EXHIBIT 4

Direct Testimony and Schedules
John M. Felling

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation
For Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-10-____
Exhibit___(JMF-1)

Overall Revenue Requirements
Rate Base
Income Statement

December 20, 2010

Table of Contents

Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John M. Felling. I am a Principle Rate Analyst in the Revenue Analysis area for Xcel Energy Services Inc. ("XES") or the "Service Company"). My qualifications and experience are summarized in my resume provided with my testimony as Exhibit___(JMF-1), Schedule 1.

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

A. I will provide testimony supporting the financial data of Northern States Power Company, a Minnesota corporation operating in North Dakota ("Xcel Energy," the "Company," or "NSPM") and its Notice of Change in Rates for Electric Service (the "Notice") for the State of North Dakota retail electric jurisdiction. My testimony addresses the North Dakota jurisdiction's retail electric operations' overall retail revenue requirement of $184.277 million and revenue deficiency of $19.773 million, determined by the cost of service for the 2011 budget test year. The interim increase is $17.355 million as discussed in the Alternative Petition for Interim Rates. I also discuss the proposed 2012 "step-in adjustment" of $4.226 million supported in the Direct Testimony of Company witness Ms. Anne E. Heuer. Taken together, the overall deficiency is $23.999 million with an overall retail revenue requirement of $188.503 million. 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. Where applicable, I indicate in my testimony when the test-year cost information is based on information provided by other witnesses.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

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

• Section II	Data Provided and Selection of Test Year
• Section III	Test-Year Budget Development
• Section IV	Test-Year Revenue Deficiency
• Section V	Description of Cost Changes
• Section VI	Jurisdictional Cost of Service Study
• Section VII	Compliance Issues and Applications
• Section VIII	Utility and Jurisdictional Allocations
• Section IX	Rate Base Compenents
• Section X	Adjustments to Rate Base And Associated Income Statement Adjustments
• Section XI	Income Statement
• Section XII	Adjustments to the Income Statement
• Section XIII	Conclusion

My testimony also includes several schedules with financial information related to the 2011 test year and 2012 step-in adjustment revenue requirements and deficiency. These schedules were prepared by me or under my supervision. Exhibit ____ (JMF-1), Schedule 2 provides an index of the financial schedules to my testimony.

II. 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, that being calendar year 2009, and the test year selected, calendar year 2011.

Financial data for the most recent fiscal year and the test year are adjusted for traditional regulatory adjustments (*e.g.* advertising expenses, economic development, etc.). The test year on which the Notice is based starts with financial data included in the Company's 2011 projected fiscal year budget, and includes ratemaking adjustments deemed necessary, along with refinements and corrections to 2011 budgeted data. These changes to the base data were made to assure appropriateness for purposes of developing a test year that provides a normalized level of rate base and expenses to establish just and reasonable rates.

Q. HOW DID THE COMPANY SELECT THE PROPOSED TEST YEAR FOR THIS PROCEEDING?

A. Calendar year 2011 was selected as the test year for this filing using Xcel Energy's first-year budget data. The test year is based on the most recent available budget information.

Q. DOES THE 2011 PROJECTED TEST YEAR MEET THE COMMISSION'S REQUIREMENTS?

A. Yes. The use of a projected test year is consistent with the intent of North Dakota Century Code ("NDCC") § 49-05-04.1, subd. 2, which 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.

I provide a comparison of past budgets to actual costs later in my testimony in compliance with the first requirement of this statute. The 2011 Company budget data, as adjusted for the known and measurable changes discussed below, is a reasonable representation of the costs and rate case expense the Company will incur to provide electric service in the State of North Dakota, and complies with NDCC § 49-05-04.1, subd. 2. Thus, the 2011 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. Lastly, for the reasons explained by Ms. Laura McCarten in her Direct Testimony, the Company will face significant additional costs in 2012 right after it moves out of the 2011 test year, and as such, the Company has also proposed a step adjustment to address these significant cost items.

Q. NDCC § 49-05-04.1, Subd. 1(c) REQUIRES A UTILITY TO FILE CERTAIN FINANCIAL DATA FOR COMPARISON WITH THE TEST YEAR DATA. IS XCEL ENERGY COMPLYING WITH THIS REQUIREMENT?

A. Yes. Exhibit___(JMF-1), Schedule 3 to my testimony is the Company's 2009 actual jurisdictional summary data. This information, which provided the most recent calendar year of actual data, is consistent with the approach that we took in our last rate case and with the financial statements in our May 3, 2010 jurisdictional annual report filed with the Commission.

III. TEST-YEAR BUDGET DEVELOPMENT

A. Budget Development Process

Q. DESCRIBE THE TEST-YEAR BUDGET PROCESS.

A. The budgeting process for the 2011 test year began in early March 2010 with the issuing of Budget Guidelines and Instructions to the various business areas for the 2011 budget preparation. The test-year budget is assembled separately by its various components: Sales Forecast (customers and consumption), Retail and Other Revenues, Cost of Production, Operating and Maintenance ("O&M") Expenses, Capital Invested, Other Rate Base Investment and Capital Structure Components. The various budgets are submitted to the Finance Council and then the capital budget and O&M budgets are submitted to the Xcel Energy Inc. Board of Directors for review and approval. Management will use the final budget, as approved, to monitor and manage the Company's operations and financial performance during 2011.

Q. DESCRIBE HOW COSTS FOR THE NORTH DAKOTA JURISDICTIONAL ELECTRIC OPERATIONS ARE DEVELOPED IN THE BUDGET PROCESS.

A. Costs directly incurred by the Company are directly assigned to the Company and then directly assigned or allocated to utility (electric or natural gas). Costs from the Service Company are typically either directly assigned or allocated to the particular Xcel Energy Operating Companies (e.g., the Company) and then further assigned or allocated to specific utility operations and jurisdiction. Finally, costs billed to the Company by Northern States Power Company, a Wisconsin corporation ("NSPW" or "NSP-Wisconsin"), under the Interchange Agreement, are directly assigned to the Company's electric utility operation; similarly, the budget process reflects the budgeted 2011 revenues from NSPW under the Interchange Agreement.

Each business area is responsible for appropriate Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts designation of its budgeted O&M dollars. Accounting codes (called "object codes") in the J.D. Edwards ("JDE") general ledger accounting system determine the FERC account to which budgeted costs apply. Each JDE business unit contains the necessary information to determine the appropriate FERC account classification. In addition, the business areas are responsible for including a location code where appropriate. This information helps direct assignment or allocation of costs to the appropriate legal entity (e. g. the Company), utility (e.g. electric or natural gas), and jurisdiction (e.g. Minnesota, North Dakota, South Dakota or full requirements wholesale).

Q. PLEASE DESCRIBE ANY PROCESS IMPROVEMENTS IMPLEMENTED TO VALIDATE THE REASONABLENESS OF THE 2011 O&M BUDGET?

A. Trend analyses were completed which compared the 2008 actual, 2009 actual, 2010 forecast with the 2011 budgeted annual O&M amounts. The analyses were prepared by Object Account (cost category) and FERC account. The comparisons included a calculation of the compound average annual and respective percentage change by account between 2008 actual and the 2011 budget amounts. Analysis of all variances exceeding ± $250,000 and ± 3 percent were reviewed to evaluate the reasonableness of the 2011 budget. This information is intended to provide greater transparency about our cost trends and causes of changes over time for the parties reviewing the case. In addition, as with previous cases, we looked for errors that occurred during the budget creation process, and have identified and corrected these in the cost of service.

Q. PLEASE DESCRIBE THE PROCESS IMPROVEMENTS IMPLEMENTED TO VALIDATE THE REASONABLENESS OF THE 2011 CAPITAL BUDGET?

A. In addition to the standard annual review process for the capital budget, capital expenditure and in-service date data was summarized and analyzed with the business areas for their review. As a result, adjustments were made for certain projects for which schedule changes had become certain.

Q. DID YOU TAKE ADDITIONAL STEPS TO UPDATE INFORMATION INCLUDED IN THE BUDGETED REVENUE REQUIREMENTS?

A. Yes. We took additional steps to ensure that we had the most accurate estimate of the 2011 cost of service based on any changes known or errors identified from the time of closing the budget and developing the initial revenue requirement. We have, for example, incorporated the impacts of bonus depreciation that was a result of Congressional action in September, 2010, which reduced our North Dakota jurisdiction revenue requirement by over $750,000. We updated our sales forecast in August 2010 with additional months of actual data (June 2010) and more recent economic indicators. Likewise, we reran our fuel and energy budget using more updated fuel costs. The combination of these adjustments lowered revenues slightly, and reduced our bad debt expense. In addition, we used new information that was not available at the time of the creation of the budget regarding nuclear fees and our use of mercury sorbent. Also, as noted above, we revisited schedules on capital projects used in creation of the budget and have made appropriate revisions. All of these efforts have improved the accuracy of the filed revenue requirement as most closely reflecting our expected 2011 costs, revenues and revenue deficiency.

Q. HAVE YOU ENGAGED ANY OUTSIDE RESOURCES TO REVIEW AND AUDIT WORK PAPERS AND SUPPORTING SCHEDULES?

A. Yes. ScottMadden, management consultants, were engaged to conduct a general review and audit of work papers (including the cost of service study, source data and adjustments), supporting schedules, required financial schedules, fuel reconciliation, and other electric operating revenue documentation. Their review included:

- Reviewing revenue requirements analyses and supporting documentation, including assumptions;
- Reviewing jurisdictional cost of service studies and allocators, and the tie to supporting sales and demand forecasts;
- Tracking supporting spreadsheet results to required filing schedules; and
- Resolving any discrepancies between financial schedules, testimony, tariffs and supporting analyses.

B. Adjustments to 2011 Budget to Calculate Test-Year Cost of Service

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2011 BUDGET. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS MADE.

A. The Company made five types of adjustments to the base data.

- *Data Corrections.* The above described process identified three items that required correction. These items are identified as data corrections.
- *Budget Updates.* Eleven updates were made to the budgeted data to reflect known reductions and additions to the 2011 projected year budgeted data along with changes to the revenue deficiency resulting from the Small Business Jobs Act of 2010, which was signed into law on September 27, 2010.
- *Traditional rate case adjustments.* Five such adjustments were made.
- *Rate Case Adjustments.* Ten adjustments were made to ensure the test year accurately reflects past Commission orders and is an accurate representation of future anticipated costs.
- *Amortizations.* One of the amortizations is continuing from our last rate case; three are new amortizations.

I discuss each of these adjustments later in my testimony, more specifically in Section X Adjustments to Rate Base and Associated Income Statement Adjustments and Section XII Adjustments to the Income Statement. A list of adjustments, organized by category, is shown on Exhibit___(JMF-1), Schedule 4.

Q. HAVE YOU PREPARED A SCHEDULE THAT IDENTIFIES THE ADJUSTMENTS TO THE PROJECTED YEAR BUDGET DATA?

A. Yes. The bridge schedules (Exhibit___(JMF-1), Schedule 5a Rate Base Adjustments and Exhibit ___(JMF-1), Schedule 5b Income Statement Adjustments), show all test period adjustments. Column one of the Rate Base bridge schedule shows the 2011 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 one of the Income Statement bridge schedule shows the 2011 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 adjustment on the revenue requirement.

C. The 2011 Test-Year Budget is Reliable for Ratemaking Purposes

Q. PLEASE DESCRIBE WHETHER THE COMPANY'S BUDGETING PROCESS IS CONSISTENT WITH PREVIOUS BUSINESS PRACTICES AND WHETHER THAT PROCESS PROVIDES REASONABLE RESULTS?

A. The budgeting process is consistent with past business practice and has provided accurate forecasts of actual costs and revenues in the past. Except for the immediate post-merger period (2001-2002), over the eight year period (2001-2008), the Company's budgeting process has produced a reasonable forecast of the expected outcome for electric utility operations. Exhibit___(JMF-1), Schedule 6 is a comparative graph of actual total Company O&M expense results with budget projections for each of the five years, 2005 through 2009. The graph illustrates the historical correlation between budgeted and actual O&M expenses from 2005 through 2008 was reinstated once the merger process was completed and also reflects 2009 reduced spending at a level lower than budget.

Q. WHY WERE ACTUAL COSTS LOWER THAN BUDGET IN 2009?

A. The depressed economic conditions that occurred during 2009, our most recent fiscal year, put significant pressure on total Company revenues and thus required the Company to reduce expenses. Even with our efforts to reduce O&M costs in 2009, the Company experienced a weather normalized earnings deficiency for its North Dakota retail electric jurisdiction in 2009 of $1.4 million.

Q. IS THE 2011 O&M EXPENSE BUDGET FOR THE ELECTRIC UTILITY OPERATIONS AN ACCURATE AND RELIABLE PROJECTION?

A. Yes. With the adjustments I previously described, it is a reasonable projection on which to base this request for rate relief.

Q. HOW WAS THE 2012 STEP-IN ADJUSTMENT DETERMINED?

A. The need for, and development of the 2012 step-in adjustment is explained by Ms. McCarten and Ms. Heuer in their Direct Testimonies and Schedules.

IV. TEST-YEAR REVENUE DEFICIENCY

Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR NORTH DAKOTA?

A. The jurisdictional retail revenue requirement for North Dakota electric utility operations is $184.277 million based on average rate base and projected net operating income for the 2011 test year, the average capital structure, short-term debt, long-term debt and 11.25 percent cost of equity, based on the return on equity ("ROE") recommended by Ms. Ann E. Bulkley in her Direct Testimony filed with this Notice. Ms. Jannell E. Marks explains the development of the sales forecast in her Direct Testimony.

The jurisdictional retail revenue requirement for North Dakota Electric utility operations including the proposed 2012 step-in adjustment is $188.503 million based on average rate base and projected net operating income for the test year with the 2012 step-in adjustment; the average capital structure, short-term debt, long-term debt and 11.25 percent cost of equity. The test year with the 2012 step-in adjustment is discussed in detail by Ms. Heuer in her Direct Testimony.

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

A. The amount of the revenue deficiency for the test year is $19.773 million. The test-year deficiency including the 2012 step-in adjustment is $23.999 million, $4.226 million higher than the test year. Ms. Heuer addresses the 2012 step-in adjustment deficiency in her Direct Testimony. A summary of the revenue deficiency for 2011 and for the 2012 step-in adjustment is shown in Exhibit___(JMF-1), Schedule 7. Schedule 7 is a comparison of the jurisdictional revenue requirement amount for the test year and for the 2012 step-in adjustment with the forecasted revenues for the same period under present rates, which were approved by the Commission in Case No. PU-07-776. The level of North Dakota retail electric rates must be increased by this amount in 2011 in order for the Company to earn an overall return on rate base of 8.74 percent as developed in Exhibit __ (JMF-1), Schedule 8a, page 5. As discussed by Ms. Heuer, the 2012 step-in adjustment will provide the

Company an opportunity to earn closer to the Commission authorized return on equity in 2012 when final rates are placed in effect. See Exhibit___(JMF-1), Schedule 8b, page 5.

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 2011 budgeted amounts. The costs and ratios associated with this capital structure are found in Exhibit __ (JMF-1), Schedule 8a, page 5, and are as follows:

	Rate	Ratio	Weighted Cost
Long Term Debt	6.07%	46.30%	2.81%
Short Term Debt	2.06%	1.14%	0.02%
Common Equity	11.25%	52.56%	5.91%
Weighted Cost			8.74%

These capital structure ratios and the cost rates are based on the 2011 budget for the Company's capital structure.

Q. IS THE COMPANY A SEPARATE CORPORATION WITH ITS OWN CAPITAL STRUCTURE?

A. Yes. The Company is a legally separate corporation that is a wholly owned subsidiary of Xcel Energy Inc. The Company is not simply a division of a larger corporation. The Company has its own, separate capital structure that consists of common equity, long-term debt and short-term debt. It has no preferred stock in its capital structure. The use of the Company's legally separate capital structure reflects the sources of capital that have been used to finance its electric utility operations.

Q. DOES THE COMPANY ISSUE ITS OWN DEBT TO THE PUBLIC?

A. Yes. The Company currently has approximately $3.3 billion principal amount of separately issued and publicly traded long-term debt securities outstanding and intends to issue additional long term debt during the test year. The Company also incurs its own short-term debt.

Q. IS THE COMPANY'S SEPARATE CAPITAL STRUCTURE SIGNIFICANT TO ITS COST OF DEBT?

A. Yes. The Company files annual and quarterly 10K and 10Q statements with the Securities and Exchange Commission ("SEC"). These SEC filings disclose and reflect the Company's actual financial capital structure. The Company's actual capital structure is significant to its financial risk. Investors in the Company's publicly traded debt securities and the credit rating agencies have relied on the Company's actual capital structure, as reflected in these SEC filings. As a result, the use of the combination of: (i) the Company's separate capital structure; and (ii) the Company's separate costs of long-term debt and short-term debt, is supported by the regulatory principle of matching.

Q. WHAT IS THE PERCENTAGE INCREASE IN BASE RATE REVENUES PROPOSED IN THIS CASE?

A. The test-year revenue deficiency amount represents a 12.02 percent overall increase in retail revenues from base rates compared to projected 2011 retail revenues at present rates. The revenue deficiency including the 2012 step-in adjustment represents a 14.59 percent increase in retail revenues from base rates compared to projected 2011 retail revenues at present rates.

Q. DID YOU PREPARE A COST OF SERVICE STUDY THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE TEST YEAR AND FOR THE TEST YEAR WITH THE 2012 STEP-IN ADJUSTMENT?

A. Yes, under my direction, a cost of service study was prepared. Exhibit___(JMF-1), Schedule 8a contains a copy of the jurisdictional cost of service study for the test year. Exhibit___(JMF-1), Schedule 8b contains a copy of the jurisdictional cost of service study for the test year including the 2012 step-in adjustment.

V. DESCRIPTION OF COST CHANGES

Q. WHAT IS YOUR COMPARISON YEAR IN DESCRIBING COST CHANGES?

A. Consistent with the analysis provided in prior rate cases, my explanation of the key deficiency cost drivers uses a comparison to the North Dakota Public Service Commission ("PSC") ordered results from our last electric rate case (Case No. PU 07-776) which used a test year based on the 2008 budget. I will refer to the comparison year as the "2008 rate case".

A. Overview of Key Cost Drivers

Q. WHAT ARE THE MAJOR CAUSES 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___(JMF-1), Schedule 9, page 1 of 2. The major cost elements driving the revenue deficiency are related to: 1) the growth in rate base and the capital recovery requirements associated with the additional rate base investments made since the 2008 rate case; and 2) increases in operating and maintenance costs due to higher production expense (primarily nuclear), increases in transmission and higher pension and benefits reflected in administrative and general.

Q. WHAT HAVE BEEN THE MAIN REASONS FOR GROWTH IN THE COMPANY'S GENERATION PLANT INVESTMENT?

A. As described in Ms. McCarten's Direct Testimony, the Company has made several new plant investments not reflected in the 2008 rate case:

- Installation of Nobles and Merricout wind generation facilities totaling 350 MW of nameplate capacity. These projects received advance determinations of prudency in dockets PU-08-907 and PU-08-908.
- A full year of rate base for the Grand Meadow wind generation facility which was completed in November of 2008.
- Completion of our repowering project at our Riverside coal plant in Minneapolis.
- A full year of rate base for the repowering project at our High Bridge coal plant in St. Paul which was completed in May, 2008.
- Extension of the operating lives and power uprates of our Monticello and Prairie Island nuclear power plants.

In total, these specific investments account for approximately $9.0 million of the $13.9 million of capital related cost drivers shown on Exhibit___(JMF-1), Schedule 9, page 1 of 2, row 1.

Q. WHAT INCREASE HAS THERE BEEN IN THE COMPANY'S TRANSMISSION PLANT INVESTMENT?

A. As described in Mr. Ian Benson's Direct Testimony, the Company has made significant investment in transmission plant in three separate groups: system performance & interconnection, transmission serving generation and other investments. Mr. Benson's Direct Testimony breaks out the amount of investment in each category for the period 2009 through 2012. The additional transmission investment since the 2008 rate case resulted in an increase in revenue requirements of approximately $3.0 million for the North Dakota jurisdiction.

Q. WHAT ARE THE ELEMENTS OF CAPITAL RECOVERY?

A. The elements of capital recovery are: (i) depreciation, which is the ratable return of investment over its estimated service life; (ii) return on investment; and (iii) related income taxes. Depreciation expense has increased by $4.2 million since the 2008 rate case. This expense is driven by the increase in utility plant investment, including significant investment in our generating facilities and transmission system. Since the 2008 rate case, utility plant in-service investment allocated to the North Dakota jurisdiction has increased by $155.9 million.

Q. ARE THERE OTHER COST ELEMENTS RELATED TO THE AMOUNT OF UTILITY PLANT IN-SERVICE INVESTMENT?

A. Yes. Real estate and personal property taxes are directly related to utility plant in-service investment. Increases in real estate and personal property taxes result from additional investment in plant and facilities and from higher assessment levels by taxing authorities. However, more than offsetting the increase is a property tax decrease as a result of lower school district levies. As a result, the revenue requirement for real estate and property taxes has decreased by $110,000 since the 2008 rate case.

Q. PLEASE DISCUSS THE COST ELEMENTS OF THE REVENUE DEFICIENCY RELATED TO OPERATING EXPENSES.

A. Exhibit___(JMF-1), Schedule 9, Page 2 of 2, shows a summary of the change in operating expenses by functional class over the three-year span between the 2008 and the 2011 test period in this case. The schedule also shows a calculation of the average annual percent of increase over the same period.

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

A. No. Although the cost of fuel and purchased energy are considered to be an operating expense, recovery occurs through the separate Fuel Cost Rider ("FCR") mechanism and true-up process.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2011 TEST-YEAR BUDGET AND THOSE CONTAINED IN 2008 RATE CASE TEST YEAR?

A. Yes. Both periods conform to the FERC Uniform System of Accounts.

Q. ARE THE DOLLARS BY FUNCTIONAL COST CATEGORY CONSISTENT WITH THE INFORMATION PROVIDED IN THE COST OF SERVICE?

A. Yes, but with the following four exceptions:

1) Transmission revenues associated with FERC 565 expenses. Revenues for the provision of transmission service included in other electric operation revenues in the Cost of Service are related to a majority of the expense included in transmission of energy by others (FERC 565). For Schedule 9, rather than show a large increase in O&M and a large

increase in Margin, we reclassified the transmission revenue as a negative expense.

2) Nuclear Management Company ("NMC") Pension and Benefits. In the 2008 rate case, the NMC was a stand alone company. The NMC charges to the NSP operating company were reflected in NSP's budget as nuclear contract costs. This line item included NSP's portion of the pension and benefits of the NMC employees. In the 2011 test year, NMC is integrated into NSP's operations. Therefore, the pension and benefits of the former NMC employees are reflected in Administrative and General FERC account 926. In order to make a functional comparison of 2008 to 2011 on schedule 9, I have reclassified an estimate of the 2008 NMC pension and benefits costs from production to Administrative and General.

3) Economic development costs. In the 2008 rate case, economic development costs were recorded in Administrative and General. In the 2011 test year, we recorded economic development costs in the Customer Sales and Services function. In order to make a functional comparison of 2008 to 2011 on schedule 9, I reclassified the 2008 rate case economic development costs from Administrative and General to Customer Sales and Services.

4) In the 2008 cost of service, variable costs to NSPM from NSPW in the interchange bill were recorded as production expenses. In the 2011 cost of service, we have recorded these expenses as fuel since fuel costs are the primary component of the variable portion of the interchange bill. In order to make a functional comparison of 2008 to 2011 on schedule 9, I reclassified the 2008 rate case variable interchange costs from Power Production to Margin.

Q. WHAT IS THE AMOUNT OF CHANGE IN O&M COSTS SINCE 2008?

A. Excluding the cost of fuel and purchased energy, and reflecting the four adjustments discussed above, operating expenses have increased in total by $8.6 million since the 2008 rate case. Most of this change reflects higher O&M costs associated with power production, $4.2 million; transmission, $1.0 million; and administrative and general expenses, $2.7 million.

Q. WHAT HAVE BEEN THE MAIN REASONS FOR INCREASE IN O&M COSTS ASSOCIATED WITH ELECTRIC GENERATING FACILITIES?

A. For the State of North Dakota, $2.3 million of the total $4.2 million increase in O&M for electric generating facilities is nuclear related, with the remaining $1.9 million being non-nuclear. Within the $2.3 million of nuclear, the primary increases are outage costs ($1.1 million), regulatory fees ($0.6 million), and security ($0.6 million). The reasons for the nuclear increases are discussed in more detail, at the total Company level, in the testimony of Mr. Dennis L. Koehl. For the $1.9 million of non-nuclear increases, the primary increases are chemical costs ($0.7 million), and the O&M costs associated with the operation and maintenance of the Company owned wind farms ($0.5 million). Ms. Pamela Graika provides additional discussion of the non-nuclear costs increases in her testimony.

Q. PLEASE BRIEFLY DISCUSS THE MAIN REASON FOR THE INCREASE IN TRANSMISSION EXPENSE.

A. Transmission expense (adjusted for the FERC 565 revenues as discussed earlier) for the North Dakota electric retail jurisdiction has increased by $1.0 million. As discussed by Mr. Benson in his Direct Testimony, this increase is due to additional O&M costs associated with new transmission infrastructure added to the system, increased O&M for aging infrastructure and the need to fulfill North American Electric Reliability Corporation ("NERC") reliability obligations.

Q. PLEASE BRIEFLY DISCUSS THE MAIN REASON FOR THE INCREASE IN ADMINISTRATIVE AND GENERAL EXPENSE.

A. Administrative and General expense for the North Dakota electric retail jurisdiction has increased by $2.7 million. This increase is largely due to increases FERC 926 employee pensions and benefits ($1.7 million) and property and other liability insurance ($0.5 million).

Q. PLEASE DISCUSS THE COMPONENTS OF YOUR CALCULATION OF "NET SALES AND GROWTH IN MARGIN" SHOWN ON EXHIBIT___(JMF-1), SCHEDULE 9, PAGE 1, LINE 12.

