax & ITC	471	666	1,137
20	Federal & State Income Tax	1,381	(536)	845
21	Payroll & Other	339	(0)	339
22	Total Taxes	$3,682	$129	$3,810
23	Total Expenses	$131,931	$3	$131,934
24	Allowance for Funds Used During Construction	$0	$0	$0
25	Total Operating Income	$8,626	($3)	$8,623

Northern States Power Company

Cost Assignment and Allocation Manual

September 2023

Table of Contents

Section

I. INTRODUCTION

This Cost Assignment and Allocation Manual ("CAAM") was developed to specify the procedures that Northern States Power Company, a Minnesota corporation ("NSPM" or the "Company") follows in assigning and allocating costs among utility departments (electric and gas), among regulated services and non-regulated business activities and among jurisdictions.

NSPM was incorporated in 2000 under the laws of Minnesota and is a wholly owned operating utility subsidiary of Xcel Energy Inc. ("Xcel Energy" or the "Parent"). Xcel Energy was initially established as a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), with oversight by the Securities and Exchange Commission ("SEC"). On August 8, 2005, the Energy Policy Act of 2005 was signed into law. This repealed PUHCA 1935 and enacted the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), which became effective on February 8, 2006. Responsibility for oversight of public utility holding companies was transferred from the SEC to the Federal Energy Regulatory Commission ("FERC") as a result of the Energy Policy Act of 2005.

NSPM conducts business in Minnesota, North Dakota, and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution, and sale of electricity. NSPM also purchases, transports, distributes, and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSPM owns the following direct subsidiaries: United Power and Land Company, which holds real estate; and NSP Nuclear Corporation.

As a member of a holding company system, NSPM receives administrative, management, environmental, and other support services from Xcel Energy Services Inc. ("XES" or the "Service Company"), a centralized service company. The Service Company provides services to Xcel Energy and its subsidiaries, at cost, pursuant to service agreements. The service agreement between NSPM and XES, including all amendments to the original Service Agreement, have been submitted to, and approved by, the Minnesota Public Utilities Commission ("Commission"). The cost allocation methodologies under which XES costs are assigned and allocated are set forth in that Commission approved service agreement, and while those allocation methodologies are not the subject of this NSPM CAAM, they are referenced in several sections herein.

The Service Company is referenced in the CAAM for the following reasons:

- The Service Company is listed as an affiliate company in the Transaction with Affiliates section for the services it provides to NSPM.
- The Service Company and all other companies in the Xcel Energy holding company system of companies are included in the Corporate Organization section to provide a listing of all affiliates of NSPM.
- The Service Company is referenced in the Cost Assignment and Allocation Process section because this section covers processes that may cross multiple legal entities.

The NSPM CAAM contains the following sections:

- Introduction (Section I)
- Corporate Organization (Section II)
- Description of Services (Section III)
- Transactions with Affiliates (Section IV)
- Cost Assignment and Allocation Process (Section V)
- Utility Allocations (Section VI)
- Non-regulated Business Activity Allocations (Sections VII)
- Jurisdictional Allocations (Section VIII)

DEFINITIONS

Abbreviations or Acronyms

The following abbreviations or acronyms are used within the CAAM document:

A&G	Administrative and general
AFUDC	Allowance for funds used during construction
ACC	Allocating cost center
CAAM	Cost Assignment and Allocation Manual
CIP	Conservation improvement program
Commission	Minnesota Public Utilities Commission
FERC	Federal Energy Regulatory Commission
FICA	Federal Insurance Contributions Act
FUTA	Federal Unemployment Tax Act
GAAP	Generally Accepted Accounting Principals
HR	Human Resources
IT	Information Technology
NSPM or the Company	Norther States Power Company, a Minnesota corporation
NSPW	Northern States Power Company, a Wisconsin corporation
NSP System	The electric production and transmission system of NSPM and NSPW operated on an integrated basis and managed by NSPM
O&M	Operating and maintenance
PSCo	Public Service Company of Colorado, a Colorado corporation
PUCHA 1935	Public Utility Holding Company Act of 1935
PUCHA 2005	Public Utility Holding Company Act of 2005
RTU	Remote terminal unit
SAP	SAP general ledger and work and asset management system
SCADA	Supervisory control and data acquisition
SEC	Securities and Exchange Commission
SKF	Statistical key figure
SPS	Southwestern Public Service Company, a New Mexico corporation
SUTA	State Unemployment Tax Authority
Utility subsidiaries or operating companies	NSPM, NSPW, PSCo, and SPS
Xcel Energy or the Parent	Xcel Energy Inc. and its subsidiaries
XES or the Service Company	Xcel Energy Services Inc.

Terms

The following terms are used within the CAAM document:

Accounts Payable – the payment and reporting department of XES.

A&G – includes activity in FERC accounts 920-935, Administrative and General Expenses.

ACC – an organizational unit that collects cost to be allocated using the allocation ratios or factors included in the SKF.

Assessment – the process used by the accounting system to allocate costs from an ACC to the receiving cost element.

Cost Element – an organizational unit to SAP that is used to track costs in the accounting system as they move through the various processing steps.

Customer Accounting Costs – includes activity in FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910, Customer Service and Informational Expenses; and FERC accounts 911-917, Sales Expenses.

Final Cost Center – final cost center defined by business function, company code, and profit center.

Home Cost Center – captures only labor and payroll postings and maps to HR departments.

Internal Order – internal orders are accounting mechanisms used to track expenses associated with certain projects or functions.

Non-Operations and Maintenance Allocations – allocations designed to apportion expenses recorded in accounts other than O&M to electric, gas, thermal and nonutility. The non-O&M costs apportioned include depreciation, payroll taxes, miscellaneous service revenues, amortization expenses, etc.

O&M – includes activity in FERC accounts 500-935 with the exception of the following FERC accounts: 501, Fuel; 901-903, Customer Accounts Expenses; 906-910, Customer Service and Informational Expenses; 911-917, Sales Expenses; and 920-935, Administrative and General Expenses.

Profit Center – SAP data element that identifies the jurisdiction or joint venture owner of revenues and expenses.

Receiving Cost Element – a cost element that receives costs when a settlement or assessment process is run.

Segment – represents electric, gas, thermal, joint venture, or other and is derived by SAP from profit center and cost center.

SKF – the method by which the allocation ratios and factors are organized in the accounting system and linked to ACCs to facilitate the performance of the assessment process to allocate charges.

Supply Chain – the supply chain department of XES.

Work Breakdown Structure – structure used to group all aspects or phases of a given project or organizational group and render them easily reportable.

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc., a Minnesota corporation, is a registered holding company. Xcel Energy directly owns four operating public utility subsidiaries that serve electric, natural gas, thermal, and propane customers in eight states. These four utility subsidiaries are Northern States Power Company, a Minnesota corporation ("NSPM"); Northern States Power Company, a Wisconsin corporation ("NSPW"); Public Service Company of Colorado, a Colorado corporation ("PSCo"); and Southwestern Public Service Company, a New Mexico corporation ("SPS"). Their collective service territories include portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas, and Wisconsin. Xcel Energy's regulated businesses also include WestGas Interstate, Inc., an interstate natural gas pipeline company regulated by the FERC. Xcel Energy also has three transmission-only operating companies, Xcel Energy Southwest Transmission Company, LLC ("XEST") and Xcel Energy Transmission Development Company, LLC ("XETD"), which are regulated by the FERC, and Xcel Energy West Transmission Company, LLC ("XEWT").

Xcel Energy's non-regulated subsidiaries include Eloigne Company; which holds investments in rental housing projects that qualify for low-income tax credits, Capital Services, LLC; which provides equipment for construction of renewable energy generation facilities for other subsidiaries, Venture Holdings; which invests in limited partnerships, including EIP funds with portfolios of investments in energy technology companies, and Nicollet Project holdings; which invests in Minnesota community solar gardens.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., , Xcel Energy WYCO Inc., Xcel Energy Transmission Holding Company, LLC, Nicollet Holdings Company, LLC, Xcel Energy Nuclear Services Holdings, LLC, and Xcel Energy Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy Inc., and many do business under the Xcel Energy name. See the following pages for a complete legal entity organizational listing for Xcel Energy and its subsidiaries.

LIST OF REGULATED & NON-REGULATED AFFILIATES (as of September 30, 2023)

Xcel Energy Inc.
- Northern States Power Company, a Minnesota corporation
  - Crowned Ridge Interconnection Company
  - NSP Nuclear Corporation
  - Private Fuel Storage LLC
  - United Power and Land Company
- Northern States Power Company, a Wisconsin corporation
  - Chippewa and Flambeau Improvement Company
  - Clearwater Investments, Inc.
    - Shoe Factory Holding LLC

- Public Service Company of Colorado, a Colorado corporation**
  - 1480 Welton, Inc.

- Beeman Irrigating Ditch and Milling Company
- Consolidated Extension Canal Company
- East Boulder Ditch Company
- Fisher Ditch Company
- Gardeners Mutual Ditch Company
- Green and Clear Lakes Company
- Hillcrest Ditch and Reservoir Company
- Larimer Land Services, LLC
- Las Animas Consolidated Canal Company
- P.S.R. Investments, Inc.
- United Water Company

Southwestern Public Service Company, a New Mexico corporation
Nicollet Holdings Company, LLC
- Capital Services, LLC
- Nicollet Land Services, LLC

Nicollet Project Holdings, LLC
- Nicollet Projects I, LLC
  - Betcher CSG LLC
  - Foreman's Hill CSG LLC
  - Grimm CSG LLC
  - Heyer CSG LLC
  - Huneke CSG LLC
  - Johnson I CSG LLC
  - Johnson II CSG LLC
  - Krause CSG LLC
  - RJC I CSG LLC
  - RJC II CSG LLC
  - Scandia CSG LLC
  - School Sisters CSG LLC
  - Webster CSG LLC
- Nicollet Projects II, LLC

WestGas InterState, Inc.
Xcel Energy Communications Group Inc.
- Seren Innovations, Inc.*

Xcel Energy Foundation
Xcel Energy International Inc.*
Xcel Energy Markets Holdings Inc.
- e prime, inc.*
- Young Gas Storage Company Ltd.

