Direct Testimony and Schedules
Anne E. Heuer

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-15-826
Exhibit___(AEH-1)

2016 Test Year
Overall Revenue Requirements
Rate Base
Income Statement

Rate Rider Recovery 2016-2018

November 2, 2015

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Anne E Heuer. I am the Director of Revenue Analysis 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___(AEH-1), Schedule 1.

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

A. I am testifying on behalf of Northern States Power Company, doing business as Xcel Energy (Xcel Energy, NSPM, or the Company). I provide testimony supporting the Company's financial data and its requests for a general rate increase and interim rate increase for the State of Minnesota retail electric jurisdiction. My testimony also addresses the Minnesota jurisdiction's electric operations 2016 test year retail deficiency of $194.612 million, with an overall revenue requirement of $3.229 billion determined by the cost of service for the 2016 budget test year ending December 31, 2016.

My testimony also supports the 2016 and 2017 requested interim increases discussed in the Petition for Interim Rates. Support for the 2017 interim rate increase as a part of our multi-year rate plan is also discussed in the Direct Testimony of Company witness Mr. Aakash Chandarana.

In addition, I explain our treatment of riders, and provide a description of cost changes, including the data we provide and our selection of the test year. I also identify certain compliance issues reflected in our Application. Further, I present:

- our jurisdictional cost of service study and the revenue requirement effects of our utility and jurisdictional allocations;
- our revenue requirement, including rate base and adjustments and income statement and adjustments; and
- our 2016 revenue requirements.

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

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

A. I present my testimony in the following sections:

- Section II, *Case Overview*, summarizes our 2016 test year jurisdictional revenue requirement and discusses the key drivers of cost increases in 2016.
- Section III, *Supporting Information*, provides information related to the data provided in our application, the selection of the test year, and the jurisdictional cost of service study.
- Section IV, *Rate Base*, identifies and explains the components of rate base, and supports the reasonableness of the Company's projected 2016 test year rate base.
- Section V, *Income Statement*, identifies and explains the major components of the income statement and supports the reasonableness of the Company's proposed 2016 test year income statement.
- Section VI, *Utility and Jurisdictional Allocations*, explains why it is necessary for the Company to allocate costs among its affiliates and

between jurisdictions, and describes the utility and jurisdictional allocators that are used in determining the test year revenue requirement.

- Section VII, *Adjustments to the Test Year*, presents all adjustments affecting the test year revenue requirement, providing both rate base and income statement impacts.
- Section VIII, *Costs Recovered in Riders*, presents our proposed treatment of costs recovered in riders during the multi-year rate plan period, providing details about which riders we propose to continue to use and costs we propose to move into base rates.
- Section IX, *Compliance with Prior Commission Orders*, provides information related to specific requirements from prior Commission Orders that have not been addressed elsewhere in my testimony.
- Section X, *Conclusion*, summarizes our request.

An index of the Schedules to my Direct Testimony is provided as Exhibit___(AEH-1), Schedule 2.

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

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

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

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

Q. DO YOU PROVIDE ANY ADDITIONAL INFORMATION RELATED TO THE REVENUE REQUIREMENT?

A. Yes. Appendix A provides a list of relevant information requests from our last two rate cases, Docket Nos. E002/GR-12-961 and E002/GR-13-868, that I respond to in this case, with new time frames as appropriate to reflect the November 2, 2015 filing date of this case. The list indicates where the responsive information is included in my testimony or schedules, or if it is included in Appendix A.

II. CASE OVERVIEW

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

A. In this section, I will:

- present the jurisdictional revenue requirement and revenue deficiencies for Minnesota for the 2016 test year;
- present a summary comparison of the costs in the 2016 test year to the costs approved in our last rate case, which include costs in the 2014 test year and the 2015 Step increase; and

- provide an explanation of the primary sources of the changes in overall costs, including plant related costs and O&M costs, and the rate moderation tools approved as a part of our last rate case.

A. Test Year Jurisdictional Revenue Requirements and Deficiencies

Q. WHAT IS THE 2016 TEST YEAR JURISDICTIONAL OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The overall jurisdiction revenue requirement for the 2016 test year is $3.229 billion. The 2016 test year revenue deficiency is $194.612 million. The 2016 test year revenue deficiency amount represents a 6.41 percent overall increase in retail revenues from base rates compared to projected 2016 retail revenues at present rates. A summary of the 2016 revenue requirement is provided in Exhibit___(AEH-1) Schedule 3, Summary of Revenue Requirements, Test Year Ending December 31, 2016. The calculation of these amounts is provided in Exhibit___(AEH-1) Schedule 4, Cost of Service Study for Proposed 2016 Test Year.

Q. WHAT IS THE AMOUNT OF THE INTERIM RATE REVENUE DEFICIENCY IN 2016?

A. The Interim Rate Petition (Petition) supports an interim revenue deficiency based on the 2016 test year of $163.670 million, which results in a proposed interim rate increase of 5.50 percent beginning January 1, 2016. As discussed in the Direct Testimony of Mr. Chandarana and in the Petition, the Company is also proposing an interim rate adjustment for 2017 as part of its multi-year rate plan filing. The 2017 interim rate revenue deficiency includes an additional $44.902 million beginning on January 1, 2017, which equates to an additional interim rate increase of 1.51 percent in 2017.

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

A. The general formula for calculation of the revenue requirement and revenue deficiency is depicted below in Table 1 as follows:

Table 1
Revenue Requirement and Revenue Deficiency

	Item	**2016 Test Year Amount ($000s)**	**Exhibit__(AEH-1), Sch. 4 Reference**
	Average Rate Base	$7,836,115	Page 2, Line 23
multiplied by	Cost of capital	7.49%	Page 5, Line 15
	Operating Income Requirement	**$586,925**	Page 5, Line 36
	Current Retail Revenue	$3,034,094	Page 3, Line 2 + Line 3
plus	Current Other Revenue	$586,984	Page 3, Line 5
equals	Current Total Revenue	$3,621,078	Page 3, Line 6
minus	Operating Expenses	$2,342,900	Page 3, Line 29
minus	Depreciation Expense	$471,286	Page 3, Line 31
minus	Amortization Expense	$39,585	Page 3, Line 32
minus	Taxes	$327,766	Page 3, Line 46
plus	AFUDC	$33,283	Page 3, Line 50 + Line 51
equals	**Total Available for Return**	**$472,824**	Page 3, Line 53
	Operating Income Requirement	$586,925	Page 5, Line 36
minus	Total Available for Return	$472,824	Page 5, Line 37
equals	Income Deficiency	$114,101	Page 5, Line 38
multiplied by	Gross Revenue Conversion Factor	1.705611	Page 5, Line 40
equals	**Revenue Deficiency**	**$194,612**	Page 5, Line 45
plus	Current Retail Revenue	$3,034,093	Page 5, Line 44
equals	**Total Revenue Requirement**	**$3,228,705**	Page 5, Line 46

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

A. Yes. An explanation is provided in the Financial Information section of Volume 3 of this Application. In addition, work papers supporting the 2016 test-year cost of service are provided in Volumes 4A and 4B of this Application (Test Year Work Papers).

B. Case Drivers

Q. HAVE YOU PREPARED A COMPARISON OF THE COSTS IN THE 2016 TEST YEAR TO THE 2014 TEST YEAR WITH THE 2015 STEP?

A. Yes. Consistent with prior rate cases, I provide an explanation of the key cost drivers of the deficiency using a comparison of the 2016 test year with the combination of the 2014 test year and 2015 Step from our last electric rate case, Docket No. E002/GR-13-868. My analysis differs from the Direct Testimony analyses of the Company's business area witnesses, who primarily compare cost changes in their 2016 budgets to prior years' total actual costs and forecasts (not revenue deficiencies). Therefore, my discussion of key cost drivers reflects dollar values that are, in large part, different from their discussions.

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

A. Yes. I provide Exhibit___(AEH-1), Schedule 6, which provides a Summary of Major Cost Elements for 2016 Test Year (an overview of the major revenue requirement elements), and a Summary of Major Cost Drivers (identification of case drivers for the 2016 test year), including:

- Capital Recovery for additional rate base investment; a reduction for Energy Supply investments, other rate base items, and NOL/federal tax items; application of the theoretical reserve; and increases in property taxes, collectively increasing the 2016 revenue deficiency by approximately $159.6 million;

- Operating Expense, including a reduction in Nuclear O&M offset by increases in Transmission, Distribution, and Administrative and General; increases in property taxes; and decreases in amortizations and payroll taxes, collectively increasing the revenue deficiency by approximately $45.5 million; and
- Total margins, which collectively decrease the deficiency by approximately $10.5 million.

Exhibit___(AEH-1), Schedule 6 also provides a Summary of Major Cost Drivers bridge schedule to the cost of service, and an illustration of Major Carryover Projects from our last rate case (Docket E002/GR-13-868). In addition to the discussion in this Section, support for our proposed increase in rates for the 2016 test year is provided in the Direct Testimonies of the Company's business area witnesses and the Direct Testimony of Company witness Mr. Gregory J. Robinson.

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

A. Table 2 below compares the 2016 test year revenue requirements with the comparable revenue requirements for the 2014 test year and the 2015 Step, by category, for capital plant related costs as shown on Exhibit___(AEH), Schedule 6 at Page 2.

Table 2
Capital Related Cost Changes

Cost Category	**Increase (Decrease)** $ in Millions	**% Change in Average Rate Base**
Nuclear (IA)	$57.5	36.0%
Energy Supply (IA)	($3.4)	-2.1%
Wind (IA)	$12.7	8.0%
Transmission (IA) net of TCR	$18.8	11.8%
Distribution	$13.0	8.1%
General & Intangible	$25.9	16.2%
Theoretical Reserve[1]	$26.1	16.3%
Other Rate Base	($2.6)	-1.7%
NOL and Fed Tax Items	($6.2)	-3.9%
Return on Equity	$20.0	12.6%
Capital Structure & Debt	($2.1)	-1.3%
Total	**$159.6**	**100.0%**

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

A. The 2016 revenue requirements include a $57.5 million (IA) increase in Nuclear. This increase reflects revenue requirement increases related to having certain large 2015 Step projects in service for a full year in 2016, including an $11.2 million (IA) increase for the Monticello Life Cycle Management/Extended Power Uprate (LCM/EPU) project and a $5.5 million (IA) increase for the Prairie Island Unit 2 Generator and GSU Transformer. These changes are illustrated in Exhibit___(AEH-1), Schedule 6 at Page 5. The Nuclear capital increase also reflects investments to comply with NRC mandates, including its Fukushima program and fire safety requirements, and to help support the ongoing reliability of the Prairie Island plant. Company witness Mr. Timothy J. O'Connor provides additional information regarding nuclear plant capital improvements in his Direct Testimony.

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

A. The 2016 test year includes a $12.7 million (IA) increase related primarily to placing the Pleasant Valley and Border Winds projects in service at the end of 2015, as illustrated by Exhibit___(AEH-1), Schedule 6 at Page 5. In addition, the Company will be placing the Courtenay Wind Farm in service in 2016, but anticipates that costs associated with this project will remain in the Renewable Energy Standard (RES) Rider, as described in the Direct Testimony of Mr. Aakash H. Chandarana. As a result of devoting substantial resources to these projects, Energy Supply capital investments are otherwise reduced by $3.4 million (IA) for the 2016 test year. Energy Supply and Wind projects are discussed in the Direct Testimony of Mr. Steven H. Mills.

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

A. The 2016 test year includes an $18.8 million (IA) revenue requirement increase associated with Transmission, net of the Transmission Cost Recovery (TCR) Rider. For Transmission, most of the large capital projects, particularly the CapX2020 projects, are recovered in Minnesota through the TCR Rider. However, a portion of the deficiency is related to capital investments in reliability projects. The 2016 deficiency related to Transmission also reflects an $11.4 million increase in billings from NSPW through the Interchange Agreement as compared to the last electric rate case, offset by $44.2 million in transmission related revenue. This is due to significant transmission projects in both NSPM and NSPW.

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

A. Approximately $13.0 million of the 2016 revenue deficiency is due to Distribution capital. Company witness Ms. Kelly A. Bloch describes the distribution capital needs relating to asset health such as pole and cable replacement, extending service to new residential and business customers, capacity investment for greater reliability, and fleet, tools, and equipment. Ms. Bloch also describes our LED street light replacement program, which will commence in 2016.

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

A. Approximately $25.9 million of the 2016 revenue deficiency is due to General & Intangible capital investments, which consist primarily of Information Technology implemented by our Business Systems business area. Company witness Mr. David C. Harkness describes the capital needs relating to cyber security, aging technology, enhanced capabilities, and the implementation of the Work and Asset Management portion of our Productivity Through Technology initiative.

Q. WHAT OTHER CAPITAL COSTS CHANGED?

A. Revenue requirements associated with the Transmission, Distribution, and General Plant categories (TDG) theoretical reserve increased by $26.1 million (IA) due to the application of 50 percent and 30 percent of the reserve in 2014 and 2015, respectively, versus 20 percent in 2016. This application of rate moderation was approved by the Commission in our prior rate case (Docket E002/GR-13-868). We also experienced a partially offsetting reduction in the revenue deficiency due to the net operating loss, federal tax items, and other rate base items.

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

A. We anticipate a $20 million increase related to return on equity (ROE), and a $2.1 million decrease due primarily to a decline in the cost of long term debt. Company witness Mr. Brian J. Van Abel describes the capital structure and costs of debt in his Direct Testimony. Company witness Mr. James M. Coyne of Concentric Energy Advisors, Inc. discusses the ROE. I provide additional detail on how these relate to the cost of service in Section V, Income Statement and Section VII, Adjustments to the Test Year.

Q. ARE AMORTIZATIONS, DEPRECIATION, AND AFUDC REFLECTED IN THESE CAPITAL DRIVERS?

A. Yes. A comparison of the Amortization costs between the 2016 test year and 2014 approved level is included in Table 3 below. Capital-related amortization expense generally relates to rider revenue offsets or specific treatment of costs for regulatory purposes as prescribed by the Commission. The Amortization line identified on Exhibit___(AEH-1), Schedule 6 Pages 1 and 2 includes the approved amortization level for rate case expense and Monticello prudence review expense from the 2014 test year and requested rate case amortization expense for the 2016 test year. Table 3 subtotals the capital-related amortizations and case-related amortizations that total the amortization line on the Income Statement.

Table 3
Comparison of Amortization Costs

	2014 Test Year	2016 Test Year	Difference	Comments
Capital-Related Amortizations				
RDF Rider (Base Data)	$22.7M	$35.1M	$12.4M	RDF Rider revenue offset
SEP Rider (Base Data)	$1.5M	$ 0.0M	($1.5M)	Nuclear Expense in 2016
PI EPU Recovery	$2.9M	$2.9M	$0.0M	Adj. 31 Section VII
Sherco 3 Depreciation	$0.5M	$0.5M	$0.0M	Adj. 33 Section VII
Black Dog Removal Costs (Base Data)	$1.6M	$0.0M	($1.6M)	Depr. Expense in 2016
Nobles No Return	$0.2M	$0.0M	($0.2M)	Other Revenue in 2016
Subtotal Capital-Related Amortizations	$29.4M	$38.5M	$9.1M	
Case-Related Amortizations				
Rate Case Expense	$1.4M	$1.1M	(0.3M)	Adj. 32 Section VII
Monti Prudence Expense	$0.5M	$0.0M	($0.5M)	Amort .ended pre-2016
Subtotal Case-Related Amortizations	$1.9M	$1.1M	($0.8M)	
Total Income Statement Amortizations	$31.3M	$39.6M	$8.3M	

Amortization adjustments are described in detail in Section VII, Adjustments to the Test Year. Compared to the 2014 test year and 2015 Step in the last electric case, this test year has $123.9 million greater depreciation expense (a 35.7 percent increase) and $3.9 million greater AFUDC offset (a 13.4 percent increase). These contribute to the revenue requirement calculations related to capital.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. We anticipate a $30.2 million (IA) increase in property taxes, offset somewhat by a $1.9 million decrease in payroll taxes. Company witness Ms. Leanna M. Chapman explains that property taxes continue to trend upward due to the Company's investments in our system.

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

A. Table 4 below compares the 2016 test year costs with the comparable cost category in our 2014 test year and 2015 Step.

Table 4
O&M Cost Changes

Cost Category	**Increase (Decrease)** $ in Millions	**% Change over 2014 Test Year/2015 Step as approved by Commission**
Nuclear (IA)	($13.4)	-4.7%
Energy Supply (IA)	$4.4	2.7%
Transmission (IA)	$2.5	6.6%
Distribution	$4.7	4.7%
Customer Accounting, Information and Sales	$0.4	0.4%
Administrative and General and Other O&M	$19.3	9.8%
Total	**$17.9**	**2.1%**

Q. WHAT ARE THE CAUSES OF THE NUCLEAR OPERATIONS COST DECREASES FOR 2016?

A. The Direct Testimony of Mr. O'Connor explains, at a total Company level, the business drivers behind these decreases for the Nuclear area, which include reductions in non-outage workforce and materials costs and outage costs, offset somewhat by increasing security costs, and nuclear fees.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN ENERGY SUPPLY O&M?

A. The Direct Testimony of Mr. Mills explains that Energy Supply anticipates increases in O&M in 2016 due to increased utilization of contract labor, increased use and cost of chemicals, and additional wind farm land easement costs related to the addition of the Pleasant Valley and Border Winds farms in 2015. These increases are offset somewhat by decreases in internal labor and materials.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN TRANSMISSION COSTS?

A. Although 2016 Transmission O&M is decreasing from an NSPM business unit expenditure standpoint, the 2016 revenue deficiency associated with Transmission O&M is increasing due to increased billings through the interchange. Mr. Benson describes Transmission O&M in more detail.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN DISTRIBUTION COSTS?

A. The increases in Distribution costs are primarily due to vegetation management and damage prevention (electric locate) costs. Company witness Ms. Bloch describes Distribution operations in more detail.

Q. PLEASE DESCRIBE OTHER O&M COST DRIVERS.

A. Administrative and general expense related to Information Technology (IT) is driven by the same factors described above with respect to IT capital drivers, and as described by Mr. Harkness in his Direct Testimony. Specifically, increased O&M expenses necessary to operate and maintain the new Company's new General Ledger system (implemented in 2015) and new Work and Asset Management costs (first implemented in 2016) are driving these cost increases. Incentive compensation costs and medical insurance are also expected to increase by $2.5 million and $6.3 million respectively compared to the authorized amounts. Company witness Ms. Ruth A. Lowenthal discusses the reasons for changes in the Company's compensation and benefit costs in her Direct Testimony.

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

A. Retail revenues are expected to increase somewhat in 2016, thereby offsetting items increasing the 2016 revenue deficiency. The largest portion of retail revenues consists of Company retail sales. As discussed by Company witness Ms. Jannell E. Marks, for 2016 the Company's total sales are projected to increase 0.7 percent from 2015 actual sales for January through May and projections from June through December. Ms. Marks explains that the projected growth is a result of moderate increases in Commercial and Industrial sales combined with declining Residential sales. Consequently, the Company's retail revenues are also expected to increase. In addition, purchased demand expense is decreasing due to contract terminations and new contracts that have been for lower purchase demand quantities. Together, these items offset the increased revenue deficiency by approximately $32.2 million.

Q. ARE THERE ANY OTHER MARGIN ITEMS WITH A SIGNIFICANT IMPACT ON THE 2016 REVENUE DEFICIENCY?

A. Yes. In our last rate case, the Commission approved the Company's proposal to utilize the amount of 2013 and 2014 Department of Energy (DOE) settlement payments (resulting from the DOE's contractual obligation to take spent nuclear fuel) in excess of the Company's 2014 and 2015 nuclear decommissioning accrual requirements to moderate rate increases in 2015. Such payments are not available in 2016, resulting in a $25.7 million difference in the 2016 revenue deficiency.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2016 TEST YEAR AND 2014 TEST YEAR?

A. Yes. Budget amounts for both periods conform to the FERC Uniform System of Accounts. To better show cost drivers, especially as they relate to operating margins, some reclassifications are made in the cost driver analysis from the Jurisdictional Cost of Service Study. Therefore, to provide additional clarity, Exhibit___(AEH-1), Schedule 6 at Pages 3 and 4 shows where each cost driver impacts the Jurisdictional Cost of Service. Also, Exhibit___(AEH-1), Schedule 6, Page 5 provides a quantification of the carryover impact in the 2016 test year that in-service for any a part of the year in the Company's last case.

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

A. No. Although the cost of fuel and purchased energy are considered to be an operating expense, recovery occurs through the Company's separate fuel clause adjustment (FCA) mechanism and true-up process. I provide a reconciliation of fuel costs in the Cost of Service to the Base Cost of Fuel filing in Exhibit___(AEH-1), Schedule 25, Fuel Reconciliation.

III. SUPPORTING INFORMATION

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

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

A. Data Provided and Selection of the Test Year

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

A. In this section, I will:

- identify the supporting financial information and related fiscal periods that we are providing in connection with the 2016 test year; and
- demonstrate that the supporting financial information and related fiscal periods that we are presenting provide appropriate information and facilitate review of our 2016 test year.

1) Overview

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

A. Following the Commission's rules, financial data is provided for the most recent fiscal year (calendar year 2014), the projected fiscal year 2015, and the 2016 test year. In addition, as discussed further by Mr. Chandarana and Mr. Burdick, we are proposing a multi-year rate plan that requests additional rate changes for years 2017 and 2018.

Q. WHAT FINANCIAL DATA IS USED IN THESE FISCAL PERIODS?

A. Financial data is provided for 2014 (the most recent fiscal year), 2015 (the projected fiscal year), and 2016 (the test year).

The most recent fiscal year (calendar year 2014) reflects the Company's actual financial results. For the projected fiscal year 2015, actual financial results through April 2015 are provided as rate base data; and actual financial results through June 2015, are provided as operating expenses and revenues. Forecast projections are provided for the remainder of 2015.

The 2016 test year is adjusted: (a) for traditional regulatory adjustments (e.g., charitable donations, etc.); (b) to update the budgets to reflect any subsequent changes to our costs that have become better known so as to provide the most accurate information about our 2016 costs and revenues as is available; and (c) to correct any errors in the budget.

I also provide schedules showing: the actual unadjusted average rate base consisting of the same rate base components; unadjusted operating income; overall rate of return; the calculation of required income; and the income deficiency and revenue requirements for the most recent fiscal year (2014), the projected fiscal year (2015), and the 2016 test year. Separate rate base and income statement bridge schedules for the 2014 test year that identify test period adjustments are provided with my testimony.

2) 2016 Test Year

Q. WHAT WAS THE BASE SOURCE FOR THE PROPOSED 2016 TEST YEAR COSTS?

A. Calendar year 2016 was selected as the test year for this filing using Xcel Energy's budget data for the first year of the budget cycle. The 2016 test year is based on the most recent available budget information. Use of a fully projected calendar test year (2016) is consistent with longstanding practice and precedent in the Company's rate cases before the Commission.

For the 2016 test year, the Company's 2016 budget is provided, as described in Mr. Robinson's Direct Testimony and Volumes 5 and 6 of the Application.

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

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

- Cost of capital to reflect the most currently available data.
- Sales and customer count forecasts using available actual sales and customer counts and updated IHS Global Insight economic data through December 2015.
- Assumptions used for calculating Qualified Pension expense based on information as of December 31, 2015.
- O&M active health care may be updated to reflect actual 2015 active medical and pharmacy claims.
- Capital projects more than $1 million currently planned to be in service in December 2016 to determine whether those projects will be completed within the 2016 test year, as well as any new or expanded projects anticipated to be completed within the test year.
- Property tax forecasts based upon property tax data that will become available during 2016.

Q. In addition to the updates listed above that will reflect the most current available data in the test year, do you anticipate any other adjustments in Rebuttal Testimony?

A. Yes. After we finalized our cost of service for this case, we identified five additional necessary adjustments. However, we either identified these adjustments or received the information too late to allow us to incorporate these changes into the revenue requirement in this initial filing. We plan to incorporate these adjustments when we file Rebuttal Testimony. In total, they result in a net $7.430 million decrease to the 2016 test year deficiency.

Following is a summary of the adjustments. I provide details related to these adjustments in Section VII.G.

1) Reflection of the Commission's October 22, 2015 decision in the 2015 Remaining Lives proceeding, Docket No. E,G002/D-15-46 (decrease of $8.046 million (IA) to the test year deficiency).
2) Removal of the 2016 test year impact of a 2017 capital addition (Hollydale) that was included in the 2017 capital budget forecast in error (decrease of $0.031 million (IA) to the test year deficiency).
3) Allocation of Prairie Island Indian Community Settlement Agreement Costs (increase of $0.663 million to the test year deficiency).
4) Removal of Economic Development Administration costs as discussed in Section VII, Adjustment 6 (decrease of $.016 million to the test year deficiency).
5) Reflection of the October 12, 2015 Decision of the Minnesota Department of Commerce on CIP expenditures in Docket No. E,G002/CIP-12-447 (equal revenues and expenditures offset, no net impact to test year deficiency).