A. This line item shows the change in operating revenues from the 2008 rate case to the 2011 test year. The level of kilowatt-hour sales has increased since the 2008 rate case, generating an increase in retail revenues, which has provided a partial offset to some of the effects of increasing costs of operations. This change is derived from the addition of new customers, as well as any changes in use per customer. Specifically, the gross margin was calculated by using total revenues excluding the following costs, which are recovered separately: (1) city franchise fees; (2) cost of fuel and purchased energy; and (3) transmission of energy by others for purposes of this analysis.

VI. JURISDICTIONAL COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE 2011 TEST YEAR.

A. The complete jurisdictional cost of service, in addition to the summary schedules described below, 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. Summary schedules taken from the complete jurisdictional cost of service are included in my testimony at Exhibit___(JMF-1), Schedule 8a for the 2011 test year and Exhibit___(JMF-1), Schedule 8b for the 2011 test year with the 2012 step-in adjustment. The jurisdictional cost of service study reflects all the adjustments discussed in my testimony.

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

A. The jurisdictional cost of service summary for the 2011 test year is included at Exhibit ___(JMF-1), Schedule 8a, (Pages 1-6). The jurisdictional cost of service summary for the 2011 test year with the 2012 step-in adjustment is included at Exhibit ___(JMF-1), Schedule 8b, (Pages 1-6).

- The cover page identifies the North Dakota Retail jurisdiction requested ROE, and shows the earned ROE under current rates, the revenue deficiency, and the percent of increase that would result if rates were increased to earn the requested ROE (11.25 percent).

- The "Rate Base Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 8a, Page 2 and Schedule 8b, Page 2.
- An "Income Statement Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 8a, Page 3 and Schedule 8b, Page 3. The income statement shows the determination of total operating income at present authorized retail rates.
- The "Income Tax Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 8a, Page 4 and Schedule 8b, Page 4. 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 8a, Page 3 and Schedule 8b, Page 3.
- The "Revenue Requirement and Return Summary" for total Company electric operations and the North Dakota jurisdiction is shown on Schedule 8a, Page 5 and Schedule 8b, Page 5. Specifically, the schedule shows: (i) the earned overall rate of return on rate base; (ii) the earned ROE: (iii) the revenue deficiency that needs to be recovered to enable the North Dakota jurisdiction electric operations to earn the requested ROE; and (iv) the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.
- The computation of cash working capital, Schedule 8a, Page 6 and Schedule 8b, Page 6, is carried back to the rate base on Schedule 8a, Page 2 and Schedule 8b, Page 2.

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 calculation is included in Exhibit ___(JMF-1), Schedule 10; and composite income tax rates are included in Exhibit ___(JMF-1), Schedule 8a, Page 5.

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___(JMF-1), Schedule 11 consists of comparative income statements for the test year. Page 1 of Schedule 11, is a comparative income statement for the 2011 test year and the 2011 test year including the 2012 step-in adjustment, showing the income effect of present authorized rates and proposed rates. This comparative income statement was prepared from the results of the jurisdictional cost of service study and includes the revenue deficiency in the North Dakota Jurisdiction electric utility operations. Schedule 11, Page 2 of 2, shows an electric utility comparative income statement for the North Dakota jurisdiction and total Company for the 2011 test year before making test period adjustments. The operating income statement after making the proposed test period adjustments is also shown on Page 2 of 2 as well as the adjustments included in the 2012 step-in.

VII. COMPLIANCE ISSUES AND APPLICATIONS

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

A. Yes. The following list briefly describes the various Commission Orders that were reviewed and addressed in preparing the test year. I will discuss required adjustments relating to each of these later in my testimony. The Filing Requirements Compliance Table included in the testimony of Ms. McCarten, Exhibit ___(LM-1), Schedule 2, documents how our rate case filing includes information submitted in compliance with these prior Commission orders.

1) Long Term Incentive

In Case No. PU-400-92-399, the Commission determined that long term incentive should be excluded from retail rates. Long term incentive has been excluded from the test year as part of out incentive adjustment

The Company has also 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

In Case No. PU-400-92-399, the Commission determined only organizational dues related to North Dakota electric operations were allowable for recovery in electric rates. Any organizational dues not related to the electric operations supporting the State of North Dakota have been eliminated from the test year in our association dues adjustment.

3) Nuclear Refueling Costs

In Case No. PU-07-774, the Commission determined that nuclear refueling costs shall be amortized over the life of the installed fuel. In Case No. PU-07-776, the Commission determined an appropriate level for recovery in that test year would be $2,492,407. The Company is amortizing its nuclear refueling costs as ordered and has included an amortization expense in the 2011 test year reflecting the levelized accounting. The amortization is recognized in the budget and therefore no adjustment is required.

4) Depreciation Lives

In Case No. PU-07-776, the Commission established principles for establishing depreciation rates for use in ND. Specifically:

- Extend the service lives of Sherco, Prairie Island, Angus Anson, Granite City, High Bridge, Inver Hills and Key City plants.
- Recalibrate Transmission & Distribution reserve balance.
- Use NPV method (or alternatively the 5-year average method) for Transmission & Distribution removal costs.
- Refund Monticello decommissioning accruals ($0.2 m decrease).
- Assume life extension for PI is approved.

The Company is adhering to the above items by:

- The Company's base plant information in the test year reflects the extended lives of the plants listed above.
- The recalibration of the reserve balance for Transmission and Distribution in Case No. PU-07-776 carries into the test year.
- Transmission and Distribution removal costs estimates used to determine the net salvage rates are consistent with the ordered rates in Case No. PU-07-776.
- The Monticello refund was a one time adjustment in Case No. PU-07-776 and does not carry forward to this case.

- The Company continues to assume that life extension for PI will be approved and has reflected the required longer life in the test year.

5) Expense Exclusions

In Case No. PU-07-776, the Commission ordered the following expenses to be excluded from the test year recovery:

- Expenses related to Renewable Development Fund Research and Development grants and disbursements.
- Costs associated with 50% of test-year charitable contributions.
- Costs associated with incentive compensation are capped at 15% of an individual's base salary.
- Mercury control monitoring costs.

The Company is adhering to the above items by:

- The Company has not included any RDF amortization expense in the test year.
- The Company has requested recovery of 50% of charitable contributions in the test year, but has removed them from our interim request.
- Any incentive in test year exceeding 15% of an individual's base salary has been removed as part of our incentive pay adjustment.
- The Company is requesting recovery of Mercury control monitoring and other mercury emission control costs in the test year. However, in response to the Case No. PU-07-776 order, we have removed not only the mercury control monitoring costs but all costs associated with control of mercury emissions from our interim request.

6) Demand Side Management

In Case No. PU-08-171, the Commission authorized NSP to record expenditures implementing its existing Savers Switch & Energy Control Service load management programs in a deferred account for amortization in the Company's next general rate case. The amount deferred may not exceed $266,904 per year. The Company has included in the test year an amortization of the anticipated Dec 31, 2010 deferred DSM balance of $451,000. This balance reflects two years of expenses and therefore does not exceed the annual spend limit.

VIII. UTILITY AND JURISDICTIONAL ALLOCATIONS

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

A. The test year includes both costs incurred directly by the Company's electric operating business and costs directly 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 Xcel Energy and the Service Company. Cost allocation and assignment principals have not changed since our last North Dakota electric rate case (Case No. PU-07-776). O&M cost assignments and allocations were the same as used by the Company in the recent Minnesota electric rate case filed with the Minnesota PUC (MPUC Docket No. E002/GR-10-971). Non-O&M costs include such items as book depreciation expense, deferred income taxes and property taxes. All of the common investments 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 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___(JMF-1), Schedule 12.

Q. HAVE THERE BEEN ANY CHANGES SINCE THE LAST ELECTRIC RATE CASE THAT WOULD SIGNIFICANTLY IMPACT THE PERCENTAGE OF COSTS THAT GET ASSIGNED TO NORTH DAKOTA FROM ANY OF THE ALLOCATION METHODOLOGIES DESCRIBED IN THE CAAM?

A. Yes. There are two significant changes. First, the integration of the Nuclear Management Company ("NMC") affected the level of costs allocated to the Company using the three-factor general allocator. Second, the Company serves fewer wholesale customers than we did in 2008 which results in more costs being allocated to the retail jurisdictions.

Q. PLEASE DESCRIBE THE IMPACT OF THE NMC INTEGRATION ON THE THREE FACTOR GENERAL ALLOCATOR.

A. When the NMC was operating as a subsidiary company, Service Company costs were allocated to the NMC as part of the three factor allocation. These costs, in turn, were included on the NMC bill to the NSPM Operating Company. Now that NMC has been integrated into NSPM, and is no longer a subsidiary, the former NMC employees are now included in the NSPM employee count which increase NSPM's allocation using the three factor general allocator. As a result, more costs from Service Company are directly billed to NSPM, where previously some costs were indirectly charged to NSPM through the NMC bill.

Q. PLEASE DESCRIBE THE IMPACT OF FEWER WHOLESALE CUSTOMERS ON COST ALLOCATIONS TO RETAIL JURISDICTIONS.

A. NSPM serves both retail and wholesale customers. The Company's generation facilities and transmission network are managed as an integrated system and the costs are shared equitably across all jurisdictions. Since 2008, the number of wholesale customers served by NSPM has dropped from 14 to 3. This drop in wholesale customers is reflected in the percent of NSPM costs assigned to the wholesale jurisdiction in our demand and energy allocators. For example, in the 2008 budget the demand allocator for wholesale was 1.917%, while in the 2011 budget the percent is 0.119%. The drop of nearly 1.8% in the wholesale allocator results in an increase in the retail jurisdiction allocation percentages, including the allocation to the State of North Dakota.

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

A. O&M cost assignments and allocations are summarized on Exhibit___(JMF-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 electric operations or allocated to the electric operations based on cost causation.

Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING THE COMPANY'S INVESTMENT IN ELECTRIC 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 electric operations income statement and rate base is contained in Exhibit___(JMF-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 (*i.e.* Production, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly, or allocated based on the use of such assets in providing electric service in a particular jurisdiction and the underlying elements of cost causation.

Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE INVESTMENT IN PRODUCTION AND TRANSMISSION FACILITIES.

A. The Company's production and transmission system is designed, built, and operated to provide an integrated source of electricity shared by the Company's electric customers first between the Company and NSP-Wisconsin operating companies through the Interchange Agreement as approved by FERC and discussed later in my testimony. The Company's portion of costs is then shared among customers in North Dakota, Minnesota and South Dakota, as well as a group of wholesale customers with rates regulated by FERC.

To determine the level of investment associated with the provision of electric service to North Dakota retail customers, it is necessary to assign or allocate a portion of the total production and transmission investment to each jurisdiction. We used each jurisdiction's respective coincident peak demands for electricity as the basis for this allocation. It is reasonable to use coincident peak demands as an allocation basis because these facilities are designed to meet peak requirements and operate as an integrated system across all jurisdictions. This is consistent with the methodology accepted in the last North Dakota electric rate cases, Case No. PU-07-776, and reflects the fact that these facilities have been designed to meet peak requirements.

Company owned wind projects (Grand Meadow, Nobles, Merricourt) are allocated to jurisdiction on the basis of energy instead of coincident peak demands. We feel this is a more reasonable allocation basis since wind farms are generally constructed to meet energy needs, not to meet demand requirements.

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

A. The Company's electric distribution plant investment amounts have been directly assigned based upon the jurisdiction(s) served by each of the individual distribution facilities.

IX. RATE BASE COMPONENTS

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

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

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

A. The test-year rate base is generally comprised 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

- Accumulated Deferred Income Taxes
- Other Rate Base Items

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

A. Exhibit___(JMF-1), Schedule 15, Page 1 of 3, shows a detailed statement of the Average Rate Base by component for the 2011 test year. Schedule 15, Page 2 of 3, is a comparative statement of the 2011 Test Year Average Rate Base for the North Dakota jurisdiction and total Company, before and after making proposed test period adjustments. Exhibit ___ (JMF-1), Schedule 15 page 3 of 3 is a detailed statement of the Average Rate Base by component for the 2012 Step for the North Dakota jurisdiction and total Company, before and after making the proposed step adjustment. Exhibit___(JMF-1), Schedule 3, page 2 shows the Company's actual 2009 Average Rate Base as provided in the May 3, 2010 jurisdictional annual report to the Commission.

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

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

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

A. The net utility plant is included in rate base at depreciated original cost reflecting the simple average of projected net plant balances at the beginning and end of the test year. Such treatment is consistent with the method employed in the most recent North Dakota electric rate case, Case No. PU-07-776.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY 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 Xcel Energy's actual net investment (Plant in Service less Accumulated Depreciation) on the books and records of the Company as of April 30, 2010. The budget projections for May through December 2010 were then applied to the April 30, 2010 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 2011 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.

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 $393 million, provided on Exhibit___(JMF-1), Schedule 8a, Page 2. As shown on this schedule, the average net utility plant is comprised of an average plant balance of $763 million minus an average depreciation reserve of $370 million.

B. Construction Work in Progress

Q. HAS CONSTRUCTION WORK IN PROGRESS ("CWIP") BEEN INCLUDED IN THE TEST-YEAR RATE BASE?

A. Yes. The only CWIP that is included in rate base are costs related to projects of a short-duration that do not accrue Allowance for Funds Used During Construction ("AFUDC"). Thus, there is no AFUDC offset added to operating income. The rate base amount reflects a simple average of projected CWIP beginning and ending test-year balances. This is consistent with the method employed in the most recent North Dakota electric rate case (Case No. PU-07-776) 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 April 30, 2010 actual balance. Construction expenditures, and transfers to Plant in Service during the remaining months of 2010 were netted against the April 30, 2010 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 2011 test year to obtain the ending test-year CWIP balance. These projections were developed from the Company's 2011 capital budget.

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

A. As shown on Exhibit___(JMF-1), Schedule 8a, Page 2, the average short-term CWIP included in rate base was $2.1 million.

C. Accumulated Deferred Income Taxes

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES ("ADIT").

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 tax depreciation generally 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 ARE ACCUMULATED DEFERRED INCOME TAXES DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent deferred income taxes have been allowed for recovery in rates, they represent a non-investor source of funds. Accordingly, 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 Exhibit___(JMF-1), Schedule 8a, Page 2, $79.4 million was deducted. This amount reflects a simple average of the beginning and projected ending test-year ADIT balances.

D. Other Rate Base

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

A. Other Rate Base is comprised of primarily what is referred to as Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations as discussed further 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 shown separately.

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 Exhibit___(JMF-1), Schedule 8a, Page 2, 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 $6.2 million. The test-year average rate base amount for Fuel Inventory is $5.7 million.

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

A. These balances as shown on Exhibit___(JMF-1), Schedule 8a, Page 2, represent the 2011 calendar year estimate of these balances. Any book/tax timing differences associated with these items has been reflected in the determination of current and deferred income tax provision and accumulated deferred tax balances previously discussed. This group is primarily comprised of liabilities that reduce test-year rate base by $6.2 million.

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

A. Items of 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, 2010, 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 on revenue requirements. The net impact of these various items increase test-year rate base by $4.0 million as shown on Exhibit___(JMF-1), Schedule 8a, Page 2.

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 RECENTLY APPROVED NORTH DAKOTA ELECTRIC RATE CASE (CASE NO. PU-07-776)?

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 XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST NORTH DAKOTA ELECTRIC RATE CASE (CASE NO. PU-07-776)?

A. Yes. Since Case No. PU-07-776, the Company has updated the study for the calculation of the lead and lag days for all categories except the Purchased Power Interchange lead days and the Interchange Agreement revenue lag days. All the lead/lag calculations have been updated through year end 2008, with the exception of the calculation of the retail revenue lag which was updated with data through 2009. 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 electric operations were incorporated into the North Dakota jurisdiction cash working capital rate base component as shown on Exhibit (JMF-1), Schedule 8a, Page 2.

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

A. The amount included in the average rate base is a positive $2.1 million. The detailed components and calculations associated with this amount are summarized in Exhibit___(JMF-1), Schedule 8a, Page 6.

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

A. Positive cash working capital indicates overall revenue collections lag the date when the associated costs of service are paid. This means that, on average, cash working capital is being provided by the Company's investors. In the Company's circumstance, taxing authorities comprise the largest source of cash working capital as offsets to working capital provided by the Company's investors. Other sources of offsets may include customers, creditors and employees. When a positive cash working capital exists, it is added to rate base to compensate the Company's investors for funds provided to meet cash working capital requirements.

Q. IS THE 2011 TEST-YEAR RATE BASE FOR THE XCEL ENERGY – NORTH DAKOTA JURISDICTION ELECTRIC 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 electric rate cases.

X. ADJUSTMENTS TO RATE BASE AND ASSOCIATED INCOME STATEMENT ADJUSTMENTS

Q. PLEASE IDENTIFY THE TEST-YEAR ADJUSTMENTS TO THE 2011 BUDGET FOR RATE BASE.

A. We have made rate base adjustments for data corrections, budget updates and rate case adjustments. While we refer to these as rate base adjustments, the adjustments discussed in this section also consider any income statement impacts resulting from the rate base adjustment (annual book deprecation as an example). These adjustments are listed below:

A. Data Corrections:

1) CAPX2020 In-Service Date Correction;

B. Budget Updates:

2) Bonus Tax Depreciation;

3) Wind2Battery Investment Tax Credit;

4) Monticello Projects Adjustment;

5) Prairie Island MUR Project;

6) Transmission Interconnection Funding Project;

C. Rate Case Adjustments:

7) Black Dog Units 3 and 4 Life Extension;

8) Prairie Island Life Extension;

9) Steam Production Net Salvage;

10) Other Production Net Salvage;

D. Other Ratemaking Adjustment

11) Cash Working Capital.

Each of these adjustments to rate base along with the associated adjustments to the income statement is discussed in more detail in this section of my testimony. The detailed cost items related to each adjustment can be found on the rate base bridge schedule (Exhibit ___ (JMF-1), Schedule 5a), and the income statement bridge schedule (Exhibit ___ (JMF-1), Schedule 5b).

A. Data Corrections

Q. DID YOU MAKE DATA CORRECTIONS TO THE 2011 CAPITAL BUDGET DATA IN PREPARING THE TEST-YEAR RATE BASE?

A. Yes. The following correction is required to the 2011 capital budget data in order to present a representative level of rate base for our proposed test year.

1) CAPX2020 In-Service Date Correction

Q. PLEASE DESCRIBE THE CAPX2020 IN-SERVICE DATE CORRECTION ADJUSTMENT.

A. During a thorough review of CAPX2020 project costs, we identified certain in-service dates that were incorrectly included in the 2011 budget. We calculated an adjustment to correct all affected test-year plant and plant-related items. The rate base correction of the in-service dates for the CAPX2020 project is reflected on Exhibit___(JMF-1), Schedule 5a, page 1, column 2. The operating income impacts of the correction are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 4. As shown on Schedule 5b, page 1, column 4, row 31, this adjustment decreases test-year revenue requirements by $143,000.

B. Budget Updates:

Q. DID YOU MAKE ADJUSTMENTS TO THE 2011 CAPITAL BUDGET DATA IN THE PREPARATION OF YOUR TEST-YEAR RATE BASE?

A. Yes. There were five adjustments identified during our review of the 2011 capital budget and preparation of testimony as necessary in order to present a representative level of rate base for our proposed test year.

2) Bonus Tax Depreciation

Q. PLEASE DESCRIBE THE BONUS TAX DEPRECIATION ADJUSTMENT.

A. During the preparation of our rate case test year, federal legislation was enacted that deals with bonus depreciation. Since our capital budget data did not include the effects of this tax law change, an adjustment was made to our base budget data to reflect this updated information.

Q. WHAT IS THE FEDERAL LEGISLATION THAT DEALS WITH THE BONUS DEPRECIATION?

A. The Small Business Jobs Act of 2010 was signed into law on September 27, 2010. This law contains a provision extending bonus depreciation to assets placed in service before January 1, 2011. Bonus depreciation is the tax expensing of 50 percent of the cost of an asset in the year it is placed in service. The depreciable base for tax purposes is then reduced by the amount of the bonus depreciation deduction and the balance is depreciated based on the existing tax depreciation Modified Accelerated Cost Recovery System ("MACRS") tables starting with the current year. The allowance of bonus depreciation for 2010 with a carryover effect in 2011 increases the accumulated deferred income tax balance. An increase in this balance causes a decrease in plant-related rate base.

Q. HAVE YOU FACTORED THESE CHANGES INTO THE RATE CASE DATA?

A. Yes. Annual deferred taxes and accumulated deferred taxes have been adjusted to reflect the impact of bonus tax depreciation for all qualifying assets. The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 1, column 3. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 5. As shown on Schedule 5b, page 1, column 5, row 31, this adjustment decreases test-year revenue requirements by $864,000.

3) Wind2Battery Investment Tax Credit

Q. PLEASE DESCRIBE THE WIND2BATTERY INVESTMENT TAX CREDIT ADJUSTMENT.

A. During the preparation of our rate case test year, the Company determined that the Wind2Battery project was eligible for the Investment Tax Credit.

Internal Revenue Code ("IRC") Sec. 48(a)(5) provides for an election to treat certain facilities that qualify under IRC Sec. 45 as qualified investment credit facilities for purposes of IRC Sec. 48. Based on its understanding of IRC Sec. 45 and 48, the Company's Tax Department determined that the Wind2Battery project qualified for this election. Consequently, the Company elected to take the IRC Sec. 48 investment tax credit in lieu of the IRC Sec. 45 production tax credit on this project. This election was made on the Company's tax return for tax year 2009 (filed September 10, 2010) pursuant to IRS Notice 2009-52. As a result of this decision, we updated our capital budget data to incorporate the effects of this change.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 1, column 4. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 6. As shown on Schedule 5b, page 1, column 6, row 31, this adjustment decreases test-year revenue requirements by $6,000.

4) Monticello Projects Adjustment

Q. PLEASE DESCRIBE THE MONTICELLO PROJECTS ADJUSTMENT.

A. During the preparation of testimony for the rate case, the Nuclear business area identified projects requiring updates to the capital budget data. The identified updates resulted in total company cost increases for the Monticello Life Cycle Management/Extended Power Uprate project of $5.1 million and an additional cost increase of $5.1 million for work related to the review of whether to implement the National Fire Protection Association ("NFPA")

Standard NFPA 805 at Monticello. As a result, we updated our capital budget data to incorporate the effects of these changes.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 1, column 5. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 7. As shown on Schedule 5b, page 1, column 7, row 31, this adjustment increases test-year revenue requirements by $48,000.

5) Prairie Island MUR Project

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND MUR PROJECT ADJUSTMENT.

A. During the preparation of testimony for the rate case, the Nuclear business area identified the Measurement Uncertainty Recapture ("MUR") project at Prairie Island Nuclear Plant Unit One as being installed into service on October 15, 2010, earlier than the September, 2011 in-service date included in the 2011 budget. Therefore, the capital budget data used in the development of the rate case test year was updated to reflect this change. The Prairie Island MUR project added $12.5 million of total Company investment to plant in service, approximately $2 million less than was included in the 2011 capital budget. Detail regarding this plant addition can be found in the Direct Testimony of Mr. Dennis L. Koehl.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 1, column 6. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 8. As shown on Schedule 5b, page

1, column 8, row 31, this adjustment increases test-year revenue requirements by $17,000.

6) Transmission Interconnection Funding Project

Q. PLEASE DESCRIBE THE TRANSMISSION INTERCONNECTION FUNDING PROJECT ADJUSTMENT.

A. At the time the 2011 capital budget was developed, the Midwest ISO was preparing a new tariff proposal related to cost recovery for transmission expansion projects driven (or partially necessitated by) new generation interconnection requests. The Midwest ISO tariff proposal under stakeholder review contemplated that new interconnection customers would pay none of the costs for network upgrades needed to interconnect the project. The Midwest ISO proposal ultimately filed with FERC in July 2010 proposes that the costs of large scale "multi value projects" ("MVPs") be regionalized and recovered from loads, but that network upgrades required to connect a generation project to an MVP project be borne by the interconnection customer. The Company initially established a capital expenditure budget of $17.6 million for 2011 for generation interconnection network upgrade projects, but has reduced that amount to $4 million to reflect the filed Midwest ISO cost allocation proposal. Therefore, the capital budget data used in the development of the rate case test year was updated to reflect this change.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 1, column 7. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 9. As shown on Schedule 5b, page

1, column 9, row 31, this adjustment decreases test-year revenue requirements by $11,000.

C. Rate Case Adjustments

Q. DID YOU MAKE RATE CASE ADJUSTMENTS TO THE 2011 CAPITAL BUDGET DATA IN THE PREPARATION OF YOUR TEST-YEAR RATE BASE?

A. Yes. Four rate case adjustments were made to our test-year rate base in order to present a representative level of rate base for our proposed test year.

7) Black Dog Units 3 and 4 Life Extension

Q. PLEASE DESCRIBE THE BLACK DOG UNITS 3 AND 4 LIFE EXTENSION ADJUSTMENT.

A. This adjustment reflects a life extension of our Black Dog generating plant units 3 and 4 by three years, to December 2015. This life extension is consistent with information filed with the Minnesota Public Utility Commission ("MPUC") in our 2010 Resource Plan (MPUC Docket No. E002/RP-10-825) on August 2, 2010, in which we identify our plan to replace the remaining 270 MW of coal fired generation capacity at Black Dog with a 680 MW natural gas, combined cycle unit in 2016. A copy of the Resource Plan was submitted to the PSC by cover letter dated August 2, 2010. This adjustment reflects the change in depreciation resulting from the life extension of these two units over their anticipated remaining life.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 2, column 8. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 21. As shown on Schedule 5b, page

3, column 21, row 31, this adjustment decreases test-year revenue requirements by $494,000.

8) Prairie Island Life Extension

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND LIFE EXTENSION ADJUSTMENT.

A. In Case No. PU-07-776 the PSC ordered final rates to reflect the pending life extension of Prairie Island. The order specifically required the life to be extended 20 years to a date of December 2032. This was an inconsistency as a 20 year extension would extend the life to April 2034. This adjustment corrects the inconsistency by extending the life an additional 16 months past the currently ordered remaining life.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 2, column 9. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 22. As shown on Schedule 5b, page 3, column 22, row 31, this adjustment decreases test-year revenue requirements by $49,000.