Xcel Energy Nuclear Services Holdings, LLC
- Xcel Energy Nuclear Services Idaho, LLC
- Xcel Energy Nuclear Services Oregon, LLC

Xcel Energy Retail Holdings Inc.
- Xcel Energy Performance Contracting Inc.
- Reddy Kilowatt Corporation

Xcel Energy Services Inc.
Xcel Energy Transmission Holding Company, LLC
- Xcel Energy Southwest Transmission Company, LLC

- Xcel Energy Transmission Development Company, LLC
  - Xcel Energy Acorn Transmission, LLC
  - Xcel Energy Birch Transmission, LLC
- Xcel Energy West Transmission Company, LLC

Xcel Energy Venture Holdings, Inc.
- Energy Impact Fund Investment LLC
- Xcel Energy Investments, LLC

Xcel Energy Ventures Inc.
- Eloigne Company
  - Bemidji Townhouse LP
  - Chaska Brickstone LP
  - Crown Ridge Apartments LP
  - Cottage Court LP
  - Edenvale Family Housing LP
  - Fairview Ridge LP
  - Farmington Family Housing LP
  - Farmington Townhome LP
  - J&D 14-93 LP
  - Lauring Green LP
  - Links Lane LP
  - Lyndale Avenue Townhomes LP
  - Mahtomedi Woodland LP
  - Mankato Townhomes LLP
  - Marvin Garden LP
  - Moorhead Townhomes LP
  - Park Rapids Townhomes LP
  - Rochester Townhome LP
  - Rushford Housing LP
  - Safe Haven Homes, LLC
  - Shade Tree Apartments LP
  - Shakopee Boulder Ridge LP
  - Shenandoah Woods LP
  - St. Cloud Housing LP
  - Tower Terrace LP

Xcel Energy Wholesale Group Inc.*
- Quixx Corporation*
  - Quixx Carolina, Inc.*
  - Quixxlin Corp.*

Xcel Energy WYCO Inc.
- WYCO Development, LLC

* Company is being classified in discontinued operations.
** Minority-ownership ditch and water companies have been excluded.

III. DESCRIPTION OF SERVICES

OVERVIEW

This section provides a description of NSPM's regulated services and non-regulated business activities. Each description identifies the types of costs associated with the service or business activity, and identifies the business area or department which offers the service.

REGULATED SERVICES

ELECTRIC UTILITY

Electric – Residential

Residential electric service represents the provision of electric service to residential customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Commercial and Industrial

Commercial and industrial electric service represents the provision of electric service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Street Lighting

Street lighting electric service represents the provision of electric service to public authorities for lighting streets, highways, parks and other public places, or for traffic or other signal system service through Company-owned or customer-owned lighting equipment. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric – Other Sales to Public Authorities

Other sales to public authorities' electric service represent the provision of electric service to public authorities under special agreements or contracts. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Resale

Resale electric service represents the provision of electric service to NSPM wholesale customers or public authorities for resale to end-user customers or to power marketers. Costs associated with this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, or through facilities owned by third parties, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Electric - Interdepartmental

Interdepartmental electric service represents the provision of electric service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the generation or purchase and delivery of electricity through Company-owned transmission and distribution facilities, primarily fuel or purchased power costs, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Electric Utility.

Off-System Electric Sales

NSPM sells electricity not required to serve its native load to off-system customers. Costs related to this activity can include fuel and purchased power costs. The revenues associated with these sales reside in FERC account 447, Sales for Resale-Electric. The costs related to this activity reside in FERC accounts 501, Fuel-Steam Generation; 555, Purchased Power; and 565, Transmission of Electricity by Others. In addition, the Company may allocate production O&M and transmission costs based on a percentage of overall sales relative to the type of off-system sales. These costs reside within the NSPM Electric Utility.

OTHER ELECTRIC OPERATING REVENUE

Rent from Electric Property

Rent from electric property results from the leasing of NSPM owned utility property not currently utilized for the provision of regulated services to non-affiliated third parties. Costs related to this service are primarily A&G costs associated with customer billings, as well as rental contract renewals. The revenue associated with the rentals resides in FERC account 454, Rent from Electric Property.

Interchange Agreement

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System based upon demand and energy ratios reflecting usage by the respective companies. The costs associated with this agreement reside in FERC account 557, Other Power Supply Expenses; and FERC 565, Transmission of Electricity by Others. The revenues reside in FERC account 456.1, Revenue from Transmission of Electricity of Others.

Joint Operating Agreement

The Joint Operating Agreement is a margin sharing agreement associated with proprietary energy trading activities. Revenues are recorded in FERC 456, Other Electric Revenues.

Miscellaneous Electric Revenue

In addition to the services detailed above, there are various activities that cannot be accounted for elsewhere, such as utility locating services, scrap metal sales, WindSource, customer connections, and refuse derived fuel incentive. These revenues are recorded in FERC account 456, Other Electric Revenues.

GAS UTILITY

Gas - Residential

Residential gas service represents the provision of natural gas service to residential customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Commercial and Industrial

Commercial and industrial gas service represents the provision of natural gas service to commercial and industrial customers within the NSPM service territory. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within commercial and industrial gas services.

Rate Class	Maximum Requirements – Daily Therms	Maximum Requirements – Annual Therms
Small commercial	Less than 500	Less than 6,000
Large commercial	Less than 500	Greater than 6,000
Small demand billed commercial*	Less than 500	
Large demand billed commercial*	Greater than 500	

* Upstream demand costs are billed based on the highest one-day usage in the customer's history.

Gas – Interruptible

Interruptible gas service represents the provision of natural gas service to interruptible customers within the NSPM service territory. Interruptible service is subject to curtailment when either additional upstream pipeline or local distribution capacity is needed to ensure service to firm customers. Costs associated with this service relate to the purchase and delivery of gas through Company-owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility. The table below shows the various rate classes within interruptible gas service.

Rate Class	Maximum Requirements – Daily Therms
Small interruptible	Less than 2,000
Medium interruptible	Greater than 2,000 and less than 50,000
Large interruptible	Greater than 50,000

Gas – Large Firm Transportation

Large firm gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interruptible Transportation

Interruptible gas transportation service represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Negotiated Transportation

Negotiated firm and interruptible gas transportation service (bypass customers) represents the provision of gas delivery service on behalf of end-use customers, third-party suppliers or marketers whereby NSPM transports gas owned by others over NSPM's gas pipeline system. Interruptible transportation gas service is subject to curtailment when either additional upstream pipeline or the local distribution capacity is needed to ensure service to firm customers. Costs associated with this service primarily include the facilities O&M and depreciation costs and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Interdepartmental

Interdepartmental gas service represents the provision of natural gas service or gas transportation service to NSPM company facilities at tariff rates. Costs associated with providing this service relate to the purchase and delivery of gas through NSPM owned facilities, primarily purchased gas, facilities O&M and depreciation costs, and A&G costs. These costs reside within the NSPM Gas Utility.

Gas – Limited Firm

Standby gas service represents on-system back-up propane service for interruptible service customers. Costs associated with this service primarily include propane purchases and the facilities O&M. These costs reside within the NSPM Gas Utility.

Gas – Daily Balancing Service

Daily balancing gas service represents a service to transportation customers that allows them to remedy deviations between nominated and delivered gas and gas consumed by the transportation customer. Costs associated with this service primarily include upstream pipeline costs. These costs reside within the NSPM Gas Utility.

OTHER GAS REVENUE

Miscellaneous Gas Revenue

Various services are provided that cannot be accounted for elsewhere such as propane transportation charges and bundled sales. These revenues are recorded in FERC account 495, Other Gas Revenues.

COMMON ELECTRIC AND GAS REVENUE

Late Payments Fees/Miscellaneous Service Revenues

Revenues from the additional charges imposed because of customers failure to pay their bill by specified due date are recorded into FERC account 450, Electric Forfeited Discounts; and FERC account 487, Gas Forfeited Discounts. Miscellaneous customer related revenue, such as service connections and returned check charges, are recorded in FERC account 451, Miscellaneous Electric Service Revenue; and FERC account 488, Miscellaneous Gas Service Revenues.

CIP Incentives

The CIP Incentive is a mechanism established by an April 7, 2000 Order of the Commission that provides utilities with an incentive to increase cost-effective utility investment in conservation improvement programs beyond the spending levels required by Minnesota Statute. The revenues associated with the CIP incentives are identified by unique accounts and are recorded in FERC account 456, Other Electric Revenues; and FERC 495, Other Gas Revenues. An adjustment is made to remove these revenues from our cost of service study and they do not impact our revenue requirements.

ConnectSmart

NSPM provides a service for customers moving into or across the region to set up utility service and other subscription services to their homes (e.g., newspaper, local and long-distance telephone, cable TV, etc.). NSPM, through its call center, receives telephone requests for this service, and sends these requests, for a fee, to AllConnect (a third-party contractor) for the coordination of installation of services. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive, pension, and benefit costs are allocated based on labor dollars, and labor-related overhead is applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. For rate making purposes, in the event this service experiences revenues in excess of direct expenses, an adjustment is made to credit the net impact in FERC 456, Other Electric Operating Revenues, to reflect the benefit of this service to the utility customers.

Hazardous Waste Disposal

NSPM has a Hazardous Waste consolidation facility at Chestnut Service Center in Minneapolis, Minnesota. The facility accepts and consolidates hazardous and specially-regulated waste materials from generating assets, service centers, substations, office buildings, and field operations projects in both NSPM and NSPW service territories. This facility ensures the wastes are properly characterized aggregated and consolidated at approved, permanent and appropriately licensed waste disposal facilities. This facility is also the central collection point for any PCB contaminated electrical equipment.

Empower Resiliency

Empower Resiliency is a program with the purpose of providing resiliency services to customers. At the Company's discretion, and except as otherwise provided in the tariff, these services may include any combination of battery energy storage systems and on-site generation assets. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive, pension, and benefit costs are allocated based on labor dollars. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 451, Miscellaneous Service Revenues; FERC 910, Miscellaneous Customer Service and Informational Expenses; FERC 408.1, Taxes Other Than Income Taxes; FERC 925, Injuries and Damages; and FERC 926, Employees Pensions and Benefits.

NON-REGULATED BUSINESS ACTIVITIES

The following business activities have been approved by the Commission as non-regulated business activities. Detailed descriptions of each of the non-regulated business activities are provided in this section.

HomeSmart

Xcel Energy HomeSmart offers resources for the repair, replacement and maintenance of major appliances and systems in customers' homes. This includes service plans to cover certain appliances, sewer and plumbing issues; heating, ventilating and air conditioning (HVAC) systems; replacement assistance coverage; and preventive maintenance. HomeSmart also sells and installs HVAC systems and water heaters. Costs related to these activities include direct charges for labor, equipment, materials, and outside services associated with the services provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars. A labor related overhead and a Customer Accounting overhead are applied to non-regulated business activities, as applicable. (Please refer to Section VII of the CAAM for more information.) The revenues and costs associated with HomeSmart are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations.