We also identified two potential adjustments that may be necessary to include in Rebuttal Testimony if we have additional information at that time. These adjustments are related to Bonus Tax Depreciation and the MISO ROE Complaints.

3) Supporting Information and the 2016 Projected Test Year

Q. WHY DOES THE COMPANY USE 2014 AS ITS MOST RECENT FISCAL YEAR INSTEAD OF 2015?

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

> "Most recent fiscal year" is the *utility's prior fiscal year unless* notice of a change in rates is filed with the commission within the last three months of the current fiscal year *and at least nine months of historical data is available for presentation of current fiscal year financial information*, in which case the most recent fiscal year is deemed to be the current fiscal year. (Emphasis added)

The Company is filing this rate case within the last three months of 2015. However, nine months of actual 2015 data is "not available for presentation." As a result, one of the two requirements for using 2015 as the "most recent fiscal year" cannot be met. Since that requirement cannot be met, the plain language of the Rule directs that 2014 be used as the most recent fiscal year, which supports the Company's long standing approach.

Nothing in the Rule requires the Company to delay its filing until additional 2015 data becomes available or to accelerate the availability of the actual data to include nine months of actual data with the filing. Rather, Minn. R. 7825.3100, subp. 10 requires the Company to treat 2014 as the prior fiscal year and Minn. R. 7825.3100, subp. 12 requires that we treat 2015 as the projected fiscal year.

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

A. No. The Company filed information for 2014 (the most recent fiscal year), 2015 (the projected year), the unadjusted 2016 year, and the adjusted 2016 test year. Definitions and financial schedules related to 2014 actual and 2015 projections are included in the following locations.

- Volume 3, Required Information, Section II.
    - Tab 2, Jurisdictional Financial Summary Schedules, Schedule A-1

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

- Exhibit___(AEH-1), Schedule 7, Page 2, Comparison of Detailed Rate Base Components.
- Exhibit___(AEH-1), Schedule 8, Page 3, Comparison of Detailed Income Statement Components.

Q. HAS THE COMPANY'S PRACTICE RELATED TO IDENTIFICATION OF THE MOST RECENT FISCAL YEAR BEEN APPROVED IN PRIOR RATE CASES?

A. Yes. In our rate case in Docket E002/GR-12-961, the Administrative Law Judge (ALJ) found that the Company's practice was consistent with its filings in past rate cases, and was in compliance with Commission rules. Therefore, the ALJ supported,[1] and the Commission adopted, the Company's use of a fully projected test year.

Q. HAVE UPDATES BEEN MADE TO THE BUDGET DATA PRESENTED IN THE JURISDICTIONAL COST OF SERVICE STUDY?

A. Yes. Updates to both rate base and income statement data were identified during our review of the 2016 capital and O&M budgets and Direct

Testimony preparation. These updates were deemed necessary to present a representative level of rate base and operating income for our proposed 2016 test year. The budget updates are identified and presented in Section VII, Adjustments to the Test Year.

B. Jurisdictional Cost of Service Study

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

A. In this section, I will:

- explain the jurisdictional cost of service studies that we prepared for the 2016 test year; and
- identify and discuss information requests from our last rate case that we have updated and provided in this case.

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE 2016 TEST YEAR.

A. The complete jurisdictional cost of service for the 2016 test year is in Volume 4 (Test Year Work Papers) of this filing and includes all the adjustments discussed in my Direct Testimony. A summary of the jurisdictional cost of service study for 2016 is provided in Exhibit___(AEH-1), Schedule 4, Cost of Service Study Summary for 2016 Test Year.

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

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[1] ALJ Report Findings 866-873 in Docket E002/GR-12-961 (July 3, 2013).

income statement; (vi) income tax calculations; and (vii) cash working capital computation.

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

A. The jurisdictional cost of service summary for the 2016 test year is included at Exhibit___(AEH-1), Schedule 4, Cost of Service Study Summary for 2016 Test Year, (Pages 1-6):

- The cover Page identifies the Minnesota 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.
- The "Rate Base Summary" for total Company electric operations and the Minnesota jurisdiction is shown on Page 2. The Rate Base Summary references a calculation of cash working capital, which is detailed on Page 6.
- An "Income Statement Summary" for total Company electric operations and the Minnesota jurisdiction is shown on Page 3. The income statement shows the determination of total operating income at present authorized retail rates. The Income Statement Summary references calculations for federal and state income taxes, which are detailed on Page 4.
- The "Revenue Requirement and Return Summary" for total Company electric operations and the Minnesota jurisdiction is shown on Page 5. It 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 Minnesota 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.

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

A. Yes. The revenue conversion factor calculation is included in Volume 3, Tab B of the Other Supplemental Information; and composite income tax rates are included in Volume 3, Tab C, Schedule C-5, of the Operating Income Schedules.

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

A. The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base. This is sometimes called "interest synchronization." The Test Year Work Papers for the interest synchronization calculation are provided in Volume 4.

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

A. I have provided three schedules related to rate base: Exhibit___(AEH-1) Schedule 7, Comparison of Detailed Rate Base Components, Exhibit___(AEH-1) Schedule 10, 2016 Rate Base Adjustment Schedule, and Exhibit___(AEH-1) Schedule 9, Rate Base, CWIP and ADIT Summary. I discuss these schedules in Section IV, Rate Base and Section VII, Adjustments to the Test Year. Additional comparative rate base schedules are provided in Required Information Volume 3.

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

A. I have provided two schedules related to the income statement: Exhibit___(AEH-1), Schedule 8, Comparison of Detailed Income Statement Components, and Schedule 11, 2016 Income Statement Adjustment Schedule. I discuss these schedules in Section V, Income Statement and Section VII, Adjustments to the Test Year. Additional comparative income statement schedules are provided in Required Information Volume 3.

IV. RATE BASE

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

A. In this section of my testimony, I support the reasonableness of the Company's projected 2016 test year rate base and identify and explain how the components of the rate base were determined.

Q. IS THE COMPANY'S PROJECTED 2016 TEST YEAR RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The projected 2016 test-year rate base for the Company's Minnesota jurisdiction electric operations was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases.

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 2016 TEST-YEAR RATE BASE.

A. The 2016 test-year rate base is generally comprised of the following major items, which I later describe in detail:

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

Q. HOW DOES THE COMPANY CALCULATE RATE BASE?

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

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

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

Plant	$16,425,447	(per AEH-1, Sched 4, Page 2, Line 2)
Reserve	(7,267,758)	(per AEH-1, Sched 4, Page 2, Line 3)
ADIT	(1,979,773)	(per AEH-1, Sched 4, Page 2, Line 11)
CWIP	444,412	(per AEH-1, Sched 4, Page 2, Line 5)
Other Rate Base	213,787	(per AEH-1, Sched 4, Page 2, Lines 13-20)
Rate Base	$7,836,115	(thousands of dollars)

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

A. Exhibit___(AEH-1), Schedule 7, Comparison of Detailed Rate Base Components, provides a detailed statement of the rate base components. Page 1 of 2 provides a comparison of the rate base components for the 2016 test year, to the 2014 test year used in our most recent rate case. Page 2 of 2 shows a comparison of detailed rate base components for the 2014 fiscal year, 2015 forecast year, and the 2016 test year.

Exhibit___(AEH-1), Schedule 10, 2016 Rate Base Adjustment Schedule, is a bridge schedule that shows the 2016 unadjusted rate base, each proposed rate base adjustment, and the resulting proposed 2016 test year rate base.

Exhibit___(AEH-1), Schedule 9, Comparison of Detailed Rate Base Components, Page 1 of 3, shows a detailed average rate base by component for the 2016 test year for the Minnesota jurisdiction and total Company, before and after making proposed test period adjustments. Schedule 9, Page 2 of 3, shows the 2016 test year average Construction Work in Progress. Schedule 9, Page 3 of 3 shows the accumulated deferred income taxes by function for the Minnesota jurisdiction and total Company for the 2016 test year, before and after making proposed test period adjustments.

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 2016 test year. Such treatment is consistent with the method employed in the most recent Minnesota electric rate case.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY USE AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE 2016 TEST YEAR?

A. The historical base used for the beginning of the 2016 test year was the Company's actual net investment (Plant in Service less Accumulated Depreciation) on the Company's books and records as of April 30, 2015.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE 2016 TEST YEAR?

A. The 2016 test year ending net plant balances were determined by applying the data contained in the 2016 capital budget to the above-described beginning test year balances, adjusted for retirements, depreciation, salvage and removal costs projected to occur during the 2016 test year.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE 2016 TEST YEAR RATE BASE?

A. The average net utility plant included in the 2016 test year rate base is $9.158 billion, as shown on Exhibit___(AEH-1), Schedule 7, Comparison of Detailed Rate Base Components, Page 2. This is comprised of an average plant balance of $16.425 billion as detailed on Schedule 7, Page 2, minus an average depreciation reserve of $7.268 billion, also shown by component on Schedule 7, Page 2.

B. Construction Work In Progress

Q. WHAT IS CWIP?

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

Q. HAS CWIP BEEN INCLUDED IN THE 2016 TEST YEAR RATE BASE?

A. Yes. CWIP is included in rate base with a corresponding offset of AFUDC added to operating income. The rate base amount reflects a simple average of projected CWIP beginning and ending 2016 test year balances. This is consistent with the method employed in Minnesota and approved by the Commission in the Company's last rate case and matches the use of an average rate base. The inclusion of CWIP in rate base and the calculation of the AFUDC offset are discussed in the Direct Testimony of Company witness Ms. Lisa H. Perkett.

Q. HOW WERE THE 2016 TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning balance for CWIP was the April 30, 2015 historical balance. The beginning CWIP balance was adjusted to reflect projected construction expenditures, AFUDC, and transfers to Plant in Service during the remainder of 2015 and in 2016 to obtain the beginning and ending 2016 test year CWIP balance. These projections were developed from Xcel Energy's 2016 capital budget.

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 income 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 IS ADIT DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

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

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED TO ARRIVE AT THE 2016 PROJECTED TEST YEAR RATE BASE?

A. As shown on Exhibit___(AEH-1), Schedule 7, Comparison of Detailed Rate Base Components, Page 2, $1.980 billion was deducted. This amount reflects a simple average of the beginning and projected ending 2016 test year ADIT balances, and incorporates IRS tax regulations. Specifically, Sec. 1.167(l) of the tax code defines a pro-rated schedule for the extent average accumulated deferred income taxes can be used to reduce rate base to comply with the tax normalization requirements of the Code when forecast information is used to set rates. Details related to ADIT are provided in Exhibit___(AEH-1), Schedule 9, on Page 3 of 3.

D. Pre-Funded AFUDC

Q. WHAT IS PRE-FUNDED AFUDC?

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

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

Q. HOW IS PRE-FUNDED AFUDC TREATED?

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

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

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

Q. HOW HAVE YOU TREATED PRE-FUNDED AFUDC IN THE 2016 TEST YEAR?

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

E. Other Rate Base

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

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

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

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

Q. HOW WERE 2016 TEST YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Exhibit___(AEH-1), Schedule 7, Page 2, Comparison of Detailed Rate Base Components, are based on the 13-month average balances ending June 30, 2015, the most recent data available. The Materials and Supplies average balance included in the test-year rate base equals $136 million. The 2016 test-year average rate base amount for Fuel Inventory is $73 million.

Q. HOW WERE 2016 TEST YEAR NON-PLANT ASSETS AND LIABILITIES DETERMINED?

A. These balances as shown on Exhibit___(AEH-1), Schedule 7, Comparison of Detailed Rate Base Components, Page 2, represent the 2016 calendar year estimate of these balances. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and ADIT balances previously discussed. This group is primarily comprised of liabilities that reduce test year rate base by $4 million.

Q. HOW WERE 2016 TEST YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances during the period ended June 30, 2015, as a proxy for the 2016 test year. Our nuclear outage amortization is also included in Other Working Capital. The average rate base for nuclear outage amortization is based on the average of the beginning of year and end of year averages. The unamortized balances included in this section are based on the amortization schedules as described in Section IV.

The net impact of these various items increase test-year rate base by $116 million as shown on Exhibit___(AEH-1), Schedule 7, Comparison of Detailed Rate Base Components, Page 2.

Q. HOW WERE 2016 TEST-YEAR CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the projected 2016 test year revenues and expenses.

Q. WERE THE COMPONENTS OF THE 2016 TEST-YEAR CASH WORKING CAPITAL CALCULATED CONSISTENT WITH METHODS USED IN THE LAST RATE CASE?

A. Yes. The 2016 test-year cash working capital has been calculated consistent with methods accepted in our most recent Minnesota electric rate case.

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

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

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST ELECTRIC RATE CASE?

A. Yes. The Company has updated the lead/lag study for the calculation of the lead and lag days for all categories through year end 2014, using the methodology for calculating the lead/lag days consistent with the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for electric operations were incorporated into the Minnesota jurisdiction cash working capital calculations as shown on Exhibit___(AEH-1), Schedule 4, Cost of Service Study Summary for 2016 Test Year, Page 6.

Q. WHAT IS THE 2016 TEST-YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included as reduction in average rate base is $108 million as shown on Exhibit___(AEH-1), Schedule 4, Page 2.

Q. HAS THERE BEEN A CHANGE IN THE TEST-YEAR CASH WORKING CAPITAL AMOUNT SINCE THE LAST RATE CASE?

A. Yes. The $108 million reduction in test year Cash Working Capital requirement is an approximately $32 million greater reduction than the amount of the reduction in the test year in the last rate case ($76 million).

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

A. The decrease in Cash Working Capital results in a corresponding decrease in average rate base. This change is primarily due to the net changes in the average expense lead and revenue lag days between the two periods. Average revenue lag days increased to 41.58 in 2016 from 40.34 in 2014, meaning the Company's revenues are being collected on average 1.24 days slower in 2016 than in 2014. Conversely, the Company's average expense lead days increased to 56.34 in 2016 from 50.45 in 2014, meaning that the Company's cash outlay for paying expenses has been extended by an average of 5.89 days. The longer time frame in disbursing cash greatly exceeded the slower collection of revenues and has reduced the level of cash working capital balance to be included in rate base.

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

A. A negative cash working capital indicates that overall revenue collections occur sooner than the date when the associated costs of service are paid, and that, on average, most cash working capital requirements are being provided by customers and vendors. The negative cash working capital reduces rate base to compensate customers for funds provided to meet cash working capital requirements.

V. INCOME STATEMENT

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

A. In this section, I will support the reasonableness of the Company's proposed 2016 test year income statement.

Q. IS THE COMPANY'S PROPOSED 2016 TEST YEAR INCOME STATEMENT REASONABLE FOR DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The proposed 2016 test-year income statement for the Company's Minnesota jurisdiction electric operations was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases.

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

A. The following are the major components of the projected income statement:

- Revenues;

- Operating and Maintenance Expenses;
- Depreciation Expense;
- Taxes;
- AFUDC; and
- Net Income

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

A. Exhibit___(AEH-1), Schedule 11, 2016 Income Statement Adjustment Schedule, is a bridge schedule that shows the 2016 unadjusted income statement, each proposed income statement adjustment, and the resulting proposed 2016 test year income statement. Schedule 11 also includes the revenue deficiency amount for each items included in this schedule

Exhibit___(AEH-1), Schedule 8, Comparison of Detailed Income Statement Components, provides a detailed statement of the income statement components. Page 1 provides a comparison of income statement components for present rates at December 31, 2016 and for final rates at December 31, 2016. Page 2 provides a comparison of income statement components for the Company's last rate case filing to the 2016 test year assuming final rates. Page 3 provides a comparison of the income statement components for 2014, 2015, and the 2016 test year.

A. Revenues

Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES FOR THE 2016 TEST YEAR CONSIDERED?

A. Yes. The test year sales volumes are supported by the Direct Testimony of Ms. Marks.

Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF UNBILLED SALES VOLUMES IN THE 2016 TEST YEAR?

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

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

A. Yes. The 2016 test year includes items such as revenues from sales to other utilities, certain revenues from wholesale trading activities, wholesale transmission revenues, and specific tariff charges, including service activation fees, reconnection fees and others. In areas where the Company did not budget for the collection of these tariffed charges, a representative level was determined and included as part of the revenues in the cost of service study. Other operating revenues also include billings to NSPW under the Interchange Agreement. Consistent with adjustments made in our last rate case, a three year average (2013, 2014 and 2015 Bridge) for certain other revenues was included in the determination of the 2016 test year level of Other Revenues. I discuss that revenue adjustment and other adjustments to revenues in more detail in Section VII, Adjustments to the Test Year.

Q. ARE ANY NON-REGULATED REVENUES OR OTHER AMOUNTS EXCLUDED FROM THE 2016 COST OF SERVICE?

A. Yes. Because the following items are not considered in the determination of base rates, we have excluded them from the 2016 Cost of Service:

- Windsource revenues and operating expenses (see Section VII, Adjustments to the Test Year, Adjustment 37);
- Asset and non-asset based margins (see Section VII, Adjustments to the Test Year, Adjustments 27 and 29); and
- CIP Incentive (see Section VII, Adjustments to the Test Year, Adjustment 18).

Q. HAVE REVENUES AND EXPENSES ASSOCIATED WITH NSPM'S NON-REGULATED BUSINESS ACTIVITIES BEEN EXCLUDED FROM THE 2016 COST OF SERVICE?

A. Yes, we have excluded the revenues and expenses associated with Commission approved non-regulated business activities (customer-owned street lighting maintenance and Sherco steam sales to Liberty Paper) from the 2016 cost of service. Because these activities are recorded in below the line accounts, they were not included in the 2016 test year. A discussion of why these two activities are classified as non-regulated activities and how these activities are treated for rate-making purposes is included in Appendix A to my Direct Testimony.

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

A. Both revenues and expenses related to the MISO schedules are included in the determination of retail rates through either base rates, the FCA or the TCR Rider. Base rate recovery, for example, includes both the revenues received from MISO and the expense billings from MISO for Schedules 1

(Scheduling, System Control and Dispatch Service) and 2 (Reactive Supply and Voltage). The FCA, for example, includes Schedule 3 (Regulating Reserve). The TCR Rider includes recovery of Schedule 26 (Network Upgrade from Transmission Expansion Plan) and 26-A (Multi-Value Project Usage Rate) revenues and expenses. The TCR Rider also includes, for capital projects not regionally shared, an Open Access Transmission Tariff (OATT) Revenue Credit to estimate the revenue that will be collected for the project from wholesale transmission customers. The treatment of revenues and expenses related to the MISO schedules is consistent with their treatment in prior rate cases. A description of each MISO schedule, its associated recovery mechanism, the 2016 test year revenues and expenses and the location of supporting information is included in Appendix A.

Q. WHAT ARE WHOLESALE MARGINS?

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

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

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

A. Because asset based margins are created by selling energy or capacity from generating facilities or PPAs paid for by ratepayers, all asset based margins have been credited to ratepayers. Asset based energy sales margins have been shared with rate payers through the FCA, and asset based capacity sales margins are included in the retail rate case cost of service and require no adjustment. In each of our last three rate cases, the Commission approved passing the energy sales margins through to ratepayers using the FCA.

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

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

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

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

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

A. Yes. At one time, the Company advocated a contribution from non-asset based margins based on incremental cost. As a consequence, the Commission ordered the Company to prepare an incremental cost study to support the Company's position as well as a fully allocated cost study. Exhibit___(AEH-1), Schedule 18, Non-Asset Based Trading Cost Study, is a report of these two studies, explaining the methodologies used and the results. In addition, Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A28 includes all calculations and their effect on the 2016 test year.

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

A. No. Consistent with past Commission decisions, we are making an adjustment to exclude costs equal to the fully allocated cost of non-asset based trading, as further explained in Section VII, Adjustments to the Test Year. Since the Company is required to exclude the fully allocated non-asset based trading costs from test year expense, we request that the requirement to prepare an incremental cost study be eliminated for future rate cases.

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

A. Yes, we make three adjustments. First, with respect to asset-based energy sales margins, the 2016 budget base data includes all fuel costs and trading revenues. However, all asset-based energy sales margins are passed through to the ratepayers in the FCA. The fuel clause revenue included in retail revenue does not include asset-based margins. Therefore, the Asset Margin Sharing adjustment also excludes asset-based energy sales revenues and expenses from the 2016 test year.

Second, the 2016 budget base data does not reserve the non-asset based trading margin for the shareholders. Therefore, the Non-Asset Margin Retention adjustment removes these revenues and expenses from the test year.

Lastly, the Non-Asset Trading O&M Credit adjustment credits the operating expenses in the income statement for the fully allocated O&M and IT-related costs of non-asset based trading activity. These 2016 test year adjustments are also included in Section VII, Adjustments to the Test Year.

Q. IS THE COMPANY MAKING ANY OTHER 2016 TEST YEAR ADJUSTMENTS TO OTHER REVENUES?

A. Yes. I have included an adjustment to use the three-year average for Other Revenues to account for variability and to be consistent with how those revenues were handled in our last rate case. This adjustment includes other unbudgeted revenue that the Company receives in an actual year that cannot be anticipated for budget purposes. This adjustment is addressed specifically in Section VII, Adjustments to the Test Year.

B. Operating and Maintenance Expenses

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

A. The principle expense categories are:

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

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

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

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

Other Operating Revenues (Other Rev) is an offset to expenses. In this case, the calculation is as follows:

Operating Exp	$2,342,900	(per AEH-1, Sch 4, Page 3, Line 29)
Depreciation	$471,286	(per AEH-1, Sch 4, Page 3, Line 31)
Amortization	$39,585	(per AEH-1, Sch 4, Page 3, Line 32)
Other Taxes	$401,292	(per AEH-1, Sch 4, Page 3, Line 43)
Income Tax	($73,527)	(per AEH-1, Sch 4, Page 3, Line 44)
Total Expenses	$ 3,181,537	(per AEH-1, Sch 4, Page 3, Line 47)

Q. HOW ARE FUEL AND PURCHASED ENERGY COSTS TREATED?

A. These fuel and purchased energy costs are collected through the FCA. Those costs are fully offset by revenues from the FCA. Therefore, these costs have no impact on the 2016 test year revenue deficiency.

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

A. Power production costs are primarily the costs of operating our generating facilities. These costs are forecast through development of a production budget prepared to serve the combined energy and demand requirements of the NSP System (used for both NSPM and NSPW). Our Risk Management Department conducts a production simulation (called PLEXOS) model run based on the forecasted system sales to derive the costs.

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

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

Q. PLEASE DESCRIBE THE INTEGRATED NSP SYSTEM AND THE INTERCHANGE AGREEMENT BETWEEN THE COMPANY AND NSPW.

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

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

A. Under the Interchange Agreement, the Company and NSPW share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 15 percent of the costs of the Company system are allocated to NSPW, and approximately 85 percent of the NSPW 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 NSPW load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually.

The Interchange Agreement also provides for an allocation of revenues received by the Company and NSPW, such as revenues from transmission services or off-system wholesale sales. Interchange Agreement costs and revenues are budgeted by the Company and NSPW annually. Thus, the

Company's budget shows Interchange Revenues, which are revenues that reflect the charges to NSPW for its share of production and transmission assets and associated expenses. Likewise, Interchange Expense reflects the Company's forecasted payments to NSPW for its proportionate share of the costs of generation and transmission assets and associated expenses incurred by NSPW to serve the NSP System needs.

The 2016 test year Interchange Revenue and Interchange Expenses have been calculated using 2016 Company and NSPW budget information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in our last two rate cases.

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

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

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

A Customer Service O&M costs are associated with operating our billing and collection and customer call centers. These costs are developed through the Customer Care budget prepared for both the NSPM electric and gas utilities. These costs and their development are detailed in the Direct Testimony of

Company witness Mr. Michael C. Gersack. The allocation of these costs to the electric utility and then to the Minnesota jurisdiction is addressed in Section VI of my Direct Testimony. As Mr. Gersack explains, our bad debt expense is affected by the level of commodity sales (retail sales). Therefore, changes in the sale forecast affect the bad debt expense. As a result of updating the sales forecast after the 2016 budget was developed, a change in the bad debt expense is needed. I discuss that adjustment in Section VII of my Direct Testimony.

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

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

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

A. No. Beginning in 1999, the Company made a conscious decision to move all lobbying costs to below the line accounting, FERC account 426.4, Expenditures For Certain Civic, Political and Related Activities. The Company prepares the unadjusted expenses for the test year using queries that restrict the data to only above-the-line accounts (FERC Accounts 500 through 935). Thus, no adjustment to the cost of service for lobbying costs is required, as these below the line amounts are not used in our development of the test year cost of service. We have also excluded the portion of organizational dues associated with lobbying activities. Company witness Mr. Gary J. O'Hara addresses our efforts to identify and remove lobbying expenses in his Direct Testimony.[2]

Q. ARE THERE ANY OTHER ISSUES OF NOTE WITH RESPECT TO THE INCOME STATEMENT?

A. Yes. As discussed by Company witness Mr. O'Connor, Nuclear costs increased by $1.050 million due to an increase in payments to the Prairie Island Indian Community consistent with the August 20, 2015, Amendment to the May 22, 2003 Settlement Agreement between Xcel Energy and the Prairie Island Indian Community, pursuant to Minn. Stat. 216B.1645, subd. 4. The Company filed for Commission approval of the Amended Settlement Agreement on October 15, 2015, in Docket No. E002/M-15-922. Because the Commission has not yet approved the Amended Settlement Agreement, the Company excluded the cost increase from Interim Rates.