It should be noted that the life extension has not yet received NRC approvals, we anticipate NRC approval in early 2011 as discussed by in the Direct Testimony of Mr. Koehl. In the event the needed regulatory approvals for life extension and fuel storage are not received, the Company proposes identical treatment as was order in Case No. PU-07-776. The amount in the tracker account shall become a regulatory asset, with appropriate offset to accumulated depreciation, that will be recoverable from customers in a manner to be determined by the Commission in the Company's next general electric rate case.

9) Steam Net Salvage

Q. PLEASE DESCRIBE THE STEAM NET SALVAGE ADJUSTMENT.

A. Every five years the Company performs a study to evaluate removal and salvage estimates for its steam production facilities. Such a study was performed in 2010 (Minnesota Docket No. E,G002/D-10-173). The study results in revised net salvage rates used in the determination of remaining life book depreciation. This adjustment reflects the results of that study on our Steam production facilities.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 2, column 10. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 23. As shown on Schedule 5b, page 3, column 23, row 31, this adjustment increases test-year revenue requirements by $515,000.

10) Other Production Net Salvage

Q. PLEASE DESCRIBE THE OTHER PRODUCTION NET SALVAGE ADJUSTMENT.

A. This adjustment reflects the impact of the five-year removal and salvage study (as described in the Steam Production discussion) on the Company's Other projection facilities. The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(JMF-1), Schedule 5a, page 2, column 11. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 24. As shown on Schedule 5b, page 1, column 24, row 31, this adjustment increases test-year revenue requirements by $63,000.

D. Other Ratemaking Adjustment

11) Cash Working Capital

Q. HAVE YOU MADE ADJUSTMENTS TO THE INCOME STATEMENT THAT ALSO AFFECTS TEST-YEAR RATE BASE?

A. Yes. The adjustments to the income statement also led to an adjustment that increases cash working capital by $285,000. As shown on Schedule 5a, page 2, column 12. This increase in cash working capital increases test-year revenue requirements by $35,000. The result of including this adjustment is reflected on Exhibit___(JMF-1), Schedule 5b, page 4, column 36.

XI. INCOME STATEMENT

A. Revenues

Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES FOR THE TEST YEAR CONSIDERED?

A. Yes. Test-year retail sales levels assume normal weather. The test-year sales volumes are supported by the Direct Testimony of Ms. Jannell E. Marks.

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

A. Yes. This adjustment is incorporated into retail sales forecast, the effect of which is to project the level of revenues on a calendar-month basis.

Q. HAS THE COMPANY MADE SIMILAR ADJUSTMENTS IN PRIOR RATE CASES TO RECOGNIZE THE NET CHANGE IN UNBILLED REVENUES DURING THE TEST YEAR?

A. Yes. The adjustment is consistent with the methodology in the last Xcel Energy North Dakota electric and natural gas rate cases (Case Nos. PU-07-776, PU-06-525).

Q. WHAT IS THE PURPOSE OF MAKING AN UNBILLED REVENUE CALCULATION IN THE TEST YEAR?

A. The unbilled revenue calculation is used to determine the total revenue requirement for electric operations in the North Dakota jurisdiction. Including unbilled revenues in the determination of revenue requirements reflects a proper matching of revenues with expense on a calendar year basis.

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 sales to other utilities, transmission-related revenue and specific tariff charges including service activation fees, reconnection fees and others. In areas where the Company did not budget for the collection of these tariffed charges, a representative level was determined and included as part of the revenues in the cost of service study. One other source of revenues comes from billings to NSP-W under the Interchange Agreement, which I discuss in more detail below.

Q. WHAT ARE WHOLESALE MARGINS?

A. There are two categories of short-term wholesale margins (revenues less costs): asset based transactions and non-asset based transactions. Asset based sales are comprised of short-term sales of excess energy from Company owned generation assets or power purchase agreements ("PPAs") executed to serve native load customers. Non-asset based transactions are wholesale (trading) transactions undertaken to obtain margins from purchases and sales of energy unrelated to meeting the energy needs of our native load customers. The only transactions that qualify as non-asset based are third-party supplied electricity or financial transactions that are not required to meet the needs of our retail customers and that are resold.

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

A. Because asset based margins are earned by selling energy from facilities or PPAs paid for by ratepayers, all asset based margins have been credited to ratepayers. As approved in the last electric case, Case No. PU-07-776, the asset based margins were credited to customers through the FCA.

Q. WHAT IS THE COMPANY RECOMMENDING WITH RESPECT TO ASSET BASED MARGINS IN ITS APPLICATION AND WHY?

A. For all of the reasons that supported crediting 100 percent of the asset based margins through the FCA in the prior case, the Company recommends that same mechanism going forward.

Q. HOW HAVE THE COSTS OF NON-ASSET BASED MARGINS BEEN ADDRESSED IN PRIOR RATE CASES?

A. In the last electric rate case, the Company received approval to use a 50/50 percent margin sharing mechanism of non-asset based trading margins. The sharing mechanism was selected as a reasonable balance of ratepayer and Company interests. By sharing with ratepayers 50 percent of the margins, the incremental cost of producing the margins was reimbursed along with a reasonable contribution to joint and common costs. The customer portion was approved to be credited through the FCA.

Q. WHAT IS THE COMPANY RECOMMENDING IN THIS CASE?

A. The Company recommends continuing the existing 50/50 sharing mechanism as an appropriate balance of ratepayer and Company interests and continue crediting customers through the FCA.

B. Operating and Maintenance Expenses

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST-YEAR PRODUCTION EXPENSE BUDGET?

A. The main area of expense in the production expense budget is fuel and purchased power. These expenses are developed through a production budget prepared to serve the combined energy and demand requirements of both the Company and NSP-Wisconsin. Our Risk Management Department conducts a PROSYM model run based on the forecasted system sales to derive the forecasted fuel and energy costs. The total system fuel and energy costs are then adjusted to remove the cost of inter-system sales and other non-recoverable fuel items so that a base cost of fuel is derived that only recovers the appropriate North Dakota jurisdictional share of these system fuel costs. The Energy Markets group also forecasts our capacity purchases for contracts that will be in place during the test year and for short-term seasonal capacity purchases for the summer season, as well as transmission expenses forecast to be paid to others.

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSP-WISCONSIN THAT YOU REFERENCED EARLIER.

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

Q. PLEASE DESCRIBE THE COSTS ALLOCATED BETWEEN THE COMPANY AND NSP-WISCONSIN UNDER THE INTERCHANGE AGREEMENT.

A. Under the Interchange Agreement, the Company and NSP-Wisconsin share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 15 percent of the costs of the Company system are allocated to NSP-Wisconsin, and approximately 85 percent of the NSP-Wisconsin system costs are allocated to the Company, because approximately 85 percent of the load on the integrated system is the Company load and 15 percent is NSP-Wisconsin load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually. The Interchange Agreement also provides for an allocation of revenues received by the Company and NSP-Wisconsin, such as revenues from off-system wholesale sales. Interchange Agreement costs and revenues are budgeted by the Company and NSP-Wisconsin annually. Thus, the Company's budget shows Interchange Revenues -- revenues that reflect the charges to NSP-Wisconsin for its share of production and transmission assets and associated expenses. Likewise, Interchange Expense reflects the Company's forecasted payments to NSP-Wisconsin for its proportionate share of the costs of generation and transmission assets and associated expenses incurred by NSP-Wisconsin to serve the system needs.

C. Depreciation Expense

Q. PLEASE IDENTIFY THE DOCKETS ASSOCIATED WITH THE DEPRECIATION RATES USED IN THIS PROCEEDING.

A. Depreciation Expense for the test year reflects the depreciation rates as ordered in Case No. PU-07-776. Where the Company proposes a depreciation rate change, that change is reflected as an adjustment on the bridge schedule (Exhibit ___(JMF-1), Schedule 5b for review in this case.

D. Lobbying Expense

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

A. No. Beginning in 1999, Northern States Power Company has 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.

XII. ADJUSTMENTS TO THE INCOME STATEMENT

Q. PLEASE IDENTIFY THE ADJUSTMENTS TO THE INCOME STATEMENT.

A. I have already discussed the adjustments to the Income Statement associated with the changes to rate base. We also made income statement adjustments for the following items:

A. Data Corrections:

1) SMMPA Worker Comp Billing
2) Transmission Charge to Proper Subledgers

B. Budget Update Adjustments:

3) LiDAR Tree Trimming
4) Bad Debt Update
5) Qwest Pole Attachment Project
6) Joint Pricing Zone Update
7) Nuclear Fees
8) Sherco Unit 3 Mercury Sorbent

C. Traditional Adjustments:

9) Economic Development
10) Advertising
11) Association Dues
12) Donations
13) Interest on Customer Deposits

D. Rate Case Adjustments:

14) Asset and Non-Asset Trading Margins
15) Wholesale Billing Adjustment
16) Incentive Pay Adjustment
17) Leases on Vacant Buildings
18) Aviation
19) Employee Expense Adjustment

E. Amortizations:

20) Private Fuel Storage Amortization

21) 2011 Rate Case Cost Amortization

22) 2011 SO2 Emission Allowances

23) 2011 DSM

F. Other Ratemaking Adjustments:

24) Cost of Capital

Each of these adjustments to the income statement is discussed in more detail in this section of my testimony. The detailed cost items related to each adjustment can be found on the income statement bridge schedule (Exhibit ___(JMF-1), Schedule 5b.

A. Data Corrections:

1) SMMPA Workers Compensation Billing

Q. PLEASE DESCRIBE THE ADJUSTMENT TO CORRECT WORKERS COMP BILLINGS TO SMMPA.

A. The 2007-08 Virchow-Krause Sherco 3 billing audit (issued in December 2009) noted a discrepancy between the Southern Minnesota Municipal Power Agency ("SMMPA") Settlement Agreement and the Sherco 3 billing. When NSP merged into Xcel Energy Inc. and LFMS (NSP's legacy general ledger system) was replaced by JDE (Xcel Energy's current general ledger system), the mapping to new object accounts inadvertently created violations of the SMMPA Settlement Agreement. The audit revealed that certain workers compensation costs explicitly excluded from Sherco 3 billings per the SMMPA Settlement Agreement were being charged to SMMPA.

The 2011 budget included this workers compensation billing error. The test-year adjustment removes these billing credits from the Sherco 3 budget (SMMPA share) to reflect that the credit will be less than the amount calculated in the 2011 budget.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 2. As shown on Schedule 5b, page 1, column 2, row 31, this adjustment increases test-year revenue requirements by $7,000.

2) Transmission Charge to Proper Subledgers.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO CORRECT TRANSMISSION BUSINESS AREAS SUBLEDGERS.

A. Also discussed by Mr. Benson, during the budgeting process, an error was made in assigning subledger accounts to the accounting record for certain transmission maintenance work. Because the subledger used was a generation subledger, the SMMPA billing process created credits to reflect anticipated billings to SMMPA. The test-year adjustment reflects the correction of the subledger accounts which then corrects the FERC account assignment and reverses the SMMPA billing credits.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 1, column 3. As shown on Schedule 5b, page 1, column 3, row 31, this adjustment increases test-year revenue requirements by $12,000.

B. Budget Update Adjustments:

3) LiDAR Tree Trimming

Q. PLEASE DESCRIBE THE LIDAR TREE TRIMMING BUDGET UPDATE.

A. Light Detection and Ranging ("LiDAR") is a three-dimensional scanning laser range finder used in vegetation management. The device is used to ensure adequate tree-to-conductor clearances for NERC reliability standards compliance purposes and generating smart maps to be used to plan routine maintenance activities. Approximately $211,000 ($10,000 allocated to the North Dakota jurisdiction) of the original 2011 transmission expense budget for LiDAR was accelerated into 2010. Since this change occurred after the 2011 budget was complete, we are excluding the amount from the test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 10. As shown on Schedule 5b, page 2, column 10, row 31, this adjustment decreases test-year revenue requirements by $10,000.

4) Bad Debt Update

Q. WHAT IS THE LEVEL OF BAD DEBT EXPENSE INCLUDED IN THE TEST YEAR?

A. The level of bad debt expense included in the test year for the North Dakota electric jurisdiction is $785,000. The total bad debt expense consists of two components: first, a commodity bad debt expense of $777,000; and second, a non-energy related bad debt expense of $8,000.

Q. WHY IS THE COMPANY RECOMMENDING AN UPDATE TO THE 2011 BUDGET BAD DEBT EXPENSE?

A. The original budget calculation for bad debt expense was generated during the budget-create process in May of 2010. In preparing the test year income statement, we reviewed our bad debt calculation and updated it with the revenue forecast included in the rate case test year. The result of this review indicated that the 2011 budget bad debt expense level assigned to the North Dakota Electric Jurisdiction should be decreased by $46,000.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 11. As shown on Schedule 5b, page 2, column 11, row 31, this adjustment decreases test - year revenue requirements by $46,000.

5) Qwest Pole Attachment Project

Q. PLEASE DESCRIBE THE QWEST POLE ATTACHMENT PROJECT BUDGET UPDATE.

A. During recent communications with Qwest, the Distribution business area was informed that Qwest is expanding their pole replacement program, which will require the Company to transfer our distribution facility pole attachments from existing Qwest poles to new Qwest poles. Although some pole replacements are done annually, Qwest's expanded program requires us to increase our budgeted amount to accommodate their pole replacement program.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 12. As shown on Schedule 5b, page 2, column 12, row 31, this adjustment increases test-year revenue requirements by $18,000.

6) Joint Pricing Zone Update

Q. PLEASE DESCRIBE THE JOINT PRICING ZONE BUDGET UPDATE ADJUSTMENT.

A. The test year reflects the 2011 forecast payments to Great River Energy ("GRE"), SMMPA and other Midwest ISO transmission owners that own transmission facilities in the NSP System pricing zone. The test year also reflects the forecast payments to GRE under a separate Joint Pricing Zone Agreement with GRE that includes Company facilities in the GRE pricing zone. An adjustment was made to the 2011 budget to update the budgeted amount to the NSP Zone rate that will be in effect during 2011.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 13. As shown on Schedule 5b, page 2, column 13, row 31, this adjustment decreases test-year revenue requirements by $43,000.

7) Nuclear Fees

Q. PLEASE DESCRIBE THE NUCLEAR FEE BUDGET UPDATE.

A. During the preparation of testimony and review of budget data, the Nuclear business area determined that the level of nuclear fees included in the 2011 budget should be reduced. This reduction is explained in greater detail in the Direct Testimony of Mr. Koehl.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 14. As shown on Schedule 5b, page 2, column 14, row 31, this adjustment decreases test-year revenue requirements by $83,000.

8) Sherco Unit 3 Mercury Sorbent

Q. PLEASE DESCRIBE THE SHERCO UNIT 3 MERCURY SORBENT BUDGET UPDATE.

A. During preparation of rate case testimony, the Energy Supply business area revised their 2011 budget for Sherco Unit 3 mercury sorbent costs. The revised forecast reduces the mercury sorbent costs included in the 2011 test year. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 15. As shown on Schedule 5b, page 2, column 15, row 31, this adjustment decreases test-year revenue requirements by $52,000.

C. Traditional Adjustments:

9) Economic Development

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR ECONOMIC DEVELOPMENT COSTS.

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. Because all economic development costs were recorded as below-the-line donations, an adjustment is necessary to include economic development contributions. This treatment is consistent with prior regulatory treatment in North Dakota.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 16. As shown on Schedule 5b, page 2, column 16, row 31, this adjustment increases test-year revenue requirements by $64,000.

10) Advertising

Q. PLEASE DESCRIBE THE ADVERTISING EXPENSE ADJUSTMENT?

A. The Company has reduced administrative and general expenses for brand and image advertising costs, which is consistent with past North Dakota electric rate case orders. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 17. As shown on Schedule 5b, page 2, column 17, row 31, this adjustment decreases test-year revenue requirements by $214,000.

11) Association Dues

Q. PLEASE DESCRIBE THE ORGANIZATIONAL DUES INCLUDED IN TEST-YEAR EXPENSE.

A. In Case No. PU-400-92-399, the Commission determined only organizational dues related to North Dakota electric operations were allowable for recovery in electric rates. This adjustment removes any organizational dues not related to the electric operations supporting the State of North Dakota The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 18. As shown on Schedule 5b, page 2, column 18, row 31, this adjustment decreases test-year revenue requirements by $3,000.

12) Donations

Q. HAVE YOU INCLUDED AMOUNTS IN THE TEST-YEAR COST OF SERVICE RELATED TO CHARITABLE CONTRIBUTIONS?

A. Yes. The Company is proposing to include fifty percent of charitable contributions attributable to the State of North Dakota in the test year. An analysis was performed on contribution detail to insure that only amounts contributed to charities and institutions that could be associated with the electric service territory in the North Dakota jurisdiction were included in the cost of service. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 19. As shown on Schedule 5b, page 2, column 19, row 31, this adjustment increases test-year revenue requirements by $132,000.

13) Interest on Customer Deposits

Q. HOW ARE CUSTOMER DEPOSITS TREATED IN THIS APPLICATION?

A. Customer deposits are treated as customer supplied capital and thus it is appropriate to pay ratepayers a return on that investment while also recovering the interest paid on those deposits. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 2, column 20. As shown on Schedule 5b, page 2, column 20, row 31, this adjustment increases test-year revenue requirements by $1,000.

D. Rate Case Adjustments:

Q. DID YOU MAKE ADDITIONAL RATE CASE ADJUSTMENTS TO THE TEST-YEAR INCOME STATEMENT?

A. Yes. I am proposing the following additional rate case adjustments to the test-year income statement.

14) Asset and Non-Asset Trading Margins

Q. WHAT MECHANISM IS THE COMPANY RECOMMENDING FOR TREATMENT OF WHOLESALE SALES MARGINS IN THIS PROCEEDING?

A. I earlier discussed the Company's recommendation to continue the existing mechanisms established in the 2008 test-year rate case: (i) return of 100 percent of the asset-based margins to ratepayers; and (ii) 50/50 percent ratepayer/shareholder sharing for non-asset based margins. The margin revenues from both types of wholesale sales would continue to be a credit to the FCA.

Q. PLEASE DESCRIBE THE ASSET/NON-ASSET BASED TRADING ADJUSTMENT.

A. The adjustment to Asset Based Margins excludes the asset based and non-asset based trading margins from the test-year deficiency. I make this adjustment so that no portion of the deficiency is reduced by the increased revenues provided from these margins since the margins already reduce rates through the FCA.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 25. As shown on Schedule 5b, page 3, column 25, row 31, this adjustment increases test-year revenue requirements by $975,000. This increase is offset by the amount of actual asset based and non-asset based margins credited to the fuel cost revenue requirement on a going forward basis in the FCA.

15) Wholesale Billing Adjustment

Q. PLEASE DESCRIBE THE WHOLESALE BILLING ADJUSTMENT.

A. In a review of cost assignments to our wholesale jurisdiction, we determined that the costs assigned to wholesale did not fairly represents the cost of providing billing and account management services to these customers. This adjustment directly assigns additional costs of $172,000 related to customer billing and account management expenses to the wholesale jurisdiction and likewise decreases costs assigned to the retail jurisdictions.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 26. As shown on Schedule 5b, page 3, column 26, row 31, this adjustment decreases test-year revenue requirements by $11,000 (North Dakota's portion of the $172,000).

16) Incentive Compensation Adjustment

Q. PLEASE SUMMARIZE ADJUSTMENTS MADE TO THE TEST-YEAR COST OF SERVICE TO EXCLUDE COSTS FOR PARTS OF THE COMPANY'S ANNUAL INCENTIVE COMPENSATION PROGRAMS.

A. Consistent with the Commission's Order in the Company's previous electric rate case (Case No. PU-07-776), the test-year reflects the exclusion of the long-term portion of the officer's incentive compensation, any non-corporate incentive plan costs, and all incentive plan costs above fifteen percent of base pay. The Company's annual incentive compensation programs were budgeted at 85% of the target level for 2011, which is consistent with the order in Case No PU-07-776. We therefore made no additional adjustment.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 27. As shown on Schedule 5b, page 3, column 27, row 31, this adjustment decreases test-year revenue requirements by $513,000.

17) Leases on Vacant Buildings

Q. PLEASE DESCRIBE THE ADJUSTMENT TO EXCLUDE LEASES ON VACANT BUILDINGS.

A. During the summer of 2010, two Xcel Energy Inc. office locations in downtown Denver (the 17th Street Plaza and the Technical Services Building) were consolidated into the new 1800 Larimer building. XES personnel serving the Company have been located in those offices. Even though these facilities are vacated, the associated lease payments continue into 2011 and were, consequently, included in the 2011 budget. Since these costs will not continue and, therefore, would not be representative of costs necessary to serve customers on a going forward basis, we excluded them from our 2011 test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 28. As shown on Schedule 5b, page 3, column 28, row 31, this adjustment decreases test-year revenue requirements by $24,000.

18) Aviation

Q. PLEASE DESCRIBE THE AVIATION ADJUSTMENT.

A. Xcel Energy Inc. owns and operates two aircraft for use of Company personnel. The NSPM electric utility was allocated approximately $1.7 million in costs related to the operation of these two aircraft for 2011, with $99,000 allocated to the State of North Dakota electric jurisdiction. These costs are incurred in lieu of commercial aviation transportation and help to facilitate the efficient use of executive time. The Company believes that use of corporate aircraft is cost effective. After carefully reviewing the costs and benefits of these aircraft, we are reducing the costs included in our test year to include only the costs of one of our corporate aircraft. We believe that this adjustment results in a conservative cost in relation to the benefits obtained. To achieve this test-year cost level, we are reducing the amount included in the 2011 test year by $49,000.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 29. As shown on Schedule 5b, page 3, column 29, row 31, this adjustment decreases test-year revenue requirements by $49,000.

19) Employee Expense Adjustment

Q. PLEASE DESCRIBE THE EMPLOYEE EXPENSE ADJUSTMENT.

A. The employee expense adjustment resulted from a review of 2009 actual accounting transactions. The review identified certain costs recorded to operating accounts and assigned to the North Dakota electric jurisdiction that did not meet accounting guidelines as recoverable from customers. We searched employee expense transactions allocated or assigned to the Company and recorded to operating accounts electronically for incorrectly recorded transactions through the use of key words and categories. An additional manual review was done of transactions recorded outside our employee expense system to identify similar transactions accounted for incorrectly. For the State of North Dakota electric jurisdiction, approximately $26,000 was identified through these reviews. Since the Company's 2011 budget data could have been developed using historical data that included these transactions, we are reducing our 2011 test-year employee expenses by this amount.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 3, column 30. As shown on Schedule 5b, page 3, column 30, row 31, this adjustment decreases test-year revenue requirements by $26,000.

E. Amortizations:

Q. ARE YOU PROPOSING TO AMORTIZE ANY TEST-YEAR EXPENSES?

A. Yes. I am proposing to amortize the following test-year expenses over a two-year period in order to normalize those expenses and prevent their over recovery. I am recommending a two-year amortization period (with the exception of private fuel storage) because we anticipate filing another electric general rate case within two years.

20) Private Fuel Storage Amortization

Q. PLEASE DESCRIBE THE RATE CASE PRIVATE FUEL STORAGE AMORTIZATION.

A. The Company spent approximately $23 million to obtain an NRC license for Private Fuel Storage, a private independent spent fuel storage installation within the Goshute Indian tribal land in Utah. Of the $23 million, $1.14 million is assigned to the State of North Dakota. In the 2008 rate case, the Commission approved a six-year amortization of the $1.14 million beginning in 2008. Based on a six-year schedule, 2011 would be the third year of amortization. The unamortized balance at year end 2010 will be approximately $588,000. Since the approved amortization in the last case extends for three years, we propose to continue the amortization over the currently approved period. A three year amortization would result in an annual amortization expense of $190,000.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 4, column 31. As shown on Schedule 5b, page 4, column 31, row 31, this adjustment increases test-year revenue requirements by $190,000.

21) 2011 Rate Case Expense Amortization

Q. PLEASE DESCRIBE THE 2011 RATE CASE EXPENSES AMORTIZATION.

A. The Company requests approval of $562,000 of projected direct expenses associated with this rate case docket and a two-year amortization period, resulting in an annual amortization amount of $281,000. A two-year amortization period is consistent with our requested amortization period for other amortizations in the rate case and is the period in which we expect rates resulting from this rate case to be in effect.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(JMF-1), Schedule 5b, page 4, column 32. As shown on Schedule 5b, page 4, column 32, row 31, this adjustment increases test-year revenue requirements by $281,000.

22) 2011 SO2 Emission Allowances

Q. PLEASE DESCRIBE THE 2011 RATE CASE SO2 ALLOWANCES AMORTIZATION.

A. The Company has placed the proceeds from emission allowance sales into FERC account 254, Other Regulatory Liabilities, pending a determination of the ratemaking treatment of the gains from such transactions. Our 2011 request includes a two-year amortization of the anticipated December 2010 balance of $260,000, which results in an annual amortization credit of $130,000.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(JMF-1), Schedule 5b, page 4, column 33. As shown on Schedule 5b, page 4, column 33, row 31, this adjustment decreases test-year revenue requirements by $130,000.

23) 2011 DSM

Q. PLEASE DESCRIBE THE 2011 DSM AMORTIZATION.

A. In Case No. PU-08-171, Demand Side Management & Cost Recovery Rider Tariff, the Commission order states

"NSP is authorized to record expenditures to further promote its existing Savers Switch and Peak & Energy Control Service load management programs in a deferred account for amortization in NSP's next general rate case. The amount deferred may not exceed $266,904 per year".

In the 2009 and 2010 calendar years, the Company has a projected deferred balance related to DSM of $451,000. We are therefore proposing a two-year amortization of $226,000 per year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(JMF-1), Schedule 5b, page 4, column 34. As shown on Schedule 5b, page 4, column 34, row 31, this adjustment increases test-year revenue requirements by $226,000.

In addition to the amortization of the past years balance, the Company has included $266,904 in its 2011 test-year O&M budget related to DSM. This represents the anticipated ongoing annual expense for DSM.