Infowise

Infowise is an energy management reporting solution with customized data for businesses to help manage and control their energy use. This product consists of unique interactive reports with detailed information, including both consumption and demand levels, to help the customer pinpoint and analyze their facility's energy use. By analyzing past energy use, this product can help drive company green strategies while helping customize a strategic business plan for facility managers, as well as deliver a bill estimator tool that keeps track of budgets and identifies cost saving opportunities. Costs related to this activity include direct charges for labor, materials and outside services associated with the service provided. In addition, payroll taxes, lost time, facilities, workers' compensation, incentive and pension and benefits are allocated based on labor dollars, and a labor-related overhead, and a customer billing overhead are applied to nonregulated business activities, as applicable. (Please refer to Section VII of the CAAM for more information.) The revenues and costs associated with Infowise are identified by unique SAP Cost Centers, and are recorded in FERC accounts 417, Revenues from Nonutility Operations, and 417.1, Expenses from Non-utility Operations. For rate making purposes, in the event this service experiences revenues in excess of direct expenses, an adjustment is made to credit the net impact in FERC 456, Other Electric Operating Revenues, to reflect the benefit of this service to the utility customers.

Customer Owned Street Lighting Maintenance

NSPM supplies maintenance services for communities that own their own street light systems. Maintenance service for customer owned street light systems is limited to the fixture service only; and ranges from full fixture service to partial fixture service where the customer provides the material necessary to repair the streetlight. The customer is responsible for all other repairs and replacements under the "Non-regulated Customer Owned Street Maintenance" service. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor related overhead are applied to non-regulated business activities. The revenues and costs associated with this service are identified by unique accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E-002/M-92-614 for the Commission order to treat this service as non-regulated.

Sherco Steam Sales to Liberty Paper Inc.

NSPM supplies steam from the Sherburne County Generating Station to Liberty Paper, Inc. ("LPI") in order to meet LPI's thermal energy needs. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time, and pension and benefit costs are allocated based on labor dollars, and a labor-related overhead is applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations which are excluded for ratemaking purposes. See Docket E002/M-19-663 for the Commission order to treat this service as non-regulated. In addition to steam services, LPI takes electric and natural gas services from NSPM which are tariffed services provided at tariffed rates.

IV. TRANSACTIONS WITH AFFILIATES

OVERVIEW

NSPM directly incurs and pays for the majority of its costs, there are, however, services provided to NSPM by other affiliates within the Xcel Energy system of companies. In addition, NSPM provides a limited amount of operations, maintenance, and management advisory services to its affiliates. NSPM has numerous Affiliated Interest Agreements that have been approved by the Commission.

The sections below separately detail the nature and terms of transactions for services and asset transfers provided by NSPM to its affiliates, as well as services and asset transfers provided to NSPM by each of its affiliates. This section includes descriptions of affiliate transactions only and does not include convenience payments.

The cost allocation methodologies under which the Service Company costs are assigned and allocated are set forth in the service agreement, and while they are not the subject of this NSPM CAAM, they are included in this section to provide as complete a picture as possible of all affiliate transactions. The NSPM Service Agreement is reviewed and filed annually with the Commission. The last filing was approved in Docket E,G002/AI-23-216 on May 26, 2023. NSPM's affiliate transactions consist primarily of transactions with the Service Company for administrative, management, accounting, legal, engineering, environmental, and other support services.

Terms of Transactions

Tariff Rate – the price charged to customers under applicable tariffs on file with federal or state regulatory commissions. Tariff rates are used for transactions with affiliates involving the provision of regulated services.

Fully Distributed Cost **–** the term fully distributed cost means that transactions billed include all direct and indirect costs, including overheads. Affiliate transactions billed by NSPM include labor related overheads and a working capital fee when appropriate. This method of assigning and allocating costs to these affiliate transactions ensures that the payments to or by NSPM are reasonable and have not resulted in any ratepayer subsidization. In the table below, fully distributed cost may also refer to a price established in a separate Affiliated Interest Agreement.

NSPM applies a labor related overhead to services provided by NSPM to affiliates and also applies a working capital fee on services NSPM provides to non-NSPM company affiliates. Both the labor related overhead and the working capital fees are discussed in Section VII.

The remainder of this section is detailed by affiliate. Affiliates may be listed under the "Services Provided by NSPM to Affiliates" section and/or the "Services Provided by Affiliates to NSPM" section. The details relating to the nature, frequency, and terms of the affiliate transactions are itemized for NSPM and each affiliate.

SERVICES PROVIDED BY NSPM TO AFFILIATES

Nature of Transactions	Terms
NSPW	
O&M – production, decommissioning, and transmission costs associated with the Interchange Agreement (FERC Docket No. ER15-1575-000).	Fully distributed cost
SCADA and Gas Dispatch – sharing of SCADA costs in accordance with Docket G-002/AI-94-831.	Fully distributed cost
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
PSCo	
Materials and Supplies – materials and supplies, including any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor, associated loadings, and lease costs.	Fully distributed cost
SPS	
Materials and Supplies – materials and supplies, and any associated freight, purchase loadings, and warehouse loadings.	Fully distributed cost
Joint Operating Agreement – margin sharing associated with proprietary energy trading activities.	Fully distributed cost
Miscellaneous – miscellaneous other charges, including labor and associated loadings and lease costs.	Fully distributed cost

Xcel Energy Inc.

Miscellaneous - miscellaneous other charges, including 401(k) match and a dividend on common stock.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM

Nature of Transactions	*Terms*
Xcel Energy Services Inc.	
*Executive Management Services** – represents charges for executive management services, including, but not limited to, officers of Xcel Energy.	Fully distributed cost
*Investor Relations** – provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting.	Fully distributed cost
*Internal Audit & Risk** – reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks and trading risks.	Fully distributed cost
*Legal** – provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate, and other legal matters.	Fully distributed cost
*Claims Services** – provides claims services related to casualty, public, and company claims.	Fully distributed cost
*Corporate Communications** – provides corporate communications, speech writing, and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy system. Manages and tracks all charitable contributions made on behalf of the Xcel Energy system.	Fully distributed cost
*Employee Communications** – develops and distributes communications to employees.	Fully distributed cost
*Corporate Strategy & Business Development** – facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance, and evaluates	Fully distributed cost

business opportunities. Develops and facilitates process improvements.	
*Government Affairs** – monitors, reviews and researches government legislation.	Fully distributed cost
*Facilities & Real Estate** – operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment.	Fully distributed cost
*Facilities Administrative Services** – includes but is not limited to the functions of mail delivery, duplicating, and records management.	Fully distributed cost
*Supply Chain**– includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting, and database management. Warehousing services includes receiving, storing, issuing, shipping, returns, and distribution of material and parts.	Fully distributed cost
*Supply Chain Special Programs** – develops and implements special programs utilized across Xcel Energy such as procurement cards, travel services, and compliance with corporate MWBE (minority women business expenditures) program goals.	Fully distributed cost
*Human Resources** – establishes and administers policies related to employment, compensation, and benefits. Maintains HR computer system, the tuition reimbursement plan, and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.	Fully distributed cost
*Finance & Treasury** – coordinates activities related to securities issuances, including maintaining relationships with financial institutions, cash management, investing activities, and monitoring the capital markets. Performs financial and economic analysis.	Fully distributed cost
*Accounting, Financial Reporting & Taxes** – maintains financial books and records. Prepares financial and statistical reports, tax filings, and ensures compliance with	Fully distributed cost

the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.	
*Payment & Reporting** – processes payments to vendors and prepares statistical reports.	Fully distributed cost
*Receipts Processing** – processes payments received from customers of the operating companies and affiliates.	Fully distributed cost
*Payroll** – processes payroll including but not limited to time reporting, calculation of salaries and wages, payroll tax reporting, and compliance reports.	Fully distributed cost
*Rates & Regulation** – determines the operating companies' regulatory strategy, revenue requirements, and rates for retail and wholesale customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.	Fully distributed cost
*Environmental Services & System Planning** – Responsible for long-term planning and integration for the generation, transmission, and distribution of electric and natural gas systems. Also, provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors compliance with environmental requirements. Oversees environmental cleanup projects.	Fully distributed cost
*Energy Supply Business Resources** – provides performance, specialists, and analytical services to the operating companies generation facilities.	Fully distributed cost
*Energy Markets Regulated Trading & Marketing** – provides electric trading services to the operating companies electric generation systems including load management, system optimization, and resource acquisition.	Fully distributed cost
*Energy Markets-Fuel Procurement** – purchases fuel for operating companies' electric generation systems (excluding nuclear).	Fully distributed cost
*Energy Delivery Marketing** – develops new business opportunities and markets the products and services for the Delivery business unit.	Fully distributed cost

*Energy Delivery Construction, Operations & Maintenance** – constructs, maintains, and operates electric and gas delivery systems.	Fully distributed cost
*Energy Delivery Engineering/Design** – provides engineering and design services in support of capacity planning, construction, operations, and materials standards.	Fully distributed cost
*Marketing & Sales** – provides marketing and sales services for the operating companies and affiliates for their electric and natural gas customers including strategic planning, segment identification, business analysis, sales planning, and customer service.	Fully distributed cost
*Customer Service** – provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center, and credit and collections.	Fully distributed cost
*Aviation Services** – provides aviation and travel services to employees.	Fully distributed cost
*Fleet** – oversees the Utility subsidiaries Fleet Services business unit.	Fully distributed cost
*Business Systems & Innovation** – provides basic information technology services such as: application management, voice and data network operations and management, customer support services, problem management services, security administration, and systems management. In addition, Business Systems & Innovation acts as a single point of contact for delivery of all information technology services to Xcel Energy. Business Systems & Innovation partner with vendors to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace.	Fully distributed cost

** Corporate Governance activities within this service function will be allocated using the average of the revenue ratio with intercompany dividends assigned to Xcel Energy Inc., full time equivalent hours including overtime, and the total assets ratio including Xcel Energy Inc.'s per book assets.*

V. COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAAM provides an overview of the cost assignment and allocation principles of NSPM and the accounting processes within the monthly accounting close and within the general ledger, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the non-regulated business activities of NSPM. Each major step of the accounting process is identified in the following paragraphs and will be explained in conjunction with the process flowchart of this section. Each major step results in costs being either directly assigned or allocated to regulated services and non-regulated business activities. The result of applying these principles is that each company, utility, jurisdiction and non-regulated business activity pays the full cost for any service provided to support their respective operations.

Many of the assignment and allocation processes occur in the Service Company or are administered by Service Company personnel. As noted in the Introduction, the Service Company provides services “at cost” to the Utility subsidiaries and affiliate companies.

The processes discussed in this section are integral to the financial books and records of NSPM and are included to provide a comprehensive picture.

COST ASSIGNMENT AND ALLOCATION PRINCIPLES

NSPM applies the following cost assignment and allocation principles. The cost assignment and allocation approach is a fully distributed costing method as approved by the Commission in NSPM’s electric and gas rates cases (E002/GR-92-1185, G002/GR-92-1186 and G002/GR-97-1606) and the Commission September 28, 1994 Order in Docket G, E-999/CI-90-1008.