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE 2016 TEST YEAR?

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

A. Depreciation expense for the 2016 test year reflects the Company's pending 2012 Average Remaining Life filing (Docket No. E, G002/D-15-46) and the results of the 2012 Transmission, Distribution and General Depreciation Five-Year Study (Docket No. E,G002/D-12-858). In the 2015 Remaining Lives filing, we proposed modifications to the remaining lives for the Blue Lake Units 1-4, Red Wing, and Wilmarth production plants. In addition to remaining life changes, we are also recommending updates to net salvage rates for electric production facilities based on a new 5-year dismantling study and the discontinuation of the use of probabilities in our dismantling analysis.

For the transmission, distribution, and general five-year study, we reflect the Commission decision to amortize the reserve surplus over three years with 50 percent of the remaining balance applied to 2014, 30 percent applied to 2015 and 20 percent applied to 2016 as Ordered in Docket No. E002/GR-13-868. Ms. Perkett discusses the Company's depreciation expense in her Direct Testimony. The necessary adjustments to the 2016 test year budget to reflect these changes are provided in Section IX of my Direct Testimony

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE 2016 TEST YEAR INCOME STATEMENT?

A. We have line items for Property, Deferred Income Tax and ITC, Federal and State Income Tax, and Payroll. The State and Federal income taxes are calculated in Exhibit___(AEH-1), Schedule 4, Cost of Service Study Summary for 2016 Test Year, Page 4 of 6.

Q. HOW ARE PROPERTY TAXES DETERMINED FOR THE JURISDICTION?

A. Property taxes are determined on a NSPM Total Company basis. The functions are then allocated to the Company's regulatory jurisdictions using the demand allocator for electric production and transmission, the gas design day allocator for gas production, and transmission and distribution is direct assigned by state for both electric and gas. Please see Volume 4, Tab P-6, Property Tax for more details.

Q. WHAT IS THE LEVEL OF PRODUCTION TAX CREDITS INCLUDED IN THE STATE AND FEDERAL INCOME TAX CALCULATION IN THE 2016 TEST YEAR?

A. As shown on Exhibit___(AEH-1), Schedule 19, Production Tax Credits and Schedule 24, Net Operating Loss, the 2016 test year assumes PTCs for the Company owned wind farms of $43.078 million, which results in a $73.474 million reduction in 2016 test year revenue requirements included in our base data ($61.457 million net of Interchange Agreement billings to NSPW). We expect production to begin at the new Courtenay wind project late in 2016. Due to the forecast in-service of this project, the Company is recommending that this project be recovered through the RES Rider. I provide a discussion later in this Section of my Direct Testimony about how PTCs interact with the deferred tax asset calculations in the 2016 test year.

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

A. In addition to the Courtenay PTCs included in the RES Rider, the Company continues to recommend that the RES Rider act as a true-up mechanism for the PTCs related to projects already in-service and included in base rates as a part of the 2016 test year cost of service. We propose that the difference in the dollar value of actual PTCs generated and the amounts included in the test year be recorded to the RES Tracker account and either returned to, or recovered from, customers through the RES Rider. This approach meets our understanding of the current regulatory treatment for PTCs.

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

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

The estimated $78.1 million in revenue requirement benefits from 2015 to 2019 shown in the May 31, 2015 Rate Compliance Report for Regulatory Treatment of Net Operating Loss (Docket E002/GR-10-971) are the sum of estimated annual revenue requirement reductions over the period from the start of carry forward utilization (2010) until the utilization balance is projected to be fully consumed (2019).

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

Had this rate treatment not been approved by the Commission, the 2016 test year revenue requirement would be the same. However, customers would not receive refunds for the revenue requirement value of the utilization of these carried forward deductions and credits if such utilization took place outside of a rate case test year.

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

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

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

For the purpose of determining the NOL, these income tax calculations are done on an all-inclusive jurisdictional cost of service basis in which rider revenues and rider related investments are included with non-rider revenues and investments. This approach determines the extent to which the NSPM Electric Utility Minnesota retail jurisdiction is in a tax loss position or in a position to utilize deductions and credits carried forward from previous periods as is the case with the 2016 test year. This approach insures that any reduction in revenue requirements resulting from the utilization of deductions or credits carried forward from prior periods is returned to customers as soon as it is available in the form of a rate refund or reduction to base rates.

These balances related to unused credits and deductions are reported in the Company's May 1 Jurisdictional Annual Report, including the May 1, 2015 Jurisdictional Annual Report. Separate detailed reporting and the revenue requirement value associated with any utilization is reported every May 31st including May 31, 2015. By having these annual determinations made on an all-in basis, the jurisdictional cost of service study (JCOSS) includes actual data for both rider recovery and base rate recovery properties. Any change in rider recovery by the Commission will be incorporated in this process.

Q. DO THE DEFERRED TAX ASSETS AFFECT THE 2016 REVENUE REQUIREMENT?

A. Yes. The Company's 2016 test year COSS includes a revenue requirement reduction of $7.383 million associated with the 2016 utilization of depreciation deductions previously carried forward, a revenue requirement reduction of $1.435 million associated the balance of 2015 utilization carried forward into 2016, along with the need to continue to carry forward a portion of the credits based on the Company's 2016 test year COSS. An accounting for the balances brought forward from the 2014 Annual Reporting and the 2015 bridge year, as well as the documented calculations supporting this revenue requirement reduction, can be found in Exhibit___(AEH-1), Schedule 24, Net Operating Loss.

The solving for a zero income tax expense for the 2016 test year on an all-inclusive basis is not the result of deductions that could not be used in the 2016 test year, but instead is the result of using deductions in the 2016 test year that were carried forward to the 2016 test year from prior periods. These deductions ($295.7 million), carried forward from prior periods to the 2016 test year, cause end of year rate base to decrease as a result of the increase ($120.7 million) in the net accumulated deferred tax liability. Also, as mentioned above, our 2016 test year includes $31.8 million of PTCs that need to continue to be carried forward to a future period due to Federal income tax requirements to utilize deductions before credits. This results in a net deferred tax asset reduction of $89.4 million in the 2016 test year. Also, because 2016 is the last year of utilizing net operating losses, the Company is able to take advantage of $3.4 million of Manufacture Production Tax Deductions that are utilized prior to Production Tax Credits. Please see Section VII, Adjustment to the Test Year, Adjustment 41) for quantification of the revenue requirement impact of these calculations.

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

A. The utilization of deferred tax assets is based on taxable income for the NSPM retail electric jurisdiction. Taxable income is determined by total revenues less total deductions. Once base rates are set in this case for the 2016 test year and any additional years considered by the Commission in the Company's multi-year rate proposal, they will remain in place until changed in another electric rate case will impact total revenue levels. The level of depreciation deductions carried forward from prior years that ultimately will be utilized in the future is dependent on a number of variables that cannot be quantified with certainty at this time. Total deductions will be dependent on the levels of O&M and depreciation deductions available on plant investments. Federal and state tax laws also continue to be reviewed and could be changed.

Q. PLEASE EXPLAIN THE EFFECT OF TAX TREATMENT OF PTCS.

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

Q. WHERE IS THE REDUCTION IN REVENUE REQUIREMENTS FOR PTCS REFLECTED IN THE 2016 TEST YEAR FINANCIAL STATEMENTS?

A. The State of Minnesota jurisdictional revenue requirement impact of $43.078 million of PTCs after applying the 1.70561 revenue conversion factor is

$73.474 million or $61.457 million net of Interchange Agreement billings to NSPW. Support for these calculations is shown on Exhibit___(AEH-1), Schedule 19 Production Tax Credits.

Because the Company is continuing to utilize tax deductions carried forward from prior periods as a result of net operating losses, the Cost of Service reclassifies a portion of the PTCs from current credits to deferred credits as a portion of these credits must continue to be deferred until all prior deductions are utilized. Exhibit___(AEH-1) Schedule 24 Net Operating Loss, line 4, shows the reversal of the $31.843 million of current PTCs for the 2016 test year. The deferral of these PTCs, netted against the deferral of excess deductions and state credits, results in a lowering of current taxes by $91.902 million (line 13). This is offset by an increase in deferred taxes of $89.409 million (line 12). These amounts do not offset exactly since the current and deferred tax rates (41.37 percent and 40.81 percent respectively) are not identical. However, the fact that they generally offset demonstrates that the $43.078 million tax credit continues to be reflected in the financial statements, but as a deferred rather than a current credit.

E. AFUDC

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

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

F. Interchange Agreement Off-Set Treatment

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT OFF-SET TREATMENT BEING EMPLOYED IN THE 2016 TEST YEAR COSS.

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

Q. WHAT SPECIFIC COMPONENTS ARE IMPACTED BY THIS SHARING IN THE 2016 TEST YEAR COSS?

A. The NSPM billings to NSPW for the sharing of NSPM costs appear as other revenues in the 2016 test year cost of service. The NSPW billings to NSPM for the sharing of NSPW costs appear as either production or transmission expenses in the 2016 test year cost of service. Also, any adjustments being proposed in the case that pertain to production or transmission are developed using the same mechanics.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

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

A. In this section I will:

- explain why it is necessary for the Company to allocate costs among its affiliates and between the jurisdictions in which it does business;
- describe the utility and jurisdictional allocations that are used in determining the revenue requirement;
- explain the circumstances of the elimination of the separate Wholesale Jurisdiction, the circumstances that led to the loss of full service wholesale customers, and the effect of those events, including the results of the Wholesale Customer Study that I identified earlier in my testimony.

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

A. Whenever, services or facilities are shared between NSPM and an affiliate, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate entity. Company witness Mr. Adam R. Dietenberger, in his Direct Testimony, explains the process used to assign or allocate O&M and Non-O&M costs (which include such items as book depreciation expense, deferred income taxes and property taxes) for services and facilities shared between NSPM and an affiliate. The cost assignment and allocation principles are unchanged from those used by the Company in the most recent Minnesota electric rate case. All of the common investments and their related costs, be it software or other common equipment or facilities, are evaluated by asset use to determine whether they should be direct assigned, or allocated using an indirect allocator or general allocator. Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM) submitted with this application as Exhibit___(ARD-1), Schedule 3.

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

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

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

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

Q. HOW ARE COSTS ASSIGNED AND ALLOCATED?

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

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

Generally, all production plant is allocated to jurisdiction using the jurisdictional demand allocator, with the exception of wind projects, which are allocated using the jurisdictional energy allocator. In addition, production costs are shared with Northern States Power Company-Wisconsin (NSPW) under the terms of the Interchange Agreement. The Interchange Agreement tariff approved by the Federal Energy Regulatory Commission (FERC) specifically requires fixed production assets to be allocated between NSPM and NSPW based on demand.

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

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

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

Q. HOW ARE THESE ALLOCATION FACTORS DEVELOPED?

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

Q. HOW ARE FUEL AND PURCHASED POWER COSTS ALLOCATED?

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

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

A. Compensation and benefit related rate case adjustments are allocated to jurisdictions using a weighted allocator based on all expenses in FERC 926 Employee Pensions and Benefits. Expenses in FERC 926 were allocated following the Cost Assignment and Allocation Manual (CAAM) submitted with this application as Exhibit___(ARD-1), Schedule 3. An additional allocator was then created by determining each jurisdiction's portion of the Total NSPM expenses. The data used to calculate this allocator can be found in Volume 4 Test Year Workpapers, Section VII Budget Allocators, Tab B-4.

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

A. Yes. Exhibit___(AEH-1) Schedule 12, Wholesale Customer Study, explains that all of our partial requirements and energy only wholesale customers are provided services pursuant to bilateral agreements and explains the treatment of costs and revenues related to services provided to those customers.

Q. WHAT SERVICES DOES THE COMPANY ANTICIPATE PROVIDING TO PARTIAL REQUIREMENTS WHOLESALE CUSTOMERS DURING 2016?

A. During 2016, the Company expects to provide services to wholesale customers in the following categories: asset based energy sales, asset based capacity sales, non-asset based energy and capacity sales, and other wholesale transactions (including interfacing and scheduling services, energy services agreements, and pass through charges).

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

Attachment A to the Wholesale Customer Study provides a list of the types of services provided, and the ratemaking treatment for each type of service. Attachment B to the Wholesale Customer Study provides a wholesale customer summary including all current agreements by customer and the expected revenues for the years 2016 to 2018.

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

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

VII. ADJUSTMENTS TO THE TEST YEAR

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

A. In this section of my testimony, I explain adjustments that affect our proposed 2016 revenue requirement. These adjustments were identified during our review of the 2016 capital budget and preparation for this case. An individual adjustment may be related to a previous Commission order, reflect Commission policy or traditional ratemaking treatment, or may be proposed to address a situation particular to this rate case. In this section, I provide details related to each adjustment and explain why each is necessary in order to present a representative level of rate base or costs in the 2016 test year. I also identify where another Company witness provides information to explain and support the adjustment.

First, I present one capital forecast update, traditional adjustments consistent with treatment in prior cases, and rate case adjustments related to this particular case. Next, I explain the various amortizations affecting the test year, the removal of certain costs and revenues being recovered through riders, and a group of adjustments that are the result of secondary dynamic calculations in the cost of service model. Finally, I discuss five adjustments we identified after we had finalized the year revenue requirement for this initial filing. We propose to include these adjustments in our 2016 revenue requirement in our Rebuttal Testimony.

Q. PLEASE LIST THE TEST YEAR ADJUSTMENTS.

A. The following adjustments were made to rate base and the income statement where applicable. Rate base adjustments are shown on Exhibit___(AEH-1), Schedule 10. Income statement (revenue requirement) adjustments are shown on Exhibit___(AEH-1), Schedule 11. As a general note, all revenue requirements shown on Schedule 11, Income Statement Adjustments, are net of Interchange Agreement billings, where applicable, and capital related revenue requirements are shown calculated at the last authorized rate of return.

Forecast Updates

1) Black Dog Screen House

Traditional Adjustments

2) Advertising
3) Customer Deposits
4) Dues – Chamber of Commerce
5) Dues – Professional Association
6) Economic Development – Administration
7) Economic Development – Donations
8) Foundation Administration
9) Foundation and Other Charitable Contributions
10) Incentive Compensation
11) Investor Relations
12) Monticello LCM/EPU Return
13) Nobles Amount Over CON
14) Non-Qualified Pension Expense

Rate Case Adjustments

15) Aviation
16) Bad Debt Expense
17) CIP Approved Program Costs
18) CIP Incentive
19) Employee Expenses
20) Like Kind Exchange Program
21) Nuclear Retention

22) Other Revenue 3-Year Average
23) Retiree Medical Discount Rate
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25) Remaining Life Depreciation Study – NSPM
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27) Trading – Asset Based Margin
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Amortizations

31) PI EPU Deferred Costs
32) Rate Case Expense
33) Sherco 3 Depreciation
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Rider Removals

35) RES Rider
36) TCR Rider
37) Windsource

Secondary Cost of Service Calculations

38) ADIT Pro-Rate – IRS Required
39) Cash Working Capital
40) Change in Cost of Capital
41) Net Operating Loss

A. Forecast Updates

1) Black Dog Screen House

Q. PLEASE DESCRIBE THE BLACK DOG SCREEN HOUSE ADJUSTMENT.

A. Subsequent to the completion of the 2016 capital budget, the in-service date for the Black Dog screen house project was moved from August 2018 to March 2016. The adjustment shows the impact of this capital forecast update. The Black Dog screen house project is discussed in the Direct Testimony of Company witness Mr. Steven H. Mills.

This adjustment decreases test year rate base by $0.272 million, as shown on Schedule 10, Rate Base Adjustments, Page 1, Column 4. The adjustment increases test year revenue requirements by $0.563 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 4. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-1.

B. Traditional Adjustments

2) Advertising

Q. PLEASE DESCRIBE THE ADVERTISING EXPENSE ADJUSTMENT.

A. Recovery of advertising costs is allowed primarily for advertising related to providing information on safety, customer information and general, non-program specific conservation messages. An adjustment is necessary to reduce administrative and general expenses for brand and image advertising costs, which are not allowed for recovery from Minnesota ratepayers.

This adjustment is consistent with the Commission's June 14, 1982 Statement of Policy on Advertising, and Docket No. E002/GR-08-1065, where the

Commission directed the Company include a discussion of the steps the Company has taken to exclude from advertising expense costs related to branding and other promotional activities.

In response to this requirement, all advertisements included in our request for cost recovery have been individually reviewed for content and appropriateness for cost recovery. Representative advertisements for which we are seeking recovery are included in Volume 3, Required Information, and the costs we have included as recoverable advertisements are summarized in Exhibit___(AEH-1), Schedule 15, Advertising.

The $2.690 million of advertising costs that have been excluded are summarized on Schedule 15, Advertising, Page 1 of 1. The Company has excluded the entire Brand and Image advertising budget, which makes up most of the exclusion. This includes costs associated with television, print, radio and outdoor advertisement, and is used by the Brand Advertising Department. Messages that relate to CIP program expenses are not included in this adjustment, as they are recorded with other CIP program costs in FERC Account 908 (Customer Information) as a part of our CIP approved program expenses. We have separately excluded an additional $0.219 million of Windsource advertising through the Windsource O&M adjustment.

Excluding non-recoverable advertising decreases test year revenue requirements by $2.690 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 5. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-2.

3) Customer Deposits

Q. PLEASE DESCRIBE THE ADJUSTMENT RELATED TO CUSTOMER DEPOSITS.

A. Customer deposits are treated as customer-supplied capital; thus it is appropriate to include interest expense on customer deposits to pay a return on that investment. The Commission's findings in Docket Nos. G002/GR-86-160 and G002/M-86-165 required that the average balance of customer deposits be deducted from rate base and at the same time allowed test year operating expenses to be increased to permit the recovery of interest paid on these deposits. An adjustment is required to include the interest expense on customer deposits in the test year.

Including interest on customer deposits increases test year revenue requirements by $0.001 million as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 6. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-3.

4) Dues – Chamber of Commerce

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

A. Yes. The Company has included membership dues paid to various Chambers of Commerce in Minnesota in the 2016 test year. Chambers of Commerce provide an essential link between the Company and the communities it serves, allowing for improved utility service. Because membership in these organizations provides benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is consistent with the Commission's June 14, 1982 Statement of Policy on Organizational Dues. Chamber of Commerce dues are initially recorded below the line; thus, an adjustment is necessary to include Chamber of Commerce dues in test year costs.

Including Chamber of Commerce dues increases test year revenue requirements by $0.220 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 7. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-4.

5) Dues – Professional Association

Q. PLEASE DESCRIBE THE PROFESSIONAL ASSOCIATION AND UTILITY ASSOCIATION DUES ADJUSTMENT.

A. An adjustment is required to remove costs associated with organizational dues that are not allowed for recovery from customers. Consistent with the Commission's June 14, 1982 Statement of Policy on Organizational Dues, the Company is required to reduce administrative and general expenses for either social organizations or organizations not associated with the State of Minnesota. Exhibit___(AEH-1), Schedule 16, Organizational Dues, provides the information required by the Commission's Policy.

Removing professional and utility association dues decreases test year revenue requirements by $0.019 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 8. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-5.

6) Economic Development – Administration

Q. AS BACKGROUND, PLEASE DESCRIBE THE COMPANY'S ACTIVITIES AND COSTS RELATED TO ECONOMIC DEVELOPMENT.

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. NSPM can, through a donation, provide communities or organizations involved in community and economic development with either an operating grant or a one-time investment in a special project that supports the community and economic development efforts of our communities. In addition to these donations, the Company incurs administrative costs associated with these donations.

Q. HAS THE COMPANY INCLUDED ECONOMIC DEVELOPMENT COSTS IN THE TEST YEAR?

A. Yes. Consistent with prior ratemaking treatment, the Company is allowed to recover from customers 50 percent of costs associated with economic development administration and donations that benefit Minnesota. Below I discuss two adjustments detailing inclusion of these costs in the test year.

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

A. Yes. We completed a cost-benefit analysis supporting the inclusion of economic development costs in the 2016 test year. Exhibit___(AEH-1), Schedule 17, Economic Development Cost-Benefit Analysis, Attachments A and B provide the potential revenue and cost impacts of the addition of one commercial/industrial customer to NSPM's electric system due to economic development programs. The results indicate that the investments made by the

Company to support economic development in our community have the potential to provide value to ratepayers as soon as the first year.

Q. PLEASE EXPLAIN THE ADJUSTMENT RELATED TO ECONOMIC DEVELOPMENT ADMINISTRATION COSTS.

A. Consistent with prior ratemaking treatment, the Company intended to exclude from recovery 50 percent of economic development administration costs. However, instead of removing this amount, we inadvertently added it to test year costs. This increase of $0.008 million to test year revenue requirements is shown as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 9. A corrected adjustment of $0.016 million (reversing the incorrect increase and removing the amount from test year costs) will be made in Rebuttal Testimony, as discussed in Section G, Rebuttal Adjustments below. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-6.

7) Economic Development – Donations

Q. PLEASE EXPLAIN THE ADJUSTMENT RELATED TO ECONOMIC DEVELOPMENT DONATIONS.

A. The Company is allowed to recover 50 percent of economic development donations benefiting Minnesota. Because economic development donations are initially recorded below the line, an adjustment is necessary to include these costs in the test year.

Including 50 percent of economic development donations increases test year revenue requirements by $0.054 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 10. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-7.

8) Foundation Administration

Q. PLEASE DESCRIBE THE FOUNDATION ADMINISTRATION ADJUSTMENT.

A. Consistent with the Commission's decision in Docket No. E002/GR-08-1065, we are excluding 100 percent of administrative costs related to the Xcel Energy Foundation administration from the 2016 test year.

This adjustment decreases test year revenue requirements by $0.281 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 11. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-8.

9) Foundation and Other Charitable Contributions

Q. PLEASE DESCRIBE THE CHARITABLE CONTRIBUTION ADJUSTMENT.

A. Consistent with Commission decisions in our prior rate cases, the Company included in the 2016 test year 50 percent of corporate charitable contributions benefiting the State of Minnesota. An analysis was performed on contribution details to ensure that only amounts contributed to charities and institutions that could be associated with the Company's electric service territory in the Minnesota jurisdiction were included in the cost of service. Because charitable donations are initially recorded below the line, an adjustment is necessary to include these costs in the test year.

Including 50 percent of charitable contributions increases test year revenue requirements by $1.625 million, as shown on Schedule 11, Income Statement

Adjustments, Page 1, Column 12. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-9.

10) Incentive Compensation

Q. PLEASE DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT.

A. Consistent with prior rate case treatment, we have adjusted 2016 test year costs to exclude the budgeted costs for: 1) the long-term portion of the incentive compensation; 2) any non-corporate incentive plan costs; and 3) all Annual Incentive Plan amounts above 15 percent of each individual's base pay. Company witness Ms. Ruth Lowenthal discusses incentive compensation in her Direct Testimony.

This adjustment decreases test year revenue requirements by $12.645 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 13. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-10.

11) Investor Relations

Q. PLEASE DESCRIBE THE INVESTOR RELATIONS ADJUSTMENT.

A. Consistent with the outcome in Docket No. E002/GR-12-961, the Company has removed 50 percent of all Investor Relation/Shareholder costs from the 2016 test year. Company witness Mr. Brian Van Abel explains the customer benefits of the Investor Relations operations and the basis for the Company's proposal in his Direct Testimony.

Removing 50 percent of Investor Relations costs decreases the test year revenue requirements by $0.475 million, as shown on Schedule 11, Income

Statement Adjustments, Page 1, Column 14. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-11.

12) Monticello LCM/EPU Return

Q. PLEASE DESCRIBE THE MONTICELLO LCM/EPU RETURN ADJUSTMENT.

A. The Commission's Order in Docket No. E002/GR-13-868 required the Company to adjust the return on rate base for this the Monticello LCM/EPU project. Specifically, any portion in excess of $415 million as determined on a total project basis must be adjusted to earn a zero return. In compliance with this Order, the Company has computed the revenue requirement adjustment to treat this portion of the project as having a zero return, and we have reduced the requested deficiency accordingly by including an offset to the deficiency in Other Revenues.

This adjustment decreases test year revenue requirements by $19.708 million ($16.582 million (IA)), as shown in Exhibit___(AEH-1), Schedule 20 Monticello LCM/EPU Project Return. This is also shown on Schedule 11, Income Statement Adjustments, Page 1, Column 15. The Interchange offset for this adjustment is included in base Interchange Agreement revenues as the Interchange Agreement has been modified to incorporate the same return adjustment as ordered by the MPUC. Because this adjustment includes a return in the calculation, if return component weighted costs are adjusted during this case, this adjustment will require a recalculation.