F. Other Ratemaking Adjustments

24) Change in the Cost of Capital

The revenue requirements associated with the above adjustments described in sections X and XII of my testimony are calculated using the approved cost of capital in Case No. PU-07-776. We calculate the revenue requirement impact of each adjustment at our currently authorized overall cost of capital of 8.80 percent (which includes a ROE of 10.75 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, shown on Exhibit___(JMF-1), Schedule 5b, page 4, column 35, reflects the impact of the change in the approved and proposed cost of capital (8.74% with an 11.25% ROE) for all of the rate base and income statement adjustments. As shown on Schedule 5b, page 4, column 35, row 31, this decreases test-year revenue requirements by $12,000.

XIII. CONCLUSION

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION?

A. I recommend that the Commission determine an overall retail revenue requirement of $184.277 million and 2011 revenue deficiency of $19.773 million for the Company's North Dakota jurisdictional electric operation, determined by the cost of service for the 2011 test year. I also recommend the Commission grant an interim rate increase of $17.355 million for the Company's North Dakota jurisdictional operation. I also recommend the Commission approve the proposed 2012 step-in adjustment of $4.226 million supported by Ms McCarten and Ms. Heuer to be included when final rates are established in 2012.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota corporation For Authority to Increase Rates for Electric Service in North Dakota	)	Case No. PU-10-___

AFFIDAVIT OF
John M. Felling

I, the undersigned, being 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.

John M Felling
John M. Felling

Subscribed and sworn to before me, this 16th day of December, 2010.

Anne Johnson
Notary Public

Notary Public
State of Minnesota
My Commission Expires January 31, 2012

Principal Analyst
Revenue Analysis

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

Current Responsibilities

Since May 2007, I have been a principal analyst in the Revenue Analysis Department. In this position, I am responsible for the preparation and analysis of cost of service studies, revenue requirement determinations and jurisdictional annual reports for the electric and gas rates filed on behalf of Northern States Power Company, a Minnesota corporation, with the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, and the South Dakota Public Utilities Commission.

Previous Employment (1981 to 2007)

Senior Analyst, Business Analytics – Xcel Energy Services Inc.
Manager, Financial Reporting – Xcel Energy Services Inc.
Project Director, Systems Integration – Xcel Energy Services Inc.
Team Lead, Delivery Finance – NSP
Manager, Corporate Budgeting – NSP
Senior Financial Analyst, Substation Engineering – NSP
Systems Developer, Information Technology – NSP
Analyst, Load and Market Research – NSP

Education

University of Minnesota, Minneapolis, Minnesota
Bachelor of Arts – Statistics
June 1980

Index of Schedules

ROE = 9.83%
Deficiency = $2,115
% Increase = 1.33%
Required ROE = 10.75%

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2009 Actuals

Summary Reports

[redacted]

Printed: 12/16/2010 13:04

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2009 Actuals
(Dollars in Thousands)

Rate Base Summary

		Total Company Electric			ND Retail Electric			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	11,512,058	12,228,752	11,870,405	618,475	654,833	636,654	10,893,583	11,573,919	11,233,751
2	Depreciation Reserve	(5,896,696)	(6,095,656)	(5,996,176)	(328,402)	(336,373)	(332,388)	(5,568,294)	(5,759,283)	(5,663,788)
3	Net Utility Plant	5,615,362	6,133,096	5,874,229	290,073	318,460	304,266	5,325,289	5,814,636	5,569,963
4	C.W.I.P.	148,908	137,757	143,333	8,472	7,976	8,224	140,436	129,781	135,109
5	Accumulated Deferred Taxes	(967,756)	(1,120,289)	(1,044,023)	(51,939)	(60,013)	(55,976)	(915,817)	(1,060,276)	(988,047)
	Other Rate Base:									
6	Cash Working Capital	0	0	0	0	0	0	0	0	0
7	Materials & Supplies	100,549	100,549	100,549	5,770	5,770	5,770	94,779	94,779	94,779
8	Fuel Inventory	99,614	99,614	99,614	6,119	6,119	6,119	93,495	93,495	93,495
9	Non-Plant Assets & Liab	(122,087)	(123,027)	(122,557)	(7,129)	(7,184)	(7,157)	(114,958)	(115,843)	(115,400)
10	Prepaids & Other	39,904	59,997	49,951	3,170	4,156	3,663	36,734	55,841	46,288
11	**Total Rate Base**	**4,914,494**	**5,287,697**	**5,101,096**	**254,536**	**275,284**	**264,909**	**4,659,958**	**5,012,413**	**4,836,187**

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2009 Actuals
(Dollars in Thousands)

Income Statement Summary

		Total Company Electric	ND Retail Electric	All Other
	Operating Revenues			
1	Retail	2,778,353	159,574	2,618,779
2	CIP Adjustment to Program Costs	0	-	0
3	Interdepartmental	414	-	414
4	Other Operating	667,097	36,842	630,255
5	Gross Earnings Tax	0	-	0
6	**Total Operating Revenues**	**3,445,864**	**196,416**	**3,249,448**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,165,683	72,993	1,092,690
8	Power Production	668,021	38,429	629,592
9	Transmission	160,634	9,301	151,333
10	Distribution	102,530	5,612	96,918
11	Customer Accounting	60,986	4,583	56,403
12	Customer Service & Information	60,889	280	60,609
13	Sales, Econ Dvlp & Other	294	50	244
14	Administrative & General	188,000	12,070	175,930
15	Total Operating Expenses	2,407,037	143,318	2,263,719
16	Depreciation	277,692	14,598	263,094
17	Amortization	41,678	294	41,384
	Taxes:			
18	Property	102,902	5,065	97,837
19	Gross Earnings	0	-	0
20	Deferred Income Tax & ITC	149,739	7,962	141,777
21	State & Federal Income (see Page 3)	25,426	1,727	23,699
22	Payroll & Other	29,006	1,743	27,263
23	Total Taxes	307,073	16,497	290,576
24	**Total Expenses**	**3,033,480**	**174,707**	**2,858,773**
25	AFUDC	0	-	0
26	**Total Operating Income**	**412,384**	**21,709**	**390,675**

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2009 Actuals
(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	ND Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,445,864	196,416	3,249,448
2	less: Total Operating Expenses	(2,407,037)	(143,318)	(2,263,719)
3	Book Depreciation & Amortization	(319,370)	(14,892)	(304,478)
4	Taxes (Other Than Current Income)	(281,647)	(14,770)	(266,877)
5	**Total Before Tax Book Income**	**437,810**	**23,436**	**414,374**
	Tax Additions			
6	Book Depreciation	277,692	14,598	263,094
7	Deferred Income Taxes & ITC	149,739	7,962	141,777
8	Nuclear Fuel Burn (ex D&D)	92,085	5,225	86,860
9	Nuclear Outage Accounting	35,729	2,307	33,422
10	Avoided Tax Interest	28,858	1,611	27,247
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	**Total Tax Additions**	**584,103**	**31,703**	**552,400**
	Tax Deductions			
18	Debt Interest Expense	156,094	8,106	147,987
19	Tax Depreciation & Removal	768,367	40,466	727,901
20	Manufacture Production Deduction	1,657	98	1,559
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	10,704	691	10,013
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**936,822**	**49,361**	**887,460**
27	**State Taxable Income**	**85,091**	**5,778**	**79,314**
28	State Income Tax Rate	9.00%	6.50%	N/A
29	State Taxes before Credits	7,662	376	7,287
30	State Credits	531	0	531
31	**Total State Income Taxes**	**7,131**	**376**	**6,756**
32	**Federal Taxable Income**	**77,960**	**5,402**	**72,558**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	27,286	1,891	25,395
35	Federal Tax Credits	8,991	539	8,452
36	**Total Federal Income Taxes**	**18,295**	**1,352**	**16,943**
37	**Total Federal & State Income Taxes**	25,426	1,727	23,699

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.5714%	46.3727%	3.0500%
2	Short Term Debt	0.9669%	1.3932%	0.0100%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	10.7500%	52.2341%	5.6200%
5	**Required Rate of Return**			**8.6800%**

Composite Income Tax Rates		
State of North Dakota Tax rate		6.50%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		32.73%
Total North Dakota Composite Tax Rate		**39.23%**
Total Corporate Composite Tax Rate		**40.85%**

		Total Company Electric	ND Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	412,384	21,709	390,675
7	Total Average Rate Base	5,101,096	264,909	4,836,187
8	**ROR** (Operating Income / Rate Base)	**8.08%**	**8.19%**	**8.08%**
	Return on Equity (ROE)			
9	Total Operating Income	412,384	21,709	390,675
10	Debt Interest (Rate Base * Weighted Debt Cost)	(156,094)	(8,106)	(147,987)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	256,290	13,602	242,688
13	Equity Rate Base (Rate Base * Equity Ratio)	2,664,512	138,373	2,526,139
14	**ROE** (Earnings for Common / Equity Rate Base)	**9.62%**	**9.83%**	**9.61%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	442,775	22,994	419,781
16	Operating Income	412,384	21,709	390,675
17	Operating Income Deficiency	30,391	1,285	29,106
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69070	1.64541	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**51,383**	**2,115**	**49,268**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,778,767	159,574	2,619,193
21	Revenue Deficiency	51,383	2,115	49,268
22	**Total Retail Revenue Requirements**	**2,830,150**	**161,689**	**2,668,461**
23	**Percentage Increase (Decrease)**	**1.85%**	**1.33%**	**1.88%**

Adjustment Type	Adjustment	Adjustment Description
Data Correction	SMMPA Worker Comp Billing	Corrects an error in the SMMPA bill pertaining to workers comp
Data Correction	Transmission Charges to Proper Sub ledgers	Corrects some transmission budget items that were billed to the wrong accounts
Data Correction	Transmission CAPX2020	Corrects some in service dates that were incorrectly budgeted
Budget Adjustment - plant related	Bonus Tax Depreciation	Adjusts for the tax law extending bonus tax depreciation on 2010 in service projects
Budget Adjustment - plant related	Wind to Battery ITC	Adjusts the budget to recognize the investment tax credit attributable to the Wind to Battery project
Budget Adjustment - plant related	Nuclear Production Monticello	Adjusts for various updates to nuclear projects at Monticello reflecting information not available when budget was finalized
Budget Adjustment - plant related	Nuclear Production MUR PI	Measurement Uncertainty Recapture (MUR) project at PI went into service in Sept 2010, earlier than budgeted
Budget Adjustment - plant related	Transmission Interconnect Agreement	Adjusts for changes in the Midwest ISO tariff
Budget Adjustment - non plant related	Transmission Tree Trimming (LIDAR)	Reflects an acceleration of Light Detection and Ranging (LIDAR) from 2011 to 2010 after the budget was completed
Budget Adjustment - non plant related	Bad Debt	To update the revenues to reflect latest revenues in test year
Budget Adjustment - non plant related	Qwest Pole Replacement	Reflects cost increases associated with higher volumes of equipment transfers to new QWEST poles than was budgeted
Budget Adjustment - non plant related	Joint Zonal Rate Update	Reduced transmission expenses resulting from a revised joint zonal tariff rate
Budget Adjustment - non plant related	Nuclear Fees	Adjusts for reduced fees at our nuclear plants
Budget Adjustment - non plant related	Mercury Sorbent Reduction at Sherco 3	Mercury sorbent costs at Sherco 3 are anticipated to be less than was budgeted
Traditional Adjustments	Economic Development	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Traditional Adjustments	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
Traditional Adjustments	Association Dues	Traditional adjustment made for Association Dues to adjust to allowed level of recovery
Traditional Adjustments	Donations	Traditional adjustment made for donations to adjust to allowed level of recovery
Traditional Adjustments	Interest on Customer Deposits	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Rate Case Adjustments - plant related	Steam Production Black Dog 3 & 4	Adjusts for the anticipated extended life of Black Dog units 3&4, from 2012 to 2015
Rate Case Adjustments - plant related	Prairie Island Life Extension	Adjusts for the correction of remaining life at PI as a result of conflicting order statements in PU-07-776
Rate Case Adjustments - plant related	Steam Production Net Salvage	Adjusts for the proposed revisions to net salvage rates for Steam Production
Rate Case Adjustments - plant related	Other Production Net Salvage	Adjusts for the proposed revisions to net salvage rates for Other Production
Rate Case Adjustments - non plant related	Asset & Non-Asset Margin Sharing	Adjusts for 100% margin sharing of asset based sales and 25% of non-asset based sales
Rate Case Adjustments - non plant related	Wholesale Billing	To allocate an appropriate level of costs to wholesale
Rate Case Adjustments - non plant related	Incentive Pay	Excludes items not eligible for recovery
Rate Case Adjustments - non plant related	Lease Expense for Vacated Buildings	Adjusts out any lease costs in the test year related to now vacated buildings
Rate Case Adjustments - non plant related	Aviation	Remove 50% of aviation costs
Rate Case Adjustments - non plant related	Employee Expenses	To ensure no inappropriate costs are included in test year based on a study of 2009 costs
Rate Case Adjustments - amortizations	2008 Private Fuel Storage	The remaining 3 years of a 6 year amortization for private fuel storage approved in the 2007 case
Rate Case Adjustments - amortizations	2011 Rate Case	The proposed 2 year amortization for 2011 rate case expenses
Rate Case Adjustments - amortizations	2011 Emissions Credit	The proposed 2 year amortization for SO2 emission credits
Rate Case Adjustments - amortizations	2011 Demand Side Management (DSM)	The proposed 2 year amortization for DSM which was approved for deferral in PU-08-171
Other	Change in Cost of Capital	Reflects the impact of the change in the cost of capital from the last ordered to proposed for all the above adjustments
Other	Cash Working Capital (CWC)	Reflects the impact of all the above adjustments on Cash Working Capital
	2012 Step	
2012 Step Adjustments	Merricourt	Updates the Merricourt Wind Farm project, which went into service in Nov 2011, to 2012 revenue requirements
2012 Step Adjustments	Nuclear Production Monticello - EPU	Updates the Monticello EPU project, which went into service in Dec 2011, to 2012 revenue requirements
2012 Step Adjustments	2011 Transmission Plant Annualization	Annualizes all transmission plant by reflecting the return on year end 2011 plant instead of average plant and reflects a full year of 2011 depreciation
2012 Step Adjustments	Nuclear Outage Amortization	Updates the nuclear outage amortization expense by the difference between 2012 and 2011
Other	Change in Cost of Capital	Reflects the impact of the change in the cost of capital from the last ordered to proposed for the four 2012 step adjustments
Other	Cash Working Capital (CWC)	Reflects the impact of the four 2012 step adjustments on Cash Working Capital

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2011 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	Description	Unadjusted (1)	Data Corrections: Transmission CAPX2020 (2)	Budget Adjustments Plant Related: Bonus Tax Depreciation (3)	Wind to Battery ITC (4)	Nuclear Production Monticello (5)	Nuclear Production MUR PI (6)	Transmission Interconnect Agreement (7)
	Electric Plant as Booked							
1	Production	$478,047			$0	$260	$209	
2	Transmission	$112,610	($1,140)					($89)
3	Distribution	$125,117						
4	General	$20,607						
5	Common	$27,596						
6	TOTAL Utility Plant in Service	$763,976	($1,140)	$0	$0	$260	$209	($89)
	Reserve for Depreciation							
7	Production	$251,781				$4	$12	
8	Transmission	$34,886	($1)					($1)
9	Distribution	$57,662						
10	General	$8,419						
11	Common	$17,390						
12	TOTAL Reserve for Depreciation	$370,138	($1)	$0	$0	$4	$12	($1)
	Net Utility Plant in Service							
13	Production	$226,266				$256	$197	
14	Transmission	$77,724	($1,139)					($88)
15	Distribution	$67,455						
16	General	$12,188						
17	Common	$10,206						
18	Net Utility Plant in Service	$393,838	($1,139)	$0	$0	$256	$197	($88)
19	Utility Plant Held for Future Use	$0						
20	Construction Work in Progress	$2,100						
21	Less: Accumulated Deferred Income Taxes	$72,101	($24)	$7,231	($8)	$2	$64	($19)
22	Cash Working Capital	$1,772						
	Other Rate Base Items:							
23	Materials and Supplies	$6,186						
24	Fuel Inventory	$5,674						
25	Non-Plant Assets & Liabilities	($6,173)						
26	Prepayments	$1,018						
27	Nuclear Outage Amortization	$2,712						
28	Customer Advances	($1)						
29	Customer Deposits	($131)						
30	Other Working Capital	$426						
31	Total Other Rate Base Items	$9,711	$0	$0	$0	$0	$0	$0
32	Total Average Rate Base	$335,320	($1,115)	($7,231)	$8	$254	$133	($70)

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2011 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

		Rate Case Adjustments Plant Related					
Line No.	Description	Steam Production Black Dog 3 & 4 (8)	Prairie Island Life Extension (9)	Steam Production Net Salvage (10)	Other Production Net Salvage (11)	Income Statement CWC (12)	Proposed 2011 Test Year (13)
	Electric Plant as Booked						
1	Production						$478,515
2	Transmission						$111,382
3	Distribution						$125,117
4	General						$20,607
5	Common						$27,596
6	TOTAL Utility Plant in Service	$0	$0	$0	$0	$0	$763,216
	Reserve for Depreciation						
7	Production	($264)	($26)	$263	$33		$251,803
8	Transmission						$34,885
9	Distribution						$57,662
10	General						$8,419
11	Common						$17,390
12	TOTAL Reserve for Depreciation	($264)	($26)	$263	$33	$0	$370,159
	Net Utility Plant in Service						
13	Production	$264	$26	($263)	($33)		$226,712
14	Transmission						$76,497
15	Distribution						$67,455
16	General						$12,188
17	Common						$10,206
18	Net Utility Plant in Service	$264	$26	($263)	($33)	$0	$393,057
19	Utility Plant Held for Future Use						$0
20	Construction Work in Progress						$2,100
21	Less: Accumulated Deferred Income Taxes	$108	$10	($101)	($13)		$79,352
22	Cash Working Capital					$285	$2,057
	Other Rate Base Items:						
23	Materials and Supplies						$6,186
24	Fuel Inventory						$5,674
25	Non-Plant Assets & Liabilities						($6,173)
26	Prepayments						$1,018
27	Nuclear Outage Amortization						$2,712
28	Customer Advances						($1)
29	Customer Deposits						($131)
30	Other Working Capital						$426
31	Total Other Rate Base Items	$0	$0	$0	$0	$0	$9,711
32	Total Average Rate Base	$156	$16	($163)	($20)	$285	$327,573

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2011 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	Description	Proposed 2011 Test Year (13)	Known and Measurable Adjustments: Merricourt (14)	Nuclear Production Monticello - LCM/EPU (15)	2011 Transmission Plant Annualization (16)	Nuclear Outage Amortization (17)	Income Statement CWC (18)	Final Proposed With 2012 Step (19)
	Electric Plant as Booked							
1	Production	$478,515	$9,749	$6,971				$495,235
2	Transmission	$111,382			$4,209			$115,591
3	Distribution	$125,117						$125,117
4	General	$20,607						$20,607
5	Common	$27,596						$27,596
6	TOTAL Utility Plant in Service	$763,216	$9,749	$6,971	$4,209	$0	$0	$784,145
	Reserve for Depreciation							
7	Production	$251,803	$476	($864)				$251,415
8	Transmission	$34,885			$869			$35,754
9	Distribution	$57,662						$57,662
10	General	$8,419						$8,419
11	Common	$17,390						$17,390
12	TOTAL Reserve for Depreciation	$370,159	$476	($864)	$869	$0	$0	$370,639
	Net Utility Plant in Service							
13	Production	$226,712	$9,274	$7,835				$243,820
14	Transmission	$76,497			$3,340			$79,837
15	Distribution	$67,455						$67,455
16	General	$12,188						$12,188
17	Common	$10,206						$10,206
18	Net Utility Plant in Service	$393,057	$9,274	$7,835	$3,340	$0	$0	$413,505
19	Utility Plant Held for Future Use	$0						$0
20	Construction Work in Progress	$2,100						$2,100
21	Less: Accumulated Deferred Income Taxes	$79,352	$1,806	$738	$677	$268		$82,840
22	Cash Working Capital	$2,057					($323)	$1,734
	Other Rate Base Items:							
23	Materials and Supplies	$6,186						$6,186
24	Fuel Inventory	$5,674						$5,674
25	Non-Plant Assets & Liabilities	($6,173)						($6,173)
26	Prepayments	$1,018						$1,018
27	Nuclear Outage Amortization	$2,712				$657		$3,368
28	Customer Advances	($1)						($1)
29	Customer Deposits	($131)						($131)
30	Other Working Capital	$426						$426
31	Total Other Rate Base Items	$9,711	$0	$0	$0	$657	$0	$10,367
32	Total Average Rate Base	$327,573	$7,468	$7,097	$2,663	$389	($323)	$344,866

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES

2011 Unadjusted Test Year versus 2011 Adjusted Test Year
($000's)

Line No.	Description	Unadjusted (1)	Data Corrections: SMMPA Worker Comp Billing (2)	Data Corrections: Transmission Charges to Proper Subledgers (3)	Data Corrections: Transmission CAPX2020 (4)	Budget Adjustments – Plant related: Bonus Tax Depreciation (5)	Budget Adjustments – Plant related: Wind to Battery ITC (6)	Budget Adjustments – Plant related: Nuclear Production Monticello (7)	Budget Adjustments – Plant related: Nuclear Production MUR PI (8)	Budget Adjustments – Plant related: Transmission Interconnect Agreement (9)
	Operating Revenues									
1	Retail	$164,504	$0	$0	$0	$0	$0	$0	$0	$0
2	Asset & Non Asset Margin Sharing									
3	Interdepartmental									
4	Other Operating	43,423	0	0	0	0	0	0	0	0
5	Gross Earnings Tax									
6	**Total Operating Revenues**	$207,927	$0	$0	$0	$0	$0	$0	$0	$0
	Expenses									
	Operating Expenses:									
7	Fuel & Purchased Energy	$81,392	$0	$0	$0	$0	$0	$0	$0	$0
8	Power Production	$43,062	$0	($78)	$0	$0	$0	$0	$0	$0
9	Transmission	$11,387	$0	$90	$0	$0	$0	$0	$0	$0
10	Distribution	$6,275	$0	$0	$0	$0	$0	$0	$0	$0
11	Customer Accounting	$4,385	$0	$0	$0	$0	$0	$0	$0	$0
12	Customer Service & Information	$548	$0	$0	$0	$0	$0	$0	$0	$0
13	Sales, Econ Dvlp & Other	$2	$0	$0	$0	$0	$0	$0	$0	$0
14	Administrative & General	$14,014	$7	$0	$0	$0	$0	$0	$0	$0
15	Total Operating Expenses	$161,065	$7	$12	$0	$0	$0	$0	$0	$0
16	Depreciation	$17,665	$0	$0	($2)	$0	$0	$7	$14	($1)
17	Amortization	$7	$0	$0	$0	$0	$0	$0	$0	$0
	Taxes:									
18	Property	$5,653	$0	$0	$0	$0	$0	$0	$0	$0
19	Gross Earnings									
20	Deferred Income Tax & ITC	$12,369	$0	$0	($47)	$485	($7)	$4	($97)	($3)
21	Federal & State Income Tax	($7,816)	($3)	($5)	$60	($374)	$3	($4)	$82	$3
22	Payroll & Other	$1,815	$0	$0	$0	$0	$0	$0	$0	$0
23	Total Taxes	$12,021	($3)	($5)	$13	$111	($4)	($0)	($15)	$0
24	**Total Expenses**	$190,758	$4	$7	$11	$111	($4)	$7	($1)	($1)
25	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Total Operating Income**	$17,169	($4)	($7)	($11)	($111)	$4	($7)	$1	$1
	Calculation of Revenue Requirements									
27	Rate Base	$335,320	$0	$0	($1,115)	($7,231)	$8	$254	$133	($70)
28	Required Operating Income	$29,307	$0	$0	($98)	($636)	$1	$22	$12	($6)
29	Operating Income	$17,169	($4)	($7)	($11)	($111)	$4	($7)	$1	$1
30	Revenue Deficiency	$12,138	$4	$7	($87)	($525)	($4)	$29	$11	($7)
31	Revenue Requirements	**$19,972**	**$7**	**$12**	**($143)**	**($864)**	**($6)**	**$48**	**$17**	**($11)**
	Calculation of Income Taxes									
32	Operating Revenue	$207,927	$0	$0	$0	$0	$0	$0	$0	$0
33	- Operating Exp	$161,065	$7	$12	$0	$0	$0	$0	$0	$0
34	- Amortizations	$7	$0	$0	$0	$0	$0	$0	$0	$0
35	- Taxes oth than Inc	$7,468	$0	$0	$0	$0	$0	$0	$0	$0
36	Operating Income before Adjs	$39,387	($7)	($12)	$0	$0	$0	$0	$0	$0
37	Additions to Income	$12,572	$0	$0	$4	$0	$0	$23	($18)	($3)
38	Deduct from Income	$58,708	$0	$0	($114)	$1,187	($7)	$25	($231)	($9)
39	Debt Synchronization	$9,490	$0	$0	($36)	($234)	$0	$8	$4	($2)
40	State Taxable Income	($16,239)	($7)	($12)	$154	($953)	$7	($10)	$209	$8
41	State Income Tax before Credits	($1,056)	($0)	($1)	$10	($62)	$0	($1)	$14	$1
42	State Tax Credits	$41	$0	$0	$0	$0	$0	$0	$0	$0
43	Federal Taxable Income	($15,142)	($7)	($11)	$144	($891)	$6	($10)	$195	$8
44	Fed Income Tax before Credits	($5,300)	($2)	($4)	$50	($312)	$2	($3)	$68	$3
45	Federal Tax Credits	$1,420	$0	$0	$0	$0	$0	$0	$0	$0
46	Income Tax	($7,816)	($3)	($5)	$60	($374)	$3	($4)	$82	$3