The hierarchical cost assignment and allocation principles are:

I. Tariffed rate shall be used to value tariffed services provided.
II. Costs shall be directly assigned to either regulated or non-regulated business activities whenever possible.
III. Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions in accordance with the following principles:
    a. Cost causation. All activities or jurisdictions that cause the cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can be traced to the specific activity or jurisdiction.
    b. Variability. If the fully distributed cost study indicates a direct correlation exists between a change and the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship.
    c. Traceability. A cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that case the cost to be incurred.

   d. Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.

IV. Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator as defined in this CAAM.

V. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

A significant portion of NSPM's costs are incurred directly by NSPM. These costs are directly assigned or allocated based on the above principles to utilities, jurisdictions, and to non-regulated business activities. Utility allocations are described in Section VII and jurisdictional allocations are described in Section IX.

ACCOUNTING PROCESSES

The flowchart in this section provides a high-level overview of the major steps in the monthly accounting close process and the systems used to generate the financial books and records of NSPM. Several steps within the process have allocations imbedded within and are included to provide as much information as possible to promote an understanding of where direct assignment or allocations can occur.

Feeder Systems (Addendum A, Flowchart Item 1)

The monthly close process initially starts with the collection of accounting information from feeder systems as identified in Item 1 on the flowchart. Feeder systems gather accounting transactions on a daily, weekly or monthly basis and 'feed,' or pass, those accounting transactions to the general ledger within SAP.

SAP General Ledger System Processing (Addendum A, Flowchart Item 2)

Journal entries to record monthly transactions such as interest accruals, amortizations, cash transactions, receivables setup, etc., are entered directly into SAP using the SAP journal entry input screens. These journal entries also include the journal entries to record overheads on non-regulated business activities (see Section VII).

Once all the transactions from the processes identified above are recorded in SAP, there are multiple processing steps within SAP, including settlements and assessments. These processes affect regulated services and non-regulated business activities and are detailed separately on the following pages.

Settlements and Assessments (Addendum A, Flowchart Item 3)

All costs identified as billable are processed using the settlement and/or assessment processes of the SAP system. These processes bill transactions from the legal entity that performed the service to the legal entity that received or is responsible for the service. This process captures:

- Service Company direct and allocated billings of all its costs to affiliated interests;
- Direct billings between a utility subsidiary and an affiliated interest other than the Service Company which are often referred to as intercompany charges or billings; and
- Direct billings between business areas within a legal entity.

For example, the settlements process will settle Service Company labor to the affiliated company if the labor is a direct charge or it will send the charges to an ACC if the charge is to be allocated. The assessment process will then clear the ACC by allocating the charges using an approved method of allocation to the legal entities to which the employee is providing services along with the appropriate labor and labor-related overheads. Transactions between affiliates (excluding XES) are direct charges, as are charges from one business area to another business area (for example, charges from the Distribution Operations business area to the Energy Supply business area). After the settlements and assessment processes are completed, all costs reside on the books of the legal entity ultimately responsible for the charge in the appropriate FERC account.

Business View (Addendum A Flowchart Item 4)

The business view of the SAP general ledger provides a GAAP view of the accounting transactions necessary to prepare SEC financial statements and other GAAP financial reports as well as the information necessary for the business areas to manage the business.

FERC Account Data Prior to Utility and Non-Regulated Allocations (Addendum A Flowchart Item 5)

At the same time that the business view is available, the pre-allocated FERC view of the SAP general ledger is available. The following utility allocations and non-regulated allocations are necessary for common costs to be allocated to the gas, electric, and non-regulated businesses.

Utility Allocations and Non-regulated Allocations (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated business activities whenever possible. When charges can't be directly assigned, they are charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. These allocations are performed monthly within the SAP system and are described in Section VII.

In addition to the costs directly assigned to the non-regulated business activities from the Service Company and within NSPM, the non-regulated business activities are charged with a labor related overhead and an allocation of corporate costs. See Section VIII for additional information related to non-regulated business activities.

All costs that can be directly assigned or allocated to the electric or gas utility operations or to the non-regulated business activities are appropriately accounted for in the books and records of NSPM before jurisdictional allocations occur. A study is performed annually, and as required for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the jurisdictions of NSPM (Minnesota, North Dakota, and South Dakota). These costs are then allocated among the jurisdictions according to the allocations described in Section IX.

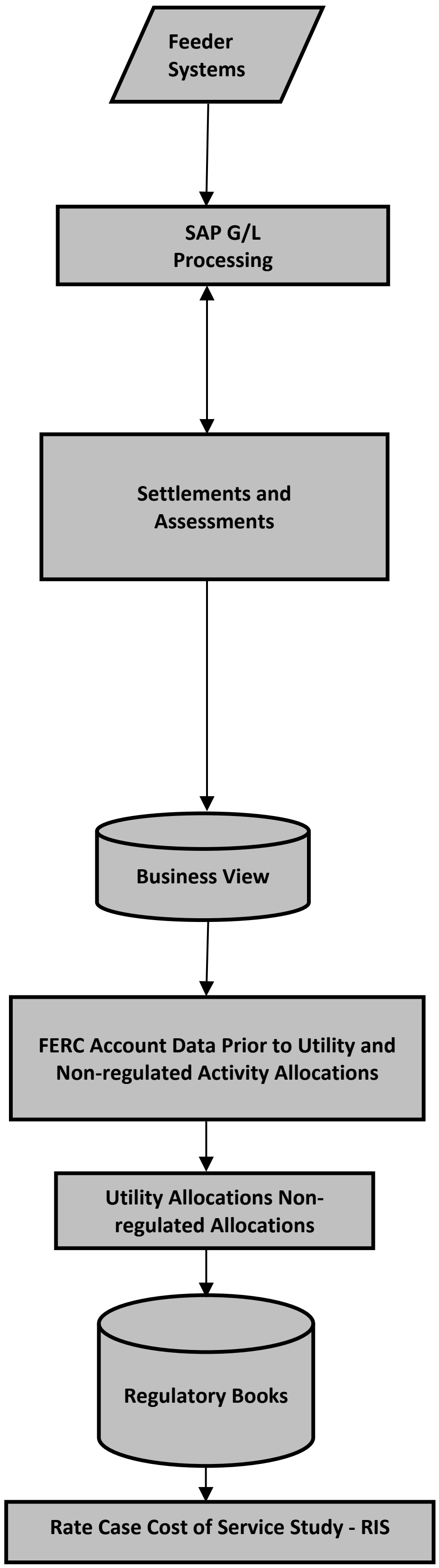
Regulatory Books and Records (Addendum A Flowchart Item 7)

After all the above processes are complete, the result is the FERC financial books and records of NSPM.

Rate Case Cost of Service Study (Addendum A Flowchart Item 8)

The FERC books and records are the starting point for the preparation of a cost of service study that will be used in a gas or electric rate case filing.

ADDENDUM A – PROCESS FLOWCHART



Item 1 – Feeder Systems
- **Labor Distribution**
- **Accounts Payable**
- **Money Pool**
- **Customer Billing**
- **Fixed Asset Ledger**
- **Employee Expenses**

Item 2 – SAP general ledger system processing

Item 3 – Settlements and Assessments
- **Labor Overheads**
- **Aviation Distribution**
- **Stores/Warehouse Overheads**
- **Purchasing Overheads**
- **Fleet Distribution**
- **Information Technology**
- **Shared Asset Distribution**
- **Facilities Distribution**
- **Engineering & Supervision**
- **Capital A&G**

Item 4 – Business View

Item 5 – FERC account data prior to Utility and Non-regulated activity allocations

Item 6 – Utility Allocations and Non-regulated allocations

Item 7 – Regulated books and records

Item 8 – Rate case cost of service study - Rate Information System (“RIS”)

Feeder and Overhead System Detail

LABOR DISTRIBUTION

Description:	Wages and salaries of employees engaged in work on behalf of regulated services and non-regulated activities are assigned or allocated based on positive time reporting through the labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-tenth of an hour or greater increments, while providing for aggregation of time when appropriate. Under this method, employees' time is reported on the basis of accounting codes related to specific operating utility companies or affiliates and/or functional services.
Provider of Service:	Service Company Operating companies or affiliates
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	All bi-weekly and semi-monthly employees' labor expenses are recorded by company personnel on time sheets and entered into the time reporting system, which feeds into the labor distribution system. The employee submitting the time sheet is responsible for coding the internal order numbers to charge the appropriate operating companies or affiliates, business function (e.g., capital, operations, maintenance, clearing, purchasing and/or warehousing, etc.) and regulated or non-regulated operations. Time must be completed and submitted for review and approval by certain cut-off dates established by the Payroll Department. The employee's supervisor or manager is responsible for reviewing and approving all time entries and verifying that the employee is using the correct accounting. The labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the internal order number charged based on the hours worked. Accrual of payroll is to facilitate the recording of labor costs on a calendar month basis. This includes any reversal of the prior month's accrual. The charge of labor dollars for semi-monthly employees to internal order numbers is based on a distribution of the monthly salary of the employee.

LABOR OVERHEADS

Description:

Employee labor overhead costs are captured in the following categories:

Benefit employees:

- Non-productive labor costs (vacation, sick, holiday, etc.)
- Pension and Insurance (401k match, retirement related consulting, active healthcare, life and LTD insurance premiums, miscellaneous benefit programs and LTD benefits for former or inactive employees before retirement, as well as the service cost portion of qualified pension, non-qualified pension and retiree healthcare)
- Benefits Non-Service (non-service cost portion of qualified pension, non-qualified pension and retiree healthcare)
- Workers compensation (FAS 112 actuarial cost and insurance premiums)
- Incentives (Incentives are a labor overhead for Service Company, PSCo, and SPS. Incentives for NSPM and NSPW are charged directly to FERC accounts 920 and 517).
- Payroll taxes (FICA, FUTA, SUTA)
- Labor and expense of the Human Resource Service Center

Non-Benefit employees:

- Payroll taxes (FICA, FUTA, SUTA)
- Workers compensation

Provider of Service:

Service Company
Operating companies or affiliates

User of Service:

Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.

Method of Allocation:

Labor overheads are allocated within a legal entity by calculating a separate loading rate for each cost category identified in the "Description" section above.

For each legal entity and each category, the costs are allocated based on a single-factor formula that is comprised of total estimated costs for the category divided by total estimated productive labor costs.

Legal entity specific rates for each category are applied to productive labor charges as appropriate for each resource type. Labor loadings applied to labor charges follow the labor charges. For example, Service Company labor overheads follow Service Company labor and NSPM labor overheads follow NSPM labor.

AVIATION DISTRIBUTION

Description:	The Aviation Services department in the Service Company is responsible for managing and operating the two corporate leased aircraft used by the Xcel Energy. Costs include: pilot salaries including labor overheads, O&M costs, lease costs, and A&G costs associated with managing the Aviation Services department.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Aviation costs are allocated using the average of the Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., Full Time Equivalent Hours Including Overtime, and the Total Assets Ratio including Xcel Energy Inc.'s per book assets. Any spousal use of the aircraft must be approved and is billed to Xcel Energy Inc.