13) Nobles Amount over Certificate of Need

Q. PLEASE DESCRIBE THE NOBLES DISALLOWED ASSETS ADJUSTMENT.

A. The Commission's Order in Docket No. E002/GR-12-961 required the Company to amortize costs related to the Nobles Wind plant above the amount estimated in the Company's CON filing over the remaining life of the plant. Specifically, the Commission ordered that the amortization includes a return of, but not a return on, the $5.6 million (IA) jurisdictional cost. To accomplish this, the Company continues to include all cost components in base data, such as net investment in rate base and depreciation expense in the income statement. To value the zero return on rate base, a rate base return revenue requirement calculation is performed and included as other revenue to reduce the deficiency for this return requirement. This is the same process used to quantify earning a zero return on a portion of the Monticello LCM/EPU project.

This adjustment decreases test year revenue requirements by $0.288 million, as shown on Schedule 11, Income Statement Adjustments, Page 1, Column 16. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-13.

14) Non-Qualified Pension Expense

Q. PLEASE DESCRIBE THE NON-QUALIFIED PENSION EXPENSE ADJUSTMENT.

A. This adjustment excludes from the 2016 test year all non-qualified pension expenses related to the Company's Supplemental Executive Retirement Plan (SERP) and Restoration Plan. Non-qualified pension expenses are discussed in the Direct Testimony of Ms. Lowenthal and Company witness Mr. Richard R. Schrubbe. Our treatment of SERP costs in this case is consistent with treatment of these costs in our last rate case, Docket No. E002/GR-13-868.

As discussed further by Ms. Lowenthal, we are making the adjustment for Restoration Plan costs to reduce the number of disputed issues in this case.

Excluding non-qualified pension costs decreases test year revenue requirements by of $1.410 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 17. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-14.

C. Rate Case Adjustments

15) Aviation

Q. PLEASE DESCRIBE THE AVIATION ADJUSTMENT.

A. The Aviation adjustment removes 100 percent of the aviation-related costs to the Minnesota electric jurisdiction. The NSPM electric utility was allocated approximately $2.2 million in costs related to the operation of two Xcel Energy corporate aircraft for use by Company personnel for 2016, with approximately $1.9 million allocated to the Minnesota electric jurisdiction. These costs are incurred in lieu of commercial aviation transportation and help to facilitate the efficient use of executive time, as discussed by Company witness Mr. Gary J. O'Hara. As further discussed by Mr. O'Hara, we are making this adjustment to reduce the number of disputed issues in this case.

Removing 100 percent of aviation costs reduces test year revenue requirements by $1.925 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 18. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-15.

16) Bad Debt Expense

Q. PLEASE DESCRIBE THE BAD DEBT EXPENSE ADJUSTMENT.

A. The original calculation for 2016 bad debt expense was generated during the budget process and is a function of projected revenues multiplied by the bad debt ratio for NSPM. Consistent with our usual test year preparation processes, in developing the 2016 test year for this proceeding, an analysis was performed to update the bad debt expense based upon the revised revenues based upon the 2015 fall sales forecast. An adjustment is needed to incorporate into the revenue requirement the updated bad debt amount, which best reflects test year costs. This update resulted in an overall reduction to the budgeted 2016 bad debt expense of approximately $0.824 million on a Total Company electric basis, and $0.729 million for the NSPM Minnesota electric jurisdiction.

This adjustment decreases test year revenue requirements by $0.729 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 19. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-16.

17) CIP Approved Program Costs

Q. PLEASE DESCRIBE THE CIP APPROVED PROGRAM LEVELS ADJUSTMENT.

A. The 2016 test year CIP expenses and corresponding revenues have been set at the 2016 level of $89.039 million as proposed in Docket E,G002/CIP-12-447.

Because we make corresponding adjustments to both revenue and expense, this adjustment has no impact on the test year deficiency, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 20. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-17.

I note that the decision of Deputy Commissioner of the Minnesota Department of Commerce in Docket No. E,G002/CIP-12-447, authorizing a higher level of CIP expenditures, was issued October 12, 2015. This timing did not allow the Company to incorporate the approved levels in this initial rate case filing. As I discuss in Section G below, the Company will propose an adjustment in Rebuttal Testimony to increase the CIP expenditures and offsetting revenues to reflect the final authorized level in the test year.

18) CIP Incentive

Q. PLEASE DESCRIBE THE CIP INCENTIVE ADJUSTMENT.

A. The CIP performance incentive is designed to compensate the Company for lost sales due to Company conservation efforts. The annual projected CIP performance incentive margin is included in the Other Revenue budget. The CIP performance margin is intended as an incentive to the Company and represents budgeted level in anticipation of achieving the 2016 CIP goals. An adjustment is necessary to remove the estimated 2016 performance margin from the 2016 test year. Failure to include this adjustment would flow the annual CIP performance incentive to customers by overstating the 2016 test year operating revenues and therefore understating the revenue deficiency for the test year.

This adjustment increases test year revenue requirements by $23.670 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column

21. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-18.

19) Employee Expenses

Q. PLEASE DESCRIBE THE EMPLOYEE EXPENSES ADJUSTMENT.

A. The employee expense adjustment accounts for employee expenses that appear inconsistent with the guidelines in our employee expense policy, or identified as generally not being needed for the provision of utility service. Our adjustment in this case is consistent with employee expense adjustments we have made in prior rate cases. Mr. O'Hara provides the background and basis for the Employee Expense adjustment in his Direct Testimony.

The employee expense adjustment decreases test year revenue requirements by $1.613 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 22. Support for this adjustment is in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-19.

20) Like Kind Exchange Program

Q. PLEASE DESCRIBE THE LIKE KIND EXCHANGE PROGRAM ADJUSTMENT.

A. There is an additional reserve adjustment due to the net salvage recognition associated with the Like Kind Exchange Program, which replaces projects with new projects similar in scope, timing, and cost to the original projects. Ms. Perkett provides the background and basis for the Like Kind Exchange Program adjustment in her Direct Testimony.

This adjustment decreases test year rate base by $2.961 million, as shown on Schedule 10, Rate Base Adjustments, Page 1, Column 5. The adjustment decreases test year revenue requirements by $0.324 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 23.

21) Nuclear Retention

Q. PLEASE DESCRIBE THE NUCLEAR RETENTION REMOVAL ADJUSTMENT.

A. The nuclear retention removal adjustment eliminates from the 2016 test year all costs associated with the Nuclear Retention program. As Company witness Mr. O'Connor discusses further in his testimony, we are making this adjustment to reduce the number of disputed issues in this case.

Removing nuclear retention program costs decreases test year revenue requirements by $0.793 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 24. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-21.

22) Other Revenue Three-Year Average

Q. PLEASE DESCRIBE THE OTHER REVENUE THREE-YEAR AVERAGE ADJUSTMENT.

A. Consistent with the Commission's order in Docket No. E002/GR-12-961, we are making an adjustment in this case to reflect a three-year average (2013 and 2014 Actual, and 2015 Bridge year) of certain Other Revenues to ensure a representative level is included in the 2016 test year. In developing our average, we did not include categories of revenue that are not included in the test year (for example, Windsource and Service Quality). The three-year average adjustment resulted from a comparison of the three-year average to the 2016 test year amounts.

This adjustment decreases test year revenue requirements by $1.123 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 25. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-22.

Q. WHY IS IT APPROPRIATE TO USE A THREE-YEAR AVERAGE FOR OTHER REVENUES BUT NOT FOR OTHER REVENUE OR EXPENSE ITEMS?

A. Historically, Other Revenues have shown substantial variability and do not reflect trends. Unlike the category of Other Revenues, a more accurate reflection of the various other items of revenue and expense can be obtained by analysis of trends and other specific factors that are reflected in our budgeting process.

23) Retiree Medical Discount Rate

Q. PLEASE DESCRIBE THE RETIREE MEDICAL DISCOUNT RATE ADJUSTMENT.

A. The Commission's Order in Docket No. E002/GR-13-868 states the discount rate used to calculate retiree medical benefit costs for ratemaking purposes shall be set to equal the five-year average of the FAS 106-based discount rates. An adjustment is necessary to reflect the use of the five-year average discount rate to calculate retiree medical benefits and reflect the appropriate expense level in the test year. Mr. Schrubbe discusses retiree medical benefits and the discount rate in his Direct Testimony.

This adjustment decreases test year revenue requirements by $0.376 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 26. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-23.

24) Pension Expense Smoothing

Q. PLEASE DESCRIBE THE PENSION PLAN SMOOTHING ADJUSTMENT.

A. In Docket No. E002/GR-12-961, the Commission adopted the Company's alternative proposal to cap Xcel Energy Services (XES) pension expense at the 2011 level, defer any excess amounts, and amortize the deferred amounts over future years. This alternative treatment had been offered as a method to smooth recovery of the expense and mitigate rate impacts. An adjustment is necessary to reflect the 2011 XES pension expense level in 2016, and reflect the resulting change in the amount amortized in the 2016 test year. Mr. Schrubbe discusses pension expense in detail in his Direct Testimony.

This adjustment increases 2016 test year revenue requirements by $0.018 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 27. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-24.

25) Remaining Life Depreciation Study – NSPM

Q. PLEASE DESCRIBE THE 2015 REMAINING LIFE DEPRECIATION STUDY ADJUSTMENT FOR NSPM.

A. This adjustment updates the test year to include the impact of Docket No. E,G002/D-15-46). In the 2015 Remaining Lives filing, we proposed modifications to the remaining lives for the Blue Lake Units 1-4, Red Wing, and Wilmarth production plants. In addition to remaining life changes we are also recommending updates to net salvage rates for electric production facilities based on a new 5-year dismantling study and the discontinuation of the use of probabilities in our dismantling analysis. Support for these changes included provided by Ms. Perkett in her Direct Testimony.

This adjustment decreases test year rate base by $0.373 million, as shown on Schedule 10, Rate Base Adjustments, Page 1, Column 6. The adjustment increases test year revenue requirements by $1.037 million (IA), as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 28. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-25.

I note that on October 22, 2015, the Commission made a decision at the hearing in our Remaining Lives proceeding. This timing did not allow the Company to incorporate in this initial rate case filing the Commission's decision on the remaining lives of three production plants. As I discuss in Section G below, the Company will propose an adjustment in Rebuttal Testimony to reflect the Commission's decision in this docket.

26) Remaining Life Depreciation Study – NSPW

Q. PLEASE DESCRIBE THE 2015 REMAINING LIFE DEPRECIATION STUDY ADJUSTMENT FOR NSPW.

A. This adjustment updates the test year to include the impact of remaining life changes to production facilities located in Wisconsin and shared between NSPM and NSPW through the Interchange Agreement. These changes reflect the Public Service Commission of Wisconsin (PSCW) October 22, 2015 Order in Docket No. 4220-DU-109. The primary change is a life extension of the Bayfront plant from a remaining life of 5 years to 19 years. In this docket the PSCW also approved minor extensions to the Saxton and French Island hydro facilities. This results in reduced billings from Wisconsin, resulting in a reduction to the Minnesota retail jurisdiction revenue requirements.

This adjustment reduces test year revenue requirements by $4.215 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 29. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-26.

27) Trading – Asset Based Margin

Q. PLEASE DESCRIBE THE ASSET BASED MARGIN ADJUSTMENT.

A. Consistent with our process to develop test year base rates, the adjustment to Asset Based Margins excludes the budgeted asset based energy sales margins from the test year. As I previously explained, asset based energy sales margins are passed through to customers through the FCA. Accordingly, this adjustment ensures no double counting occurs between base rates and the FCA.

This adjustment increases test year revenue requirements by $17.221 (IA), as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 30. This increase is offset by the amount of actual asset based margins credited to the fuel cost revenue requirement on a going forward basis in the FCA. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-27.

28) Trading – Non-Asset Based Administration

Q. PLEASE DESCRIBE THE NON-ASSET TRADING ADJUSTMENT RELATED TO ADMINISTRATION.

A. This adjustment excludes the fully allocated non-asset based trading O&M and associated IT costs from the test year deficiency based on a cost study. The cost study measures the fully allocated non-asset based trading costs included in the 2016 capital and O&M budget and is provided as Exhibit___(AEH-1), Schedule 18, Non-Asset Based Trading Cost Study.

This adjustment decreases test year revenue requirements by $0.985 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 31. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-28.

29) Trading – Non-Asset Based Margin

Q. PLEASE DESCRIBE THE NON-ASSET BASED MARGIN ADJUSTMENT.

A. Consistent with our process to develop test year base rates, the adjustment to Non-Asset Based Margins excludes the non-asset based trading margins from the test year so that the Company retains all margins resulting from non-asset based trading activity. As discussed above, the Company excludes from the test year the fully allocated costs of performing activities associated with achieving these trades.

This adjustment increases test year revenue requirements by $3.099 million, as shown on Schedule 11, Income Statement Adjustments, Page 2, Column 32. Support for this adjustment is in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-29.

30) XES Allocation on Labor Hours

Q. PLEASE DESCRIBE THE ADJUSTMENT TO ALLOCATE XES COSTS BASED ON LABOR HOURS RATHER THAN EMPLOYEE COUNT.

A. Xcel Energy's budgeting method of allocating XES costs to operating companies involves many factors, some of which are based on a three-part general allocator that uses number of employees as one of the three factors. The Commission's Order in Docket No. E,G002/AI-10-690 required the Company to use a general allocator that replaces number of employees with allocated labor hours with overtime. An adjustment is necessary to recalculate the allocations using the general allocator to one using labor hours with overtime rather than number of employees. Mr. Dietenberger discusses this change and provides additional detail in his Direct Testimony.

This adjustment decreases test year revenue requirements by $1.475 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 33. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-30.

D. Amortizations

31) Prairie Island EPU Deferred Costs

Q. PLEASE EXPLAIN THE ADJUSTMENT NEEDED TO RECOVER THE PRAIRIE ISLAND EPU DEFERRED COSTS.

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

Q. PLEASE DESCRIBED THE ADJUSTMENTS INCLUDED IN THE 2016 COSS TO COMPLY WITH THIS ORDER.

A. First, the various rate base and income statement components related to the amortization of this deferred cost are input as an adjustment to the cost of service. This results in the calculation of the overall revenue requirement associated with this project. Embedded in these calculations is a computation of return on rate base at the overall weighted cost of capital (debt and equity). To adjust for the ordered weighted cost of debt return requirement, the Company computes the revenue requirements associated with the weighted cost of equity and includes the result of this calculation as Other Revenues to reduce the deficiency by this amount. The Minnesota jurisdictional revenue requirement for the deferral and amortization equals $6.234 million (IA). The revenue requirement offset to reduce this requirement to limit the return on rate base to the weight cost of debt equals $2.694 million (IA). Support for these adjustments can be found in Exhibit (AEH-1), Schedule 21, PI EPU Recovery.

This adjustment increases test year rate base by $30.407 million, as shown on Schedule 10, Rate Base Adjustments, Page 1, Column 7. The adjustment increases test year revenue requirements by $3.540 million (IA), as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 34. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-31. Because this adjustment includes a return in the calculation, this adjustment will require a recalculation if return component weighted costs are adjusted during this case.

32) Rate Case Expense

Q. PLEASE DESCRIBE THE RATE CASE EXPENSE AMORTIZATION.

A. The Company is requesting authorization to recover a total of $1.113 million in rate case costs in the 2016 test year. This is the first year of a three-year amortization based upon total anticipated rate case costs of $3.340 million.

We are requesting recovery of these costs over the three-year period 2016 through 2018, consistent with our Multi-Year Rate Plan. The Company proposes to return any over-recovery of rate case expenses if the collection continues beyond the three-year amortization period by crediting the revenue requirement in our next rate case. Support for these adjustments can be found in Exhibit (AEH-1), Schedule 22, Rate Case Expense Amortization.

This adjustment increases test year revenue requirements by $1.113 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 35. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-32.

33) Sherco 3 Depreciation

Q. PLEASE DESCRIBE THE SHERCO 3 DEPRECIATION DEFERRAL AMORTIZATION.

A. The Commission's Order in Docket No. E002/GR-12-961 requires that the depreciation expense incurred for Sherco 3 during the extended repair outage following the 2011 catastrophic event must be deferred and amortized over the remaining life of the plant.

The adjustment to reflect the amortization of Sherco 3 depreciation costs increases test year rate base by $5.509 million as shown on Schedule 10, Page 1, Column 8, and increases revenue requirements by $1.110 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 36. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-33.

34) Transco Costs

Q. PLEASE DESCRIBE THE TRANSCO AMORTIZATION.

A. On August 3, 2015, in Docket No. E002/AI-14-759, the Commission approved the Company's request for an Affiliated Interest Agreement with a newly formed Transco. In the Company's original petition, we proposed to track and defer the costs that had been included in the 2014 rate case test year (Docket No. E002/GR-13-868) but supported activities associated with Xcel Energy Inc.'s Transco initiative. The costs deferred would then be included as a credit in the cost of service in the Company's next electric rate case. The Transco amortization reflects that credit of $138,450 amortized over a three year period, as provided in the Company's Compliance Filing in Docket No. E002/AI-14-759.

The adjustment to reflect the amortization of Transco costs decreases test year revenue requirements by $0.046 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 37. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-34.

E. Rider Removals

35) RES Rider

Q. PLEASE DESCRIBE THE RES RIDER REMOVAL ADJUSTMENT.

A. As I describe in detail in Section VIII, Costs Recovered in Riders, we propose continued use of the RES Rider during the multi-year rate plan period. Specifically, we propose to include the costs and Production Tax Credits (PTCs) related to the Courtenay wind project in the RES Rider. For PTCs related to energy production at other Company-owned wind farms, currently included in base rates, we propose to continue the true-up to actual PTCs in the RES Rider. Finally, should the Company sell any Renewable Energy Credits (RECs), the proceeds from those sales would be shared with customers through the RES Rider. These proposals are consistent with our 2016 RES Rider filing in Docket No. E002/M-15-809.

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

Q. WHAT COSTS ARE INCLUDED IN THE RES RIDER REMOVAL ADJUSTMENT FOR THE 2016 TEST YEAR?

A. The only costs included in our proposed adjustment to the test year are the costs and revenues for the Courtenay wind project. Costs or revenues associated with the PTC true-up and RECs sales occur only on an actual basis and, as such, require no test year adjustment.

This adjustment decreases test year rate base by $134.116 million, as shown on Schedule 10, Rate Base Adjustments, Page 1, Column 9. The adjustment increases test year revenue requirements by $0.122 million (IA), as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 38. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-35.

36) TCR Rider

Q. PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.

A. As I describe in detail in Section VIII, Costs Recovered in Riders, and as described in our recent 2016 TCR Rider true-up report,[3] we propose continued use of the TCR Rider during the multi-year rate plan period. Specifically, we propose to continue use of the TCR Rider for three projects and MISO Regional Expansion Criteria and Benefits (RECB) Schedule 26 and 26A revenues net of expenses. The TCR Rider removal adjustment removes all costs and revenues from the test year jurisdictional cost of service for the CapX2020 La Crosse, Big Stone-Brookings, and La Crosse-Madison projects and MISO RECB Schedule 26 and 26A net revenues. In our 2016 TCR Rider filing, we proposed to include these project costs and revenues in the TCR Rider, and to continue cost recovery for these projects in the rider after the implementation of final rates in this case. The TCR Rider test year adjustment ensures no double recovery of these costs.

We also propose to move two projects currently in the rider to base rates at the conclusion of this rate case. As I describe in detail in Section VIII, Costs Recovered in Riders, the 2016 test year reflects our proposal to move the CapX2020 Brookings and CapX2020 Fargo projects from the TCR Rider to base rates upon implementation of final rates in this case, as these projects will be in service by the end of this year. Thus no adjustment to test year costs is necessary for these two projects. However, as costs for these projects will remain in the TCR Rider during the period interim rates are in effect, an interim rate adjustment necessary to ensure no double recovery of these costs

[3] Petition and Compliance Filing, Docket No. E002/M-15-891 (Oct. 1, 2015) (2016 TCR Rider Filing). We plan to supplement this filing in early November to confirm our request for TCR Rider recovery during the Interim Rate period.

during the interim rate period. I describe this interim rate adjustment in detail in Section VIII.

Q. IS THE TCR RIDER REMOVAL BASED ON THE SAME DATA AS WAS USED IN THE 2016 TCR RIDER FILING?

A. No, the vintage of data differs between the rate case test year and our TCR Rider filing. As explained in Section III, Supporting Information, the 2016 test year plant related budget data uses actual information through April 2015. Therefore, in order to remove the amounts included in the test year, the TCR Rider adjustment is developed using the same four months of 2015 actual data. However, because the TCR Rider filing is more limited in scope, we were able to incorporate more current data when preparing that filing. Although the vintage of data differs between the test year and the TCR Rider filing, we used the same project and the same vintage of data for both the test year and test year adjustment calculations, ensuring all costs initially included in the test year data that are being recovered in the Rider are removed.

Q. PLEASE QUANTIFY THE COSTS INCLUDED IN THE TCR RATE RIDER REMOVAL ADJUSTMENT FOR THE 2016 TEST YEAR.

A. This adjustment includes project costs, MISO RECB Schedule 26 and 26A net revenue, and TCR Rider present revenue associated with these items that are proposed to be included in the TCR Rider after the implementation of final rates.

Q. PLEASE EXPLAIN WHY THE TCR RIDER ADJUSTMENT, WHICH REMOVES BOTH PRESENT REVENUES AND PROJECT REVENUE REQUIREMENTS, DOES NOT RESULT IN A ZERO IMPACT TO THE TEST YEAR DEFICIENCY.

A. The TCR Rider present revenue is calculated based on the most recently authorized overall rate of return. The TCR Project revenue requirement included in the rate case is calculated based on the test year overall rate of return, which is being proposed with this rate case. Thus, the present revenue and the revenue requirement are not exactly the same.

Q. PLEASE QUANTIFY THE TCR RIDER REMOVAL ADJUSTMENT FOR THE TEST YEAR.

A. This adjustment decreases test year rate base by $241.455 million, as shown on Schedule 10, Rate Base Adjustments, Page 1, Column 7. The adjustment decreases test year revenue requirements by $0.233 million (IA), as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 39. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-36.

37) Windsource Removal and Avoided Capacity

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

A. The Windsource program is a stand-alone retail service program with discrete revenues, purchase power contracts and operating expenses. We have excluded all Windsource revenues and associated expenses from our 2016 test year revenue requirements determination, which reduces test year revenue requirements by $0.368 million.

Including wind energy generation as part of a utility's resource mix means that the utility avoided building or purchasing from other sources. The kWh cost of wind energy purchased by a utility includes a capacity factor or value which would otherwise have been included in the utility's base rates and paid by all ratepayers because all ratepayers benefit from the capacity. This capacity credit is subtracted from the Windsource rate because it is a cost that should be shared by all customers, rather than only Windsource customers. An adjustment to increase test year revenue requirements by $0.579 million is necessary to include this amount in the test year. The Direct Testimony of Company witness Mr. Michael A. Peppin further supports the development of the Windsource avoided capacity credit.

The net of these two adjustments increases test year revenue requirements by $0.210 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 40. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-37.

F. Secondary Cost of Service Calculations

38) ADIT Pro-Rate – IRS Required

Q. PLEASE DESCRIBE THE ADIT PRO-RATE ADJUSTMENT THAT IS REQUIRED BY THE IRS AND INCLUDED IN THESE SECONDARY CALCULATIONS?

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

This secondary calculation limits the ADIT deduction from rate base by applying the IRS defined pro-rate method to only the forecast entries to this balance. Support for this calculation is included in Exhibit (AEH-1), Schedule 23, ADIT Pro-Rate. The IRS requirements and mechanics of this adjustment are described in more detail in the direct testimony of Ms. Perkett.

This adjustment increases test year rate base by $57.910 million, as shown on Schedule 10, Rate Base Adjustments, Page 1, Column 11. The adjustment increases test year revenue requirements by $6.335 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 41. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-38.

39) Cash Working Capital Adjustment

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

A. As discussed earlier in Section E, Other Rate Base, the Company has incorporated a secondary calculation to apply the various revenue lead days and expense lag days to the various income statement components to result in the appropriate cash working capital rate base adjustment. The incremental cash working capital adjustment to rate base associated with the various incremental adjustments to the unadjusted base data equals $13.041 million, as shown on Schedule 10, Page 1, Column 12. This increase in cash working capital increases test year revenue requirements $1.427 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 42. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-39.

40) Change in Cost of Capital

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

A. The change in the cost of capital adjustment is the effect of the change in the overall cost of capital between the cost of capital (also referred to as the overall rate of return, or ROR) being requested in this case of 7.49 percent and the effective cost of capital authorized in Docket No. E002/GR-13-868 of 7.34 percent, an increase in the overall cost of capital of 0.15 percent.