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES

2011 Unadjusted Test Year versus 2011 Adjusted Test Year
($000's)

Line No.	Description	Budget Adjustments: Non Plant Related						Traditional Adjustments				
		Transmission Tree Trimming (LIDAR) (10)	Bad Debt (11)	Qwest Pole Replacement (12)	Joint Pricing Zone Update (13)	Nuclear Fees (14)	Mercury Sorbent Reduction at Sherco 3 (15)	Economic Development (16)	Advertising (17)	Association Dues (18)	Donations (19)	Interest on Customer Deposits (20)
	Operating Revenues											
1	Retail	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Asset & Non Asset Margin Sharing											
3	Interdepartmental											
4	Other Operating	0	0	0	(3)	0	0	0	0	0	0	0
5	Gross Earnings Tax											
6	**Total Operating Revenues**	$0	$0	$0	($3)	$0	$0	$0	$0	$0	$0	$0
	Expenses											
	Operating Expenses:											
7	Fuel & Purchased Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Power Production	$0	$0	$0	$0	($83)	($52)	$0	$0	$0	$0	$0
9	Transmission	($10)	$0	$0	($46)	$0	$0	$0	$0	$0	$0	$0
10	Distribution	$0	$0	$18	$0	$0	$0	$0	$0	$0	$0	$0
11	Customer Accounting	$0	($46)	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Customer Service & Information	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Sales, Econ Dvlp & Other	$0	$0	$0	$0	$0	$0	$64	$0	$0	$0	$0
14	Administrative & General	$0	$0	$0	$0	$0	$0	$0	($214)	($3)	$132	$1
15	Total Operating Expenses	($10)	($46)	$18	($46)	($83)	($52)	$64	($214)	($3)	$132	$1
16	Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxes:											
18	Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Gross Earnings											
20	Deferred Income Tax & ITC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Federal & State Income Tax	$4	$18	($7)	$17	$33	$20	($25)	$84	$1	($52)	($0)
22	Payroll & Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Total Taxes	$4	$18	($7)	$17	$33	$20	($25)	$84	$1	($52)	($0)
24	**Total Expenses**	($6)	($28)	$11	($29)	($50)	($32)	$39	($130)	($2)	$80	$1
25	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Total Operating Income**	$6	$28	($11)	$26	$50	$32	($39)	$130	$2	($80)	($1)
	Calculation of Revenue Requirements											
27	Rate Base	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Required Operating Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	Operating Income	$6	$28	($11)	$26	$50	$32	($39)	$130	$2	($80)	($1)
30	Revenue Deficiency	($6)	($28)	$11	($26)	($50)	($32)	$39	($130)	($2)	$80	$1
31	Revenue Requirements	($10)	($46)	$18	($43)	($83)	($52)	$64	($214)	($3)	$132	$1
	Calculation of Income Taxes											
32	Operating Revenue	$0	$0	$0	($3)	$0	$0	$0	$0	$0	$0	$0
33	- Operating Exp	($10)	($46)	$18	($46)	($83)	($52)	$64	($214)	($3)	$132	$1
34	- Amortizations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	- Taxes oth than Inc	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Operating Income before Adjs	$10	$46	($18)	$43	$83	$52	($64)	$214	$3	($132)	($1)
37	Additions to Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	Deduct from Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	Debt Synchronization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
40	State Taxable Income	$10	$46	($18)	$43	$83	$52	($64)	$214	$3	($132)	($1)
41	State Income Tax before Credits	$1	$3	($1)	$3	$5	$3	($4)	$14	$0	($9)	($0)
42	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Federal Taxable Income	$9	$43	($17)	$40	$78	$49	($60)	$200	$3	($123)	($1)
44	Fed Income Tax before Credits	$3	$15	($6)	$14	$27	$17	($21)	$70	$1	($43)	($0)
45	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	Income Tax	$4	$18	($7)	$17	$33	$20	($25)	$84	$1	($52)	($0)

2011 Unadjusted Test Year versus 2011 Adjusted Test Year
($000's)

Line No.	Description	Rate Case Adjustments: Plant Related: Steam Production Black Dog 3 & 4 (21)	Prairie Island Life Extension (22)	Steam Production Net Salvage (23)	Other Production Net Salvage (24)	Non-Plant Related: Asset & Non-Asset Margin Sharing (25)	Wholesale Billing (26)	Incentive Pay (27)	Lease Expense for Vacated Buildings (28)	Aviation (29)	Employee Expenses (30)
	Operating Revenues										
1	Retail	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Asset & Non Asset Margin Sharing										
3	Interdepartmental										
4	Other Operating	0	0	0	0	(975)	0	0	0	0	0
5	Gross Earnings Tax										
6	**Total Operating Revenues**	$0	$0	$0	$0	($975)	$0	$0	$0	$0	$0
	Expenses										
	Operating Expenses:										
7	Fuel & Purchased Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Power Production	$0	$0	$0	$0	$0	$0	$0	($5)	$0	$0
9	Transmission	$0	$0	$0	$0	$0	$0	$0	($2)	$0	$0
10	Distribution	$0	$0	$0	$0	$0	$0	$0	($1)	$0	$0
11	Customer Accounting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Customer Service & Information	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Sales, Econ Dvlp & Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Administrative & General	$0	$0	$0	$0	$0	($11)	($513)	($16)	($49)	($26)
15	Total Operating Expenses	$0	$0	$0	$0	$0	($11)	($513)	($24)	($49)	($26)
16	Depreciation	($527)	($51)	$526	$66	$0	$0	$0	$0	$0	$0
17	Amortization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Taxes:										
18	Property	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Gross Earnings										
20	Deferred Income Tax & ITC	$215	$20	($201)	($26)	$0	$0	$0	$0	$0	$0
21	Federal & State Income Tax	($2)	($0)	$2	$0	($382)	$4	$201	$9	$19	$10
22	Payroll & Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Total Taxes	$213	$20	($199)	($26)	($382)	$4	$201	$9	$19	$10
24	**Total Expenses**	($314)	($31)	$327	$40	($382)	($7)	($312)	($15)	($30)	($16)
25	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	**Total Operating Income**	$314	$31	($327)	($40)	($593)	$7	$312	$15	$30	$16
	Calculation of Revenue Requirements										
27	Rate Base	$156	$16	($163)	($20)	$0	$0	$0	$0	$0	$0
28	Required Operating Income	$14	$1	($14)	($2)	$0	$0	$0	$0	$0	$0
29	Operating Income	$314	$31	($327)	($40)	($593)	$7	$312	$15	$30	$16
30	Revenue Deficiency	($300)	($30)	$313	$38	$593	($7)	($312)	($15)	($30)	($16)
31	Revenue Requirements	($494)	($49)	$515	$63	$975	($11)	($513)	($24)	($49)	($26)
	Calculation of Income Taxes										
32	Operating Revenue	$0	$0	$0	$0	($975)	$0	$0	$0	$0	$0
33	- Operating Exp	$0	$0	$0	$0	$0	($11)	($513)	($24)	($49)	($26)
34	- Amortizations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	- Taxes oth than Inc	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Operating Income before Adjs	$0	$0	$0	$0	($975)	$11	$513	$24	$49	$26
37	Additions to Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	Deduct from Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	Debt Synchronization	$5	$1	($5)	($1)	$0	$0	$0	$0	$0	$0
40	State Taxable Income	($5)	($1)	$5	$1	($975)	$11	$513	$24	$49	$26
41	State Income Tax before Credits	($0)	($0)	$0	$0	($63)	$1	$33	$2	$3	$2
42	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	Federal Taxable Income	($5)	($0)	$5	$1	($912)	$10	$480	$22	$46	$24
44	Fed Income Tax before Credits	($2)	($0)	$2	$0	($319)	$4	$168	$8	$16	$9
45	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	Income Tax	($2)	($0)	$2	$0	($382)	$4	$201	$9	$19	$10

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES

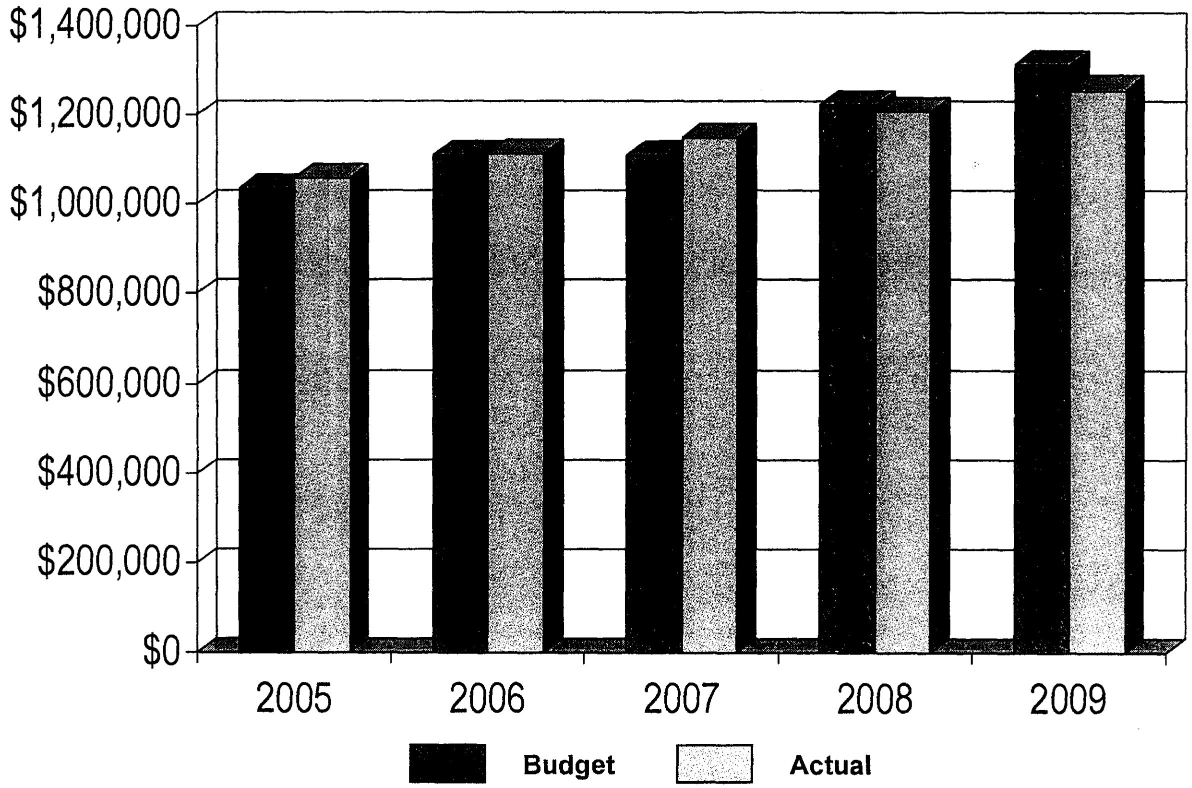
2011 Unadjusted Test Year versus 2011 Adjusted Test Year
($000's)

Line No.	Description	Amortizations: 2008 Private Fuel Storage (31)	Amortizations: 2011 Rate Case (32)	Amortizations: 2011 Emissions Credit (33)	Amortizations: 2011 DSM (34)	Chg in Cost of Capital (35)	Income Statement CWC (36)	Proposed 2011 Test Year (37)
	Operating Revenues							
1	Retail	$0	$0	$0	$0			$164,504
2	Asset & Non Asset Margin Sharing							$0
3	Interdepartmental							$0
4	Other Operating	0	0	0	0			$42,445
5	Gross Earnings Tax							$0
6	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$206,949
	Expenses							
	Operating Expenses:							
7	Fuel & Purchased Energy	$0	$0	$0	$0			$81,392
8	Power Production	$0	$0	$0	$0			$42,844
9	Transmission	$0	$0	$0	$0			$11,419
10	Distribution	$0	$0	$0	$0			$6,292
11	Customer Accounting	$0	$0	$0	$0			$4,339
12	Customer Service & Information	$0	$0	$0	$0			$548
13	Sales, Econ Dvlp & Other	$0	$0	$0	$0			$66
14	Administrative & General	$0	$0	$0	$0			$13,322
15	Total Operating Expenses	$0	$0	$0	$0	$0	$0	$160,222
16	Depreciation	$0	$0	$0	$0			$17,697
17	Amortization	$190	$281	($130)	$226			$574
	Taxes:							
18	Property	$0	$0	$0	$0			$5,653
19	Gross Earnings							
20	Deferred Income Tax & ITC	$0	$0	$0	$0			$12,712
21	Federal & State Income Tax	($75)	($110)	$51	($89)	($12)	($4)	($8,337)
22	Payroll & Other	$0	$0	$0	$0			$1,815
23	Total Taxes	($75)	($110)	$51	($89)	($12)	($4)	$11,843
24	**Total Expenses**	$115	$171	($79)	$137	($12)	($4)	$190,336
25	Allowance for Funds Used During Construction	$0	$0	$0	$0			$0
26	**Total Operating Income**	($115)	($171)	$79	($137)	$12	$4	$16,613
	Calculation of Revenue Requirements							
27	Rate Base	$0	$0	$0	$0	$0	$285	$327,573
28	Required Operating Income	$0	$0	$0	$0	$5	$25	$28,630
29	Operating Income	($115)	($171)	$79	($137)	$12	$4	$16,613
30	Revenue Deficiency	$115	$171	($79)	$137	($8)	$21	$12,017
31	Revenue Requirements	$190	$281	($130)	$226	($12)	$35	$19,773
	Calculation of Income Taxes							
32	Operating Revenue	$0	$0	$0	$0	$0	$0	$206,949
33	- Operating Exp	$0	$0	$0	$0	$0	$0	$160,222
34	- Amortizations	$190	$281	($130)	$226	$0	$0	$574
35	- Taxes oth than Inc	$0	$0	$0	$0	$0	$0	$7,468
36	Operating Income before Adjs	($190)	($281)	$130	($226)	$0	$0	$38,685
37	Additions to Income	$0	$0	$0	$0	$0	$0	$12,578
38	Deduct from Income	$0	$0	$0	$0	$0	$0	$59,559
39	Debt Synchronization	$0	$0	$0	$0	$31	$9	$9,270
40	State Taxable Income	($190)	($281)	$130	($226)	($31)	($9)	($17,566)
41	State Income Tax before Credits	($12)	($18)	$8	($15)	($2)	($1)	($1,142)
42	State Tax Credits	$0	$0	$0	$0	$0	$0	$41
43	Federal Taxable Income	($178)	($263)	$122	($211)	($29)	($9)	($16,384)
44	Fed Income Tax before Credits	($62)	($92)	$43	($74)	($10)	($3)	($5,734)
45	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$1,420
46	Income Tax	($75)	($110)	$51	($89)	($12)	($4)	($8,337)

2011 Unadjusted Test Year versus 2011 Adjusted Test Year
($000's)

			Known and Measurable						
Line No.	Description	Proposed 2011 Test Year (38)	Merricourt (39)	Nuclear Production Monticello - LCM/EPU (40)	2011 Transmission Plant Annualization (41)	Nuclear Outage Amortization (42)	Chg in Cost of Capital (43)	Income Statement CWC (44)	Final Adjusted w/2012 Step (45)
	Operating Revenues								
1	Retail	$164,504	$0	$0	$0	$0			$164,504
2	Asset & Non Asset Margin Sharing	$0							$0
3	Interdepartmental	$0	$0	$0	$0	$0			$0
4	Other Operating	$42,445	$0	$0	$0	$0			$42,445
5	Gross Earnings Tax	$0							$0
6	**Total Operating Revenues**	$206,949	$0	$0	$0	$0	$0	$0	$206,949
	Expenses								
	Operating Expenses:								
7	Fuel & Purchased Energy	$81,392	$0	$0	$0	$0			$81,392
8	Power Production	$42,844	$0	$0	$0	$271			$43,115
9	Transmission	$11,419	$216	$0	$0	$0			$11,635
10	Distribution	$6,292	$0	$0	$0	$0			$6,292
11	Customer Accounting	$4,339	$0	$0	$0	$0			$4,339
12	Customer Service & Information	$548	$0	$0	$0	$0			$548
13	Sales, Econ Dvlp & Other	$66	$0	$0	$0	$0			$66
14	Administrative & General	$13,322	$0	$0	$0	$0			$13,322
15	Total Operating Expenses	$160,222	$216	$0	$0	$271	$0	$0	$160,709
16	Depreciation	$17,697	$741	$704	$86	$0			$19,228
17	Amortization	$574	$0	$0	$0	$0			$574
	Taxes:								
18	Property	$5,653	$110	$159	$99	$0			$6,021
19	Gross Earnings								$0
20	Deferred Income Tax & ITC	$12,712	$718	($1,131)		$297			$12,596
21	Federal & State Income Tax	($8,337)	($1,315)	$574	($106)	($396)	$27	$4	($9,550)
22	Payroll & Other	$1,815	$0	$0	$0	$0			$1,815
23	Total Taxes	$11,843	($487)	($398)	($7)	($99)	$27	$4	$10,882
24	**Total Expenses**	$190,336	$470	$306	$79	$172	$27	$4	$191,393
25	Allowance for Funds Used During Construction	$0	$0	$0	$0	$0			$0
26	**Total Operating Income**	$16,613	($470)	($306)	($79)	($172)	($27)	($4)	$15,556
	Calculation of Revenue Requirements								
27	Rate Base	$327,573	$7,468	$7,097	$2,663	$389	$0	($323)	$344,866
28	Required Operating Income	$28,630	$657	$625	$234	$34	($10)	($28)	$30,141
29	Operating Income	$16,613	($470)	($306)	($79)	($172)	($27)	($4)	$15,556
30	Revenue Deficiency	$12,017	$1,127	$930	$313	$206	$17	($24)	$14,586
31	Revenue Requirements	$19,773	$1,855	$1,531	$515	$339	$28	($40)	$23,999
	Calculation of Income Taxes								
32	Operating Revenue	$206,949	$0	$0	$0	$0	$0	$0	$206,949
33	- Operating Exp	$160,222	$216	$0	$0	$271	$0	$0	$160,709
34	- Amortizations	$574	$0	$0	$0	$0	$0	$0	$574
35	- Taxes oth than Inc	$7,468	$110	$159	$99	$0	$0	$0	$7,836
36	Operating Income before Adjs	$38,685	($326)	($159)	($99)	($271)	$0	$0	$37,830
37	Additions to Income	$12,578	($488)	($453)	$0	$271	$0	$0	$11,908
38	Deduct from Income	$59,559	$2,297	($2,304)	$86	$998	$0	$0	$60,636
39	Debt Synchronization	$9,270	$241	$229	$86	$13	($69)	($10)	$9,760
40	State Taxable Income	($17,566)	($3,352)	$1,463	($271)	($1,011)	$69	$10	($20,658)
41	State Income Tax before Credits	($1,142)	($218)	$95	($18)	($66)	$4	$1	($1,343)
42	State Tax Credits	$41	$0	$0	$0	$0	$0	$0	$41
43	Federal Taxable Income	($16,384)	($3,134)	$1,368	($253)	($945)	$65	$10	($19,274)
44	Fed Income Tax before Credits	($5,734)	($1,097)	$479	($89)	($331)	$23	$3	($6,746)
45	Federal Tax Credits	$1,420	$0	$0	$0	$0	$0	$0	$1,420
46	Income Tax	($8,337)	($1,315)	$574	($106)	($396)	$27	$4	($9,550)

NSPM Electric 2005 – 2009
O&M Expenses



Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
SUMMARY OF REVENUE REQUIREMENTS
Test Year Ending December 31, 2011
($000's)

Line	Description	Adjusted Proposed Test Year 2011	Final Proposed With 2012 Step
1	Average Rate Base	$327,573	$344,866
2	Operating Income (Before AFUDC)	$16,613	$15,556
3	Allowance for Funds Used During Construction	$0	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$16,613	$15,556
5	Overall Rate of Return (Line 4 / Line 1)	5.07%	4.51%
6	Required Rate of Return	8.74%	8.74%
7	Operating Income Requirement (Line 1 x Line 6)	$28,630	$30,141
8	Income Deficiency (Line 7 - Line 4)	$12,017	$14,586
9	Gross Revenue Conversion Factor	1.64541	1.64541
10	Revenue Deficiency (Line 8 x Line 9)	$19,773	$23,999
11	Retail Related Revenue Under Present Rates	$164,504	$164,504
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	12.02%	14.59%

ROE = 4.26%
Deficiency = $19,773
% Increase = 12.02%
Required ROE = 11.25%

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Proposed 2011 Test Year

Summary Reports

[redacted]

Printed: 12/16/2010 21:26

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Proposed 2011 Test Year
(Dollars in Thousands)

Rate Base Summary

		Total Company Electric			ND Retail Electric			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	13,136,894	14,509,692	13,823,293	723,869	802,562	763,216	12,413,025	13,707,130	13,060,077
2	Depreciation Reserve	(6,423,703)	(6,780,240)	(6,601,972)	(360,670)	(379,648)	(370,159)	(6,063,033)	(6,400,592)	(6,231,813)
3	Net Utility Plant	6,713,191	7,729,452	7,221,321	363,199	422,914	393,057	6,349,992	7,306,538	6,828,264
4	C.W.I.P.	38,545	26,653	32,599	2,501	1,698	2,100	36,044	24,955	30,499
5	Accumulated Deferred Taxes	(1,321,097)	(1,530,280)	(1,425,689)	(72,938)	(85,765)	(79,352)	(1,248,159)	(1,444,515)	(1,346,337)
	Other Rate Base:									
6	Cash Working Capital	20,496	20,496	20,496	2,057	2,057	2,057	18,439	18,439	18,439
7	Materials & Supplies	105,544	105,544	105,544	6,186	6,186	6,186	99,358	99,358	99,358
8	Fuel Inventory	90,609	90,609	90,609	5,674	5,674	5,674	84,935	84,935	84,935
9	Non-Plant Assets & Liab	(113,973)	(91,197)	(102,585)	(6,866)	(5,480)	(6,173)	(107,107)	(85,717)	(96,412)
10	Prepaids & Other	62,822	69,020	65,921	3,849	4,198	4,024	58,973	64,822	61,897
11	**Total Rate Base**	**5,596,137**	**6,420,297**	**6,008,216**	**303,662**	**351,482**	**327,573**	**5,292,475**	**6,068,815**	**5,680,643**

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Proposed 2011 Test Year
(Dollars in Thousands)

Income Statement Summary

		Total Company Electric	ND Retail Electric	All Other
	Operating Revenues			
1	Retail	3,034,853	164,504	2,870,349
2	CIP Adjustment to Program Costs	0	-	0
3	Interdepartmental	607	-	607
4	Other Operating	717,960	42,445	675,515
5	Gross Earnings Tax	0	-	0
6	**Total Operating Revenues**	**3,753,420**	**206,949**	**3,546,471**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,309,223	81,392	1,227,831
8	Power Production	728,867	42,844	686,023
9	Transmission	196,516	11,419	185,097
10	Distribution	105,263	6,292	98,971
11	Customer Accounting	61,413	4,339	57,074
12	Customer Service & Information	87,277	548	86,729
13	Sales, Econ Dvlp & Other	268	66	202
14	Administrative & General	205,270	13,322	191,948
15	Total Operating Expenses	2,694,097	160,222	2,533,875
16	Depreciation	345,385	17,697	327,688
17	Amortization	15,949	574	15,375
	Taxes:			
18	Property	115,650	5,653	109,997
19	Gross Earnings	0	-	0
20	Deferred Income Tax & ITC	206,292	12,712	193,580
21	State & Federal Income (see Page 3)	(64,785)	(8,337)	(56,448)
22	Payroll & Other	30,033	1,815	28,218
23	Total Taxes	287,190	11,843	275,347
24	**Total Expenses**	**3,342,621**	**190,336**	**3,152,285**
25	AFUDC	0	-	0
26	**Total Operating Income**	**410,799**	**16,613**	**394,186**

(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	ND Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,753,420	206,949	3,546,471
2	less: Total Operating Expenses	(2,694,097)	(160,222)	(2,533,875)
3	Book Depreciation & Amortization	(361,334)	(18,271)	(343,063)
4	Taxes (Other Than Current Income)	(351,975)	(20,180)	(331,795)
5	**Total Before Tax Book Income**	**346,014**	**8,276**	**337,738**
	Tax Additions			
6	Book Depreciation	345,385	17,697	327,688
7	Deferred Income Taxes & ITC	206,292	12,712	193,580
8	Nuclear Fuel Burn (ex D&D)	111,477	6,478	104,999
9	Nuclear Outage Accounting	59,245	3,580	55,665
10	Avoided Tax Interest	43,512	2,520	40,992
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	**Total Tax Additions**	**765,911**	**42,987**	**722,924**
	Tax Deductions			
18	Debt Interest Expense	170,033	9,270	160,762
19	Tax Depreciation & Removal	1,019,261	58,113	961,148
20	Manufacture Production Deduction	0	0	0
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	23,807	1,446	22,361
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**1,213,101**	**68,829**	**1,144,271**
27	**State Taxable Income**	**(101,175)**	**(17,566)**	**(83,609)**
28	State Income Tax Rate	9.03%	6.50%	N/A
29	State Taxes before Credits	(9,132)	(1,142)	(7,990)
30	State Credits	1,180	41	1,139
31	**Total State Income Taxes**	**(10,312)**	**(1,183)**	**(9,129)**
32	**Federal Taxable Income**	**(90,863)**	**(16,384)**	**(74,480)**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	(31,802)	(5,734)	(26,068)
35	Federal Tax Credits	22,671	1,420	21,251
36	**Total Federal Income Taxes**	**(54,473)**	**(7,154)**	**(47,319)**
37	**Total Federal & State Income Taxes**	(64,785)	(8,337)	(56,448)

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.0700%	46.3000%	2.8100%
2	Short Term Debt	2.0600%	1.1400%	0.0200%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.2500%	52.5600%	5.9100%
5	**Required Rate of Return**			**8.7400%**

Composite Income Tax Rates		
State of North Dakota Tax rate		6.50%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		32.73%
Total North Dakota Composite Tax Rate		**39.23%**
Total Corporate Composite Tax Rate		**40.87%**

		Total Company Electric	ND Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	410,799	16,613	394,186
7	Total Average Rate Base	6,008,216	327,573	5,680,643
8	**ROR** (Operating Income / Rate Base)	**6.84%**	**5.07%**	**6.94%**
	Return on Equity (ROE)			
9	Total Operating Income	410,799	16,613	394,186
10	Debt Interest (Rate Base * Weighted Debt Cost)	(170,033)	(9,270)	(160,762)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	240,767	7,343	233,424
13	Equity Rate Base (Rate Base * Equity Ratio)	3,157,918	172,173	2,985,746
14	**ROE** (Earnings for Common / Equity Rate Base)	**7.62%**	**4.26%**	**7.82%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	525,118	28,630	496,488
16	Operating Income	410,799	16,613	394,186
17	Operating Income Deficiency	114,319	12,017	102,302
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69110	1.64541	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**193,324**	**19,773**	**173,551**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	3,035,460	164,504	2,870,956
21	Revenue Deficiency	193,324	19,773	173,551
22	**Total Retail Revenue Requirements**	**3,228,784**	**184,277**	**3,044,507**
23	**Percentage Increase (Decrease)**	**6.37%**	**12.02%**	**6.05%**