STORES/WAREHOUSE OVERHEAD

Description:	Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools to the business areas as an overhead on materials and supplies as materials and supplies are issued from/returned to a storeroom or warehouse.
Provider of Service:	Service Company Operating companies
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	The overhead costs for inventory items as noted above and associated adjustments are accumulated within the Supply Chain warehouse ACC's. These accumulated overhead costs are allocated to material issuances/returns from the storeroom. Costs are collected in ACC's on the Service Company and Operating Companies; then cleared using a warehouse overhead loading based on a costing sheet, cost element and AP document type criterion.

PURCHASING OVERHEAD

Description:	The Supply Chain organization in the Service Company has the responsibility for distributing the corporate purchasing and contract services costs to the functional area(s) of the operating companies or affiliates along with the cost of the materials and supplies ordered. Purchasing costs are made up of activities such as developing requisitions, contracts and purchase orders to procure materials and services and manage supplier relationships, negotiating complex procurement agreements/contracts for strategic supplier partnerships and service contracts, monitoring supplier performance, and managing purchase records, supplier qualification records, supplier diversity program, and support, maintenance, and performance monitoring of key applications and metrics used throughout the purchasing process. The Supply Chain organization is supported by specific Human Resources personnel who assist with supplier qualification processes as well as by the Enterprise Security department who manages the Security Vendor Risk Assessment process.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and the operating companies and cleared using an overhead loading based on costing sheet, cost element, and AP document type criterion.

FLEET DISTRIBUTION

Description:	The Fleet Services department in the Service Company is responsible for managing the fleet assets owned by the operating companies. Fleet assets are vehicle units that are organized into fleet work centers, which group together vehicles similar in nature for a specific business function within an Operating Company. The SAP Work Manager records the utilization of our fleet assets and allocates the cost to the business areas of operating companies and affiliates for the costs of using vehicles or associated equipment using fleet activity rates based on work centers. Fleet costs included in the calculation of the monthly billing rate include: licensing taxes and fees, lease costs, material and labor costs for maintenance and repair, fuel, labor loadings, and overhead for overall management of the Fleet Services department that includes labor, facilities, insurance, utilities, computers, phones, and office supplies.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions and non-regulated business activities within an operating company.
Method of Allocation:	Costs are collected in ACC's on the Service Company and operating companies which are cleared using an overhead fleet rate based on the weighted vehicle type to the respective business area.

INFORMATION TECHNOLOGY

Description:	The Technology Services organization in the Service Company is responsible for managing the corporate IT assets and services of Xcel Energy. Technology Services bills out O&M and capital costs related to Xcel Energy's corporate IT equipment and services incurred internally, as well as costs incurred through third party vendors. Costs include system O&M, desktop services, phone service, servers, infrastructure costs, software, software licensing, system design and implementation, labor and labor overheads, etc.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies, or affiliates, including utility operations, jurisdictions and non-regulated activities within an operating company.
Method of Allocation:	IT costs are charged through several different methods. Costs are charged directly to the operating companies, affiliates, jurisdictions or non-regulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible. If costs cannot be charged directly to an operating company, affiliate, jurisdiction or non-regulated activity, the costs are charged to the appropriate Service Company indirect ACC that will assign the costs using a cost causative method to the companies benefiting from the system, application, or service. For costs that can be identified as benefiting a particular service function, those services would be charged to a Service Company indirect ACC using the approved allocation factor for that business area. If an indirect ACC cannot be identified that would assign costs in a cost causative method, a new indirect ACC will be created. However, if the project will be in-serviced within one year and if O&M costs will be less than $250,000 in total for the project, an internal order will be used to assign costs using a cost causative method to the companies benefiting from the system, application, or service.

ACCOUNTS PAYABLE

Description:	The Payment and Reporting Department (Accounts Payable), in the Service Company, processes several types of documents for payment on behalf of the operating companies and affiliates. Accounts Payable uses SAP to process invoice payments associated with purchase orders, contracts, requests for payment (non-purchase orders, non-contract invoices) and employee payments, including per diem charges, suggestion system award payments and employee expense reimbursements. The charges for goods, materials and services, which post directly to the general ledger of each operating company and affiliate, differ for each type of document.
Provider of Service:	Service Company
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and non-regulated activities within an operating company.
Method of Allocation:	Within each operating company and affiliate, charges are directly assigned whenever possible. Charges may be distributed to multiple business functions or business areas based on the accounting code(s) on each document. If necessary, costs may be allocated using any surrogate measure that has a logical or observable correlation to the charges in the quantities sold, the services that caused the cost to be incurred or that benefited from the cost. The following are examples of some of the logical or observable correlations used to allocate costs contained on Accounts Payable documents: • Quantity (units, count, etc.) • Measurement or size (length, space, columnar inch, etc.) • Volume (barrels, gallons, liters, etc.) • Weight (ounce, pound, ton, etc.) • Hours (hours of professional or contract services) • Labor dollars (charge is in the same proportion as the labor hours of the department) • Number of customers, meters, employees, etc. • Revenue dollars • Plant in service • Square footage

SHARED ASSETS DISTRIBUTION

Description:	Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include land structures and improvements, office furniture and equipment, computer and communication equipment, and some software systems that are used by employees in the performance of their jobs.
Provider of Service:	Operating companies or affiliates
User of Service:	Service Company, operating companies and affiliates
Method of Allocation:	All allocations are billed through the Service Company and charged to a Service Company internal order that will assign the costs using a cost causative method to the companies benefiting shared assets. For IT related assets, the costs will be charged to the system application or service internal order. For facility assets, the costs will be charged to the respective Service Company facilities ACC that will assign the costs following employee labor.

FACIALITIES DISTRIBUTION

Description:	Facilities costs are assigned or allocated to the functional areas of operating companies and other affiliates who benefit from the use of the facilities. Depending on whether a building is used by one utility company or is a "shared" building, i.e., building used by employees of more than one operating company or affiliate, facility costs may include: Single-utility facility: The administrative property services labor and non-labor costs, utility expenses, maintenance costs for structures and systems, pro-rated share of property taxes (for owned buildings), and the rent and occupancy expenses (for leased buildings). Shared facility: Administrative property services labor and non-labor costs, utilities expenses, and the maintenance costs for structures and systems are captured. If the building is leased, the rent is included. If the building is owned, the carrying costs of the shared assets, such as the depreciation and a return on rate base, are included in the facilities' cost. The Property Services department is responsible for the owned and leased facility.
Provider of Service:	Service Company or operating companies
User of Service:	Service Company, operating companies, and affiliates
Method of Allocation:	Costs for a single-utility facility are accumulated in the ACC of the company benefitting from the use of the building and are then allocated to functional FERC accounts based on the most recent quarter's labor charges. Costs related to a shared facility, i.e., buildings used by employees of more than one operating company or affiliate, are first accumulated in ACC's specific to the shared facility and then distributed to each operating company and affiliate based upon the most recent quarter's labor for the specific employees located in each facility. Once costs are assigned to the appropriate company, they are then allocated to the functional FERC accounts based on the most recent quarter's labor charges.

MONEY POOL

Description:	Through the Utility Money Pool ("UMP"), temporary surplus funds of Xcel Energy are available for short-term loans to other operating companies with cash needs.
Provider of Service:	Service Company
User of Service:	Operating companies
Method of Allocation:	An operating company can borrow from, and make loans to, the UMP, which is administered at cost by the Service Company. In addition, Xcel Energy Inc., the Holding Company, can deposit surplus funds into the UMP but cannot borrow from the UMP. Interest income or expense is charged or credited, as appropriate, to the UMP participants. All charges are directly billed from the Service Company to the appropriate operating company. NSPM petitioned for and received approval on the use of a UMP in Docket No. AI-04-100.

INCOME TAX EXPENSE DISTRIBUTION

Description:	Income tax expense incurred by the Service Company.
Provider of Service:	Service Company
User of Service:	Service Company and all entities included in the Accounting, Reporting, & Tax – Corporate Governance allocator.
Method of Allocation:	Income tax expense incurred by the Service Company is allocated to all entities included in the Accounting, Reporting, & Tax – Corporate Governance allocator.

CUSTOMER BILLING

Description:	NSPM bills customers for electric, gas, propane, and miscellaneous non-regulated activities through the customer billing system.
Provider of Service:	Operating companies
User of Service:	Operating companies, including utility operations, jurisdictions, and non-regulated activities.
Method of Allocation:	Costs related to customer billing are direct charged to specific operating companies whenever possible. When costs cannot be directly assigned to a specific operating company, they are allocated based on the number of customers. Non-regulated activities that use the customer billing system are allocated a customer accounting overhead based on revenue dollars. See Section VII.

ENGINEERING AND SUPERVISION ("E&S") OVERHEAD

Description:	E&S costs are capitalized as construction overheads. E&S overheads are applied where it is not practical to direct charge the pay and expense of the engineers, surveyors, draftsmen, inspectors, first line management, and their assistants to construction. NSPM uses the E&S overhead allocation to charge these expenses to capital projects.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Costs related to E&S are gathered in an ACC separately by functional class and utility (production, transmission, and distribution). The ACC's are fully allocated on a monthly basis to clear the balances to zero. These costs are sent to the fixed asset ledger and then are allocated to each eligible capital internal order based on current month charges and the calculated rate. The fixed asset ledger tracks all capital projects and work order expenditures for Xcel Energy on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, the fixed asset ledger system generates the overhead allocations, and if appropriate, AFUDC, which are then applied to the individual internal orders. In addition, the fixed asset ledger calculates monthly depreciation by legal entity and handles the transfer of work orders from FERC account 107, Construction Work in Progress; to FERC account 106, Completed Construction-Not Unitized; to FERC account 101, Utility Plant in Service. The transfer of non-utility costs is within FERC account 121, Non-Utility Property using sub accounts.

CAPITAL A&G

Description:	A&G costs are capitalized as construction overheads. The overhead relates to all the personnel in the administrative office that work on construction to assure its continued operation but are not direct to any one project. A prime example is the payroll analyst whose responsibility it is to assure the construction labor receives its payroll checks. Because it is inefficient for these employees to direct charge all the work orders an overhead process is used to facilitate charging the capital work orders.
Provider of Service:	Operating companies and Service Company
User of Service:	Operating companies.
Method of Allocation:	Each operating company performs an A&G study every other year to review the time employees in certain administrative departments spend on capital work. A percent of payroll for these employees, based on the A&G study results is charged to an overhead allocating cost center, one-twelfth each month. The overhead cost center is allocated to each work order based on current month charges.