On Schedule 11, Income Statement Adjustments, the revenue deficiencies for the base data and all other adjustments is calculated at the 7.34 percent overall cost of capital. This adjustment calculates the required operating income resulting from the change in the overall cost of capital applied to the requested rate base. The requested rate base on Schedule 10, Page 1, Column 15, line 42 of $7,836.115 million times 0.15 percent (7.49 percent - 7.34 percent) equals $11.754 million. The required operating income times the revenue conversion factor (1.705611) results in the change in the cost of capital revenue deficiency of $20.048 million.

We calculated the revenue deficiencies in this manner so that changes, if any, in the overall cost of capital that occurs during the duration of the rate case do not affect the revenue requirements for each adjustment. The adjustment reflects both the change in the in ROE from 9.72 percent to 10.00 percent and the changes in short term and long term debt.

This adjustment increases test year revenue requirements by $20.048 million, as shown on Schedule 11, Income Statement Adjustments, Page 3, Column 43.

41) Net Operating Loss

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

A. The NSPM income tax determination has been in a net operating loss position since 2010. This means that more deductions exist in the current period than is needed to bring current taxable income to zero. As a result, excess deductions and unused credits were deferred and tracked for use in future periods. The Company worked with the Department on this issue, which resulted in a process for reporting these deferred balances and returning to customers the revenue requirement reduction associated with the utilization of these deferred balances in the form of a refund or as a reduction to base rates.

Net Operating Losses and the associated ratemaking treatment are discussed in detail earlier in my testimony in Section V. D. Taxes.

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

A. Yes. As a result of the ongoing reporting and tracking, the Company has completed its compliance reporting of balances beginning with the 2010 tax year. Based on the results of the 2016 test year cost of service study, the Company is able to utilize the remainder of the deductions previously deferred. In order to return the value of this utilization to customers as soon as possible, the Company has included an adjustment in the test year to reduce the overall revenue requirement by the value of this utilization.

The result of including this adjustment in the test year is reflected on Schedule 10, Rate Base Adjustments, Page 1, Column 2, for the base data, decreasing test year rate base by approximately $54.005 million, and on Schedule 10, Page 1, Column 14, for the adjustments, decreasing test year rate base by approximately $3.818 million. The adjustment is also reflected on Schedule 11, Income Statement Adjustments, Page 1, Column 2, for the base data, decreasing test year revenue requirements by $9.498 million, and on Schedule 11, Page 3, Column 44, for the adjustments, decreasing test year revenue requirements by $1.365 million. It should be noted that these references also include the impact of Section 199 Manufacture Production Tax Deductions. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A-41 and Exhibit___(AEH-1), Schedule 24, Net Operating Loss.

G. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I provide details related to five adjustments to the test year cost of service that we plan to incorporate into the 2016 test year revenue requirement when we file Rebuttal Testimony. These adjustments reflect necessary changes we identified after we finalized our cost of service that we were not able to incorporate due to timing constraints. In total, they result in a net $7.430 million decrease to the 2016 test year revenue requirement. These adjustments are for the following items:

1) Remaining Lives – NSPM

2) Hollydale Transmission Costs
3) Prairie Island Indian Community Settlement Agreement
4) Economic Development Administration
5) CIP Approved Program Costs

Q. DID YOU ADJUST INTERIM RATES FOR THESE REBUTTAL ADJUSTMENTS?

A. Yes. We adjusted Interim Rates for the material Remaining Lives adjustment described below. This adjustment reduces our Interim Rate request by $8.046 million.

Q. ARE THERE OTHER POTENTIAL REBUTTAL ADJUSTMENTS?

A. Yes. Below I also discuss two potential rebuttal adjustments that may be necessary to include in Rebuttal Testimony if we have additional information at that time. These adjustments are related to:

6) Bonus Tax Depreciation
7) MISO ROE Complaints

Q. DID YOU ADJUST INTERIM RATES FOR THESE POTENTIAL REBUTTAL ADJUSTMENTS?

A. No. We do not have certainty with respect to timing or amounts for these items. Therefore, we do not have enough information at this time to make an Interim Rate adjustment.

1) Remaining Lives – NSPM (Rebuttal Adjustment)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REBUTTAL ADJUSTMENT RELATED TO THE NSPM REMAINING LIVES PROCEEDING.

A. On October 22, 2015, the Commission issued decisions in our Remaining Lives proceeding (Docket No. E.G002/D-15-46) with respect to the remaining lives of three production plants: Angus Anson, Granite City, and Sherco Unit 1. This timing did not allow the Company to incorporate these outcomes in this initial rate case. The Company proposes to make an adjustment in Rebuttal Testimony to reflect the Commission's decision.

This adjustment will decrease test year revenue requirements by $8.046 million (IA), as shown on Exhibit___(AEH-1), Schedule 26. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section X Rebuttal Adjustments, Tab R-1. Ms. Perkett further discusses the impact of the Commission's recent decision on the test year.

2) Hollydale Transmission (Rebuttal Adjustment)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REBUTTAL ADJUSTMENT RELATED TO THE HOLLYDALE TRANSMISSION PROJECT.

A. As discussed in the Direct Testimony of Company witness Mr. Benson, during the process of reviewing data in preparation for filing this case, it was discovered that a $2.7 million capital addition for the Hollydale project was included in the 2017 capital budget in error. Thus the 2016 test year includes this project in CWIP with an AFUDC offset on the Income Statement. We propose to make an adjustment in Rebuttal Testimony to remove the impact of this project from the test year.

This adjustment will decrease test year revenue requirements by $0.031 million (IA). Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section X Rebuttal Adjustments, Tab R-2.

3) Prairie Island Indian Community Settlement Costs (Rebuttal Adjustment)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REBUTTAL ADJUSTMENT RELATED TO THE PRAIRIE ISLAND INDIAN COMMUNITY SETTLEMENT AGREEMENT COSTS.

A. The Company included in the 2016 test year the costs ($2.5 million) associated with the 2003 Settlement Agreement as amended April 20, 2015, between the Company and the Prairie Island Indian Community. While these costs should have been direct assigned to the Minnesota electric jurisdiction, they were instead allocated to all NSPM jurisdictions. We propose to make an adjustment in Rebuttal Testimony to reflect the correct direct assignment of these costs.

This adjustment will increase test year revenue requirements by $0.663 million. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section X Rebuttal Adjustments, Tab R-3.

4) Economic Development Administration (Rebuttal Adjustment)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REBUTTAL ADJUSTMENT RELATED TO ECONOMIC DEVELOPMENT ADMINISTRATION COSTS.

A. As described in Section VII, Adjustments to the Test Year, Adjustment 6, the Company intended to exclude from recovery 50 percent of economic development administration costs. However, instead of removing this amount, we inadvertently added it to test year costs. We propose to make an adjustment in Rebuttal Testimony to reverse the incorrect increase and remove the correct amount from test year costs.

This adjustment will decrease test year revenue requirements by $0.016 million. Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section X Rebuttal Adjustments, Tab R-4.

5) CIP Approved Costs (Rebuttal Adjustment)

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REBUTTAL ADJUSTMENT RELATED TO ECONOMIC DEVELOPMENT ADMINISTRATION COSTS

A. Test year CIP expenses are set at $89.038 million, the level that the Company proposed in Docket No. E002/CIP-12-447. On October 12, 2015, the Deputy Commissioner of the Minnesota Department of Commerce approved a CIP level of $92.897 million for 2016. This timing did not allow the Company to incorporate the approved levels in this initial rate case filing. We propose to include an adjustment in Rebuttal Testimony to increase the CIP expenditures and offsetting revenues to reflect the final authorized level in the test year. This adjustment will have no impact on the test year deficiency.

Support for the corresponding CIP expenditure and CIP revenue adjustments to reflect the approved $92.897 million level can be found in Volume 4 Test Year Workpapers, Section X Rebuttal Adjustments, Tab R-5.

6) Bonus Tax Depreciation (Potential Adjustment)

Q. PLEASE DESCRIBE THE POTENTIAL REBUTTAL ADJUSTMENT RELATED TO BONUS TAX DEPRECIATION.

A. As discussed in the Direct Testimony of Ms. Perkett, as of July 21, 2015 a bill containing a two-year extension to the current legislation, "The Tax Increase Prevention Act of 2014" (2014 Tax Act) was passed through the Senate Committee on Finance. The bill would extend bonus depreciation on qualified property purchased and placed in service before January 1, 2017 (before January 1, 2018 for certain long-lived assets). The full Senate must give approval of the bill and differences with the House of Representative's tax extender bill must be reconciled in order to move forward with the two-year extension. In the event that this legislation is passed, the Company would update its filing

Q. WHAT IS THE ESTIMATED IMPACT ON THE FILED CASE IF SUCH A CHANGE IS PASSED?

A. Based on the Company's knowledge of the legislation as it exists today, the Company has attempted to make an approximation of its impact. To do so, the Capital Asset Accounting department has provided my area with estimated changes to all of the various plant related information items input into the cost of service by functional class detail. The Revenue Requirements area has then processed this information in the COSS model to quantify the impact. By processing this in the COSS model, changes in Net Operating Losses, Section 199 Manufacture Production Tax Deductions, Rider removals and ADIT Pro-Rate are all considered. It is important to consider all of these related changes because the additional bonus tax depreciation will reduce rider revenue requirements which in turn needs to be considered in the NOL solve process which is performed on an all-inclusive basis (base rate data and riders) as the Company does not do a NOL solve on individual riders. The estimated impact of this change on the Company's revenue requirements is depicted below in Table 5 as follows:

Table 5

Impact of Bonus Tax Depreciation Extension
Estimate based on best available information
Dollars in Millions

	2016	2017	2018
Annual Revenue Requirement Change	$5.9	$16.1	($23.9)

Q. WHY DOES THIS CHANGE CAUSE AN INCREASE IN REVENUE REQUIREMENTS?

A. As filed, our three-year rate plan anticipates using all of the previously accumulated Net Operating Loss deductions in 2016, allowing the Company to claim additional Section 199 Manufacture Production Tax Deductions and start utilizing PTCs. Both of these reduce revenue requirements. With the additional bonus tax depreciation, the Company is again in a net operating loss tax position. As a result, the Company has no production taxable income eliminating the Section 199 deductions and also causing a deferral in the utilization of accumulated unused PTCs. Both of these items return again in 2018, causing a revenue requirement reduction.

Support for this adjustment can be found in Volume 4 Test Year Workpapers, Section X Rebuttal Adjustments, Tab R-6.

7) MISO ROE Complaint (Potential Adjustment)

Q. PLEASE DESCRIBE THE POTENTIAL REBUTTAL ADJUSTMENT RELATED TO THE MISO ROE COMPLAINT.

A. In his Direct Testimony, Company witness Mr. Benson describes the MISO ROE complaints and the potential test year impact on transmission revenues and expenses of any final decision from FERC related to the November 2013 and February 2015 MISO ROE Complaints. As discussed by Mr. Benson, since the timing of a decision by the FERC in unknown and since it could occur after this case is concluded, the Company requests the ability to true-up the test year transmission revenue net of any change in transmission expense due to the FERC decision in the TCR Rider. We request the true-up be retroactive to January 1, 2016, the beginning this test year.

Q. PLEASE DESCRIBE THE POTENTIAL TRUE-UP IN THE TCR RIDER.

A. Transmission revenues are an offset to the Company's test year revenue requirement, including the revenue requirement for transmission expense. It is likely that FERC's final decision on the ROE complaints will require the Company to refund to transmission customers amounts billed through the MISO transmission tariff retroactive to November 2013. This refund would decrease the Company's net transmission revenues. As noted above, should the FERC issue its decision after this rate case is concluded, the Company requests the ability to true-up the impact of their decision retroactive to January 1, 2016, in the TCR Rider. Our request for TCR Rider recovery would include a full accounting of the transmission customer refunds net of any refunds the Company receives, to ensure the true-up only covers the period beginning January 1, 2016.

VIII. COSTS RECOVERED IN RIDERS

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

A. In this section, I present our proposed treatment of costs recovered in riders during the multi-year rate plan period, including riders that we propose to continue to use and costs we propose to move to base rates. I provide detailed information supporting the adjustments to the 2016 test year that I presented in Section VII of my testimony, as well as the adjustments Mr. Burdick incorporates into the revenue requirements for the 2017 and 2018 plan years.

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

A. The Company currently uses six cost recovery riders:

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

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

A. As discussed and supported in detail in the Direct Testimony of Mr. Chandarana, we propose to:

- Continue use of the RES Rider for recovery of costs for the Courtenay Wind Farm and the associated PTCs, the PTC true-up for other Company owned wind projects, and sharing with customers potential proceeds related to any Renewable Energy Credits the Company may sell in the future.
- Continue use of the TCR Rider, with costs for three projects and MISO RECB Schedule 26 and 26A net revenues to continue to be included in the rider, and costs for two completed projects to be moved to base rates upon implementation of final rates in this case.

- Continue use of the RDF Rider, CIP Rider, Windsource Rider, and the FCR in their current forms.

These proposals are consistent with the rider filings we made during 2015 in our separate rider dockets. In the following subsections of my testimony, I will address our proposed rate case treatment for each of these riders in detail, and discuss how the Company ensures there is no double recovery of these costs.

Q. WHAT IS THE COMPANY'S TOTAL PROPOSED COST RECOVERY IN 2016, 2017, AND 2018 INCLUDING THE COMPANY'S PROPOSED RIDER TREATMENT?

A. Our proposed total recovery from customers in 2016, 2017, and 2018, including our proposed increase in base rates and estimated rider revenue, is approximately $3.304 billion in 2016, $3.382 billion in 2017 and $3.464 billion in 2018, as shown in Table 6 below.

Table 6
Total Cost Recovery Including Riders

$ in Thousands			
Recovery Method	**2016 Test Year**	**2017 Plan Year**	**2018 Plan Year**
Present Revenues	$3,034,093	$3,032,608	$3,031,173
Cumulative Rate Increase	194,612	246,667	297,133
Base Rate Recovery	$3,228,705	$3,279,275	$3,328,306
Less: Rider Revenue included in Present Revenue			
TCR Rider	59,087	57,602	56,167
CIP Rider	202	202	202
FCA Rider	829,073	$829,073	$829,073
RDF Rider	35,085	35,085	35,085
Total Rider Revenue Included in Present Revenue	923,447	921,962	920,527
Net Base Rate Recovery	**2,305,258**	**2,357,313**	**2,407,779**
Plus: Most Recent Proposed Rider Revenue			
TCR Rider	78,256	89,086	93,295
CIP Rider	41,281	24,044	23,858
FCA Rider	829,073	867,767	902,800
RDF Rider	27,679	20,516	16,931
RES Rider	17,244	18,072	14,356
Windsource Rider	5,145	5,204	5,264
Total Rate Rider Recovery	**998,678**	**1,024,689**	**1,056,504**
Total Recovery from Minnesota Customers	**3,303,936**	**3,382,002**	**3,464,283**

Exhibit___(AEH-1), Schedule 4, Cost of Service Study Summary for 2016 Test Year, provides additional detail for the 2016 test year. Company witness Mr. Burdick provides support for the 2017 and 2018 Plan Years in the following testimony schedules: Exhibit___(CRB-1), Schedule 4, Cost of Service Study Summary for 2017 and Exhibit___(CRB-1), Schedule 5, Cost of

Service Study Summary for 2018. Rate rider recovery estimates are preliminary, are subject to change, and are also subject to the Commission's decision in individual rate rider dockets. We provide this information so that the Commission, parties, and our customers can understand the combined impact of our requests.

A. RES Rider

Q. WHAT IS THE RES RIDER?

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

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

A. As noted above, we propose to include in the RES Rider:

- costs of the Courtenay wind project;
- the true-up of actual PTCs related to energy production at Company-owned wind farms compared to the amount included in base rates; and
- customers' share of potential proceeds related to any Renewable Energy Credits the Company may sell in the future.

These costs are fully supported in our 2016 RES Rider petition as revised September 29, 2015 in Docket No. E002/M-15-805. Our 2016 RES Rider filing requested recovery of $15.9 million in 2016 and $18.1 million in 2017 related to the Courtenay Wind project.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF THE COURTENAY WIND PROJECT IN THE RES RIDER.

A. As described by Mr. Chandarana, the Company proposes to recover the Courtenay Wind project through the RES Rider. We propose to recover the capital related revenue requirements and property taxes as well as incremental operating and maintenance expenses. We also propose to include all of the PTCs associated with this project in the RES Rider. Therefore, we have not included any PTCs for the Courtenay wind project in the 2016 baseline PTCs as a part of our 2016 test year.

Q. HOW IS THE RES RIDER TREATED WITH RESPECT TO PTCS IN THE 2016 TEST YEAR?

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

1) A new baseline PTC be set in this rate case. We have included $43.1 million of PTCs as the base amount in the test year, resulting in a $61.5 million (IA) reduction to the 2016 test year revenue requirement. See Exhibit___(AEH-1), Schedule 19, Production Tax Credit Baseline. These PTCs are generated from the Grand Meadows, Nobles, Pleasant Valley, and Border Winds facilities which are included in the 2016 test year.
2) The difference between actual and baseline PTCs be recorded in the RES Tracker account.
3) The difference be either refunded to, or recovered from, customers as established in future RES Rider filings.

Because we propose that the true up of PTCs included in base rates to actual PTCs earned will occur through the RES Rider, we do not anticipate a need to address this issue in the base rate revenue requirement in the final compliance filing.

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

A. I provide information related to the 2016 test year adjustment that ensures no double recovery of these costs in Section VII.E. Rider Removals, RES Rider Adjustment 35. Mr. Burdick discusses adjustments to the 2017 and 2018 Plan Years in his Direct Testimony.

B. TCR Rider

Q. WHAT IS THE TCR RIDER?

A. The TCR Rider is authorized by Minn. Stat. § 216B.16, subd. 7b to allow the recovery of capital costs related to transmission investments and for MISO charges incurred for projects for which MISO assigns regional costs under Schedule 26 and Schedule 26A of its Tariff. Recently, the TCR statute was modified to include costs associated with Grid Modernization.

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

A. The Commission's Order in Docket No. E002/M-14-852 approved our 2015 TCR Rider request to recover the following projects in the TCR Rider:

- CapX2020 Brookings;
- CapX2020 Fargo;
- CapX2020 La Crosse; and

- MISO RECB Schedule 26 and 26A net revenue.

Q. MR. CHANDARANA, MS. BLOCH, AND MR. HARKNESS DISCUSS THE USE OF A NEW GRID MODERNIZATION RIDER ENABLED BY AN AMENDMENT TO THE TCR RIDER STATUTE. ARE THERE ANY GRID MODERNIZATION COSTS INCLUDED IN THE TCR RIDER AT THIS TIME OR IN THE COMPANY'S 2016 TCR RIDER PETITION?

A. No. Although we have identified the ADMS and Belle Plaine Battery projects as candidates for a Grid Modernization Rider, we have not included any Grid Modernization projects in the TCR Rider at this time. Ms. Bloch and Mr. Harkness provide further information about these projects in their Direct Testimonies.

Q. MR. HARKNESS DISCUSSES $4.4 MILLION IN CAPITAL ADDITION COSTS FOR 2018 RELATED TO ADMS. WILL THOSE COSTS ALSO BE RECOVERED THROUGH THE GRID MODERNIZATION RIDER?

A. No. Although Mr. Harkness discusses a small portion of ADMS in his testimony as part of this case, the costs discussed in his testimony are incremental to the grid modernization dollars we plan to request in the TCR rider. We will ensure we provide a detailed discussion of the cost recovery mechanics in our TCR filing next fall.

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

A. As described earlier, we propose to:

- Move the CapX2020 Brookings and CapX2020 Fargo projects from TCR Rider recovery to base rate recovery coincident with implementation of final rates in this rate case.
- Continue recovery of the CapX2020 La Crosse project in the TCR Rider;
- Begin recovery of the Big Stone – Brookings and La Crosse – Madison projects in the TCR Rider; and
- Continue recovery of MISO RECB Schedule 26 and 26A net revenue in the TCR Rider.

These costs are fully supported in our 2016 TCR Rider petition in Docket No. E002/M-15-891 and as discussed in the Direct Testimony of Company witness Mr. Ian R. Benson.

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

A. The Company is requesting continued recovery of the CapX2020 La Crosse, Big Stone-Brookings, and La Crosse-Madison projects through the TCR Rider. We propose to recover these projects through the TCR Rider because these are large qualifying projects that are not yet fully in service. We are also requesting to continue recovery of the MISO RECB Schedule 26 and 26A net revenues through the TCR Rider. The revenue requirements for these three projects and RECB net revenue as included in our 2016 TCR Rider petition are summarized in Table 7 below. Please note that this summary does not include the 2015 carry over balance or the revenue collected through the TCR Rider.

Table 7
Revenue Requirements for Projects Remaining in the TCR Rider Throughout the Three-Year Plan

Description	2016	2017	2018
CapX2020 La Crosse			
Local	$5,827,371	$7,063,438	$6,835,387
MISO	$6,971,744	$6,790,614	$6,620,419
MISO-WI	$13,522,327	$13,189,718	$12,818,666
Big Stone-Brookings	$1,921,637	$5,196,753	$7,990,087
La Crosse-Madison	$2,717,735	$8,101,228	$13,236,926
MISO RECB Schedule 26 and 26A	($19,875,653)	($9,146,286)	($10,526,346)
Total Project Costs in TCR Rider	$11,085,161	$31,195,465	$36,975,139

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

A. I provide information related to the 2016 test year adjustment that ensures no double recovery of these costs in Section VII.E. Rider Removals, TCR Rider Adjustment 36. Mr. Burdick discusses adjustments to the 2017 and 2018 Plan Years in his Direct Testimony.

Q. YOU NOTED YOU ARE PROPOSING TO MOVE THE CAPX2020 BROOKINGS AND FARGO PROJECTS TO BASE RATES AT THE CONCLUSION OF THIS RATE CASE. PLEASE DESCRIBE HOW THESE PROJECTS WILL BE ROLLED IN TO BASE RATES.

A. We propose to move the CapX2020 Brookings and CapX2020 Fargo projects from the TCR Rider to base rates at the conclusion of this case because it reduces the Interim Rate increase and helps eliminate any potential for double recovery of costs. Coincident with the implementation of final rates in this rate case, the project costs will be removed from the TCR Rider for the remaining months of the year and final rates will be designed to recover the costs of these two projects. This approach is consistent with the method used in Docket No. E002/GR-10-971, where we moved the Metropolitan Emission Reduction Project (MERP) costs recovered through the Environmental Improvement Rider (EIR) and the Nobles Wind, Grand Meadow Wind and Wind2Battery projects recovered through the RES Rider into base rates when final rates were implemented in that case.

More specifically, the TCR rate rider will be updated to exclude the CapX2020 Brookings and CapX2020 Fargo project costs from the TCR Rider for the remaining months of the year following implementation. The TCR present revenues will be excluded from the 2017 test year and final rates will be designed to recover the final revenue requirement approved by the Commission, including the final revenue requirement for these two projects. The interim rate refund will not be affected for these projects as any over/under recovery during the Interim Rate period related to these projects will remain in the TCR rider.

Q. WILL THERE BE A NEED TO UPDATE THE CASE FOR THE PROJECTS MOVING FROM THE TCR RIDER TO BASE RATES?

A. Yes. The TCR Rider is trued up for actual costs and revised forecasts. Therefore, the test year costs should be updated to reflect the 2016 actual costs as well as updated 2017 and 2018 forecast costs as reflected in the TCR Rider. As a result, the Company is proposing an update to test year costs after actual 2016 costs are known. This update to the 2016 test year and the 2017 and 2018 plan years will occur at the same time as our proposed 2016 Capital true-up discussed by Company witness Mr. Burdick. This update will ensure that the costs recovered in base rates are as close as possible to costs that would have been recovered through the TCR Rider.

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

A. We propose to submit a TCR Rider compliance report with Final Rate compliance. This report will clearly identify the revenue requirements removed from the TCR Rider, the revenue recovered from customers for the projects moving to base rates during the Interim Rate period, and the development of the revised TCR Rider adjustment factor. The Company anticipates this process will be similar to the process used to move recovery of CIP costs from the CIP Rider to base rates.

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

A. During the interim rate period, the Company proposes that the CapX2020 Brookings and Fargo projects continue recovery through the TCR Rider, along with the other costs that we are proposing to continue to recover through the TCR Rider after implementation of final rates. Table 8 below summarizes the costs and revenues included in the TCR Rider during the interim rate period. Please note that this summary does not include the 2015 carry over balance or the revenue collected through the TCR Rider.