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Proposed 2011 Test Year
(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Line	Expenses / Includable Expenses	Lead Days	Total Company Electric Dollars	Total Company Electric Dollar x Days	ND Retail Electric Days	ND Retail Electric Dollars	ND Retail Electric Dollar x Days	All Other Days	All Other Dollars	All Other Dollar x Days
	Fuel Expenses									
1	Coal & Rail Transport	21.08	353,157	7,444,550		22,115	466,184		331,042	6,978,365
2	Gas for Generation	38.45	180,884	6,954,990		11,327	435,523		169,557	6,519,467
3	Oil	22.51	683	15,374		43	968		640	14,406
4	Nuclear & EOL	0.00	111,499	0		6,982	0		104,517	0
5	Nuclear Disposal	76.00	11,164	848,464		649	49,324		10,515	799,140
6			657,387	15,263,378		41,116	951,999		616,271	14,311,378
	Purchased Power									
7	Purchases	28.12	894,154	25,143,610		54,286	1,526,522		839,868	23,617,088
8	Interchange	38.21	119,793	4,577,291		7,047	269,266		112,746	4,308,025
			1,013,947	29,720,901		61,333	1,795,788		952,614	27,925,113
	Labor & Related Costs									
9	Regular Payroll	12.31	367,828	4,527,963		22,236	273,725		345,592	4,254,238
10	Incentive Compensation	255.05	21,732	5,542,747		1,329	338,961		20,403	5,203,785
11	Pension & Benefits	19.20	79,160	1,519,872		4,828	92,698		74,332	1,427,174
12	Subtotal Labor & Related		468,720	11,590,581		28,393	705,384		440,327	10,885,197
13										
14	All Other Operating Expenses	35.01	554,043	19,397,042		29,380	1,028,594		524,663	18,368,448
15	Property Tax	356.72	115,650	41,254,668		5,653	2,016,538		109,997	39,238,130
16	Employer's Payroll Taxes	26.56	30,033	797,676		1,815	48,206		28,218	749,470
17	Gross Earnings Tax	41.48	0	0		0	0		0	0
18	Federal Income Tax	37.75	(54,473)	(2,056,362)		(7,154)	(270,072)		(47,319)	(1,786,290)
19	State Income Tax	37.75	(10,312)	(389,282)		(1,183)	(44,651)		(9,129)	(344,630)
20	State Sales Tax Customer Billings	35.73	138,595	4,951,999		0	0		138,595	4,951,999
21	Total Expenses	41.37	2,913,590	120,530,602	39.11	159,353	6,231,787	41.50	2,754,237	114,298,816
22	**Net Annual Expense Amount**			330,221			17,073			313,147

Line	Revenues		Lag Days	Total Company Electric Dollars	Total Company Electric Dollar x Days	ND Retail Electric Days	ND Retail Electric Dollars	ND Retail Electric Dollar x Days	All Other Days	All Other Dollars	All Other Dollar x Days
23	Computer Billing	100.00%	45.45	3,034,853	137,942,263		164,504	7,477,151		2,870,349	130,465,112
24	Hand Billed	0.00%	43.07	0	0		0	0		0	0
25	Retail Revenue Adjustments		0.00	0	0		0	0		0	0
26	Interdepartmental		0.00	607	0		0	0		607	0
27	Late Payment		0.00	5,490	0		355	0		5,135	0
28	Connect and Trouble Charges		42.85	2,261	96,888		243	10,413		2,018	86,475
29	CIP Incentive		0.00	0	0		0	0		0	0
30	Rentals		114.17	4,032	460,333		255	29,113		3,777	431,220
31	Interchange Revenues		38.21	446,657	17,066,764		26,889	1,027,429		419,768	16,039,335
32	Sales for Resale		37.10	148,783	5,519,849		9,166	340,059		139,617	5,179,791
33	Production Associated Revenues		37.10	6,436	238,776		403	14,951		6,033	223,824
34	MISO		14.00	13,342	186,788		775	10,850		12,567	175,938
35	Point to Point Firm		37.10	59,651	2,213,052		3,466	128,589		56,185	2,084,464
36	Services & Facilities		37.10	8,828	327,519		507	18,810		8,321	308,709
37	Ancillary		37.10	23,148	858,791		1,345	49,900		21,803	808,891
38	Distribution Associated Revenues		42.85	1,872	80,219		0	0		1,872	80,219
39	Other		42.85	2,356	100,959		(652)	(27,940)		3,008	128,899
40	JOA - Rev fr/to PSC		37.10	(4,896)	(181,642)		(307)	(11,390)		(4,589)	(170,252)
41	(blank)		0.00	0	0		0	0		0	0
42	(blank)		0.00	0	0		0	0		0	0
43	(blank)		0.00	0	0		0	0		0	0
44	Total Revenues		43.94	3,753,420	164,910,560	43.82	206,949	9,067,935	43.94	3,546,471	155,842,625
45	Net Annual Amount				451,810			24,844			426,966
46	Expense / Revenue Factor				0.7762			0.7700			
47	**Allocated Revenue Amount**				350,717			19,130			
48	**Net Cash Working Capital**		Page 1 - Line 6		20,496			2,056			18,440

ROE = 3.20%
Deficiency = $23,999
% Increase = 14.59%
Required ROE = 11.25%

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Final Proposed with 2012 Step

Summary Reports

[redacted]

Printed: 12/16/2010 21:27

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Final Proposed with 2012 Step
(Dollars in Thousands)

Rate Base Summary

		Total Company Electric			ND Retail Electric			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	13,715,885	14,514,613	14,115,249	761,476	806,813	784,145	12,954,409	13,707,800	13,331,104
2	Depreciation Reserve	(6,380,331)	(6,811,996)	(6,596,164)	(358,968)	(382,311)	(370,640)	(6,021,363)	(6,429,685)	(6,225,524)
3	Net Utility Plant	7,335,554	7,702,617	7,519,085	402,508	424,502	413,505	6,933,046	7,278,115	7,105,580
4	C.W.I.P.	38,545	26,653	32,599	2,501	1,698	2,100	36,044	24,955	30,499
5	Accumulated Deferred Taxes	(1,369,095)	(1,571,169)	(1,470,132)	(76,485)	(89,195)	(82,840)	(1,292,610)	(1,481,974)	(1,387,292)
	Other Rate Base:									
6	Cash Working Capital	18,386	18,386	18,386	1,734	1,734	1,734	16,653	16,653	16,653
7	Materials & Supplies	105,544	105,544	105,544	6,186	6,186	6,186	99,358	99,358	99,358
8	Fuel Inventory	90,609	90,609	90,609	5,674	5,674	5,674	84,935	84,935	84,935
9	Non-Plant Assets & Liab	(113,973)	(91,197)	(102,585)	(6,866)	(5,480)	(6,173)	(107,107)	(85,717)	(96,412)
10	Prepaids & Other	62,822	69,020	65,921	4,142	5,218	4,680	58,680	63,802	61,241
11	**Total Rate Base**	**6,168,392**	**6,350,463**	**6,259,427**	**339,394**	**350,337**	**344,866**	**5,828,999**	**6,000,127**	**5,914,562**

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Final Proposed with 2012 Step
(Dollars in Thousands)

Case No. PU-10-____
Exhibit___(JMF-1), Schedule 8b
Page 3 of 6

Income Statement Summary

		Total Company Electric	ND Retail Electric	All Other
	Operating Revenues			
1	Retail	3,034,853	164,504	2,870,349
2	CIP Adjustment to Program Costs	0	-	0
3	Interdepartmental	607	-	607
4	Other Operating	717,960	42,445	675,515
5	Gross Earnings Tax	0	-	0
6	**Total Operating Revenues**	**3,753,420**	**206,949**	**3,546,471**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,309,223	81,392	1,227,831
8	Power Production	728,867	43,115	685,752
9	Transmission	196,516	11,635	184,881
10	Distribution	105,263	6,292	98,971
11	Customer Accounting	61,413	4,339	57,074
12	Customer Service & Information	87,277	548	86,729
13	Sales, Econ Dvlp & Other	268	66	202
14	Administrative & General	205,270	13,322	191,948
15	Total Operating Expenses	2,694,097	160,709	2,533,388
16	Depreciation	358,224	19,228	338,996
17	Amortization	15,949	574	15,375
	Taxes:			
18	Property	117,651	6,021	111,630
19	Gross Earnings	0	-	0
20	Deferred Income Tax & ITC	218,642	12,596	206,046
21	State & Federal Income (see Page 3)	(88,089)	(9,550)	(78,540)
22	Payroll & Other	30,033	1,815	28,218
23	Total Taxes	278,237	10,882	267,354
24	**Total Expenses**	**3,346,507**	**191,393**	**3,155,113**
25	AFUDC	0	-	0
26	**Total Operating Income**	**406,913**	**15,556**	**391,358**

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Final Proposed with 2012 Step
(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	ND Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,753,420	206,949	3,546,471
2	less: Total Operating Expenses	(2,694,097)	(160,709)	(2,533,388)
3	Book Depreciation & Amortization	(374,173)	(19,802)	(354,371)
4	Taxes (Other Than Current Income)	(366,326)	(20,432)	(345,894)
5	**Total Before Tax Book Income**	**318,824**	**6,006**	**312,818**
	Tax Additions			
6	Book Depreciation	358,224	19,228	338,996
7	Deferred Income Taxes & ITC	218,642	12,596	206,046
8	Nuclear Fuel Burn (ex D&D)	111,477	6,478	104,999
9	Nuclear Outage Accounting	59,245	3,851	55,394
10	Avoided Tax Interest	35,122	1,579	33,543
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	**Total Tax Additions**	**782,710**	**43,732**	**738,978**
	Tax Deductions			
18	Debt Interest Expense	177,142	9,760	167,382
19	Tax Depreciation & Removal	1,058,785	59,190	999,595
20	Manufacture Production Deduction	0	0	0
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	23,807	1,446	22,361
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**1,259,734**	**70,396**	**1,189,338**
27	**State Taxable Income**	**(158,200)**	**(20,658)**	**(137,542)**
28	State Income Tax Rate	9.03%	6.50%	N/A
29	State Taxes before Credits	(14,279)	(1,343)	(12,936)
30	State Credits	1,180	41	1,139
31	**Total State Income Taxes**	**(15,459)**	**(1,384)**	**(14,075)**
32	**Federal Taxable Income**	**(142,741)**	**(19,274)**	**(123,467)**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	(49,959)	(6,746)	(43,213)
35	Federal Tax Credits	22,671	1,420	21,251
36	**Total Federal Income Taxes**	**(72,630)**	**(8,166)**	**(64,464)**
37	**Total Federal & State Income Taxes**	(88,089)	(9,550)	(78,540)

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.0700%	46.3000%	2.8100%
2	Short Term Debt	2.0600%	1.1400%	0.0200%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.2500%	52.5600%	5.9100%
5	**Required Rate of Return**			8.7400%

Composite Income Tax Rates		
State of North Dakota Tax rate		6.50%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		32.73%
Total North Dakota Composite Tax Rate		**39.23%**
Total Corporate Composite Tax Rate		**40.87%**

		Total Company Electric	ND Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	406,913	15,556	391,358
7	Total Average Rate Base	6,259,427	344,866	5,914,562
8	**ROR** (Operating Income / Rate Base)	**6.50%**	**4.51%**	**6.62%**
	Return on Equity (ROE)			
9	Total Operating Income	406,913	15,556	391,358
10	Debt Interest (Rate Base * Weighted Debt Cost)	(177,142)	(9,760)	(167,382)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	229,772	5,796	223,976
13	Equity Rate Base (Rate Base * Equity Ratio)	3,289,955	181,261	3,108,694
14	**ROE** (Earnings for Common / Equity Rate Base)	**6.98%**	**3.20%**	**7.20%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	547,074	30,141	516,933
16	Operating Income	406,913	15,556	391,358
17	Operating Income Deficiency	140,161	14,586	125,575
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69110	1.64541	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**237,026**	**23,999**	**213,027**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	3,035,460	164,504	2,870,956
21	Revenue Deficiency	237,026	23,999	213,027
22	**Total Retail Revenue Requirements**	**3,272,486**	**188,503**	**3,083,983**
23	**Percentage Increase (Decrease)**	**7.81%**	**14.59%**	**7.42%**

Northern States Power Company (ND)
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Final Proposed with 2012 Step
(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Line		Lead Days	Total Company Electric Dollars	Total Company Electric Dollar x Days		ND Retail Electric Dollars	ND Retail Electric Dollar x Days		All Other Dollars	All Other Dollar x Days
	Expenses									
	Includable Expenses	**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Fuel Expenses									
1	Coal & Rail Transport	21.08	353,157	7,444,550		22,115	466,184		331,042	6,978,365
2	Gas for Generation	38.45	180,884	6,954,990		11,327	435,523		169,557	6,519,467
3	Oil	22.51	683	15,374		43	968		640	14,406
4	Nuclear & EOL	0.00	111,499	0		6,982	0		104,517	0
5	Nuclear Disposal	76.00	11,164	848,464		649	49,324		10,515	799,140
6			657,387	15,263,378		41,116	951,999		616,271	14,311,378
	Purchased Power									
7	Purchases	28.12	894,154	25,143,610		54,286	1,526,522		839,868	23,617,088
8	Interchange	38.21	119,793	4,577,291		7,047	269,266		112,746	4,308,025
			1,013,947	29,720,901		61,333	1,795,788		952,614	27,925,113
	Labor & Related Costs									
9	Regular Payroll	12.31	367,828	4,527,963		22,236	273,725		345,592	4,254,238
10	Incentive Compensation	255.05	21,732	5,542,747		1,329	338,961		20,403	5,203,785
11	Pension & Benefits	19.20	79,160	1,519,872		4,828	92,698		74,332	1,427,174
12	Subtotal Labor & Related		468,720	11,590,581		28,393	705,384		440,327	10,885,197
13										
14	All Other Operating Expenses	35.01	554,043	19,397,042		29,867	1,045,644		524,176	18,351,398
15	Property Tax	356.72	117,651	41,968,465		6,021	2,147,811		111,630	39,820,654
16	Employer's Payroll Taxes	26.56	30,033	797,676		1,815	48,206		28,218	749,470
17	Gross Earnings Tax	41.48	0	0		0	0		0	0
18	Federal Income Tax	37.75	(72,630)	(2,741,790)		(8,166)	(308,262)		(64,464)	(2,433,528)
19	State Income Tax	37.75	(15,459)	(583,581)		(1,384)	(52,237)		(14,075)	(531,345)
20	State Sales Tax Customer Billings	35.73	138,595	4,951,999		0	0		138,595	4,951,999
21	Total Expenses	41.62	2,892,287	120,364,671	39.84	158,995	6,334,334	41.72	2,733,291	114,030,337
22	**Net Annual Expense Amount**			329,766			17,354			312,412
	Revenues	**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
23	Computer Billing 100.00%	45.45	3,034,853	137,942,263		164,504	7,477,151		2,870,349	130,465,112
24	Hand Billed 0.00%	43.07	0	0		0	0		0	0
25	Retail Revenue Adjustments	0.00	0	0		0	0		0	0
26	Interdepartmental	0.00	607	0		0	0		607	0
27	Late Payment	0.00	5,490	0		355	0		5,135	0
28	Connect and Trouble Charges	42.85	2,261	96,888		243	10,413		2,018	86,475
29	CIP Incentive	0.00	0	0		0	0		0	0
30	Rentals	114.17	4,032	460,333		255	29,113		3,777	431,220
31	Interchange Revenues	38.21	446,657	17,066,764		26,889	1,027,429		419,768	16,039,335
32	Sales for Resale	37.10	148,783	5,519,849		9,166	340,059		139,617	5,179,791
33	Production Associated Revenues	37.10	6,436	238,776		403	14,951		6,033	223,824
34	MISO	14.00	13,342	186,788		775	10,850		12,567	175,938
35	Point to Point Firm	37.10	59,651	2,213,052		3,466	128,589		56,185	2,084,464
36	Services & Facilities	37.10	8,828	327,519		507	18,810		8,321	308,709
37	Ancillary	37.10	23,148	858,791		1,345	49,900		21,803	808,891
38	Distribution Associated Revenues	42.85	1,872	80,219		0	0		1,872	80,219
39	Other	42.85	2,356	100,959		(652)	(27,940)		3,008	128,899
40	JOA - Rev fr/to PSC	37.10	(4,896)	(181,642)		(307)	(11,390)		(4,589)	(170,252)
41	(blank)	0.00	0	0		0	0		0	0
42	(blank)	0.00	0	0		0	0		0	0
43	(blank)	0.00	0	0		0	0		0	0
44	Total Revenues	43.94	3,753,420	164,910,560	43.82	206,949	9,067,935	43.94	3,546,471	155,842,625
45	Net Annual Amount			451,810			24,844			426,966
46	Expense / Revenue Factor			0.7706			0.7683			
47	**Allocated Revenue Amount**			348,153			19,087			
48	**Net Cash Working Capital**	Page 1 - Line 6		18,386			1,733			16,654

SUMMARY OF MAJOR COST ELEMENTS
Test Year Ending December 31, 2011

Line	of the Revenue Deficiency	Revenue Deficiency (millions)
1	Capital Recovery: for additional rate base investment (includes return requirement, change in capital structure, cost of capital and depreciation)	$13.9
	Operating Expenses (including reclasses shown on Schedule 11):	
2	Power Production	$4.2
3	Transmission	$1.0
4	Distribution	$0.6
5	Customer Accounts	($0.0)
6	Customer Info Services, Sales & Economic Development	$0.1
7	Administrative and General Expense	$2.7
8	Total Operating Expenses	$8.6
9	Taxes Other than Income Taxes - Payroll, Real Estate, Personal Property:	$0.4
10	Amortizations	$0.3
11	Subtotal	$23.2
12	Less, Net Sales and Growth in Margin (including reclasses)	($3.4)
13	Net Revenue Deficiency	$19.8

Summary of Test Year O & M Expense Changes
Since Case No. PU-07-776
Shown by Functional Grouping, Gross Dollar Change Over
Three Year Interval Since the 2008 Test Year
(dollars in thousands)

Line	Functional Class	Increase (Decrease)	Annual Avg % Chg
	Power Production	$2,365	
	Reclass 2009 Variable Interchange to Margin	$1,340	
	Reclass NMC 2008 Pension and Benefits to A&G	$530	
1	Net Power Production	$4,235	3.7%
	Transmission Operating and Maintenance	$3,959	
	Reclass Transmission of Energy by Others - FERC 565	($2,971)	
2	Net Transmission Operating and Maintenance	$988	7.7%
3	Distribution and Maintenance Expense	$637	3.8%
4	Customer Accounting	($4)	0.0%
5	Customer Services and Sales Expenses	$244	
	Reclass Economic Development from A&G	($173)	
	Net Customer Services and Sales Expense	$71	4.4%
6	Administrative and General Expenses	$3,044	
	Reclass Economic Development to Customer Services	$173	
	Reclass NMC 2008 Pension and Benefits from Production	($530)	
	Net Administrative and General Expenses	$2,687	8.4%
7	Total Change In Operating Expenses	$8,614	4.5%

Definition: The incremental amount of gross revenue rquired to generate an additional dollar of operating income. Gross earnings fees included.

Let: GR = Gross Revenue Conversion Factor
T= Federal and North Dakota Income Tax

Formula for Gross Revenue Conversion Factor

$$GR = \frac{1}{1 - T}$$

Gross Revenue Conversion Factor:

$$GR = \frac{1}{1 - 0.39225}$$

$$GR = 1.64541$$

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
Test Year Ending December 31, 2011
(Dollars in Thousands)

Case No. PU-10-____
Exhibit___(JMF-1), Schedule 11

Line No.	Description	Test Year Ending 12/31/11 Present Rates	Final Increase	Test Year Ending 12/31/11 Final Rates	2011 Final With Step Present Rates	Final Increase	2011 Final With Step Final Rates
		(A)	(B)	(C) = (B) + (A)	(D)	(E)	(F) = (E) + (D)
	Operating Revenues						
1	Retail	$164,504	$19,773	$184,277	$164,504	$23,999	$188,503
2	CIP Revenue Adjustment	0		0	0		0
3	Interdepartmental	0		0	0		0
4	Other Operating	42,445		42,446	42,445		42,446
5	Gross Earnings Tax	0		0	0		0
6	**Total Operating Revenues**	$206,949	$19,773	$226,723	$206,949	$23,999	$230,949
	Expenses						
	Operating Expenses:						
7	Fuel & Purchased Energy	$81,392		$81,392	$81,392		$81,392
8	Power Production	42,844		42,844	43,115		43,115
9	Transmission	11,419		11,419	11,635		11,635
10	Distribution	6,292		6,292	6,292		6,292
11	Customer Accounting	4,339		4,339	4,339		4,339
12	Customer Service & Information	548		548	548		548
13	Sales, Econ Dvlp & Other	66		66	66		66
14	Administrative & General	13,322		13,322	13,322		13,322
15	Total Operating Expenses	$160,222	$0	$160,222	$160,709	$0	$160,709
16	Depreciation	$17,697		$17,697	$19,228		$19,228
17	Amortizations	574		574	574		574
	Taxes:						
18	Property	$5,653		$5,653	$6,021		$6,021
19	Gross Earnings	0		0	0		0
20	Deferred Income Tax & ITC	12,712		12,712	12,596		12,596
21	Federal & State Income Tax	(8,337)	7,756	(582)	(9,550)	9,414	(137)
22	Payroll & Other	1,815		1,815	1,815		1,815
23	Total Taxes	$11,843	$7,756	$19,598	$10,882	$9,414	$20,295
24	**Total Expenses**	$190,336	$7,756	$198,093	$191,393	$9,414	$200,808
25	AFUDC	$0		$0	$0		$0
26	**Total Operating Income**	$16,613	$12,017	$28,630	$15,556	$14,585	$30,141

Note: Revenues reflect calendar month sales.

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
Statement of Operating Income
(000's)

Case No. PU-10-____
Exhibit ___ (JMF-1), Schedule 11

Line No.	Description	Total Utility Unadjusted (G)	2011 Test Year Unadjusted (H)	Proposed Test Year 2011 Adjustments (I)	Proposed Test Year 2011 2011 Test Year Adjusted (J) (Col F + G)	Adjustments (K)	Final Proposed With 2012 Step (L) (Col F + G)
	Operating Revenues						
1	Retail	$3,034,853	$164,504	$0	$164,504	$0	$164,504
2	CIP Adjustment to Program Costs	0	0	0	0	0	0
3	Interdepartmental	607	0	0	0	0	0
4	Other Operating	733,539	43,423	(978)	42,445	0	42,445
5	Gross Eamings Tax	0	0	0	0	0	0
6	**Total Operating Revenues**	$3,768,999	$207,927	($978)	$206,949	$0	$206,949
	Expenses						
	Operating Expenses:						
7	Fuel & Purchased Energy	$1,309,223	$81,392	$0	$81,392	$0	$81,392
8	Power Production	732,518	43,062	(218)	42,844	271	43,115
9	Transmission	195,974	11,387	32	11,419	216	11,635
10	Distribution	104,653	6,275	17	6,292	0	6,292
11	Customer Accounting	62,194	4,385	(46)	4,339	0	4,339
12	Customer Service & Information	87,394	548	0	548	0	548
13	Sales, Econ Dvlp & Other	126	2	64	66	0	66
14	Administrative & General	215,510	14,014	(692)	13,322	0	13,322
15	Total Operating Expenses	$2,707,592	$161,065	($843)	$160,222	$487	$160,709
16	Depreciation	$344,712	$17,665	$32	$17,697	$1,531	$19,228
17	Amortizations	12,164	7	$567	574	$0	574
	Taxes:						
18	Property	$115,650	$5,653	$0	$5,653	$368	$6,021
19	Gross Eamings	0	0	0	0	0	0
20	Deferred Income Tax & ITC	200,600	12,369	343	12,712	(116)	12,596
21	Federal & State Income Tax	(58,187)	(7,816)	(521)	(8,337)	(1,213)	(9,550)
22	Payroll & Other	30,033	1,815	0	1,815	0	1,815
23	Total Taxes	$288,096	$12,021	($178)	$11,843	($961)	$10,882
24	**Total Expenses**	$3,352,564	$190,758	($422)	$190,336	$1,057	$191,393
25	Allowance for Funds Used During Constructi	$0	$0	0	$0	0	$0
26	**Total Operating Income**	$416,435	$17,169	($556)	$16,613	($1,057)	$15,556

Northern States Power Company, a Minnesota corporation

Cost Assignment and Allocation Manual

November 2010

Northern States Power Company, a Minnesota corporation
Cost Assignment and Allocation Manual

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 nonregulated business activities and among jurisdictions.

NSPM was incorporated in 2000 under the laws of Minnesota and is an operating utility subsidiary of Xcel Energy Inc. (sometimes referred to as the "Parent"). Xcel Energy Inc. 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 is engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. NSPM also purchases, 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 Co., which holds real estate; and Private Fuel Storage LLC, which is involved in developing a private temporary spent nuclear fuel facility. NSPM is a wholly owned subsidiary of Xcel Energy.

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 the Xcel Energy Inc. subsidiaries, at cost, pursuant to service agreements. The service agreement between NSPM and XES was 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 of the CAAM.

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

- The Service Company is listed as an affiliate company in the Affiliate Transaction section for the services it provides to NSPM.

- The Service Company and all other companies in the Xcel Energy Inc. holding company system of companies are included in the Corporate Organization to provide a listing of all affiliates of NSPM.
- The Service Company is also 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)
- Allocating Workorders (Section VI)
- Utility Allocations (Section VII)
- Nonregulated Business Activity Allocations (Sections VIII)
- Jurisdictional Allocations (Section IX)
- Definitions, Abbreviations and Acronyms (Section X)

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc., a Minnesota corporation, is a registered holding company. The Parent directly owns four operating public utility subsidiaries that serve electric, natural gas, thermal and propane customers in eight states. These four utility subsidiaries are 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. The Parent's regulated businesses also include WestGas InterState, Inc., an interstate natural gas pipeline company regulated by the FERC.