VI. UTILITY ALLOCATIONS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas, or non-regulated activities whenever possible or charged as common and then allocated to the electric and gas utilities using utility allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are processed monthly within SAP and are explained below. The common rate base and non-O&M utility allocations are completed as part of an annual study and for rate case filing purposes which are explained below.

O&M UTILITY ALLOCATIONS

Introduction

Common O&M utility allocations are applied to common costs that are recorded in A&G (FERC accounts 920-935), customer accounting, and customer information and sales (FERC accounts 901-917). Table A in this section lists the NSPM allocation methodology applied to each FERC account or range of FERC accounts.

Methodology

NSPM uses the following methods to allocate common O&M costs. These methods were developed to achieve the most cost causative relationship that each FERC account or range of FERC accounts has with electric and gas utility operations. The allocators used are as follows:

Customer Allocator

The customer allocator is used to allocate common utility costs in FERC accounts 901-903, and the non-commodity bad debt portion of FERC 904 and 905-917 among electric and gas operations. The allocation is based on the customer bill counts for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual customer bill count.

Revenue Allocator

The revenue allocator is used to allocate common utility costs for commodity bad debt, recorded in FERC account 904, among electric and gas operations. The allocation is based on a rolling four-year average of actual electric and gas revenues. The allocator in the current year is developed based on the four previous years' actual operating revenues from the corporate income statement.

Three-Factor Allocator

The three-factor allocator is used to allocate common utility costs in FERC account ranges 920-924 and 927-935 among electric and gas utilities. The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Labor Allocator

The labor allocator is used to allocate common utility costs in FERC accounts 925-926 to the electric and gas departments. The allocation is based on operating labor for the electric and gas utilities. The allocator used in the current year is developed based on the previous years' actual operating labor.

RATE BASE AND NON-O&M UTILITY ALLOCATIONS

Introduction

A study is performed annually, and for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM in order to allocate them to the electric and gas utilities.

Methodology

NSPM uses the following methodology to allocate common rate base and non-O&M costs. These allocation factors were developed to achieve the most cost causative methodology based on the pool of costs being allocated. Table B in this section lists the methodology applied to specific pools of costs. The allocators used are as follows:

Three-Factor Allocator

The allocation is based on the weighted average of operating revenue, plant in service, and supervised O&M. The allocator used in the current year is developed based on the previous years' actual operating revenue, plant in service and supervised O&M.

Computer Software Study

A composite allocator is used to allocate common computer software rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Software assets and related costs are presented in a cost of service study using a single amount. A study of all computer software is done to determine how each individual software asset that is part of the single amount should be allocated. All individual allocations are summarized to create a single composite allocation that is then applied to the summarized computer software plant and plant related costs.

Transportation Study

Individual allocators are used to allocate common transportation rate base (plant) and non-O&M (plant related) costs among electric and gas utilities. Transportation assets are reviewed to determine where vehicles are used and allocation factors are developed.

Table A – O&M Utility Allocations

FERC Account	Allocation Method	Basis for Allocation Selection
901-917 (excluding commodity bad debt in FERC 904)	Customer Allocator	Customer bill counts are a reasonable methodology to use to allocate common customer accounting and customer information and sales costs recorded in FERC accounts 901-917 because these costs are customer related costs, e.g., credit and collection, customer accounting, bad debt, etc.
904 (commodity bad debt portion)	Revenue Allocator	A revenue allocator is a reasonable methodology to allocate commodity bad debt because these costs have a cost-causative relationship to uncollectible utility revenues.
920-924	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost-causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.
925-926	Labor Allocator	A labor allocation is reasonable because the costs recorded in these accounts are injuries and damages and pension and benefit costs. These costs have a cost-causative relationship with labor.
927-935	Three-factor Allocator	A three-factor allocation is reasonable because there is no single allocator that could provide a cost causative link. A three-factor allocator that measures three distinct aspects of the Company and results in an overall fair assignment of costs to the electric and gas utilities is used and is based on equally weighting operating revenue, plant in service and supervised O&M.

Table B – Rate Base and Non-O&M Utility Allocations

Utility	Functional Class	Pool of Costs	Allocation Methodology
Electric			Direct Assignment
Gas			Direct Assignment
Common	26/Common Intangible Plant	Computer Software	Computer Software Study
Common	31/Common General Plant	General Furniture & Equipment	Three-Factor Allocation
Common	31/Common General Plant	Electric Distribution – Mass – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – ND	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Distribution Vaults	Direct Assignment to Electric
Common	31/Common General Plant	Allen S King Plant	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Line – MN	Direct Assignment to Electric
Common	31/Common General Plant	Electric Transmission Substation – MN	Direct Assignment to Electric
Common	31/Common General Plant	Gas Distribution – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – MN	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – ND	Three-Factor Allocation
Common	31/Common General Plant	Office, Service & Other Bldgs – SD	Three-Factor Allocation
Common	31/Common General Plant	Software – Minnesota	Three-Factor Allocation
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – MN	Transportation Study
Common	31/Common General Plant	Transportation Equipment – SD	Transportation Study
Common	31/Common General Plant	Prairie Island	Direct Assignment to Electric
Common	31/Common General Plant	Inver Hills – Prod Other	Direct Assignment to Electric
Common	31/Common General Plant	Big Oaks Rec Area	Three-Factor Allocation
Common	31/Common General Plant	Black Dog	Direct Assignment to Electric
Common	31/Common General Plant	High Bridge	Direct Assignment to Electric
Common	31/Common General Plant	Riverside	Direct Assignment to Electric
Common	31/Common General Plant	Sherco	Direct Assignment to Electric
Common	31/Common General Plant	Gas Prod – Wescott – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	General Plant – MN	Three-Factor Allocation
Common	31/Common General Plant	General Plant – SD	Three-Factor Allocation
Common	31/Common General Plant	General Plant – ND	Three-Factor Allocation

VII. NON-REGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

The purpose of this section is to detail the methods of assigning and allocating costs between the regulated services and the non-regulated activities of NSPM.

NSPM follows the same approach for all types of costs for its fully distributed costing method. As discussed earlier in the CAAM, NSPM's method was approved by the Commission in its electric and gas rate cases (E002-GR-92-1185, G002-GR-92-1186 and G002/GR-97-1606) and the Commission's September 28, 1994 Order in Docket No. G,E-999/CI-90-1008.

The Commission established the following hierarchical cost assignment and allocation principles in Docket No. G,E-999/CI-90- 1008:

1. Tariffed rate shall be used to value tariffed services provided to non-regulated activities.
2. Costs shall be directly assigned to either regulated or non-regulated activities whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogenous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost causation.
4. Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.

This process accomplishes the proper separation of costs between NSPM's regulated utility business and non-regulated activities. Each activity that could be considered as being outside of NSPM's electric and gas business is reviewed for regulated/non-regulated treatment. If the activity is approved to be treated as a non-regulated operation, the non-regulated cost allocation process is followed.

There are limited situations where an activity that would be in the public interest could not be pursued if a fully distributed costing approach was followed. In such circumstances, NSPM has filed, and will continue to file, any deviation from a fully distributed costing process on a project-specific basis. Any existing exceptions have been filed and approved by the Commission.

Evaluation Process

NSPM's approach to fully distributed costing includes the following steps of analysis: business profile, direct charging, labor overheads, cost causation allocation, labor related overhead, customer accounting overhead, and corporate residual allocation. Non-NSPM affiliates are charged a working capital fee as discussed in Section IV.

Business Profile

The allocation process begins by reviewing each non-regulated activity for the services NSPM's utility business will be providing to the non-regulated activity.

Direct Charging (Addresses Principle #2)

Cross charges between NSPM service providers and non-regulated activities are reviewed with the business. Any process, project, or service performed for the direct benefit of a non-regulated activity is directly charged to the non-regulated activity. The business area providing service to the non-regulated activity communicates the anticipated level of service and how much the service will cost.

Labor charges are directly assigned to the non-regulated activity within the budgeting process, generally based on historical charges and taking into consideration known changes. The non-labor charges are directly charged. This process enables charging for all service that will be provided.

Cost Causation Allocations (Addresses Principle #3)

If no direct charge has been established for a service expected to be provided, a cost causation allocation is developed. Direct charging is preferred. However, if a service is expected to be provided and was not budgeted as a direct charge, an estimate of the cost of the service is made and allocated to the non-regulated business. An example of this would be, when a service is being provided, but it is at such a minimal level that it would be very difficult or cost prohibitive to charge on a direct basis.

Overhead Costs (Addresses Principle #4)

The overhead allocation factors capture indirect costs associated with providing services to non-regulated activities.

Non-regulated services wholly contained within NSPM and affiliate or third-party transactions are allocated a portion of NSPM's administrative and general (A&G) costs. A&G costs are allocated to non-regulated activities on the basis of labor of each non-regulated activity. The Company utilizes labor dollars for regulated activities and non- regulated activities to allocate the A&G costs, recorded in FERC accounts 920-935, to the non-regulated activities. The labor overhead is applied to unloaded labor.

Most non-regulated activities are also allocated a portion of NSPM's common Customer Accounting Costs. The distinction here is whether the non-regulated activity uses the customer accounting services of NSPM. For those activities that do use these services, common Customer Accounting Costs are allocated on the basis of revenues earned by each non-regulated activity. The Company utilizes revenue dollars for regulated activities and non-regulated activities to allocate the common portion of Customer Accounting Costs, recorded in FERC accounts 901-916, to the non-regulated activities. Excluded from the Common Costs in FERC accounts 901-916 are: FERC account 902, Meter Reading Expenses; FERC account 904, Uncollectible Accounts; and CIP costs in FERC account 908, Customer Assistance Expenses. These costs have been excluded because they are not pertinent to NSPM's non-regulated activities, as the non-regulated activities account for their own bad debt expenses separately.

Working Capital Fee (Addresses Principle #3)

The working capital fee is applied to non-NSPM affiliates. The fee is based on the current Prime Rate and is reviewed and updated quarterly. This fee is to compensate the regulated business for the cost of working capital used by affiliates.

VIII. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

NSPM's methods for assigning and allocating common O&M costs, plant and plant related, and other rate base investment to jurisdictions is intended to distribute costs in a manner that most closely reflects the benefit received from the expenditure. Accurately stating the assigned and allocated costs of the Company, as they relate to causation of the costs, is a fundamental part of creating a fair distribution of those costs to jurisdiction.

NSPM uses three methods to assign and allocate O&M expense, plant and plant related, and other rate base investment to jurisdiction:

1. direct assignment based on FERC account and location,
2. allocate based on cost causation, and
3. allocate based on a default allocator.

Determination of the assignment and allocation of costs to jurisdiction is an annual process designed to identify the jurisdiction(s) that receive the benefit from the cost or investment. During the review, the three methods stated above are used to ensure that the appropriate jurisdiction(s) is assigned or allocated the cost. It is NSPM's primary goal to direct assign or allocate based on cost causation as often as possible, and allocate based on a default as little as possible.