Table 8
TCR Rider Recovery
During Interim Rate Period

Description	2016	2017
CAPX2020 Brookings	$40,475,384	$39,461,230
CAPX2020 Fargo	$18,611,685	$18,140,394
CAPX2020 La Crosse		
Local	$5,827,371	$7,063,438
MISO	$6,971,744	$6,790,614
MISO - WI	$13,522,327	$13,189,718
Big Stone-Brookings	$1,921,637	$5,196,753
La Crosse-Madison	$2,717,735	$8,101,228
MISO RECB Schedule 26 and 26A	($19,875,653)	($9,146,286)
ADIT Pro-Rate	$150,830	$134,628
Project Revenue Requirement	**$70,323,061**	**$88,931717**
TCR Tracker Balance Carryover from Prior Year	$8,087,398	$154,062
TCR Revenue Requirement	**$78,410,459**	**$89,085,779**
Projected Revenue Collections	**($78,256,397)**	**($89,085,779)**
TCR Tracker Balance Carryover to Next Year	$154,062	$0

Q. IF YOU ARE PROPOSING TO INCLUDE THE CAPX2020 BROOKINGS AND FARGO PROJECTS IN THE TCR RIDER DURING THE INTERIM RATE PERIOD, HOW WILL YOU ENSURE NO DOUBLE RECOVERY OF THESE PROJECT COSTS OCCURS DURING THIS TIME?

A. Because we are proposing to continue recovery of these projects through the TCR Rider during the interim period, and move these projects into base rates at the end of this case, the 2016 test year also includes the project costs in the test year cost of service as well as the project revenues (from the TCR Rider) in present revenue. Thus, an interim rate adjustment is necessary to ensure no double recovery of these costs during the interim rate period. Accordingly, our 2016 and 2017 Interim Rate requests each include an adjustment to remove the CapX2020 Brookings and CapX2020 Fargo project present revenue and revenue requirements from the development of Interim Rates.

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

A. The Interim Rate Adjustment removes the present revenue and project revenue requirements included in the test year from the Interim Cost of Service. Table 9 below summarizes the 2016 and 2017 Interim Rate Adjustments for these two projects.

Table 9
TCR Rider – Interim Rate Adjustment

Description	**2016**	**2017**
Present Revenue		
CapX2020 Brookings	$40,475,384	$39,461,230
CapX2020 Fargo	$18,611,685	$18,140,394
Total Present Revenues	$59,087,069	$57,601,624
Revenue Requirement		
CapX2020 Brookings	$40,806,481	$40,017,227
CapX2020 Fargo	$19,084,413	$18,649,554
Total Revenue Requirement	$59,890,894	$58,666,781
Interim Rate Adjustment	($803,825)	($1,065,157)

The TCR Rider removal for Interim Rates results in a reduction to our Interim Rate request primarily because the present revenue from the TCR Rider revenue requirement is calculated at the last authorized rate of return rather than the rate of return requested in this case. Additional detail on these adjustments can be found in Volume 1, Notice of Change in Rates and Interim Rate Petition, Interim Rate Supporting Schedules and Workpapers.

Q. Do you provide any other information related to treatment of TCR Rider costs and projects during the multi-year rate plan period?

A. Yes. Exhibit___(AEH-1), Schedule 27 provides a timeline illustrating how projects will be rolled in to base rates or will remain in the TCR Rider during the course of the multi-year rate plan. This timeline was developed based on the Company's proposed compliance activities identified in the Direct Testimony of Mr. Burdick.

C. RDF Rider

Q. What costs are recovered through the RDF Rider?

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

Q. How is the RDF Rider treated in the 2016 test year?

A. Both revenue and amortization expense for the RDF Rider are included in the 2016 test year. The amount of each is equal and, therefore, does not contribute to the 2016 test year deficiency. Any true up of the revenues and costs during the 2016 test year will occur in the RDF Rider and, therefore, there will be no need to address a change in revenue requirement in the final compliance filing.

D. CIP Rider

Q. What costs are recovered through the CIP Rider?

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

Q. HOW IS THE CIP RIDER TREATED IN THE 2016 TEST YEAR?

A. The CIP Rider amount in the case is at the level needed to assure that both the CIP revenue (Base and Rider) is equal to the expense in the 2016 test year. With the total amount of CIP expense and CIP revenue equal, the overall CIP program does not contribute to the test year deficiency. The total CIP expense level included in the test year is $89.038 million. Total CIP revenues included in the test year is $89.038 million ($87.836 million in base revenues and $0.202 million in CIP Rider revenue). In the cost of service included in the original filing for this proceeding, the level of CIP expense was set at the requested level that had been proposed by the Company in Docket No. E002/CIP-12-447 of $89.038 million. On October 12, 2015 the Deputy Commissioner of the Minnesota Department of Commerce, Division of Energy Resources in Xcel Energy's CIP filing approved a CIP level of $92.897 million for plan year 2016. The timing of this decision on the higher approved level precluded the Company from reflecting this increase in the test year. The Company will include in Rebuttal Testimony an adjustment to increase both the CIP expense and CIP recovery to the approved $92.897 million level for final rate determination. The final level of CIP expense approved in the rate case will move to base rate recovery at the conclusion of the rate case. Further information is provided in Section VII, Adjustments to the Test Year.

E. Windsource Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE WINDSOURCE RIDER?

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

Q. HOW IS THE WINDSOURCE RIDER TREATED IN THE 2016 TEST YEAR?

A. All revenue and expense related to the Windsource program is excluded from the 2016 test year. Any true up of the revenues and costs incurred during the 2016 test year will occur in the Windsource Rider and, therefore, there will be no need to address a change in revenue requirement in the final compliance filing. Further information is provided in Section VII, Adjustments to the Test Year.

F. Fuel Clause Rider (FCR)

Q. WHAT COSTS ARE RECOVERED THROUGH THE FCR?

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

Q. HOW IS THE FCR TREATED IN THE 2016 TEST YEAR?

A. Both revenue and fuel expenses recovered through the FCR are included in the 2016 test year. The total amount of each is equal and the Minnesota jurisdictional amount differs only by the difference in allocators (fuel expense is allocated to the Minnesota jurisdiction based on the energy allocator while fuel revenue is recovered from customers based on sales). As a result, fuel recovery contributes only minimally to the test year deficiency. Any true up of the revenues and costs during the 2016 test year will occur in the FCR and, therefore, there will be no need to address a change in revenue requirement in the final compliance filing. I provide a reconciliation of fuel costs in the Cost of Service to the Base Cost of Fuel filing in Exhibit___(AEH-1), Schedule 25, Fuel Reconciliation.

IX. COMPLIANCE WITH PRIOR COMMISSION ORDERS

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

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

A. General Rate Case – Docket No. E002/GR-13-868

1) Amortization of Reserve Surplus for Transmission, Distribution and General Assets

In compliance with the Commission's Order in our most recent rate case, we amortized 50 percent of the theoretical depreciation reserve surplus for transmission, distribution, and general assets in 2014, 30 percent in 2015, and the 2016 test year includes the final 20 percent amortization. This adjustment is supported by Ms. Perkett in her Direct Testimony and is further discussed in Section V, Rate Base.

2) Monticello Prudence Review Costs

Order Point 5 requires that the Company amortize the Monticello prudency review costs over a two-year amortization period. If the Company had not filed its next rate case within this two year period, we would be required to return any over-recovery to customers when filing our next rate case. Because this filing is being made within the two-year period, the Company will complete collection of those costs in 2015, and no refund of any excess amounts is required.

3) Alliant Billing

In 2014, the Company received an NSPM total Company refund of $790,966, $692,320 for the State of Minnesota electric jurisdiction, from Alliant Energy for a previous overbilling of transmission expense. This refund was recorded as Other Revenues. We have included this refund in our calculation of the 3 Year Average adjustment to other revenues discussed in Adjustment 22.

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

1) Mapping to FERC Form 1

Order Point 47 from Docket E002/GR-12-961 stated:

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

These requirements have been met. The mapping to FERC Form 1 is located in Volume 3, Required Information, Section IV, Other Required Information, Tab 5, GAAP/FERC/COSS Comparison. There we provide accounting of the NSPM Total Company for 2012 to 2014. For each year, we provide the GAAP financial statements reconciled to the FERC Form 1. We then provide the FERC Form 1 reconciled to the Minnesota Jurisdictional Annual Report total company amounts.

2) Changes Between Actuals and 2016 Test Year

Order Point 47 also requests explanations for deviations ten percent or greater (+/- 10 percent) "between actuals and [the Company's] test-year request." Explanations of operating expense variations of +/-5 percent and +/-$500,000 are provided for 2014 actuals compared to the 2016 budget by FERC account in Volume 6, Budget Documentation, Variance Analysis. Explanations of variations of +/-10 percent on rate base items are provided with the schedules in Volume 3, Required Information, Section IV, Other Required Information, Tab 5, GAAP/FERC/COSS Comparison

3) Financial Labeling

In my Rebuttal Testimony in Docket E002/GR-12-961, we agreed to make efforts to label all costs and revenues to the relevant financial source: Xcel Energy Services, Inc.; NSP System; NSP-Minnesota or NSPM (total Company – electric and gas utilities); NSPM Electric; and State of Minnesota Electric Jurisdiction. We have made a good faith effort to satisfy that commitment.

For reference, following is a list of the labels used and the definitions of each.

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

NSPW through the Interchange Agreement has been netted against the item to show the net impact to Minnesota electric customers.

Other Company witnesses provide amounts in their Direct Testimonies from several applicable financial sources. To the extent practicable, they have also provided the State of Minnesota jurisdictional amount. The jurisdictional amounts were developed under my guidance and are consistent with development of allocators as explained in the Cost Assignment and Allocation Manual, (Exhibit___(ARD-1), Schedule 3), and the Cost of Service Study. In order to provide further context, an index to these financial sources is included as Exhibit___(AEH-1), Schedule 5, Labeling of Financial Sources.

4) Wholesale Customer Study

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

> The Company will provide as a compliance filing in future rate cases a wholesale customer study which shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.[4]

Exhibit___(AEH-1), Schedule 12, Wholesale Customer Study, provides the required information. The study does not address wholesale transmission

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

revenues. Wholesale transmission revenues and associated costs are discussed in detail in the Direct Testimony of Company witness Mr. Ian Benson.

C. Depreciation

Depreciation expense reflects the service lives, net salvage rates, and depreciation rates approved by the Commission in Docket No. E,G002/D-12-858 (2012 five-year study for Transmission, Distribution and General Assets) and proposed by the Company in its 2015 Annual Review of Remaining Lives filed May 18, 2015, in Docket No. E,G002/D-15-46. This filing is discussed by Ms. Perkett in her Direct Testimony. I make the necessary adjustment to reflect the Company's proposed remaining lives for electric production facilities, and propose a Rebuttal Adjustment to reflect the Commission's October 22, 2015 decision in this docket, in Section VII, Adjustments to the Test Year.

D. Decommissioning

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

E. Other Compliance Requirements

1) Incentive Compensation Refunds

In Docket No. E002/GR-10-971, the Commission required Xcel Energy to continue to refund all incentive compensation payments earned according to the Xcel Energy incentive compensation plan and recoverable in rates under the Order, but not paid. For plan year 2014 (paid in March 2015), incentive plan payouts were at a level that did not require the Company to refund any amounts to customers, as reported in our annual incentive compensation compliance filing in Dockets E002/GR-92-1185 and G002/GR-92-1186 on May 31, 2015. Our last rate case, which was based on a 2014 test year, included the forecasted incentive compensation costs accrued in 2014 and payable in March 2015, after excluding certain costs (*e.g.*, executive long term incentive). It is too early to determine whether any refund will be needed with respect to the 2015 plan year.

The 2016 test year includes the forecasted incentive compensation costs accrued in 2016 and payable in March 2017, after excluding certain costs (*e.g.*, executive long term incentive), which I identified in Section VII. B. 10, Adjustments to Test Year. As in the past, if the Company does not pay a level of incentive compensation at least equal to the amount of expense recovered in rates, the Company agrees to track and refund the difference to customers.

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

In Docket E002/GR-10-971, the Company was directed to file in its next rate case both an incremental and fully allocated cost study of its non-asset based trading activities. I discuss those studies and a related adjustment above in Section VII Adjustments to Test Year. For future rate cases, we request that only a fully allocated cost study be submitted because the incremental cost study is not used to determine the level of costs to charge this activity.

3) Nuclear Fuel Outage Costs

In Docket No. E002/GR-08-1065, the Company was directed to include an analysis of nuclear plant outage costs as shown in Exhibit 86 to the hearing record. Attached as Exhibit___(AEH-1) Schedule 14, Nuclear Outage Accounting, is the required information. Volume 4A Test Year Workpapers also includes schedules in support of the 2017 and 2018 Plan Year nuclear fuel outage costs. These schedules provide a determination of the Minnesota retail jurisdiction revenue requirements associated with the Nuclear Outage Deferral and Amortization method, as well as a comparison to the Direct Expense method for the 2016 test year and the 2017 and 2018 Plan Years.

4) Capacity Cost Report

In Docket No. E002/GR-08-1065, the Commission ordered the Company to describe NSP System short-term and long-term capacity costs by contract. The required information is attached as Exhibit___(AEH-1) Schedule 13, Capacity Cost Study, which is Trade Secret. The methodology for forecasting capacity costs for the 2016 test year is similar to that described by Mr. David G. Horneck in his direct testimony from Docket No. E002/GR-10-971. Contracts with which NSPM has long-term obligations to purchase capacity remain the same as described in that docket, except the Cyprus contract was terminated in 2011, the Pine Bend contract no longer has a purchased capacity obligation, the contract with Minnkota Power Cooperative was terminated in 2015 and a new contract with Manitoba Hydro began in 2015 as approved by the Commission in Docket No. E-002/M-10-633. The Company anticipates that it can meet the expected Midcontinent Independent System Operator (MISO) capacity planning reserve requirements for the 2016 planning year from its current generation and long term purchased capacity contracts. Therefore, the Company does not expect to purchase short term capacity contracts for the 2016 test year.

Forecast capacity cost calculations for 2017 and 2018 are consistent with calculations done to forecast costs for the 2016 test year. However, contracts with Rapidan and HERC will terminate in 2017 and the extended contract with Calpine Mankato, Mankato II, is assumed to begin in 2018. As in the 2016 test year, the Company anticipates that it can meet the expected MISO capacity planning reserve requirements in 2017 and 2018 from its current generation and long term purchased capacity contracts and does not expect to purchase short term capacity contracts.

5) Lobbyist Compensation

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

6) North Dakota Income Tax Credits

In Docket No. E-002/M-15-401, the Company was instructed to discuss non-Minnesota state tax credits as follows;

> The Company shall include in the initial filing in its next rate case both testimony and schedules disclosing, in detail and by project, all North Dakota Investment Tax Credits and all other non-Minnesota state tax credits earned or held by the Company as a result of its investments and activity.

The main reason for this treatment is that income taxes (state and Federal) for jurisdictional cost of service are calculated on a stand-alone basis by applying the state-specific and Federal defined deductions and credits to the calculation of current taxes. For example, with respect to deductions, for the computation of state taxable income, one State may adopt the Federal Bonus provision and another state may not. For the calculation of Minnesota state taxes, the Minnesota definition of state deductions is used. With respect to credits, the same applies. Minnesota defined Research and Experimentation (R&E) Credits are used to derive Minnesota current taxes for the Minnesota retail COSS. The R&E Credit is primarily derived from Company and contract engineering labor during the design and test phases of capital projects. The largest projects that contribute to the Minnesota R&E Credit are nuclear. The other two key areas are fossil projects (such as pollution control equipment) and transmission (such as substation design).

In North Dakota, state tax regulations provide for a state tax credit to encourage wind development located in the state. As a result, in the North Dakota retail COSS this credit is applied in determining North Dakota state taxes. By consistently applying this stand-alone logic, Minnesota ratepayers are not asked to sponsor North Dakota current state income taxes and North Dakota ratepayers are not asked to sponsor Minnesota current state income taxes. For these reasons, the Company has not applied any North Dakota specific state tax credit to the calculation of Minnesota state and Federal current income taxes in the jurisdictional COSS.

The North Dakota state credit for North Dakota-located wind generation is the only non-Minnesota state credit utilized by NSPM. Due to the size of the credits available relative to the North Dakota state taxable income, it is anticipated that the utilization of these credits will be limited by taxable income and not specifically known until North Dakota state tax returns are filed. The potential for credits are primarily the result of the Border Winds project. Table 10 below is an estimate of the dollar value of these credits in North Dakota. This value could be substantially reduced if additional deductions reduce taxable income.

Table 10

NSPM Separate Company Basis
ESTIMATE

Dollars

Year	North Dakota Tax	North Dakota Tax, Net of Federal	ND Gross Up Factor	Revenue Requirement
2015	0	0	1.60776	0
2016	56,217	36,541	1.60776	(58,749)
2017	586,271	381,076	1.60776	(612,677)
2018	649,581	422,228	1.60776	(678,840)

For comparison, the Minnesota R&E credit included in the 2016 test year and all future years equals $559,000. As described above, this credit is generated from generation and transmission qualifying costs and is applied only in the Minnesota retail COSS and not shared with other jurisdictions. This reduces Minnesota retail revenue requirements annually by $619,734 ($559,000 x 65 percent x 1.705611 conversion factor). The Company recommends that the stand-alone tax logic utilized in COSS remain in-place and state tax policy with respect to state deductions and credits apply to each state's specific COSS.

7) Recurring Compliance Reporting Requirements

The following compliance requirements are of a recurring nature reported upon in each rate case:

a) Edison Electric Institute Spare Transformer Sharing Agreement

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

b) Minnesota Emissions Allowance

In Docket E002/M-94-13, the Commission ordered deferred accounting for revenues from the sale of certain emission allowances. The accumulated unamortized deferred balance of emission sales is less than $3,400 (IA). Due to the small level in this account, the Company is recommending to continue to defer the emission allowance sales proceeds to a future rate filing. Thus, there is no adjustment included in this filing.

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

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

d) Liberty Paper

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

e) Tax Benefit Transfer Leases

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

f) Sale of Renewable Energy Credits

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

g) Competitive Bidding

In Docket No. E002/M-95-174 the Company was permitted to offer Company owned generation to compete against other provider offerings. The Company is required to track capacity-related non-performance penalties on

NSP Generation projects for return to ratepayers. We have incurred no such penalties.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission determine an overall 2016 retail revenue requirement of $3.229 billion and 2016 revenue deficiency of $194.612 million for the Company's Minnesota jurisdictional electric operation, determined by the cost of service for the 2016 test year. I also recommend the Commission grant a 2016 interim rate increase of $163.670 million and an additional 2017 interim rate increase of $44.902 million, for the Company's Minnesota jurisdictional operation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Resume of Anne E. Heuer
Director
Revenue Analysis

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

Current Responsibilities

Since January 2007, I have managed the Revenue Requirements-North team. In this position, I am responsible for the general administration of the Northern States Power Company-Minnesota (NSPM) Revenue Requirements area and for the preparation and presentation of cost of service studies, revenue requirement determinations and jurisdictional annual reports for the electric and gas rates filed on behalf of NSPM with the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, the South Dakota Public Utilities Commission and the Federal Energy Regulatory Commission.

Previous Employment (1975 to 2006)

Rate Consultant – Xcel Energy Services Inc.
Manager, Regulatory Development – NSP
Principal Rate Analyst – NSP
Senior Electric Financial Analyst – Electric Finance – NSP
Senior Budget Analyst – Financial Accounting – NSP
Senior Systems Cost Analyst – Information Services – NSP

Education

Augsburg College, Minneapolis, Minnesota
Bachelor of Arts – Business Administration – Finance
December 1985

Current Testimony

FERC – Proposed Regulatory Accounting and Revised Interchange Agreement Tariffs,
Docket No. ER15-698-000, 2015
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,
Docket No. E002/GR-13-868, 2013
North Dakota – Overall Revenue Requirements, Rate Base, Income Statement,
Case No. PU 12-813, 2012
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,
Docket No. E002/GR-12-961, 2012
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,
Docket No. E002/GR-10-971, 2010
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,
Docket No. G002/GR-09-1153, 2009
South Dakota - Overall Revenue Requirements, Rate Base, Income Statement,

Current Testimony – Cont.

Docket No. EL09-009, 2009
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement,
Docket No. E002/GR-08-1065, 2008
North Dakota - Overall Revenue Requirements, Rate Base, Income Statement,
Case No. PU 07-776, 2007

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PRE-FILED INFORMATION

Appendix A	Pre-Filed Discovery

SUMMARY OF REVENUE REQUIREMENTS

Test Year Ending December 31, 2016
($000's)

Line	Description	Adjusted Proposed Test Year 2016
1	Average Rate Base	$7,836,115
2	Operating Income (Before AFUDC)	$439,541
3	Allowance for Funds Used During Construction	$33,283
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$472,824
5	Overall Rate of Return (Line 4 / Line 1)	6.03%
6	Required Rate of Return	7.49%
7	Operating Income Requirement (Line 1 x Line 6)	$586,925
8	Income Deficiency (Line 7 - Line 4)	$114,101
9	Gross Revenue Conversion Factor	1.70561
10	Revenue Deficiency (Line 8 x Line 9)	$194,612
11	Retail Related Revenue Under Present Rates	$3,034,093
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	6.41%

ROE = 7.23%
Deficiency = $194,612
% Increase = 6.41%
Required ROE = 10.00%

Northern States Power Company (MN)
Electric Utility - Minnesota Retail Jurisdiction
Cost of Service Study
Proposed 2016 Test Year

Summary Reports

November 2015

Line No.	NSPM - 01 Rate Base Schedule with BOY/EOY	Total			MN Electric			Other		
		BOY	EOY	BOY/EOY Avg	BOY	EOY	BOY/EOY Avg	BOY	EOY	BOY/EOY Avg
1	**Rate Base**									
2	Plant Investment	18,493,454	19,229,488	18,861,471	16,128,168	16,722,727	16,425,447	2,365,286	2,506,761	2,436,023
3	Depreciation Reserve	8,028,823	8,614,317	8,321,570	7,014,728	7,520,789	7,267,758	1,014,095	1,093,528	1,053,812
4	Net Utility Plant	10,464,631	10,615,171	10,539,901	9,113,440	9,201,938	9,157,689	1,351,191	1,413,233	1,382,212
5	CWIP	495,880	552,332	524,106	416,284	472,539	444,412	79,595	79,793	79,694
6										
7	Accumulated Deferred Taxes	2,495,909	2,551,785	2,523,847	2,188,228	2,236,114	2,212,171	307,680	315,671	311,676
8	DTA - NOL Average Balance	(189,262)	(72,266)	(130,764)	(141,865)	(43,310)	(92,588)	(47,397)	(28,956)	(38,177)
9	DTA - State Tax Credit Average Balance	(559)	0	(279)	(559)	0	(279)	0	0	0
10	DTA - Federal Tax Credit Average Balance	(138,231)	(176,325)	(157,278)	(123,610)	(155,453)	(139,531)	(14,621)	(20,872)	(17,747)
11	Total Accum Deferred Taxes	2,167,857	2,303,194	2,235,525	1,922,195	2,037,351	1,979,773	245,662	265,843	255,752
12										
13	Cash Working Capital	(120,446)	(120,446)	(120,446)	(108,129)	(108,129)	(108,129)	(12,318)	(12,318)	(12,318)
14	Materials and Supplies	155,470	155,470	155,470	135,797	135,797	135,797	19,672	19,672	19,672
15	Fuel Inventory	84,138	84,138	84,138	73,476	73,476	73,476	10,662	10,662	10,662
16	Non-plant Assets and Liabilities	(9,565)	1,014	(4,275)	(8,338)	906	(3,716)	(1,227)	108	(559)
17	Customer Advances	(8,227)	(8,227)	(8,227)	(5,562)	(5,562)	(5,562)	(2,665)	(2,665)	(2,665)
18	Customer Deposits	(28,480)	(28,480)	(28,480)	(28,127)	(28,127)	(28,127)	(352)	(352)	(352)
19	Prepaids and Other	114,386	90,151	102,268	99,890	78,724	89,307	14,496	11,427	12,961
20	Regulatory Amortizations	62,434	59,047	60,741	62,434	59,047	60,741	0	0	0
21	Total Other Rate Base Items	249,709	232,666	241,188	221,442	206,132	213,787	28,267	26,534	27,401
22										
23	**Total Rate Base**	**9,042,363**	**9,096,975**	**9,069,669**	**7,828,972**	**7,843,258**	**7,836,115**	**1,213,391**	**1,253,717**	**1,233,554**