The Parent's nonregulated subsidiaries include Eloigne Co., which holds investments in rental housing projects that qualify for low-income housing tax credits.

The Parent 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., and Xcel Energy Services Inc. Xcel Energy Inc. 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 Inc. and its subsidiaries.

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2009)

Xcel Energy Inc.
- Northern States Power Co., a Minnesota corporation
  - NSP Nuclear Corporation
    - Nuclear Management Company, LLC
  - Private Fuel Storage LLC
  - United Power and Land Company
- Northern States Power Co., a Wisconsin corporation
  - Chippewa and Flambeau Improvement Company
  - Clearwater Investments, Inc.
    - CMS LLC
    - Plover LLC
    - Shoe Factory Holdings LLC
    - Woodsedge Eau Claire LP
  - NSP Lands, Inc.

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2009) (continued)

- Public Service Company of Colorado, a Colorado corporation
  - 1480 Welton, Inc.
  - Beeman Ditch Company
  - Consolidated Extension Canal Company
  - East Boulder Ditch Company
  - Fisher Ditch Company
  - Gardeners' Mutual Ditch Company
  - Green & Clear Lakes Company
  - Hillcrest Ditch and Reservoir Company
  - Las Animas Consolidated Canal Company
  - PSR Investments, Inc.
  - United Water Company
- Southwestern Public Service Company, a New Mexico corporation
- WestGas InterState, Inc.
- Xcel Energy Communications Group Inc.
  - Seren Innovations, Inc. *
  - NCE Communications Inc.
- Xcel Energy Foundation
- Xcel Energy International Inc.
  - Xcel Energy Argentina Inc. *
- Xcel Energy Markets Holdings Inc.
  - e prime, Inc. *
  - Young Gas Storage Company Ltd.
- Xcel Energy Retail Holdings, Inc.
  - Reddy Kilowatt Corporation
  - Xcel Energy-Cadence Inc.
  - Xcel Energy Performance Contracting Inc.
- Xcel Energy Services Inc.
- Xcel Energy Ventures Inc.
  - Eloigne Company
    - Albany Countryside LP
    - Bemicil Townhouse LP
    - Central Towers LP
    - Chaska Brickstone LP
    - Civic Center Apartment LLLP
    - Colfax Prairie Homes LP
    - Cottage Court LP
    - Cottage Homesteads of Hillcrest LP
    - Cottage Homesteads of Willow Ponds LP
    - Cottages of Vadnais Heights LP
    - Crown Ridge Apartments LP
    - Dakotah Pioneer LP
    - Driftwood Partners LP
    - East Creek LP

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2009) (continued)

Edenvale Family Housing LP
Fairview Ridge LP
Farmington Family Housing LP
Farmington Townhome LP
Granite Hill LP
Groveland Terrace Townhomes LP
Hearthstone Village LP
J&D 14-93 LP
Jefferson Heights of Zumbrota LP
Lakeville Court LP
Lauring Green LP
Links Lane LP
Lyndale Avenue Townhomes LP
Mahtomeci Woodland LP
Majestic View LP
Mankato Townhomes LLP
Marsh Run of Brainerd LP
Marvin Garden LP
MDI LP #44
Moorhead Townhomes LP
Oakdale Leased Housing Associates LP
Park Rapids Townhomes LP
Plover LLC
Rochester Townhome LP
Rushford Housing LP
RWIC Credit Fund LP-1993
Safe Haven Homes, LLC
Shade Tree Apartments LP
Shakopee Boulder Ridge LP
Shenandoah Woods LP
Sioux Falls Housing Equity Fund II LP
Sioux Falls Partners LP
Sioux River LP
St. Cloud Housing LP
Stradford Flats LP
Tower Terrace LP
Woodland Village LP
Wyoming LP
Wyoming LP II

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2009) (continued)

- Xcel Energy Wholesale Group Inc.
  - Quixx Corporation *
    - Quixx Carolina, Inc. *
    - Quixx Linden, LP *
    - Quixxlin Corp. *
      - Quixx Linden LP *
- Xcel Energy WYCO Inc.
  - WYCO Development, LLC

* Company is being classified in discontinued operations

III. DESCRIPTION OF SERVICES

OVERVIEW

The following pages provide a description of NSPM's regulated services and nonregulated business activities. Each description identifies the types of costs associated with each 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 operation and maintenance ("O&M") and depreciation costs, and administrative and general ("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 represents 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 Interchange Agreement is a FERC-approved rate schedule that provides for the intercompany sharing of production and transmission costs of NSPM and NSPW. NSPM and NSPW operate an integrated production and transmission system, and the Interchange Agreement provides for the costs of that integrated system to be shared between NSPM and NSPW 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 566, Miscellaneous Transmission Expenses. The revenues reside in FERC account 456, Other Electric Revenues.

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 actually 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 DSM (demand-side management) beyond the spending levels required by Minnesota Statute. The revenues associated with the CIP incentives are identified by unique JDE accounts and are recorded in FERC account 456, Other Electric Revenues; and FERC 495, Other Gas Revenues. We make an adjustment to remove these costs 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 (i.e., 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 and pension and benefit costs are allocated based on labor dollars. The revenues and costs associated with this service are identified by unique JDE 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 gathers hazardous waste material from power plants and service centers in both NSPM and NSPW service territories, consolidates and compacts the material, and packages it for shipment to a permanent hazardous waste disposal site. In addition, NSPM provides these services to various third-party customers.

NONREGULATED BUSINESS ACTIVITIES

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

HomeSmart

NSPM offers a preventive maintenance subscription option for electric and gas appliances, as well as for HVAC equipment, and provides related repairs as part of this service. In addition, NSPM installs furnaces and air conditioners. Costs related to these activities include direct charges for labor, 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, and a labor related overhead and a corporate residual overhead are applied to nonregulated business activities. (Please refer to Section VIII of the CAAM for more information.) The revenues and costs associated with this service are identified by unique JDE accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations.

Customer Owned Street Lighting Maintenance

NSPM supplies maintenance services for communities that own their own street light systems. Services range from lamp replacement and cleaning to a full service maintenance package, which includes pole, fixture and underground fault repair. 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 and a corporate residual overhead are applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique JDE 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 nonregulated.

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. The revenues and costs associated with this service are identified by unique JDE accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E002/M-93-1253 for the Commission order to treat this service as nonregulated.

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, primarily the Service Company. 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. Refer to Section X for a definition of convenience payments.

As noted in the Introduction, NSPM receives administrative, management, accounting, legal, engineering, environmental and other support services from the Service Company. The Service Company provides the services to the Xcel Energy Inc. subsidiaries, at cost, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. While federal supervision over utility holding companies was transferred from the SEC to FERC in 2005, there have been no changes or updates in the XES allocation methods since 2004 and only minor changes in the service agreement to reflect transfer of oversight to the FERC. The updated service agreement between NSPM and the Service Company has been approved by the Commission. 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. NSPM's affiliate transactions currently consist primarily of transactions with the Service Company for these 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 below table, the term 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 fee are discussed in Section VIII.

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	
Operations and Maintenance – Production, decommissioning and transmission costs associated with the Interchange Agreement (FERC Docket No. ER02-808-000).	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, lease costs, lawn care, sewer, trash removal, and cash advances through PSC-Wisconsin approved borrowing agreement (Certificate of Authority and Order) and an Intercompany Note.	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

SERVICES PROVIDED BY NSPM TO AFFILIATES (continued)

Nature of Transactions	Terms
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
Eloigne Company	
Miscellaneous – Miscellaneous other charges, including lease costs.	Fully distributed cost
United Power and Land Company	
Electric – Commercial and Wholesale – Regulated electric services.	Tariff Rate
Xcel Energy Inc.	
Miscellaneous - Miscellaneous other charges, including 401(k) match.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM

Xcel Energy Services Inc.

Xcel Energy Services Inc. is the service company for the Xcel Energy Inc. system and provides a variety of accounting, administrative, management, legal, engineering, construction, environmental and support services. The Service Company provides its services to the Xcel Energy Inc. system at cost, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. While supervision over utility holding companies was transferred from the SEC to FERC in 2005, there have been no changes or updates in the XES allocation methods since 2004 and only minor changes in the service agreement to reflect transfer of oversight to the FERC. The updated service agreement between NSPM and the Service Company has been approved by the Commission. The nature, frequency and terms of the services provided by the Service Company to NSPM are as follows:

Nature of Transactions	Terms
*Executive Management Services** – Represents charges for Xcel Energy Inc. executive management and services, including, but not limited to, officers of Xcel Energy Inc.	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** – Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract 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

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

Nature of Transactions	Terms
*Corporate Communications** – Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy Inc. system. Manages and tracks all contributions made on behalf of the Xcel Energy Inc. 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 business opportunities. Develops and facilitates process improvements.	Fully distributed cost
*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 include receiving, storing, issuing, shipping, returns and distribution of material and parts.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

Nature of Transactions	Terms
*Supply Chain Special Programs** – Develops and implements special programs utilized across the company such as procurement cards, travel services and compliance with corporate minority women business expenditures program goals.	Fully distributed cost
*Human Resources ("HR")** – 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 issuance, 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 the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.	Fully distributed cost
*Business Unit Accounting and Budgeting** – Provides financial analysis, budgeting and administrative support for the business units. (In addition, certain Business Unit Presidents are here rather than in the Executives service function.)	Fully distributed cost
*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

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

Nature of Transactions	Terms
*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 electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.	Fully distributed cost
*Energy Supply Engineering and Environmental** – 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 clean up 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

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

Nature of Transactions	Terms
*Energy Delivery Engineering/Design** – Provides engineering and design services in support of capacity planning, construction, operations and material 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
*Business Systems** – 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 acts as a single point of contact for delivery of all technical services to Xcel Energy Inc. They partner with IBM to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace. They work collaboratively with partners and vendors to identify and co-fund opportunities that significantly benefit Xcel Energy Inc.'s business.	Fully distributed cost
*Aviation Services** – Provides aviation and travel services to employees.	Fully distributed cost
*Fleet** – Oversees the operating companies' Fleet Services.	Fully distributed cost

SERVICES PROVIDED BY AFFILIATES TO NSPM (continued)

Nature of Transactions	Terms
* Corporate Governance activities within this Service Function will be allocated using the average of the Assets Ratio including Xcel Energy Inc.'s per book assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and Employee Ratio with number of common officers assigned to Xcel Energy Inc.	
NSPW	
Operations and Maintenance – Production, decommissioning and transmission costs associated with the Interchange Agreement (FERC Docket No. ER02-808-000).	Fully distributed cost
Miscellaneous – Miscellaneous other charges, including labor and associated loadings, contract labor, employee expenses, and cash advances through PSC-Wisconsin approved borrowing agreement (Certificate of Authority and Order) and an Intercompany Note.	Fully distributed cost
Materials and Supplies – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost
PSCo	
Miscellaneous – Miscellaneous other charges, including labor and associated loadings, lease costs, and employee expenses.	Fully distributed cost
SPS	
Miscellaneous – Miscellaneous other charges, including labor and associated loadings and lease costs.	Fully distributed cost
Xcel Energy Inc.	
Miscellaneous – Miscellaneous other charges including contributions of capital, restricted stock units, and performance share plan.	Fully distributed cost

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 JD Edwards ("JDE") general ledger system, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the nonregulated 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 on page V-18. Each major step results in costs being either directly assigned or allocated to regulated services and nonregulated business activities. The result of applying these principles is that each company, utility, jurisdiction and nonregulated business activity pays the full cost for any service provided to support their respective operations.

Many of the assignment and allocation processes occur either in the Service Company or are administered by Service Company personnel. As noted in the Introduction, the Service Company provides these services "at cost" to the Xcel Energy Inc. subsidiaries, including NSPM, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. While federal supervision over utility holding companies was transferred from the SEC to FERC in 2005, there have been no changes or updates in the XES allocation methods since 2004 and only minor changes in the service agreement to reflect transfer of oversight to the FERC. The updated service agreement between NSPM and the Service Company has been approved by the Commission.

The processes discussed in this section are integral to the 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:

1. Tariffed rate shall be used to value tariffed services provided.
2. Costs shall be directly assigned to either regulated or nonregulated business activities whenever possible.

3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous 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 nor 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 nonregulated business activities. Utility allocations are described in Section VII and jurisdictional allocations are described in Section IX.

ACCOUNTING PROCESSES

The flowchart on page V-18 provides a high level overview of the various major steps in the monthly accounting close process and the various systems used to generate the books and records of NSPM. Several steps within the process have allocations imbedded in them and are therefore included to provide as much information as possible to promote an understanding of the major steps where direct assignment and allocation can occur.

FEEDER SYSTEMS (Addendum A, Flowchart Item 1)

The monthly close process initially starts with the collection of accounting information from numerous feeder systems as identified in Item 1 on the flowchart. Feeder systems gather accounting transactions on a monthly basis and 'feed,' or pass, those accounting transactions to JDE to build the monthly books and records of each utility operating company or affiliate of Xcel Energy Inc. that uses the JDE general ledger system.

There are two basic types of transactions in the feeder systems:

- The first basic group consists of individual transactions fed directly to JDE. These transactions come from the PowerPlant System ("PowerPlant"), the Indus PassPort Integrated Supply Chain/Accounts Payable System ("PassPort") and the Maximo System.

  PowerPlant System
  PowerPlant tracks all capital projects and work order expenditures for Xcel Energy Inc. utility operating companies on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, PowerPlant generates the overhead allocations and if appropriate the Allowance for Funds Used During Construction ("AFUDC"), and applies the overheads to the individual work orders. In addition, PowerPlant 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; from FERC account 12140, Non-Utility Construction Work in Progress, to FERC account 12112, Non-Utility Completed Construction-Not Unitized, to FERC account 12111, Non-Utility Plant in Service-Unitized.

Indus PassPort Integrated Supply Chain/Work Management/Accounts Payable System

The Supply Chain/Work Management components are used for inventory and work management processes by the Transmission and Distribution business areas. This system is used to maintain inventory records by legal entity and bill materials to operation and maintenance jobs or capital jobs. In addition, the system is used as a work management tool by these business areas too. The system is also used to process and pay invoices of NSPM.

Maximo System

The Maximo system is an inventory and work management system used by the Energy Supply business area across the operating companies. This system is used to maintain inventory records by legal entity and bill materials to operation and maintenance jobs or capital jobs. In addition, the system is used as a work management tool by the Energy Supply business area.

- The second basic group of transactions is where costs are developed by either applying an internal billing rate to a unit of measure or by an allocation within a process, which charges costs to a legal entity, business area and regulated or nonregulated business activity. Transactions from Labor Distribution, Transportation Distribution and Information Technology are some of the major processes that fall within this category. Each of these distribution processes may have one or more internal billing rates to charge costs to internal users. Individual transactions are generated within any one of these distribution processes to charge costs to the regulated services and nonregulated business activities within an operating company or affiliate. For example, labor distribution charges can be directly assigned to the nonregulated JDE accounts for HomeSmart within NSPM and linked directly to FERC account 417.1, Expenses from Nonutility Operations.

  The following processes are described in greater detail later in this section.

  - Labor Distribution
  - Labor Overheads
  - Aviation Distribution
  - Stores/Warehouse Overhead
  - Purchasing Overhead
  - Transportation Distribution
  - Accounts Payable
  - Information Technology
  - Shared Assets Distribution

- Facilities Distribution
- Money Pool
- Customer Billing

JDE GENERAL LEDGER 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 JDE using the JDE journal entry input screens. These journal entries also include the journal entries to record overheads on nonregulated business activities (see Section VIII).

All of the transactions from the above processes are gathered together in JDE. Once all the transactions are recorded in JDE there are multiple processing steps within JDE, including Service Billings and Utility Allocations. These steps specifically affect regulated services and nonregulated business activities and are detailed separately on the following pages.

SERVICE BILLING (Addendum A, Flowchart Item 3)

The Service Billing function within JDE is the accounting process that is used primarily to bill the operating companies and affiliates for Service Company charges. The process is also used to bill charges from one operating company or affiliate to another operating company or affiliate and from one business area to another business area within the same legal entity.

The Service Billing function bills the Service Company direct charges and indirect allocations from the Service Company legal entity to the operating companies or affiliates. As discussed earlier in this document, the indirect allocation methods have been approved. All labor billed includes labor overheads. Whenever possible, costs related to the nonregulated business activities within an operating company or affiliate are directly charged to JDE accounts, which are linked directly to the 417 FERC accounts.

The Service Billing function may also include transactions billed out of the feeder systems, transactions billed between affiliates and transactions billed within an affiliate. For example, transactions billed from NSPM to PSCo for emergency work would flow through Service Billing.

CLEARING ACCOUNTS (Addendum A, Flowchart Item 4)

The clearing account process is being noted in this section of the CAAM because it uses the functionality of the allocation process within JDE to move the net of all expenditures and other clearings recorded on the income statement to the balance sheet for processes such as labor overheads.

ALLOCATING WORK ORDERS (Addendum A, Flowchart Item 5)

The Allocating Work Order functionality is a feature developed as part of JDE that is currently used by NSPM to allocate certain information technology costs that support multiple utility processes to the appropriate FERC functional accounts related to these processes. NSPM has four allocating work orders, which are described in Section VI.

UTILITY ALLOCATIONS (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated business activities whenever possible or charged as common and 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 done monthly within the JDE system and are explained below. 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 and these costs are allocated among the utilities according to the allocations described in Section VII.

NONREGULATED BUSINESS ACTIVITY ALLOCATIONS (Addendum A, Flowchart Item 7)

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

JURISDICTIONAL ALLOCATIONS (Addendum A, Item 8)

All costs that can be directly assigned or allocated to the electric or gas utility operations or to the nonregulated business activities are appropriately accounted for in the books and records of NSPM before jurisdictional allocations occur. 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 jurisdictions of NSPM (Minnesota, North Dakota, and South Dakota), and these costs are allocated among the jurisdictions according to the allocations described in Section IX.

Service: **LABOR DISTRIBUTION**

Description: Wages and salaries of employees engaged in work on behalf of regulated services and nonregulated activities are assigned or allocated based on positive time reporting through the TIME labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-sixth 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 nonregulated 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 various time reporting systems, all of which feed into the TIME labor distribution system. The employee submitting the time sheet is responsible for coding the JDE account 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 nonregulated operations.

Time sheets must be completed and delivered to the employee's designated timekeeper by certain cut-off dates established by the Payroll Department. The employee's supervisor or manager is responsible for reviewing and approving all time sheets submitted, and verifying that the employee is using the correct JDE account numbers.

The TIME labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the JDE account 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 JDE account numbers is based on a distribution of the monthly salary of the employee.

Service: **LABOR OVERHEADS**

Description: Employee labor overhead costs are captured in the following categories:

Benefit employees:

- Non-productive labor costs (vacation, sick, holiday, etc.)
- Pension (401k match, SERP/Deferred compensation, FAS87 and aggregate cost pension, pension consulting)
- Medical (healthcare, FAS106 retiree healthcare, FAS112 LTD, health and welfare, life and LTD premiums)
- Workers compensation
- Incentives (Incentives are a labor overhead for Service Company, PSCo, and SPS. Incentives for NSPM and NSPW employees are charged directly to the 920 and 517 FERC accounts).
- Payroll taxes (FICA, FUTA, SUTA)
- Facilities

Non-Benefit employees:

- Payroll taxes (FICA, FUTA, SUTA)

Provider of Service: Service Company
Operating companies or affiliates

User of Service: Operating companies or affiliates, including utility operations, jurisdictions, and nonregulated 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 forecasted costs for the category divided by total forecasted productive labor costs. Legal entity specific rates for each category are entered into the TIME labor distribution system and 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.

Labor overheads are generally updated on a monthly basis for actuals using the latest forecast information and a year-end true up is made to bring the overhead clearing accounts to zero for the calendar year.

Service:	**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 system of companies. Costs include: pilot salaries and labor overheads, operation and maintenance costs, lease costs, hangar costs and administrative and general 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 nonregulated activities within an operating company.
Method of Allocation:	Aviation costs are billed out using the corporate governance three-factor formula based on revenues, assets and number of employees. Any spousal use of the aircraft must be approved and is billed to the holding company.

Service:	**STORES/WAREHOUSE OVERHEAD**
Description:	Corporate - Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools specific to business area as an overhead on materials and supplies as materials and supplies are issued/returned from a storeroom or warehouse. Energy Supply - Costs are direct charged to station operating and maintenance (O&M) and capital projects (when dedicated capital project support is performed).
Provider of Service:	Service Company Operating companies
User of Service:	Operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.
Method of Allocation:	Overhead costs for Corporate inventory items, including rent, labor, supervision and adjustments, are accumulated within the Supply Chain business area and allocated to material issuances from the storeroom using the same account coding as the materials are charged. The Energy Supply business area direct charges an overhead to each issuance from the storeroom using the same account coding as the materials are charged. Each business area has a separate pool for each operating company and sets an overhead application rate for budgeting for the year based on projected overhead and materials activity. During the year as actuals are recorded, the balances in the undistributed stores/warehouse clearing accounts are compared to the materials activity and historical trending and a new rate is determined.

Service:	**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 and the supplier diversity program. The purchasing function is done in two different areas of the company. Supply Chain uses PassPort for companywide purchases and the Energy Supply business area uses Maximo for production related purchases.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies and affiliates, including utility operations, jurisdictions, and nonregulated business activities within an operating company.
Method of Allocation:	Costs are collected in clearing accounts on the Service Company and the operating companies and cleared via an overhead loading. The loading follows the accounting for certain purchases with the offset going to a contra clearing account. For PassPort and Maximo, certain purchases are loaded with the purchasing overhead loading up to a $3,500 cap. The $3,500 cap is calculated based on the value of the purchase order for purchase order payments, the total value of the contract payment authorization or the total value of the invoice for the request for payment. For PassPort, the loading is calculated and a new record is posted to the general ledger as a detail item. For Maximo, the loading is calculated once a month and shows up as a separate summary transaction on the general ledger.

Service:	**TRANSPORTATION 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 class categories, which group together vehicles similar in nature. These classes are also grouped on vehicle features and costs of the units. For example, automobiles are classified by compact, mid-sized or intermediate and full size. Each of these classes will have its own unique individual fixed rate to bill users. The Transportation Distribution system bills internal functional areas of operating companies and affiliates for the cost of using vehicles or associated equipment. It distributes the operating costs related to vehicle units using usage rates based on the type of unit. Costs included in the calculation of the monthly billing rate are: depreciation, lease costs, property taxes, material and labor costs for maintenance, fuel, labor loadings, and an overhead that includes labor, facilities, insurance, utilities, computer, phone and office supplies.
Provider of Service:	Service Company Operating companies
User of Service:	Service Company, operating companies or affiliates, including utility operations, jurisdictions and nonregulated business activities within an operating company.
Method of Allocation:	The Transportation Distribution system bills each user for units assigned based on the monthly rates calculated by class category. Each month a validation report is reviewed to ensure all costs are billed and any invalid accounts are reviewed and corrected.

Service:	**INFORMATION TECHNOLOGY**
Description:	The Business Systems organization in the Service Company is responsible for managing the corporate Information Technology ("IT") assets and services of Xcel Energy. Business Systems 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 external sources, primarily IBM. 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 nonregulated 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 nonregulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible.

If costs can not be charged directly to an operating company, affiliate, jurisdiction or nonregulated activity, the costs are charged to a Service Company indirect allocation workorder 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 allocation workorder using the approved allocation factor for that business area.

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 PassPort and Concur 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 nonregulated 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

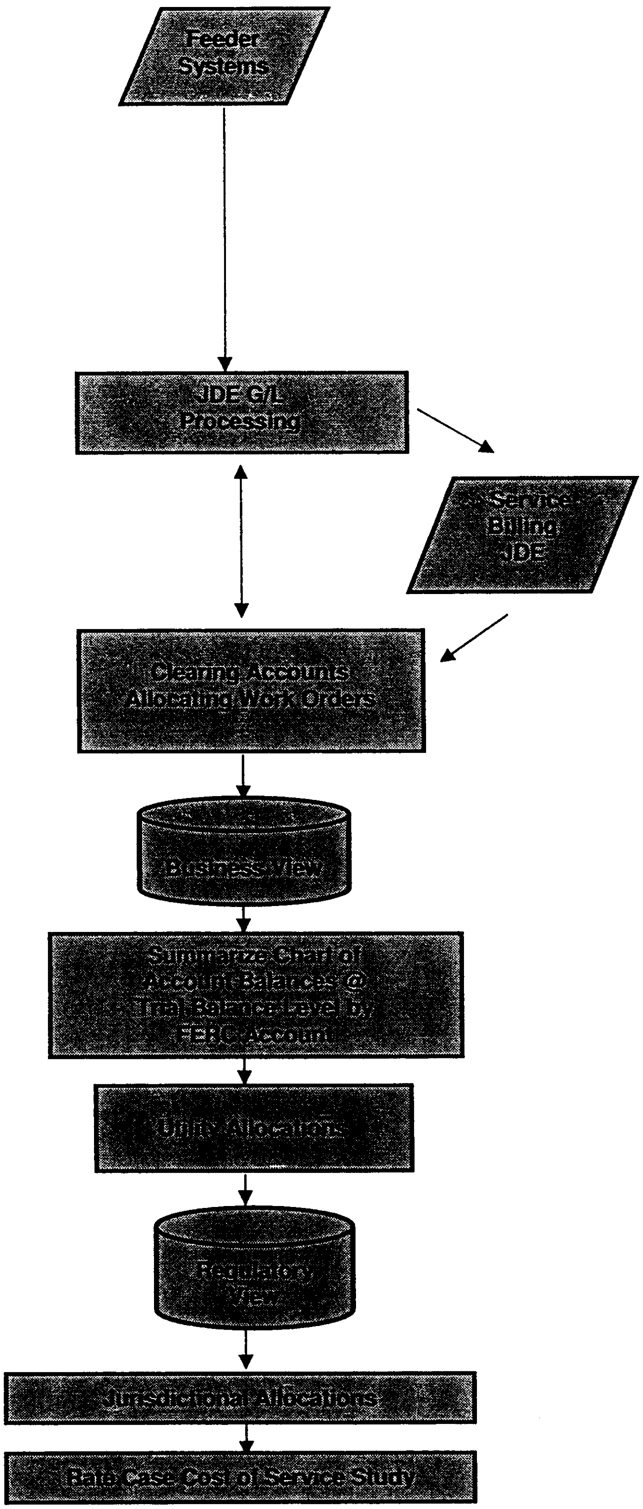
Service:	**SHARED ASSETS DISTRIBUTION**
Description:	Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include structures and improvements, office furniture and equipment, computer and communication equipment and some software systems that are used by Service Company 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 shared asset costs are billed through the Service Company and either charged to a Service Company indirect workorder that will assign the costs using a cost causative method to the companies benefiting from the system application or service, or charged to the Service Company facilities clearing pool that will assign the costs following the labor of the Service Company employees.