The first step in assigning costs and investments to a jurisdiction is to identify all costs that can be directly assigned to a jurisdiction (Minnesota, North Dakota or South Dakota), based on the location where work is being performed. For O&M expense, the SAP general ledger account has a location indicator (Profit Center) and a FERC account number associated with it and these are used to determine the appropriate jurisdiction(s) for assigning costs. The individual business areas determine and maintain the appropriate values for these codes based on the type of work being performed and which customers benefit from it. For plant investment data, the PowerPlan system's functional class ID, state code and the function that it is serving are used to determine the appropriate jurisdictions to assign costs for plant, plant related and other rate base costs.

Direct Assignment Based on FERC Account and Location

The first method NSPM uses is to direct assign costs whenever possible. For example, the distribution portion of an electric substation (that which is assigned to a distribution FERC account function) and is located in the Twin Cities metro area can be directly assigned to the Minnesota jurisdiction based on location as it directly serves only customers in Minnesota. In addition, all gas transmission and distribution property are directly assigned to the jurisdiction based on where the property is located as defined within the PowerPlan system. The Capital Asset Accounting organization maintains the capitalized property data.

An O&M example of direct assignment (expense) would be either electric or gas special meter reading done in the Twin Cities metro area (assigned to a distribution FERC account). The meters read are for customers in the State of Minnesota; therefore, the related costs are directly assigned to the Minnesota jurisdiction.

All regulatory expenses specific to a jurisdiction are directly assigned to that jurisdiction. For example, indirect assessments charged to NSPM, from the Minnesota Department of Commerce and the Commission, are directly assigned to the Minnesota jurisdiction.

Allocation Based on Cost Causal Relationship

The second method NSPM uses identifies all investments and costs that can be assigned to jurisdiction based on a causal relationship, and allocates these costs using the most cost causal allocation method. Examples of electric and gas analyses are as follows:

Electric

NSPM operates an integrated electric transmission system that transports electricity to NSPM's distribution system that in turn, supplies electricity to all of NSPM's customers. The transmission system is built to meet the demand created by serving its customers and, therefore, NSPM uses a coincident peak transmission demand taken from twelve consecutive months that constitute a calendar year method, to allocate transmission investment to all of its jurisdictions. All of the expense and plant investment, assigned to transmission function, exists to support NSPM's infrastructure, is fixed in nature and is assigned to jurisdiction based on transmission demand.

The cost causation allocators used for electric production expense or plant investment is a twelve-month coincident peak demand or energy, depending on the type of expense or plant investment. If the expense is variable in nature, energy is used to make the assignment to jurisdiction. If it is determined that the expense or plant investment exists to support NSPM's infrastructure and is fixed in nature, the demand allocator is used to make the assignment to jurisdiction.

Gas

From a supply standpoint, for example, NSPM operates its gas distribution system as a single unit. NSPM purchases natural gas, pipeline delivery capacity, and transmission of gas purchased to meet its customers' requirements on a system-wide basis. In addition, NSPM also operates propane-air (LPG) peak shaving facilities and liquefied natural gas (LNG) peaking facilities to meet firm demand in excess of natural gas daily pipeline entitlement for the benefit of the entire NSPM system. Because these types of costs support the entire operating company system, it is not possible to direct assign them to a specific jurisdiction. For this example, the O&M production and storage functions are allocated to jurisdiction based on the type of expense within the FERC account number. The transmission function is allocated based on the gas load dispatch allocator that is a combination of the design day firm demand allocator and total annual throughput. For plant investment, all production and storage facilities are allocated based on the gas design day allocator related to the design day firm demand.

Electric & Gas

Cost and investment in support of NSPM's distribution, customer accounting, and customer information & sales are more easily identified by state based on the location or where the work is being performed, or they can be allocated to jurisdiction using customers as a basis. In cases where services are provided and serve all regional customers, a regional allocator is developed which reflects the number of customers served in Minnesota and North Dakota or Minnesota and South Dakota, depending on the region. This represents a causal relationship between costs incurred in those regions and the assignment of costs to jurisdiction. Locating services performed in the Fargo area is an example of these types of costs. Locating services are performed for customers on both sides of the Minnesota/North Dakota border and are, therefore allocated to jurisdiction based on the number of year-end average customers in the North Dakota Region, which includes Fargo, Moorhead, Grand Forks, East Grand Forks and Minot.

Allocation Based on a Default Allocator

Allocation of common and general investment or A&G expense: costs and investment that cannot be assigned to jurisdiction using either direct assignment or allocation based on cost causation as described above are allocated to jurisdiction using a default allocator.

Common and General Plant Investment

The default allocator for electric plant investment is determined by the function that it serves. Common and general plant that serves production uses a twelve-month coincident peak demand allocator to allocate costs to jurisdiction. Plant serving transmission uses a twelve-month coincident peak transmission demand allocator to allocate costs to jurisdiction. For plant serving distribution, the number of year-end average customers is used to allocate costs to jurisdiction.

For Gas plant a default allocator is also determined by the function that it serves. For general and common plant, a year-end average customer allocator is used as the default. If the investment function has been determined to be gas production related, then the default jurisdictional allocator used in the production allocator is gas design day.

Administrative and General Expenses

When assigning or allocating A&G expenses to jurisdiction, a cost causative allocator is used if a functional relationship is easily established. In other instances, Electric A&G costs are allocated to jurisdiction using an equally weighted two-factor allocator based on electric plant in service and electric O&M expense (excluding A&G). The two factor allocator is developed by first calculating a three part historical ratio of plant investment directly serving production, transmission or distribution and a three part historical ratio of O&M expenses assigned to FERC accounts that are either production, transmission or directly serve customers (distribution, customer accounting, customer information or sales). These two ratios are then averaged to develop an equally weighted production, transmission and distribution ratio. This resulting three part ratio is then multiplied times the jurisdictional O&M default allocation ratios. The electric production portion is allocated to jurisdiction using a twelve-month coincident peak demand allocator; the transmission portion using the transmission demand allocator; and the customer portion is allocated using twelve-month end-of-year customers. The final step is to add the three sets of jurisdictional ratios together to form the two factor jurisdictional allocator used to allocate electric A&G costs supporting corporate functions.

Gas A&G expenses are allocated to jurisdiction using the appropriate customer allocation as a default allocator, based on the SAP account location indicator (profit center).

A more detailed description of each allocation type and method of allocation, including examples of why the allocation was chosen to assign costs to jurisdiction is included below.
Table C in this section lists the methodology applied to specific pools of costs.

ALLOCATION METHODS

GAS & ELECTRIC

Allocation: Direct Assigned

This allocation type is used to assign all expenses that are determined to be directly assignable to a jurisdiction (Minnesota, North Dakota, and South Dakota).

Allocation: Direct Assigned: State of Minnesota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the Minnesota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to one of Minnesota's regulatory bodies, legal department expense budgeted in support of Minnesota, economic development activities in the state of Minnesota, facilities expenses in support of the distribution business unit in the state of Minnesota, delivery system operation and maintenance costs in the Twin Cities metro area, Northwest and Southeast regions and automated energy system (AES) expenses.

Allocation: Direct Assigned: State of North Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of North Dakota jurisdiction. The types of costs direct assigned include: regulatory development activities based out of the North Dakota regional offices, direct and indirect assessments related to the North Dakota regulatory bodies, legal department expenses budgeted in support of North Dakota, economic development activities performed directly for North Dakota and work performed in the Minot area for the sole benefit of North Dakota customers.

Allocation: Direct Assigned: State of South Dakota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the state of South Dakota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to the South Dakota regulatory bodies, legal department expenses budgeted in support of South Dakota, economic development activities performed directly for South Dakota.

Allocation: Customers - Year-End Average - (Electric or Gas)

This allocation type is used to assign expenses where there is a cost causative relationship between the number of electric and gas utility NSP customers in a particular area and the service provided. This allocator is based on year-end average customer by utility.

Allocation: Customers Year-End Average Minnesota Co. MN/ND/SD

This allocation type is used to assign costs to all of Minnesota Company's jurisdictions (Minnesota, North Dakota, and South Dakota) when the work performed benefits all of the company's customers equally. This is the default allocator that is used for the electric and gas distribution, customer accounting, customer information, sales, and A& G FERC accounts.

This is also the gas utility A&G corporate function default allocator type.

Allocation: Customers Year End Average Minnesota/North Dakota

This allocation type is used to assign costs to both the North Dakota and Minnesota jurisdictions based on customers in the entire North Dakota region. This includes customers in Fargo, Moorhead, Grand Forks, East Grand Forks and Minot service areas. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/North Dakota.

Allocation: Customers Year End Average Minnesota/South Dakota

This allocation type is used to assign costs to both the South Dakota and Minnesota jurisdictions based on customers in the entire South Dakota region. This method is the default allocator for O&M expenses associated with general ledger accounts where the SAP profit center designates support for Minnesota/South Dakota.

Allocation: Study Jurisdictional Budget Transmission

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of transmission. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

Allocation: Study Jurisdictional Budget Distribution

This allocation is used for all budgeted plant investment that is determined to be for the direct benefit or in direct support of Distribution. It is a historical allocator based on the plant investment that has been direct assigned to jurisdiction based on its state location.

ELECTRIC UTILITY ONLY

Allocation: Energy

Fuel and fuel-related items are assigned to jurisdiction based on the energy allocator because of the direct correlation of customer sales and the level of fuel consumed. These items include all fuel, purchased energy, interchange agreement energy, and variable production expenses.

Allocation: Demand Prod (Coincident Peak)

The 12 coincident peak (CP) demand production allocator is used to assign fixed capacity related expenses, plant, and plant related items to jurisdiction. Other expenses allocated to jurisdiction based on demand include: fixed production expenses, purchased power demand expense, interchange agreement demand charges and regulatory expenses not directly related to one of NSPM's jurisdictions. Also, any A&G costs that are directly in support of production are allocated using this method.

Allocation: Demand Tran (Coincident Peak)

The 12 CP demand transmission allocator is used to assign transmission FERC Accounts in support of NSPM's jurisdictions. Also, any A&G costs that are directly in support of transmission are allocated using this method.

Allocation: Two-Factor Allocator (A&G Only)

Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G); the two-factor allocator is used to allocate electric A&G costs when there is not a direct or cost causative method available. Generally, all corporate electric A&G costs are allocated using this method.

GAS UTILITY ONLY

Allocation: Retail Revenues Cost of Gas Recovery - Demand, Commodity and Purchased Gas Adjustment True-up Study

Retail revenues include components for the recovery of costs associated with product and delivery of product to the service area. Such costs include capacity or entitlement costs, pipeline transportation costs, commodity costs and costs of alternative gas (LPG or LNG) supplied during times of firm peak demand. Regulations provide for the automatic adjustment of billing rates for price changes and the annual true up of the cost of gas incurred. Demand, commodity, and purchased gas adjustment are components of the retail revenues cost of gas recovery study. The portion of total NSPM cost of gas included in retail revenues that the Minnesota jurisdiction represents is also applied to total Minnesota company cost of gas expense accounts to achieve revenue neutrality for revenue requirements consideration.