Line No.	NSPM - 02 Income Statement Schedule	Dec - 2016		
		Total	MN Electric	Other
1	**Operating Revenues**			
2	Retail	3,487,931	3,033,285	454,647
3	Interdepartmental	809	809	
4	Transportation			
5	Other Operating Rev - Non-Retail	670,500	586,984	83,515
6	**Total Operating Revenues**	4,159,240	3,621,078	538,162
7				
8	**Expenses**			
9	Operating Expenses:			
10	Fuel	1,138,449	995,513	142,936
11	Variable IA Production Fuel	5,726	5,001	726
12	Purchased Energy - Windsource	583	583	0
13	**Fuel & Purchased Energy Total**	1,144,758	1,001,096	143,661
14	Production - Fixed	447,315	390,602	56,713
15	Production - Fixed IA Investment	53,592	46,811	6,782
16	Production - Fixed IA O&M	(4,826)	(4,215)	(611)
17	Production - Variable	122,113	106,639	15,475
18	Production - Purchased Demand	154,140	134,635	19,505
19	Production - Other	0	0	0
20	**Production Total**	772,335	674,472	97,863
21	Regional Markets	8,070	7,049	1,021
22	Transmission IA	111,588	97,468	14,120
23	Transmission	123,353	107,718	15,634
24	Distribution	124,690	108,023	16,666
25	Customer Accounting	57,948	49,315	8,633
26	Customer Service & Information	92,454	91,110	1,344
27	Sales, Econ Dvlp & Other	119	69	51
28	Administrative & General	237,995	206,579	31,416
29	**Total Operating Expenses**	2,673,311	2,342,900	330,410
30				
31	Depreciation	545,308	471,286	74,022
32	Amortization	39,447	39,585	(138)
33				
34	**Taxes:**			
35	Property Taxes	210,192	186,751	23,441
36	ITC Amortization	(1,486)	(1,340)	(145)
37	Deferred Taxes	115,529	98,922	16,607
38	Deferred Taxes - NOL	143,535	120,693	22,842
39	Less Deferred State Tax Credits	559	559	0
40	Less Deferred Federal Tax Credits	(38,094)	(31,843)	(6,251)
41	Deferred Income Tax & ITC	220,043	186,991	33,052
42	Payroll & Other Taxes	31,616	27,550	4,066
43	**Total Taxes Other Than Income**	461,852	401,292	60,559
44	**Total State & Federal Income Taxes**	(79,244)	(73,527)	(5,717)
45				
46	**Total Taxes**	382,608	327,766	54,842
47	**Total Expenses**	3,640,673	3,181,537	459,136
48	**Total Operating Income**	518,566	439,541	79,026
49				
50	AFDC Debt	12,939	10,959	1,980
51	AFDC Equity	26,359	22,324	4,034
52				
53	**Net Income**	557,864	472,824	85,040

Line No.	NSPM - 03 Income Tax Schedule	Dec - 2016		
		Total	MN Electric	Other
1	**Income Before Taxes**			
2	Total Operating Revenues	4,159,240	3,621,078	538,162
3	less: Total Operating Expenses	2,673,311	2,342,900	330,410
4	Book Depreciation	545,308	471,286	74,022
5	Amortization	39,447	39,585	(138)
6	Taxes Other than Income	461,852	401,292	60,559
7	**Total Before Tax Book Income**	**439,322**	**366,014**	**73,309**
8				
9	**Tax Additions**			
10	Book Depreciation	545,308	471,286	74,022
11	Deferred Income Taxes and ITC	220,043	186,991	33,052
12	Nuclear Fuel Burn (ex D&D)	119,232	104,144	15,087
13	Nuclear Outage Accounting	69,733	60,902	8,831
14	Avoided Tax Interest	14,621	11,819	2,803
15	Other Book Additions	3,387	3,387	0
16	**Total Tax Additions**	**972,324**	**838,529**	**133,795**
17				
18	**Tax Deductions**			
19	Total Rate Base	9,069,669	7,836,115	1,233,554
20	Weighted Cost of Debt	2.24%	2.24%	2.24%
21	Debt Interest Expense (Line 19 x Line 20)	203,161	175,529	27,632
22	Nuclear Outage Accounting	45,498	39,736	5,762
23	Tax Depreciation and Removals	960,303	830,104	130,199
24	NOL Utilization	351,718	295,746	55,972
25	Other Tax / Book Timing Differences	10,766	9,407	1,359
26	**Total Tax Deductions**	**1,571,446**	**1,350,522**	**220,924**
27				
28	**State Taxes**			
29	State Taxable Income	(159,800)	(145,980)	(13,820)
30	State Income Tax Rate	9.80%	9.80%	9.80%
31	State Taxes before Credits (Line 31 x Line 32)	(15,660)	(14,306)	(1,354)
32	Less State Tax Credits	(559)	(559)	0
33	Deferred State Tax Credits due to NOL	(559)	(559)	0
34	**Total State Income Taxes**	**(16,778)**	**(15,424)**	**(1,354)**
35				
36	**Federal Taxes**			
37	Federal Sec 199 Production Deduction	3,426	3,426	0
38	Federal Taxable Income	(146,447)	(133,982)	(12,466)
39	Federal Income Tax Rate	35.00%	35.00%	35.00%
40	Federal Tax before Credits (Line 39 x Line 40)	(51,257)	(46,894)	(4,363)
41	Less Federal Tax Credits	(49,303)	(43,052)	(6,251)
42	Deferred Federal Tax Credits due to NOL	38,094	31,843	6,251
43	**Total Federal Income Taxes**	**(62,466)**	**(58,103)**	**(4,363)**
44				
45	**Total Taxes**			
46	**Total Federal and State Income Taxes**	**(79,244)**	**(73,527)**	**(5,717)**

Line No.	NSPM - 04 Revenue Deficiency Schedule	Dec - 2016		
		Total	MN Electric	Other
1	**Weighted Cost of Capital**			
2	Cost of Short Term Debt	1.84%	1.84%	1.84%
3	Cost of Long Term Debt	4.81%	4.81%	4.81%
4	Cost of Preferred Stock			
5	Cost of Common Equity	10.00%	10.00%	10.00%
6	Ratio of Short Term Debt	1.26%	1.26%	1.26%
7	Ratio of Long Term Debt	46.24%	46.24%	46.24%
8	Ratio of Preferred Stock			
9	Ratio of Common Equity	52.50%	52.50%	52.50%
10	Weighted Cost of STD	0.02%	0.02%	0.02%
11	Weighted Cost of LTD	2.22%	2.22%	2.22%
12	Weighted Cost of Debt	2.24%	2.24%	2.24%
13	Weighted Cost of Preferred Stock	0.0%	0.0%	0.0%
14	Weighted Cost of Equity	5.25%	5.25%	5.25%
15	**Required Rate Of Return**	**7.49%**	**7.49%**	**7.49%**
16				
17	**Composite Income Tax Rate**			
18	State Tax Rate	9.80%	9.80%	9.80%
19	Federal Statuatory Tax Rate	35.00%	35.00%	35.00%
20	Federal Effective Tax Rate	31.57%	31.57%	31.57%
21	**Composite Tax Rate**	**41.37%**	**41.37%**	**41.37%**
22				
23	**Rate of Return (ROR)**			
24	Total Operating Income	557,864	472,824	85,040
25	Total Rate Base	9,069,669	7,836,115	1,233,554
26	**ROR (Operating Income / Rate Base)**	**6.15%**	**6.03%**	**6.89%**
27				
28	**Return on Equity (ROE)**			
29	Total Operating Income	557,864	472,824	85,040
30	Debt Interest (Rate Base * Weighted Cost of Debt)	(203,161)	(175,529)	(27,632)
31	Earnings Available for Common	354,704	297,295	57,409
32	Equity Rate Base (Rate Base * Equity Ratio)	4,761,576	4,113,960	647,616
33	**ROE (earnings for Common/Equity Rate Base)**	**7.45%**	**7.23%**	**8.86%**
34				
35	**Revenue Deficiency**			
36	Required Operating Income (Rate Base * Required Return)	680,068	586,925	93,143
37	Total Operating Income	557,864	472,824	85,040
38	Operating Income Deficiency	122,204	114,101	8,103
39				
40	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.705611	1.705611	1.705611
41	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**208,432**	**194,612**	**13,820**
42				
43	**Total Revenue Requirements**			
44	Total Retail Revenues	3,488,740	3,034,093	454,647
45	Revenue Deficiency	208,432	194,612	13,820
46	**Total Revenue Requirements**	**3,697,172**	**3,228,705**	**468,467**
47				

Northern States Power Company
State of MN Electric Jurisdiction
2016 Test Year

Line No.	NSPM - 05 Summary Cash Working Capital	Lead/Lag	Total		MN Electric		Other	
		Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
1	**Fuel Expenses**							
2	Coal and Rail Transport	19.07	319,061	6,084,501	278,629	5,313,461	40,432	771,040
3	Gas for Generation	37.68	240,705	9,069,749	210,202	7,920,412	30,503	1,149,337
4	Oil	19.87	784	15,571	684	13,598	99	1,973
5	Nuclear and EOL	(0)	119,232	(0)	104,122	(0)	15,109	(0)
6	Nuclear Disposal	(0)	(0)	(0)	(0)	(0)	(0)	(0)
7	**Subtotal Fuel Expenses**		**679,782**	**15,169,822**	**593,638**	**13,247,471**	**86,143**	**1,922,350**
8								
9	**Purchased Power**							
10	Purchases	35.62	562,853	20,048,811	491,614	17,511,277	71,239	2,537,534
11	Interchange	38.21	106,763	4,079,398	93,253	3,563,195	13,510	516,203
12	**SubTotal Purchased Power**		**669,615**	**24,128,209**	**584,867**	**21,074,472**	**84,749**	**3,053,737**
13								
14	**Labor and Related**							
15	Regular Payroll	11.56	396,695	4,585,796	344,910	3,987,159	51,785	598,637
16	Incentive	253.17	25,346	6,416,838	22,151	5,608,034	3,195	808,805
17	Pension and Benefits	35.67	89,242	3,183,270	77,707	2,771,794	11,536	411,476
18	**SubTotal Labor and Related**		**511,283**	**14,185,905**	**444,768**	**12,366,987**	**66,516**	**1,818,918**
19								
20	**All Other Operating Expenses**	43.76	812,630	35,560,705	719,628	31,490,909	93,003	4,069,796
21	Property taxes	355.31	210,192	74,683,492	186,751	66,354,590	23,441	8,328,902
22	Employer's Payroll Taxes	33.72	31,616	1,066,099	27,550	928,998	4,066	137,100
23	Gross Earnings Tax	55.46	53,210	2,951,047	53,210	2,951,047	(0)	(0)
24	Federal Income Tax	36.75	(62,466)	(2,295,626)	(58,103)	(2,135,288)	(4,363)	(160,338)
25	State Income Tax	29.50	(16,778)	(494,953)	(15,424)	(454,999)	(1,354)	(39,953)
26	State Sales Tax Customer Billings	35.20	136,608	4,808,617	136,608	4,808,617	0	0
27	**Total Expenses**		**3,025,694**	**169,763,316**	**2,673,494**	**150,632,804**	**352,200**	**19,130,512**
28	Net Annual Expense			465,105		412,693		52,412
29								
30	**Revenues**							
31	Retail Revenue	41.42	3,487,931	144,470,120	3,033,285	125,638,646	454,647	18,831,474
32	Late Payment	-	7,031	(0)	6,058	(0)	(0)	(0)
33	Interdepartmental	-	809	(0)	809	(0)	(0)	(0)
34	Misc Services	41.42	3,200	132,546	2,493	103,261	707	29,285
35	CIP Incentive	-	228	(0)	(0)	(0)	228	(0)
36	Rentals	(40.86)	5,120	(209,201)	4,472	(182,742)	648	(26,459)
37	Interchange	38.21	517,879	19,788,171	452,309	17,282,744	65,570	2,505,427
38	Sales for Resale	38.27	(0)	(0)	(0)	(0)	(0)	(0)
39	Retail Rev Lag Days	38.27	2,431	93,036	2,223	85,082	208	7,954
40	MISO	14.00	(140,682)	(1,969,541)	(123,042)	(1,722,592)	(17,639)	(246,950)
41	Wholesale Lag Days	38.27	248,775	9,520,612	217,294	8,315,838	31,481	1,204,773
42	**Total Revenues**		**4,132,722**	**171,825,743**	**3,595,901**	**149,520,239**	**536,821**	**22,305,504**
43								
44	Net Annual Amount			470,755		409,644		61,111
45	Expense/Revenue Factor		0.732131	10.284675	0.743484	3.717419	0.656084	6.567256
46	Allocated Revenue Amount		-	344,658	-	304,564	-	40,094
47	**Net Cash Working Capital**			**(120,447)**		**(108,129)**		**(12,318)**

LABELING OF FINANCIAL SOURCES

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

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

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

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

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

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

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

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

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

Notes:

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

Order	Topic	Witness	Financial Source
1	Policy / MYRP Policy	Chandarana	NSPM Electric
2	MYRP	Burdick	State of MN Electric Jurisdiction
3	Global Insights / MYRP Escalators	Mothersole	N/A
4	Revenue Requirements	Heuer	State of MN Electric Jurisdiction
5	Budgeting	Robinson	NSPM Electric
6	Capital Structure	Van Abel	NSPM (Total Company)
7	Return on Equity	Coyne	State of MN Electric Jurisdiction
8	Cost Allocations	Dietenberger	NSPM Electric
9	Sales Forecast	Marks	NSPM Electric
10	Nuclear Operations	O'Connor	NSPM Electric
11	Transmission	Benson	NSPM Electric
12	Energy Supply	Mills	NSPM Electric
13	Distribution	Bloch	NSPM Electric / State of MN Electric Jurisdiction
14	Business Systems	Harkness	NSPM (Total Company)
15	Insurance	Miller	XEI and NSPM (Total Company)
16	Property Tax	Chapman	NSPM (Total Company)
17	Customer Care/Bad Debt	Gersack	NSPM Electric
18	Employee Expenses	O'Hara	NSPM (Total Company)
19	Compensation and Benefits	Lowenthal	Xcel Energy, NSPM (Total Company), and NSPM Electric
20	Pension	Schrubbe	State of MN Electric Jurisdiction
21	Pension Investments	Tyson	N/A
22	Pension Investment	Inglis	N/A
23	Depreciation	Perkett	NSPM Electric
24	Decoupling	Peterson	N/A
25	CCOSS	Peppin	State of MN Electric Jurisdiction
26	Rate Design	Huso	State of MN Electric Jurisdiction

Northern States Power Company
State of Minnesota Electric Jurisdiction

SUMMARY OF MAJOR COST ELEMENTS
Test Year Ending December 31, 2016
Amounts in millions

Line	of the Revenue Deficiency	2016 Revenue Deficiency	reference
1	Capital Recovery: for additional rate base investment (includes return requirement, change in capital structure, cost of capital, depreciation and Allowance for Funds Used During Construction)	$159.6	row 22 of page 2
	Operating Expenses:		
2	Power Production	($9.0)	row 25 & 26 of page 2
3	Transmission	$2.5	row 27 of page 2
4	Distribution	$4.7	row 28 of page 2
5	Customer Accounts, Info Services, Sales & Economic Development	$0.4	row 29 of page 2
6	Administrative and General Expense	$19.3	row 30 of page 2
7	Total Operating Expenses	$17.9	
	Taxes Other than Income Taxes:		
8	Real Estate and Personal Property	$30.2	row 34 of page 2
9	Payroll Taxes and Other	($1.9)	row 35 of page 2
10	Total Taxes Other Than Income Taxes	$28.3	
11	Amortizations	($0.7)	row 39 of page 2
12	Subtotal	$205.1	
13	Less, Net Sales and Growth in Margin	($10.5)	row 47 of page 2
14	Net Revenue Deficiency	$194.6	

SUMMARY OF MAJOR COST DRIVERS
Test Year Ending December 31, 2016
Amounts in millions

	13-868 Outcome 2014 TY + 2015 Step	2016 TY	2016 TY over last case	reference
Capital-Related				
Nuclear	200.1	257.6	57.5	column 1 of page 3
Energy Supply	207.7	204.2	(3.4)	column 2 of page 3
Wind	31.6	44.3	12.7	column 3 of page 3
Transmission net of TCR	169.7	188.5	18.8	column 4 of page 3
Distribution	235.6	248.6	13.0	column 5 of page 3
General & Intangible	88.3	114.2	25.9	column 6 of page 3
Theoretical Reserve	(58.5)	(32.4)	26.1	column 7 of page 3
Other Rate Base	10.6	7.9	(2.6)	column 8 of page 3
NOL & Fed Tax Items	22.3	16.1	(6.2)	column 9 of page 3
ROE	-	20.0	20.0	column 10 of page 3
Cap Structure & Debt	-	(2.1)	(2.1)	column 11 of page 3
TOTAL Capital-Related	907.4	1,067.0	159.6	
O&M				
Nuclear	287.3	274.0	(13.4)	column 12 of page 3
Energy Supply	161.1	165.4	4.4	column 13 of page 3
Transmission	37.9	40.3	2.5	column 14 of page 3
Distribution (MN only)	103.0	107.7	4.7	column 15 of page 3
Customer Acctg, Info, Sales	49.9	50.3	0.4	column 16 of page 3
A&G and Other O&M	197.3	216.6	19.3	column 17 of page 3
TOTAL O&M	836.4	854.4	17.9	
Taxes				
Property Taxes	146.0	176.2	30.2	column 18 of page 4
Payroll Taxes	29.4	27.6	(1.9)	column 19 of page 4
TOTAL Taxes	175.4	203.7	28.3	
Amortizations				
Amortizations	1.8	1.1	(0.7)	column 20 of page 4
TOTAL Amortizations	1.8	1.1	(0.7)	
Margins				
Retail Revenue & COGS	(2,001.0)	(2,015.4)	(14.4)	column 21 of page 4
Purchased Demand	131.2	113.4	(17.8)	column 22 of page 4
DOE Payment	(25.7)	-	25.7	column 23 of page 4
Non-Retail Revenue	(25.5)	(29.6)	(4.0)	column 24 of page 4
TOTAL Margins	(1,921.0)	(1,931.6)	(10.5)	
TOTAL Deficiency	**-**	**194.612**	**194.612**	

Northern States Power Company
State of Minnesota Electric Jurisdiction

Docket No. E002/GR-15-826
Exhibit___(AEH-1), Schedule 6

SUMMARY OF MAJOR COST DRIVERS BRIDGE
Test Year Ending December 31, 2016
Amounts in thousands

			Capital											O&M					
Line No.	Description	13-868 Outcome	Nuclear	Energy Supply	Wind	Transmission net of TCR	Distribution	General & Intangible	Theoretical Reserve	Other Rate Base	NOL and Fed Tax Items	ROE	Cap Structure & Debt	Nuclear	Energy Supply	Transmission	Distribution (MN only)	Customer Acctg, Info, Sales	A&G and Other O&M
1			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
2																			
3	Rate Base	6,988,288	211,941	(84,455)	226,698	361,593	53,956	128,397	36,252	(31,820)	(54,735)								
4																			
5	Operating Revenues																		
6	Retail Revenue	2,976,081				59,066													
7	Interdepartmental	962																	
8	Other Operating	664,598	10,601	865	3,581	(14,824)	2	76	2,487	(425)	(3,031)			(82)	981	59			968
9	Total Revenue	3,641,641	10,601	865	3,581	44,242	2	76	2,487	(425)	(3,031)			(82)	981	59			968
10																			
11	Expenses																		
12	Operating Expenses																		
13	Fuel & Purchased Energy	1,086,327								638					1,075				27
14	Power Production	701,051						8		(580)	(10)			(11,944)	4,273				3,739
15	Transmission	191,916		(6)		11,449	2	144								2,548			611
16	Distribution	103,317															4,650		56
17	Customer Accounting	48,049																1,155	112
18	Customer Service and Information	93,490																(680)	(22)
19	Sales, Econ Dev, & Other	101																(33)	(0)
20	Administrative and General	190,741																	15,787
21	Total Operating Expenses	2,414,992		(6)		11,449	2	152		58	(10)			(11,944)	5,348	2,548	4,650	442	20,308
22																			
23	Depreciation	347,346	37,787	11,029	19,942	10,303	5,822	15,964	23,092										
24	Amortization	31,300	0	(1,640)	(239)	0								(1,512)					
25																			
26	Taxes																		
27	Property	155,282																	
28	Deferred Income Tax and ITC	173,215	2,483	3,524	20,500	(6,291)	(282)	6,167	(8,685)	(4,776)	1,136								
29	Federal and State Income Tax	4,416	(8,413)	(6,131)	(47,185)	12,527	(2,281)	(14,845)	693	5,079	(3,773)		867	5,533	(1,807)	(1,029)	(1,924)	(183)	(8,001)
30	Payroll and Other	29,409																	
31	Total Taxes	362,322	(5,931)	(2,607)	(26,685)	6,236	(2,563)	(8,679)	(7,992)	303	(2,637)		867	5,533	(1,807)	(1,029)	(1,924)	(183)	(8,001)
32																			
33	Total Expenses	3,155,960	31,856	6,777	(6,982)	27,988	3,261	7,437	15,101	360	(2,647)		867	(7,924)	3,542	1,518	2,726	259	12,307
34																			
35	Allowance for Funds Used During Construction	29,355	3,098	1,717	(1,378)	(713)	(404)	1,607											
36																			
37	Total Operating Income	515,037	(18,157)	(4,195)	9,184	15,542	(3,663)	(5,753)	(12,613)	(786)	(384)		(867)	7,841	(2,561)	(1,459)	(2,726)	(259)	(11,339)
38																			
39	Calculation of Revenue Requirements																		
40	Rate Base	6,988,288	211,941	(84,455)	226,698	361,593	53,956	128,397	36,252	(31,820)	(54,735)								
41	Required Operating Income	515,037	15,556	(6,199)	16,640	26,541	3,960	9,424	2,661	(2,336)	(4,018)	11,754	(2,096)						
42	Operating Income	515,037	(18,157)	(4,195)	9,184	15,542	(3,663)	(5,753)	(12,613)	(786)	(384)		(867)	7,841	(2,561)	(1,459)	(2,726)	(259)	(11,339)
43	Income Deficiency	0	33,714	(2,004)	7,455	10,999	7,623	15,178	15,274	(1,550)	(3,634)	11,754	(1,229)	(7,841)	2,561	1,459	2,726	259	11,339
44	**Revenue Deficiency**	**0**	**57,502**	**(3,419)**	**12,716**	**18,760**	**13,003**	**25,887**	**26,052**	**(2,643)**	**(6,198)**	**20,048**	**(2,096)**	**(13,374)**	**4,367**	**2,488**	**4,650**	**442**	**19,340**
45																			
46	Calculation of Income Taxes																		
47	Operating Revenue	3,641,641	10,601	865	3,581	44,242	2	76	2,487	(425)	(3,031)			(82)	981	59			968
48	-Operating Expense	2,414,992		(6)		11,449	2	152		58	(10)			(11,944)	5,348	2,548	4,650	442	20,308
49	-Amortization	31,300	0	(1,640)	(239)	0								(1,512)					
50	-Taxes Other then Income	184,691																	
51	Operating Income Before Adjs	1,010,658	10,601	2,511	3,819	32,794	0	(75)	2,487	(483)	(3,021)			13,374	(4,367)	(2,488)	(4,650)	(442)	(19,340)
52	Additions to Income	211,819	(11,123)	(17,835)	(545)	(2,092)	(130)	159											
53	Deductions from Income	1,052,164	15,068	1,387	70,418	(7,677)	4,175	33,092		(12,047)	18,415								
54	Debt Synchonization	158,634	4,747	(1,892)	5,078	8,100	1,209	2,876	812	(713)	(1,226)		(2,096)						
55	State Taxable Income	11,679	(20,337)	(14,820)	(72,222)	30,280	(5,514)	(35,885)	1,675	12,277	(20,209)		2,096	13,374	(4,367)	(2,488)	(4,650)	(442)	(19,340)
56	State Income Tax Before Credits	1,145	(1,993)	(1,452)	(7,078)	2,967	(540)	(3,517)	164	1,203	(1,981)		205	1,311	(428)	(244)	(456)	(43)	(1,895)
57	State Tax Credits	640			(640)						1,118								
58	Federal Tax Deductions										3,426								
59	Federal Taxable Income	11,174	(18,344)	(13,367)	(65,784)	27,312	(4,973)	(32,368)	1,511	11,074	(20,537)		1,891	12,063	(3,939)	(2,244)	(4,194)	(398)	(17,445)
60	Federal Income Tax Before Credits	3,911	(6,420)	(4,679)	(23,024)	9,559	(1,741)	(11,329)	529	3,876	(7,188)		662	4,222	(1,379)	(786)	(1,468)	(139)	(6,106)
61	Federal Tax Credits				17,723						(6,513)								
62	Total Income Taxes	4,416	(8,413)	(6,131)	(47,185)	12,527	(2,281)	(14,845)	693	5,079	(3,773)		867	5,533	(1,807)	(1,029)	(1,924)	(183)	(8,001)
63																			

Northern States Power Company
State of Minnesota Electric Jurisdiction

Docket No. E002/GR-15-826
Exhibit___(AEH-1), Schedule 6

SUMMARY OF MAJOR COST DRIVERS BRIDGE
Test Year Ending December 31, 2016
Amounts in thousands