Service:	**FACILITIES DISTRIBUTION**
Description:	Facilities costs, which include owned and leased buildings, operation and maintenance costs for the leased and owned buildings (unless covered by the rent or lease agreement), as well as internal administrative and general labor and non-labor costs are allocated to the functional area(s) of operating companies and other affiliates who benefit from the use of these facilities. The Property Services department is responsible for the owned and leased facility records. Utility owned facilities have depreciation costs with an allowed rate of return for the assets owned, the costs of which are charged directly to depreciation expense.
Provider of Service:	Service Company or operating companies
User of Service:	Service Company, operating companies and affiliates
Method of Allocation:	Costs are accumulated in the clearing account of the company benefitting from the use of the building, and are then allocated to functional FERC rent accounts based on the most recent quarter's labor charges.

Service:	**MONEY POOL**
Description:	Through the Utility Money Pool, temporary surplus funds of Xcel Energy Inc. and the operating companies 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 Utility Money Pool, which is administered at cost by the Service Company. In addition, the holding company can deposit surplus funds into the utility money pool. The holding company can be repaid for funds deposited, but cannot borrow from the utility money pool. Interest income or expense is charged or credited, as appropriate, to the Utility Money Pool participants. All charges are directly billed to the appropriate operating company. NSPM petitioned for and received approval on the use of a utility money pool in Docket No. AI-04-100.

Service:	**CUSTOMER BILLING**
Description:	NSPM bills customers for electric, gas, propane and miscellaneous nonregulated activities through the customer billing system.
Provider of Service:	Operating companies
User of Service:	Operating companies, including utility operations, jurisdictions, and nonregulated 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. Nonregulated activities that use the customer billing system are billed for services provided based on the number of customers being billed and/or the number of phone calls which come into the call center and are then transferred to the nonregulated activity.

ADDENDUM A - PROCESS FLOWCHART



Item 1 – Feeder Systems
- PowerPlant System
- PassPort System
- Maximo System
- Labor Distribution
- Labor Overheads
- Aviation Distribution
- Stores/Warehouse Overhead
- Purchasing Overhead
- Transportation Distribution
- Information Technology
- Accounts Payable
- Shared Assets Distribution
- Facilities Distribution
- Money Pool
- Customer Billing

Item 2 – JDE General Ledger Processing

Item 3 – Service Billing

Item 4 – Clearing Accounts
Item 5 – Allocating Work Orders

Item 6 – Utility Allocations

Item 7 – Nonregulated Business Activity Allocations

Item 8 – Jurisdictional Allocations

VI. ALLOCATING WORKORDERS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated activities whenever possible. An allocating workorder is used to allocate costs to specific FERC accounts based on predefined allocation factors.

ALLOCATIONS

NSPM currently has four allocating workorders. These are as follows:

Compass/Maximo
This workorder is being used to allocate costs associated with the Business Systems' O&M costs for the Energy Supply Maximo system. These costs include information technology application, development and maintenance costs, or system support costs. The allocator is based on the number of Maximo system users. The allocator used in the current year is based on the previous years' actual number of users. The allocation was developed to distribute these costs to production FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12001	Maximo system users	Maximo system users is a reasonable methodology because the operation and maintenance costs associated with the system have a cost causative relationship with the number of users who have access to the system.

The operation and maintenance cost of the Maximo system are allocated to the following FERC accounts:

FERC account 506, Miscellaneous Steam Power Expenses
FERC account 539, Miscellaneous Hydraulic Power Generation Expenses
FERC account 549, Miscellaneous Other Power Generation Expenses

<u>Electric Management System (EMS, also known as Electric SCADA)</u>
This workorder is being used to allocate costs associated with Business Systems' O&M costs for the electric SCADA system. The allocator is based on the number of remote terminal units (RTUs). The allocator used in the current year is based on the previous years' actual number of RTUs. The allocation was developed to distribute these costs among production, transmission and distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12004	Number of RTUs	Number of RTUs is a reasonable methodology because the RTUs transmit the data used by the SCADA system.

The operation and maintenance costs of the EMS are allocated to the following FERC accounts:

FERC account 556, System Control and Load Dispatching (Production)
FERC account 561.2, Load Dispatching-Monitor/Operate Transmission System
FERC account 581, Load Dispatching (Distribution)

<u>Gas SCADA</u>
This workorder is being used to allocate costs associated with Business Systems' O&M costs for the gas SCADA system. The allocator is based on gas transmission and distribution plant. The allocation was developed to distribute these costs among transmission and distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12008	Gas Transmission & Distribution Plant	Gas transmission and distribution plant is a reasonable methodology because this system is used to communicate between the control rooms at the plants, transmission and distribution areas.

The operation and maintenance costs of the gas SCADA system are allocated to the following FERC accounts:

FERC account 851, System Control and Load Dispatching (Transmission)
FERC account 871, Distribution Load Dispatching (Gas)

Network Services

This workorder is being used to allocate circuit costs for service centers that primarily benefit electric and gas distribution. The allocator is based on total distribution plant. The allocation was developed to distribute these costs between electric and gas distribution FERC accounts as noted below.

Workorder Number	Allocation Method	Basis for Allocation Selection
12011	Distribution Plant	Distribution plant is a reasonable methodology because these locations primarily benefit electric and gas distribution.

These circuit costs are allocated to the following FERC accounts:

FERC account 588, Miscellaneous Distribution Expenses (Electric)
FERC account 880, Other Expenses (Gas Distribution)

VII. UTILITY ALLOCATIONS

OVERVIEW

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated activities whenever possible or charged as common and 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 the JDE system 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, and are also 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) and 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 901-917 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.

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	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.
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	Major Location	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

VIII. NONREGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

The purpose of this section is to detail the methods of assigning and allocating costs between the regulated services and the nonregulated 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 1008:

1. Tariffed rate shall be used to value tariffed services provided to nonregulated activities.
2. Costs shall be directly assigned to either regulated or nonregulated 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 nor 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 nonregulated activities. Each activity that could be considered as being outside of NSPM's core electric and gas business is reviewed for regulated/nonregulated treatment. If the activity is approved to be treated as a nonregulated operation, the nonregulated 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, and corporate residual allocation. Non-NSPM affiliates are charged a working capital fee as discussed in Section V.

Business Profile
The allocation process begins by reviewing each nonregulated activity for the services NSPM's utility business will be providing to the nonregulated activity.

Direct Charging (Addresses Principle #2)
Cross charges between NSPM service providers and nonregulated activities are reviewed with the business. Any process, project or service performed for the direct benefit of a nonregulated activity is directly charged to the nonregulated activity. The business area providing service to the nonregulated activity communicates the anticipated level of service and how much the service will cost.

Labor charges are directly assigned to the nonregulated 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 nonregulated 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 nonregulated activities.

NSPM currently uses a labor overhead rate developed by reviewing the expenses incurred in support of employee related activities (such as employee programs, employee relations, training, employment, compensation and benefits program development costs, diversity, safety), office equipment needs, and supervision of the service provider. The labor overhead is applied to fully loaded labor. The labor related overhead is applied to nonregulated services wholly contained within NSPM and affiliate or third party transactions.

For nonregulated services wholly contained within NSPM, a portion of NSPM's corporation costs are allocated based on a two-factor formula that takes into consideration the relative size of the nonregulated business by using number of employees and revenues.

Working Capital Fee (Addresses Principle #3)
The working capital fee is applied to non-NSPM company 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.

IX. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

NSPM's methods for assigning and allocating common O&M costs, plant and plant related, and other rate base investment to jurisdiction 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 JDE general ledger account has a location code 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 PowerPlant 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 State of Minnesota jurisdiction based on location as it directly serves only customers in Minnesota. In addition, all gas transmission and distribution property is directly assigned to the jurisdiction based on where the property is located as defined within the PowerPlant 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 Minnesota jurisdiction.

All regulatory expenses specific to a jurisdiction are directly assigned to that jurisdiction. For example, indirect assessments charged to NSPM from the Office of Energy Securities (OES) and the Commission are directly assigned to the Minnesota jurisdiction.

<u>Allocation Based on Cost Causal Relationship</u>

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:

<u>Electric</u>
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.

<u>Gas</u>
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, they can be directly assigned to jurisdiction using customers as a basis. NSPM has service territory that borders on North Dakota and South Dakota. 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 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 can not 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, the business area associated with the JDE general ledger account is an additional piece of information used in determining the jurisdiction(s) benefiting from the expenditure. A&G costs for business areas that support the electric production portion of the business, Energy Supply and Nuclear Generation, are allocated to jurisdiction using the twelve-month coincident peak demand allocator. Any Distribution business area A&G costs that cannot be directly assigned to jurisdictions based on the location code are allocated to jurisdiction using the twelve-month end-of-year average customer allocator.

Electric A&G costs for the remaining business areas that support a corporate function are allocated to jurisdiction using a 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 JDE account location code.

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 or 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 State of 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 Twin Cities metro area, facilities expenses in support of the Distribution business unit in Twin Cities metro area, delivery system operation and maintenance costs in the 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, Law 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, Law 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.

<u>Allocation</u>: 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 Administrative & General FERC accounts where the general ledger account JDE Business Unit Category Code 6 (Location code) designates support of NSPM company.

This is also the Gas Utility A&G Corporate Function default allocator type.

<u>Allocation</u>: 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 JDE business unit category Code 6 (Location code) designates support for Minnesota/North Dakota.

<u>Allocation</u>: 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 JDE Business Unit Category Code 6 (Location code) designates support for Minnesota/South Dakota.

<u>Allocation</u>: 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.

<u>Allocation</u>: Study for Distribution Plant Serving Wholesale
This study is used for distribution substations that are also serving wholesale customers to insure an appropriate amount goes to that jurisdiction.

<u>Allocation</u>: 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: **DemandProd (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: **DemandTran (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 (propane-air or liquefied natural gas) 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 Minnesota Company 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.

<u>Allocation</u>: **Design Demand Day**
Expressed as a percentage, Design Demand Day is the ratio of the Minnesota jurisdiction firm peak demand volume to the total Minnesota Company 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.

<u>Allocation</u>: **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.

<u>Allocation</u>: **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 Minnesota Company; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total Minnesota Company program product costs.

Table C

Allocation to Jurisdiction

Selection Criteria *							
CC2 (SBU) SubBU	**Plant Function**	**Functional Class ID / Desc**	**CC6 (LOC)**	**Functional Use**	**Utility**	**JUR**	**Allocation**
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Production	2 /Electric Nuclear Production Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/SD	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	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	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
CC2 (SBU) SubBU	Plant Function	Functional Class ID / Desc	CC6 (LOC)	Functional Use	Utility	JUR	Allocation
		Budget					
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/SD	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/SD	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
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/SD	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/SD	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD	Customer Year End Average - Electric Minnesota Company MN/ND/SD
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD	Customer Year End Average - Electric Minnesota Company MN/ND/SD
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/SD	Customer Year End Average - Electric Minnesota Company MN/ND/SD
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/SD	Customer Year End Average - Electric Minnesota Company MN/ND/SD
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 *							
CC2 (SBU) SubBU	Plant Function	Functional Class ID / Desc	CC6 (LOC)	Functional Use	Utility	JUR	Allocation
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.

X. 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
CAAM	Cost Assignment and Allocation Manual
Commission	Minnesota Public Utilities Commission
Company	Northern States Power Co., a Minnesota Corporation
FERC	Federal Energy Regulatory Commission
Fleet Services	Xcel Energy Services Inc. Fleet Services Department
Holding Company	Xcel Energy Inc.
HR	Human Resources
JDE	J.D. Edwards Financial System
LPI	Liberty Paper, Inc.
NSPM	Northern States Power Co., a Minnesota Corporation
NSPW	Northern States Power Co., a Wisconsin Corporation
O&M	Operations and Maintenance
OES	Office of Energy Securities
Parent	Xcel Energy Inc.
PassPort	Indus PassPort Integrated Supply Chain/Accounts Payable System
PowerPlant	PowerPlant System
PSCo	Public Service Company of Colorado, a Colorado Corporation
PUHCA	Public Utility Holding Company Act of 1935
SCADA	Supervisory Control and Data Acquisition
Service Company	Xcel Energy Services Inc.
SEC	Securities and Exchange Commission
SPS	Southwestern Public Service Company, a New Mexico Corporation
XES	Xcel Energy Services Inc.

Terms

The following terms are used within the CAAM document:

Accounts Payable	The Payment and Reporting Department of Xcel Energy Services Inc.
Administrative and General	Includes activity in FERC accounts 920-935, Administrative and General Expenses.
Affiliate Transaction	A transfer of a good, service or asset from the utility to a non-regulated division, subsidiary or affiliate, or from a non-regulated division, subsidiary or affiliate to the utility.
Allocated	To distribute a joint or common cost to more than one affiliate, utility operation, jurisdiction or non-regulated business activity. For example, labor of an employee who works for more than one affiliate, shall be allocated based on positive time reporting or other allocation method as identified in the CAAM. Similarly, non-labor joint or common costs such as vehicles, advertising, space, etc. are subject to the cost allocation principles.
Convenience Payments	Payments made by an operating company or the Service Company on behalf of another operating company or affiliate. Convenience payments are recorded in the intercompany accounts of the company. Convenience payments are not the result of the Operating Company or the Service Company providing a service (a good, product or service) to an operating company or affiliate.
Cost Allocation	The method(s) used to allocate a joint or common cost.
Cost Assignment	The method or process of directly assigning a cost.
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.
Fully Distributed Cost	Transactions billed include all direct and indirect costs, including overheads.
Operations and Maintenance	Includes activity in FERC accounts 500-935 with the exception of FERC account 501, Fuel; FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910; Customer Service and Informational Expenses; FERC accounts 911-917, Sales Expenses and FERC accounts 920-935, Administrative and General Expenses.
Supply Chain	The Supply Chain Department of the Service Company.

Terms (continued)

Service Function	A specific function of an Organizational Area. Examples include but not limited to: Executive Management, Internal Audit, Payroll and Marketing and Sales.
Subledger	A JDE Business Unit code or Work Order that designates who the charge is being billed to. A subledger is assigned to only one company or legal entity.
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.
Work Order	Accumulates costs, either for Capital, Expense or to be further allocated.

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

OPERATING INCOME JURISDICTIONAL ALLOCATION FACTORS

Line No.	Allocation Factor	Test Year 2011 Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Demand	70,726,027	4,109,688	5.8107%
2	Energy	37,081,339	2,322,121	6.2622%
3	Customers	1,408,989	89,033	6.3189%
4	Two-Factor			5.9684%

(1) Demand
(2) Energy
(3) Average number of Customers
(4) Two-Factor Allocator (A&G Only) See page 3
Expressed as an equally weighted factor based on electric plant in service and electric O&M expense (excluding A&G).
These costs are then allocated to jurisdiction based on the O&M default for that Regulatory Business Unit.
The production and transmission portions are allocated to jurisdiction using a 12 CP demand allocator, and the customer portion is allocated using 12- month end-of-year average electric customers.

Allocators for Common and General Plant
for 2011 Budget
Based on 2009 Actual Data

O&M Allocator

O&M excluding A&G	2009 Actuals	Ratio
Production	$ 457,455,821	63.30%
Transmission	$ 39,948,936	5.53%
Distribution/Customer	$ 225,266,593	31.17%
	$ 722,671,350	100.00%

Plant in Service used to allocate Electric General Plant
Source - 2009 FERC Form 1
Pages 204-207

	2009 Year End Balance	Ratio
Production	$ 4,842,806,813	51.07%
Transmission	$ 1,711,985,627	18.05%
Distribution	$ 2,928,723,088	30.88%
	$ 9,483,515,528	100.00%

Combined Allocator used for Electric Portion of Common Plant
Equally Weighted Plant in Service and O&M ratio

Production	57.18%
Transmission	11.79%
Distribution	31.03%
	100.00%

11 Budget Allocators

EProd Demand Alloc

MN	88.4924%
ND	5.8107%
SD	5.5779%
WHLSL	0.1190%
	100.0000%

ETrans Demand Alloc

MN	88.4924%
ND	5.8107%
SD	5.5779%
WHLSL	0.1190%
	100.0000%

ECustomerMN/SD/ND

MN	87.6785%
ND	6.3189%
SD	6.0024%
WHLSL	0.0002%
	100.0000%

2008 Budget A&G Jurisdictional Allocators

ELECTRIC A&G Alloc

2 Factor Allocator	O&M and Plant	MN	ND	SD	WHLSL	Check
Production	57.1800%	50.6000%	3.3226%	3.1894%	0.0680%	57.1800%
Transmission	11.7900%	10.4333%	0.6851%	0.6576%	0.0140%	11.7900%
Distribution/Customers	31.0300%	27.2066%	1.9608%	1.8625%	0.0001%	31.0300%
Resulting Allocator	**100.00%**	**88.2399%**	**5.9684%**	**5.7096%**	**0.0821%**	**100.0000%**

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Rate Base Jurisdictional Allocation Factors

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	Demand/Energy
2	Transmission	Demand
3	General Production Transmission Other	Demand/Customers/Direct Assigned
4	Common Production Transmission Other	Demand/Customers/Direct Assigned
	In addition, the following allocation factors are used to compute North Dakota jurisdictional amounts:	
5	Other Rate Base:	
	Materials & Supplies	Demand/Customers/Direct Assigned
	Non-Plant Assets & Liabilities	Demand/Customers/Direct Assigned
	Prepayments	Demand/Customers/Direct Assigned
	Fuel Inventory	Energy

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Rate Base Jurisdictional Allocation Factors

		Test Year 2011		
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Demand	70,726,027	4,109,688	5.8107%
2	Energy	37,081,339	2,322,121	6.2622%
3	Customers	1,408,989	89,033	6.3189%

(1) Demand
(2) Energy
(3) Average number of Customers

Average Rate Base
($000's)

Line No.	Description	Proposed 2011 Test Year Average Rate Base (A)	Final Proposed With 2012 Step Average Rate Base (A)
	Electric Plant as Booked		
1	Production	$478,515	$495,235
2	Transmission	111,382	115,591
3	Distribution	125,117	125,117
4	General	20,607	20,607
5	Common	27,596	27,596
6	TOTAL Utility Plant in Service	$763,216	$784,145
	Reserve for Depreciation		
7	Production	$251,803	$251,415
8	Transmission	34,885	35,754
9	Distribution	57,662	57,662
10	General	8,419	8,419
11	Common	17,390	17,390
12	TOTAL Reserve for Depreciation	$370,159	$370,639
	Net Utility Plant in Service		
13	Production	$226,712	$243,820
14	Transmission	76,497	79,837
15	Distribution	67,455	67,455
16	General	12,188	12,188
17	Common	10,206	10,206
18	Net Utility Plant in Service	$393,058	$413,505
19	Utility Plant Held for Future Use	$0	$0
20	Construction Work in Progress	$2,100	$2,100
21	Less: Accumulated Deferred Income Taxes	$79,352	$82,840
22	Cash Working Capital	$2,057	$1,734
	Other Rate Base Items:		
23	Materials and Supplies	$6,186	$6,186
24	Fuel Inventory	5,674	5,674
25	Non-Plant Assets & Liabilities	(6,173)	(6,173)
26	Prepayments	1,018	1,018
27	Nuclear Outage Amortization	2,712	3,368
28	Customer Advances	(1)	(1)
29	Customer Deposits	(131)	(131)
30	Other Working Capital	426	426
31	Total Other Rate Base Items	$9,711	$10,367
32	Total Average Rate Base	$327,573	$344,866

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
Comparison of Detail Rate Base
($000's)

		Proposed Test Year 2011					
		Total Utility			North Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	2011 Proposed (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	2011 Proposed (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$8,043,671	$9,609	$8,053,280	$478,047	$468	$478,515
2	Transmission	1,927,489	(21,427)	1,906,062	112,610	(1,228)	111,382
3	Distribution	3,064,875	0	3,064,875	125,117	0	125,117
4	General	344,185	0	344,185	20,607	0	20,607
5	Common	454,891	0	454,891	27,596	0	27,596
6	TOTAL Utility Plant in Service	$13,835,111	($11,818)	$13,823,293	$763,976	($760)	$763,216
	Reserve for Depreciation						
7	Production	$4,321,970	$463	$4,322,433	$251,781	$23	$251,803
8	Transmission	600,949	(30)	600,919	34,886	(2)	34,885
9	Distribution	1,252,391	0	1,252,391	57,662	0	57,662
10	General	140,763	0	140,763	8,419	0	8,419
11	Common	285,467	0	285,467	17,390	0	17,390
12	TOTAL Reserve for Depreciation	$6,601,539	$433	$6,601,972	$370,138	$21	$370,159
	Net Utility Plant in Service						
13	Production	$3,721,701	$9,147	$3,730,847	$226,266	$446	$226,712
14	Transmission	1,326,541	(21,398)	1,305,143	77,724	(1,227)	76,497
15	Distribution	1,812,485	0	1,812,485	67,455	0	67,455
16	General	203,422	0	203,422	12,188	0	12,188
17	Common	169,424	0	169,424	10,206	0	10,206
18	Net Utility Plant in Service	$7,233,572	($12,251)	$7,221,321	$393,839	($781)	$393,058
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$32,599	$0	$32,599	$2,100	$0	$2,100
21	Less: Accumulated Deferred Income	$1,302,319	$123,370	$1,425,689	$72,101	$7,251	$79,352
22	Cash Working Capital	$15,824	$4,672	$20,496	$1,772	$285	$2,057
	Other Rate Base Items:						
23	Materials and Supplies	$105,544	$0	$105,544	$6,186	$0	$6,186
24	Fuel Inventory	90,609	0	90,609	5,674	0	5,674
25	Non-Plant Assets & Liabilities	(102,585)	0	(102,585)	(6,173)	0	(6,173)
26	Prepayments	17,235	0	17,235	1,018	0	1,018
27	Nuclear Outage Amortization	44,856	0	44,856	2,712	0	2,712
28	Customer Advances	(841)	0	(841)	(1)	0	(1)
29	Customer Deposits	(2,076)	0	(2,076)	(131)	0	(131)
30	Other Working Capital	6,747	0	6,747	426	0	426
31	Total Other Rate Base Items	$159,489	$0	$159,489	$9,711	$0	$9,711
32	Total Average Rate Base	$6,139,165	($130,949)	$6,008,216	$335,320	($7,747)	$327,573

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
Comparison of Detail Rate Base
($000's)

		Final Proposed Test Year With 2012 Step					
		Total Utility			North Dakota Jurisdiction		
Line No.	Description	2011 Proposed (A)	Adjustments (B)	Final Proposed With 2012 Step (C) (A) + (B)	2011 Proposed (D)	Adjustments (E)	Final Proposed With 2012 Step (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$8,053,280	$287,746	$8,341,026	$478,515	$16,720	$495,235
2	Transmission	1,906,062	4,209	1,910,271	111,382	4,209	115,591
3	Distribution	3,064,875	0	3,064,875	125,117	0	125,117
4	General	344,185	0	344,185	20,607	0	20,607
5	Common	454,891	0	454,891	27,596	0	27,596
6	TOTAL Utility Plant in Service	$13,823,293	$291,955	$14,115,249	$763,216	$20,929	$784,145
	Reserve for Depreciation						
7	Production	$4,322,433	($6,677)	$4,315,756	$251,803	($389)	$251,415
8	Transmission	600,919	869	601,788	34,885	869	35,754
9	Distribution	1,252,391	0	1,252,391	57,662	0	57,662
10	General	140,763	0	140,763	8,419	0	8,419
11	Common	285,467	0	285,467	17,390	0	17,390
12	TOTAL Reserve for Depreciation	$6,601,972	($5,808)	$6,596,164	$370,159	$481	$370,640
	Net Utility Plant in Service						
13	Production	$3,730,847	$294,423	$4,025,270	$226,712	$17,109	$243,820
14	Transmission	1,305,143	3,340	1,308,483	76,497	3,340	79,837
15	Distribution	1,812,485	0	1,812,485	67,455	0	67,455
16	General	203,422	0	203,422	12,188	0	12,188
17	Common	169,424	0	169,424	10,206	0	10,206
18	Net Utility Plant in Service	$7,221,321	$297,763	$7,519,085	$393,058	$20,449	$413,505
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$32,599	$0	$32,599	$2,100	$0	$2,100
21	Less: Accumulated Deferred Income	$1,425,689	$44,443	$1,470,132	$79,352	$3,488	$82,840
22	Cash Working Capital	$20,496	($2,110)	$18,386	$2,057	($323)	$1,734
	Other Rate Base Items:						
23	Materials and Supplies	$105,544	$0	$105,544	$6,186	$0	$6,186
24	Fuel Inventory	90,609	0	90,609	5,674	0	5,674
25	Non-Plant Assets & Liabilities	(102,585)	0	(102,585)	(6,173)	0	(6,173)
26	Prepayments	17,235	0	17,235	1,018	0	1,018
27	Nuclear Outage Amortization	44,856	0	44,856	2,712	657	3,368
28	Customer Advances	(841)	0	(841)	(1)	0	(1)
29	Customer Deposits	(2,076)	0	(2,076)	(131)	0	(131)
30	Other Working Capital	6,747	0	6,747	426	0	426
31	Total Other Rate Base Items	$159,489	$0	$159,489	$9,711	$657	$10,367
32	Total Average Rate Base	$6,008,216	$251,210	$6,259,427	$327,573	$17,294	$344,866