Allocation: Design Demand Day

Expressed as a percentage, design demand day is the ratio of the Minnesota jurisdiction firm peak demand volume to the total NSPM firm peak demand volume that could occur on the distribution system on a day considered to be the most severe weather conditions that can be experienced.

Allocation: Load Dispatch

Expressed as a percentage, load dispatch is a combination of the Minnesota jurisdiction design demand day and the Minnesota jurisdiction total retail sales and transportation throughput each weighted equally.

Allocation: Limited Firm and Standby Services Study

Expressed as a percentage, limited firm and standby services, in revenues, is the ratio of Minnesota jurisdiction availability charges and volumetric charges to the total NSPM system; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total NSPM program product costs.

Table C

Allocation to Jurisdiction

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	2 /Electric Nuclear Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant-Wind			Electric	MN/ND/SD/WHSL	Electric - Energy
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Production	Production	23 / Decommissioning	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Production	Production	23 / Decommissioning	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Production	23 / Decommissioning	Wisconsin		Electric	WI	Direct Assigned - Wisconsin
Electric Transmission	Transmission	5 / Electric Transmission Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Transmission	5 / Transmission Direct Assignment	Minnesota	DRCT	Electric	MN	Direct Assigned – State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Transmission	5 / Transmission Generation Step-up		BSLD, PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
Sub-Business Unit	**Plant Function**	**Functional Class ID / Description**	**Location**	**Functional Use**	**Utility**	**Jurisdiction**	**Allocation Methodology**
Budget							
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Distribution	6 / Electric Distribution Plant	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Distribution	6 / Electric Distribution Plant	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	Wholesale		Electric	WHSL	Direct Assigned - Wholesale Full Requirements
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Gas	Production	7 / Gas Manufactured Production Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Storage	9 / Gas Underground Storage Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Transmission	10 / Gas Transmission Plant			Gas	MN	Direct Assigned – State Of Minnesota
Gas	Transmission	10 / Gas Transmission Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Distribution	11 / Gas Distribution Plant			Gas	MN	Direct Assigned – State of Minnesota
Gas	Distribution	11 / Gas Distribution Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Gas - Design Demand Day

Selection Criteria *							
Sub-Business Unit	Plant Function	Functional Class ID / Description	Location	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	34 / Gas Other Storage Plant			Gas	MN/ND	Gas - Design Demand Day

* All items under the Selection Criteria must be met before this allocation takes place.

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional O&M expense amounts for all of the years presented in these schedules.	
1	Production	Design Day Demand
2	Transmission	Load Dispatch
3	Distribution	Customers/Direct Assigned
4	Customer Accounting	Customers
5	Customer Service & Information	Customers
6	Sales, Econ Dvlp & Other	Customers
7	Administrative & General	Customers

		Test Year 2024		
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	**Design Day Demand**	897,827	118,491	**13.1975%**
2	Design Day Demand	897,827	118,491	13.1975%
	MCF	133,116,539	14,337,878	10.7709%
	Load Dispatch			**11.9842%**
3	**Customers**	555,347	64,674	**11.6457%**

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules.	
	The following allocation factors are used to compute North Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress:	
1	Production (LPG Production)	Design Day Demand
2	Storage (LNG Storage)	Design Day Demand
3	General	
	Production	Design Day Demand
	Other	Customers
4	Common	
	Production	Design Day Demand
	Other	Customers
	In addition, the following allocation factors are used to compute North Dakota jurisdictional amounts:	
5	Other Rate Base:	
	Materials & Supplies	Customers
	Gas in Storage	Design Day Demand
	Gas in Storage-Underground	Load Dispatch
	Non-Plant Assets & Liabilities	Customers and Load Dispatch
	Prepayments	Customers

		Test Year 2024		
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	**Design Day Demand**	897,827	118,491	**13.1975%**
2	Design Day Demand	897,827	118,491	13.1975%
	MCF	133,116,539	14,337,878	10.7709%
	Load Dispatch			**11.9842%**
3	**Customers**	555,347	64,674	**11.6457%**

Northern States Power Company
State of North Dakota Gas Jurisdiction
Average Rate Base
($000's)

Line No.	Description	Proposed 2024 Test Year Average Rate Base (A)
	Gas Plant as Booked	
1	Gas Manufactured Plant	$11,445
2	Gas Storage	14,311
3	Gas Transmission	4,006
4	Gas Distribution	214,184
5	General	19,609
6	Common	16,280
7	TOTAL Utility Plant in Service	$279,835
	Reserve for Depreciation	
8	Gas Manufactured Plant	$2,944
9	Gas Storage	$8,376
10	Gas Transmission	$1,823
11	Gas Distribution	$66,906
12	General	$7,878
13	Common	$8,077
14	TOTAL Reserve for Depreciation	$96,003
	Net Utility Plant in Service	
15	Gas Manufactured Plant	$8,501
16	Gas Storage	$5,935
17	Gas Transmission	$2,183
18	Gas Distribution	$147,278
19	General	$11,731
20	Common	$8,204
21	Net Utility Plant in Service	$183,832
22	Utility Plant Held for Future Use	$0
23	Construction Work in Progress	$678
24	Less: Accumulated Deferred Income Taxes	$22,872
25	Cash Working Capital	($726)
	Other Rate Base Items:	
26	Materials and Supplies	$306
27	Fuel Inventory	6,008
28	Non-Plant Assets & Liabilities	1,049
29	Customer Advances	(1,560)
30	Customer Deposits	(20)
31	Prepaids and Other	287
32	Regulatory Amortizations	990
33	Total Other Rate Base Items	$7,058
34	Total Average Rate Base	$167,970

($000's)

		Proposed Test Year 2024					
		Total Utility			North Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Proposed (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Proposed (F) (D) + (E)
	Gas Plant as Booked						
1	Gas Manufactured Plant	$86,718	$0	$86,718	$11,445	$0	$11,445
2	Gas Storage	108,434	0	108,434	14,311	0	14,311
3	Gas Transmission	144,750	(4,632)	140,118	4,006	0	4,006
4	Gas Distribution	1,843,960	0	1,843,960	214,184	0	214,184
5	General	168,375	0	168,375	19,609	0	19,609
6	Common	139,797	0	139,797	16,280	0	16,280
7	TOTAL Utility Plant in Service	$2,492,034	($4,632)	$2,487,402	$279,835	$0	$279,835
	Reserve for Depreciation						
8	Gas Manufactured Plant	$22,307	$0	$22,307	$2,944	$0	$2,944
9	Gas Storage	63,463	0	63,463	8,376	0	8,376
10	Gas Transmission	34,848	(418)	34,430	1,818	5	1,823
11	Gas Distribution	631,646	124	631,770	66,782	124	66,906
12	General	69,073	(1,427)	67,646	8,044	(166)	7,878
13	Common	69,773	(419)	69,354	8,126	(49)	8,077
14	TOTAL Reserve for Depreciation	$891,111	($2,141)	$888,971	$96,089	($86)	$96,003
	Net Utility Plant in Service						
15	Gas Manufactured Plant	$64,411	$0	$64,411	$8,501	$0	$8,501
16	Gas Storage	44,971	0	44,971	5,935	0	$5,935
17	Gas Transmission	109,902	(4,213)	105,688	2,188	(5)	2,183
18	Gas Distribution	1,212,314	(124)	1,212,190	147,402	(124)	147,278
19	General	99,302	1,427	100,729	11,564	166	11,731
20	Common	70,024	419	70,443	8,155	49	8,204
21	Net Utility Plant in Service	$1,600,923	($2,491)	$1,598,432	$183,746	$86	$183,832
22	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
23	Construction Work in Progress	$5,715	$0	$5,715	$678	$0	$678
24	Less: Accumulated Deferred Income	$236,872	($8)	$236,864	$22,847	$25	$22,872
25	Cash Working Capital	($14,443)	$666	($13,777)	($802)	$77	($726)
	Other Rate Base Items:						
26	Materials and Supplies	$2,624	$0	$2,624	$306	$0	$306
27	Fuel Inventory	49,763	0	49,763	6,008	0	6,008
28	Non-Plant Assets & Liabilities	9,017	0	9,017	1,049	0	1,049
29	Customer Advances	(1,755)	0	(1,755)	(1,560)	0	(1,560)
30	Customer Deposits	(173)	0	(173)	(20)	0	(20)
31	Prepaids and Other	2,455	0	2,455	287	0	287
32	Regulatory Amortizations	0	990	990	0	990	990
33	Total Other Rate Base Items	$61,930	$990	$62,920	$6,068	$990	$7,058
34	Total Average Rate Base	$1,417,253	($827)	$1,416,425	$166,843	$1,127	$167,970

($000's)

Line No.	Description	Proposed Test Year 2024					
		Total Utility			North Dakota Jurisdiction		
		Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Construction Work in Progress						
1	Gas Manufactured Plant	$962	$0	$962	$127	$0	$127
2	Gas Storage	1,989	0	1,989	263	0	263
3	Gas Transmission	129	0	129	0	0	0
4	Gas Distribution	874	0	874	83	0	83
5	General	338	0	338	39	0	39
6	Common	1,423	0	1,423	166	0	166
7	TOTAL Construction Work In Progre	$5,715	$0	$5,715	$678	$0	$678

Line No.	Description	Proposed Test Year 2024					
		Total Utility			North Dakota Jurisdiction		
		Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Accumulated Deferred Income Taxes						
8	Gas Manufactured Plant	($125)	($1)	($127)	($17)	$0	($17)
9	Gas Storage	(880)	(4)	(883)	(117)	0	(117)
10	Gas Transmission	21,479	(495)	20,984	614	4	618
11	Gas Distribution	192,796	(50)	192,746	19,623	(47)	19,576
12	General	12,884	425	13,309	1,496	54	1,550
13	Common	8,849	116	8,966	1,030	14	1,044
14	Net Operating Loss (NOL)	0	0	0	0	0	0
15	Non-Plant Related	1,869	0	1,869	217	0	217
16	TOTAL Accum Deferred Income Ta:	$236,872	($8)	$236,864	$22,847	$25	$22,872

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY 2024 NATURAL GAS RATE INCREASE APPLICATION	)))))	Case No. PU-23-___

AFFIDAVIT OF
Benjamin C. Halama

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

Benjamin C. Halama

Subscribed and sworn to before me, this 14th day of December, 2023.

Notary Public
My Commission Expires: 1/31/2027

JODI LYNN YANZ
NOTARY PUBLIC
MINNESOTA
My Commission Expires 01/31/2027