Line No.	Description	Taxes		Margin					2016 Test Year
		Property Taxes	Payroll Taxes	Amortizations	Retail Revenue/ COGS	Purchased Demand	DOE Payment	Non-Retail (Misc) Revenue	
1		(18)	(19)	(20)	(21)	(22)	(23)	(24)	
2									
3	Rate Base								7,836,115
4									
5	Operating Revenues								
6	Retail Revenue				(1,862)				3,033,285
7	Interdepartmental				(154)				809
8	Other Operating	4,151			(63,153)	1,821	(25,735)	4,041	586,984
9	Total Revenue	4,151			(65,169)	1,821	(25,735)	4,041	3,621,078
10									
11	Expenses								
12	Operating Expenses								
13	Fuel & Purchased Energy				(86,970)				1,001,096
14	Power Production	246			693	(15,954)			681,521
15	Transmission	2,627			(4,105)				205,186
16	Distribution								108,023
17	Customer Accounting								49,315
18	Customer Service and Information				(1,677)				91,110
19	Sales, Econ Dev, & Other								69
20	Administrative and General				52				206,579
21	Total Operating Expenses	2,873			(92,007)	(15,954)			2,342,900
22									
23	Depreciation								471,286
24	Amortization			(719)	12,395				39,585
25									
26	Taxes								
27	Property	31,469							186,751
28	Deferred Income Tax and ITC								186,991
29	Federal and State Income Tax	(12,490)	769	297	5,975	7,354	(10,646)	1,672	(73,527)
30	Payroll and Other		(1,859)						27,550
31	Total Taxes	18,979	(1,090)	297	5,975	7,354	(10,646)	1,672	327,766
32									
33	Total Expenses	21,853	(1,090)	(422)	(73,637)	(8,601)	(10,646)	1,672	3,181,537
34									
35	Allowance for Funds Used During Construction								33,283
36									
37	Total Operating Income	(17,701)	1,090	422	8,468	10,422	(15,088)	2,370	472,824
38									
39	Calculation of Revenue Requirements								
40	Rate Base								7,836,115
41	Required Operating Income								586,925
42	Operating Income	(17,701)	1,090	422	8,468	10,422	(15,088)	2,370	472,824
43	Income Deficiency	17,701	(1,090)	(422)	(8,468)	(10,422)	15,088	(2,370)	114,101
44	**Revenue Deficiency**	**30,191**	**(1,859)**	**(719)**	**(14,443)**	**(17,776)**	**25,735**	**(4,041)**	**194,612**
45									
46	Calculation of Income Taxes								
47	Operating Revenue	4,151			(65,169)	1,821	(25,735)	4,041	3,621,078
48	-Operating Expense	2,873			(92,007)	(15,954)			2,342,900
49	-Amortization			(719)	12,395				39,585
50	-Taxes Other then Income	31,469	(1,859)						214,302
51	Operating Income Before Adjs	(30,191)	1,859	719	14,443	17,776	(25,735)	4,041	1,024,290
52	Additions to Income								180,252
53	Deductions from Income								1,174,993
54	Debt Synchonization								175,529
55	State Taxable Income	(30,191)	1,859	719	14,443	17,776	(25,735)	4,041	(145,980)
56	State Income Tax Before Credits	(2,959)	182	70	1,415	1,742	(2,522)	396	(14,306)
57	State Tax Credits								1,118
58	Federal Tax Deductions								3,426
59	Federal Taxable Income	(27,233)	1,676	649	13,028	16,034	(23,213)	3,645	(133,982)
60	Federal Income Tax Before Credits	(9,531)	587	227	4,560	5,612	(8,124)	1,276	(46,894)
61	Federal Tax Credits								11,209
62	Total Income Taxes	(12,490)	769	297	5,975	7,354	(10,646)	1,672	(73,527)
63									

Northern States Power Company
State of Minnesota Electric Jurisdiction

Docket No. E002/GR-15-826
Exhibit___(AEH-1), Schedule 6

MAJOR CARRYOVER PROJECTS
Test Year Ending December 31, 2016
Amounts in thousands

Line		Monticello LCM/EPU			PI U2 Generator/GSU Transformer			Pleasant Valley Wind			Border Winds		
No.	Description	13-868	16 TY	Difference	13-868	16 TY	Difference	13-868	16 TY	Difference	13-868	16 TY	Difference
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
2													
3	Rate Base	316,046	331,226	15,180	43,469	50,666	7,197	124,769	260,211	135,442	96,999	201,577	104,578
4													
5	Operating Revenues												
6	Retail Revenue												
7	Interdepartmental												
8	Other Operating	17,952	16,167	(1,784)	419	1,452	1,032	1,489	3,540	2,051	813	2,869	2,056
9	Total Revenue	17,952	16,167	(1,784)	419	1,452	1,032	1,489	3,540	2,051	813	2,869	2,056
10													
11	Expenses												
12	Operating Expenses												
13	Fuel & Purchased Energy												
14	Power Production												
15	Transmission												
16	Distribution												
17	Customer Accounting												
18	Customer Service and Information												
19	Sales, Econ Dev, & Other												
20	Administrative and General												
21	Total Operating Expenses												
22													
23	Depreciation	22,979	30,353	7,374	600	3,457	2,857	2,287	13,063	10,776	1,063	10,119	9,056
24	Amortization												
25													
26	Taxes												
27	Property												
28	Deferred Income Tax and ITC	(2,197)	(3,504)	(1,307)	2,275	154	(2,122)	19,557	33,828	14,272	15,439	26,202	10,763
29	Federal and State Income Tax	(2,068)	(4,446)	(2,378)	(2,520)	(1,365)	1,154	(24,851)	(53,948)	(29,097)	(19,166)	(41,264)	(22,098)
30	Payroll and Other												
31	Total Taxes	(4,265)	(7,950)	(3,685)	(244)	(1,212)	(967)	(5,295)	(20,120)	(14,825)	(3,727)	(15,062)	(11,335)
32													
33	Total Expenses	18,714	22,402	3,688	356	2,246	1,890	(3,008)	(7,058)	(4,049)	(2,664)	(4,943)	(2,279)
34													
35	Allowance for Funds Used During Construction				1,823		(1,823)	1,233		(1,233)	1,742		(1,742)
36													
37	Total Operating Income	(762)	(6,235)	(5,473)	1,887	(794)	(2,681)	5,730	10,598	4,868	5,219	7,812	2,593
38													
39	Calculation of Revenue Requirements												
40	Rate Base	316,046	331,226	15,180	43,469	50,666	7,197	124,769	260,211	135,442	96,999	201,577	104,578
41	Required Operating Income	23,198	24,312	1,114	3,191	3,719	528	9,158	19,099	9,941	7,120	14,796	7,676
42	Operating Income	(762)	(6,235)	(5,473)	1,887	(794)	(2,681)	5,730	10,598	4,868	5,219	7,812	2,593
43	Income Deficiency	23,960	30,547	6,587	1,304	4,513	3,209	3,429	8,502	5,073	1,901	6,984	5,083
44	**Revenue Deficiency**	**40,867**	**52,101**	**11,235**	**2,224**	**7,698**	**5,474**	**5,848**	**14,501**	**8,653**	**3,242**	**11,911**	**8,669**
45													
46	Calculation of Income Taxes												
47	Operating Revenue	17,952	16,167	(1,784)	419	1,452	1,032	1,489	3,540	2,051	813	2,869	2,056
48	-Operating Expense												
49	-Amortization												
50	-Taxes Other then Income												
51	Operating Income Before Adjs	17,952	16,167	(1,784)	419	1,452	1,032	1,489	3,540	2,051	813	2,869	2,056
52	Additions to Income				890		(890)	619		(619)	648		(648)
53	Deductions from Income	15,871	19,495	3,624	6,426	3,617	(2,809)	50,351	95,902	45,551	38,929	74,281	35,352
54	Debt Synchonization	7,079	7,419	340	974	1,135	161	2,795	5,829	3,034	2,173	4,515	2,343
55	State Taxable Income	(4,999)	(10,747)	(5,748)	(6,091)	(3,301)	2,790	(51,038)	(98,190)	(47,152)	(39,641)	(75,927)	(36,286)
56	State Income Tax Before Credits	(490)	(1,053)	(563)	(597)	(323)	273	(5,002)	(9,623)	(4,621)	(3,885)	(7,441)	(3,556)
57	State Tax Credits												
58	Federal Tax Deductions												
59	Federal Taxable Income	(4,509)	(9,694)	(5,185)	(5,494)	(2,977)	2,517	(46,036)	(88,568)	(42,531)	(35,756)	(68,486)	(32,730)
60	Federal Income Tax Before Credits	(1,578)	(3,393)	(1,815)	(1,923)	(1,042)	881	(16,113)	(30,999)	(14,886)	(12,515)	(23,970)	(11,456)
61	Federal Tax Credits							3,737	13,327	9,590	2,767	9,853	7,086
62	Total Income Taxes	(2,068)	(4,446)	(2,378)	(2,520)	(1,365)	1,154	(24,851)	(53,948)	(29,097)	(19,166)	(41,264)	(22,098)

COMPARISON OF DETAILED RATE BASE COMPONENTS

Test Year Ending December 31, 2016
($000's)

Line No.	Description	General Rate Case Filing Docket No. E002/GR-13-868 (A)	General Rate Case Filing Docket No. E002/GR-15-826 Final Rates (B)	Change (C) = (B) - (A)
	Electric Plant as Booked			
1	Production	$8,463,834	$9,192,783	$728,949
2	Transmission	2,080,979	2,690,961	609,982
3	Distribution	3,029,265	3,272,959	243,694
4	General	503,226	727,748	224,522
5	Common	466,842	540,996	74,154
6	TOTAL Utility Plant in Service	$14,544,147	$16,425,447	1,881,300
	Reserve for Depreciation			
7	Production	$4,492,896	$4,947,590	$454,694
8	Transmission	516,358	551,324	34,966
9	Distribution	1,105,553	1,232,993	127,441
10	General	178,301	267,760	89,459
11	Common	245,228	268,091	22,863
12	TOTAL Reserve for Depreciation	$6,538,336	$7,267,758	$729,422
	Net Utility Plant in Service			
13	Production	$3,970,938	$4,245,193	$274,255
14	Transmission	$1,564,621	2,139,637	575,016
15	Distribution	$1,923,713	2,039,966	116,253
16	General	$324,925	459,989	135,063
17	Common	$221,614	272,905	51,291
18	Net Utility Plant in Service	$8,005,811	$9,157,689	$1,151,878
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$418,546	$444,412	$25,866
21	Less: Accumulated Deferred Income Taxes	$1,702,954	$1,979,773	$276,819
22	Cash Working Capital	($75,756)	($108,129)	($32,373)
	Other Rate Base Items:			
23	Materials and Supplies	$116,514	$135,797	$19,283
24	Fuel Inventory	74,663	73,476	(1,187)
25	Non-Plant Assets & Liabilities	(13,137)	(3,716)	9,421
26	Prepayments	14,103	17,295	3,192
27	Nuclear Outage Amortization	82,801	69,844	(12,957)
28	Customer Advances	(3,301)	(5,562)	(2,261)
29	Customer Deposits	(2,763)	(28,127)	(25,364)
30	Sherco 3 Deferral	10,250	9,308	(942)
31	Black Dog Reg Asset Amortization	2,962	0	(2,962)
32	PI EPU Amortization	55,349	51,433	(3,916)
33	Other Working Capital	5,202	2,168	(3,034)
34	Total Other Rate Base Items	$342,642	$321,916	($20,726)
35	Total Average Rate Base	$6,988,289	$7,836,115	$847,826

DETAILED RATE BASE COMPONENTS

Test Year Ending December 31, 2016
($000's)

Line No.	Description	2014 Adjusted (1)	2015 Adjusted (1)	2016 Test Year Unadjusted	2016 Test Year Adjusted (1)
	Electric Plant as Booked				
1	Production	$7,811,440	$8,633,507	$9,293,468	$9,192,783
2	Transmission	1,980,112	2,530,192	2,906,669	2,690,961
3	Distribution	3,041,307	3,153,755	3,272,959	3,272,959
4	General	561,189	649,372	727,748	727,748
5	Common	409,587	467,564	540,996	540,996
6	TOTAL Utility Plant in Service	$13,803,634	$15,434,390	$16,741,841	$16,425,447
	Reserve for Depreciation				
7	Production	$4,414,973	$4,662,092	$4,947,014	$4,947,590
8	Transmission	556,061	544,041	554,837	551,324
9	Distribution	1,188,543	1,203,925	1,231,334	1,232,993
10	General	174,666	214,209	266,556	267,760
11	Common	201,590	228,348	267,994	268,091
12	TOTAL Reserve for Depreciation	$6,535,833	$6,852,615	$7,267,734	$7,267,758
	Net Utility Plant in Service				
13	Production	$3,396,467	$3,971,415	$4,346,455	$4,245,193
14	Transmission	1,424,051	1,986,151	2,351,832	2,139,637
15	Distribution	1,852,764	1,949,830	2,041,625	2,039,966
16	General	386,523	435,163	461,192	459,988
17	Common	207,996	239,216	273,002	272,905
18	Net Utility Plant in Service	$7,267,801	$8,581,775	$9,474,106	$9,157,689
19	Utility Plant Held for Future Use	$0	$0	$0	$0
20	Construction Work in Progress	$499,486	$529,651	$541,694	$444,412
21	Less: Accumulated Deferred Income Tax	$1,580,818	$1,823,023	$2,043,563	$1,979,773
22	Cash Working Capital	($80,446)	($92,268)	($121,170)	($108,129)
	Other Rate Base Items:				
23	Materials and Supplies	$128,884	$135,797	$135,797	$135,797
24	Fuel Inventory	63,676	73,476	73,476	73,476
25	Non-Plant Assets & Liabilities	3,558	2,145	(3,716)	(3,716)
26	Prepayments	18,806	17,295	17,295	17,295
27	Nuclear Outage Amortization	89,746	76,128	69,844	69,844
28	Customer Advances	(5,137)	(5,562)	(5,562)	(5,562)
29	Customer Deposits	(5,476)	(28,127)	(28,127)	(28,127)
30	Sherco 3 Deferral	10,314	9,811	0	9,308
31	PI EPU Amortization	57,201	54,317	0	51,433
32	Other Working Capital	2,303	2,168	2,168	2,168
33	Total Other Rate Base Items	$363,873	$337,448	$261,175	$321,916
34	Total Average Rate Base	$6,469,897	$7,533,584	$8,112,243	$7,836,115

(1) Revenues and expenses for Transmission Cost Recovery (TCR) rider have been excluded.

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
Test Year Ending December 31, 2016
($000's)

Line No.	Description	Test Year Ending 12/31/16 Present Rates (A)	Final Increase (B)	Test Year Ending 12/31/16 Final Rates (C) = (B) + (A)
	Operating Revenues			
1	Retail	$3,033,285	$194,612	$3,227,897
2	CIP Revenue Adjustment	0		0
3	Interdepartmental	809		809
4	Other Operating	586,984		586,984
5	Gross Earnings Tax	0		0
6	**Total Operating Revenues**	$3,621,078	$194,612	$3,815,690
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$1,001,096		$1,001,096
8	Power Production	681,521		681,521
9	Transmission	205,186		205,186
10	Distribution	108,023		108,023
11	Customer Accounting	49,315		49,315
12	Customer Service & Information	91,110		91,110
13	Sales, Econ Dvlp & Other	69		69
14	Administrative & General	206,579		206,579
15	Total Operating Expenses	$2,342,900	$0	$2,342,900
16	Depreciation	$471,286		$471,286
17	Amortizations	39,585		39,585
	Taxes:			
18	Property	$186,751		$186,751
19	Gross Earnings	0		0
20	Deferred Income Tax & ITC	186,991		186,991
21	Federal & State Income Tax	(73,527)	80,511	6,984
22	Payroll & Other	27,550		27,550
23	Total Taxes	$327,766	$80,511	$408,277
24	**Total Expenses**	$3,181,537	$80,511	$3,262,048
25	AFUDC	$33,283		$33,283
26	**Total Operating Income**	$472,824	$114,101	$586,925

Note: Revenues reflect calendar month sales.

STATEMENT OF OPERATING INCOME
2014 Allowed Test Year versus 2016 Test Year
($000's)

Line No.	Description	General Rate Case Filing E002/GR-13-868 Final Rates	General Rate Case Filing E002/GR-15-826 Final Rates	Change
		(A)	(B)	(C) = (B) - (A)
	Operating Revenues			
1	Retail	2,976,081	3,227,897	$251,816
2	CIP Revenue Adjustment	0	0	0
3	Interdepartmental	962	809	(154)
4	Other Operating	664,598	586,984	(77,614)
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$3,641,641	$3,815,690	$174,049
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$1,086,327	$1,001,096	($85,230)
8	Power Production	701,051	681,521	(19,530)
9	Transmission	191,916	205,186	13,270
10	Distribution	103,317	108,023	4,706
11	Customer Accounting	48,049	49,315	1,266
12	Customer Service & Information	93,490	91,110	(2,380)
13	Sales, Econ Dvlp & Other	101	69	(33)
14	Administrative & General	190,741	206,579	15,838
15	Total Operating Expenses	$2,414,992	$2,342,900	($72,092)
16	Depreciation	$347,346	$471,286	$123,940
17	Amortizations	31,300	39,585	8,286
	Taxes:			
18	Property	$155,282	$186,751	$31,469
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	173,215	186,991	13,775
21	Federal & State Income Tax	4,416	6,984	2,568
22	Payroll & Other	29,409	27,550	(1,859)
23	Total Taxes	$362,322	$408,277	$45,955
24	**Total Expenses**	$3,155,960	$3,262,048	$106,088
25	AFUDC	$29,355	$33,283	$3,928
26	**Total Operating Income**	$515,037	$586,925	$71,888

Note: Revenues reflect calendar month sales.

OPERATING INCOME SCHEDULES
JURISDICTIONAL STATEMENT OF OPERATING INCOME
($000's)

Line No.	Description	Adjusted (1) Most Recent Fiscal Year 2014 (B)	Adjusted (1) Projected Fiscal Year 2015 (B)	Unadjusted Test Year 2016 (C)	Adjusted (1) Proposed Test Year 2016 (D)
	Operating Revenues				
1	Retail	$2,923,494	$2,971,036	$3,113,282	$3,033,285
2	CIP Revenue Adjustment	0	0	$0	$0
3	Interdepartmental & Transportation	937	763	$798	$809
4	Other Operating	591,100	589,842	$766,339	$586,984
5	Gross Earnings Tax	0	0	$0	$0
6	**Total Operating Revenues**	$3,515,532	$3,561,641	$3,880,419	$3,621,078
	Expenses				
	Operating Expenses:				
7	Fuel & Purchased Energy	$1,139,367	$998,819	$1,078,508	$1,001,096
8	Power Production	704,206	698,539	$689,903	$681,521
9	Transmission	172,943	193,173	$311,312	$205,186
10	Distribution	102,974	99,054	$108,023	$108,023
11	Customer Accounting	49,664	48,860	$50,044	$49,315
12	Customer Service & Information	122,270	91,643	$87,584	$91,110
13	Sales, Econ Dvlp & Other	39	108	$6	$69
14	Administrative & General	206,850	205,938	$225,485	$206,579
15	Total Operating Expenses	$2,498,313	$2,336,135	$2,550,866	$2,342,900
16	Depreciation	$269,372	$384,847	$473,932	$471,286
17	Amortizations	$26,506	$22,748	$46,148	$39,585
	Taxes:				
18	Property	$149,092	$165,558	$189,976	$186,751
19	Gross Earnings	0	0	$0	$0
20	Deferred Income Tax & ITC	103,224	143,140	$203,731	$186,991
21	Federal & State Income Tax	39,550	14,935	($76,438)	($73,527)
22	Payroll & Other	28,065	29,626	$27,599	$27,550
23	Total Taxes	$319,931	$353,259	$344,868	$327,766
24	**Total Expenses**	$3,114,121	$3,096,989	$3,415,813	$3,181,537
25	AFUDC	31,170	32,189	33,560	33,283
26	**Total Operating Income**	$432,581	$496,841	$498,165	$472,824

Note: Revenues reflect calendar month sales.

(1) Revenues and expenses for Transmission Cost Recovery (TCR) rider have been excluded.

RATE BASE SCHEDULES: CWIP and ADIT Summary

Detailed Rate Base Components
($000's)

		Proposed Test Year 2016					
		Total Utility			Minnesota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$10,656,624	($100,298)	$10,556,326	$9,293,468	($100,685)	$9,192,783
2	Transmission	3,329,231	(215,708)	3,113,523	2,906,669	(215,708)	2,690,961
3	Distribution	3,739,105	0	3,739,105	3,272,959	0	3,272,959
4	General	833,164	0	833,164	727,748	0	727,748
5	Common	619,353	0	619,353	540,996	0	540,996
6	TOTAL Utility Plant in Service	$19,177,477	($316,006)	$18,861,471	$16,741,841	($316,393)	$16,425,447
	Reserve for Depreciation						
7	Production	$5,667,812	$687	$5,668,499	$4,947,014	$576	$4,947,590
8	Transmission	655,194	(3,513)	651,681	554,837	(3,513)	551,324
9	Distribution	1,385,972	1,660	1,387,632	1,231,334	1,660	1,232,993
10	General	305,460	1,378	306,838	266,556	1,204	267,760
11	Common	306,809	111	306,920	267,994	97	268,091
12	TOTAL Reserve for Depreciation	$8,321,247	$323	$8,321,570	$7,267,735	$24	$7,267,758
	Net Utility Plant in Service						
13	Production	$4,988,812	($100,985)	$4,887,827	$4,346,455	($101,262)	$4,245,193
14	Transmission	2,674,037	(212,195)	2,461,842	2,351,832	(212,195)	2,139,637
15	Distribution	2,353,133	(1,660)	2,351,473	2,041,625	(1,660)	2,039,966
16	General	527,704	(1,378)	526,326	461,192	(1,204)	459,988
17	Common	312,544	(111)	312,433	273,002	(97)	272,905
18	Net Utility Plant in Service	$10,856,230	($316,329)	$10,539,901	$9,474,106	($316,418)	$9,157,688
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$621,795	($97,690)	$524,106	$541,694	($97,282)	$444,412
21	Less: Accumulated Deferred Income Taxes	$2,308,728	($73,203)	$2,235,525	$2,043,563	($63,790)	$1,979,773
22	Cash Working Capital	($135,081)	$14,634	($120,447)	($121,170)	$13,041	($108,129)
	Other Rate Base Items:						
23	Materials and Supplies	$155,470	$0	$155,470	$135,797	$0	$135,797
24	Fuel Inventory	84,138	0	84,138	73,476	0	73,476
25	Non-Plant Assets & Liabilities	(4,275)	0	(4,275)	(3,716)	0	(3,716)
26	Prepayments	19,800	0	19,800	17,295	0	17,295
27	Nuclear Outage Amortization	79,971	0	79,971	69,844	0	69,844
28	Customer Advances	(8,227)	0	(8,227)	(5,562)	0	(5,562)
29	Interest on Customer Deposits	(28,480)	0	(28,480)	(28,127)	0	(28,127)
30	Sherco 3 Deferral	0	9,308	9,308	0	9,308	9,308
31	PI EPU Amortization	0	51,433	51,433	0	51,433	51,433
32	Other Working Capital	2,497	0	2,497	2,168	0	2,168
33	Total Other Rate Base Items	$300,894	$60,741	$361,634	$261,175	$60,741	$321,916
34	Total Average Rate Base	$9,335,111	($265,441)	$9,069,669	$8,112,243	($276,128)	$7,836,114

COMPARISON OF DETAILED RATE BASE COMPONENTS: CWIP

Test Year Ending December 31, 2016
($000's)

		Proposed Test Year 2016					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
1	Production	$435,594	($35,844)	$399,750	$380,411	($35,438)	$344,973
2	Transmission	75,475	(61,845)	13,630	66,002	(61,844)	4,158
3	Distribution	23,234	0	23,234	18,858	0	18,858
4	General	34,455	0	34,455	30,096	0	30,096
5	Common	53,037	0	53,037	46,327	0	46,327
6	TOTAL Construction Work In Progress	$621,795	($97,689)	$524,106	$541,694	($97,282)	$444,412

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

COMPARISON OF DETAILED RATE BASE COMPONENTS: ADIT

Test Year Ending December 31, 2016
($000's)

		Proposed Test Year 2016					
		Total Utility			Minnesota Jurisdiction *		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	$1,152,331	$4,578	$1,156,909	$1,000,339	$6,959	$1,007,298
2	Transmission	645,502	(37,382)	608,120	570,742	(36,334)	534,408
3	Distribution	649,355	(6,187)	643,168	574,673	(5,335)	569,338
4	General	80,498	138	80,636	70,422	113	70,535
5	Common	40,649	(709)	39,940	35,507	(619)	34,888
6	Net Operating Loss (NOL)	(254,681)	(33,641)	(288,321)	(203,825)	(28,573)	(232,398)
7	Non-Plant Related	(4,926)	0	(4,926)	(4,295)	0	(4,295)
8	TOTAL Accum Deferred Income Taxes	$2,308,728	($73,203)	$2,235,525	$2,043,563	($63,790)	$1,979,773

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

Northern States Power Company
State of Minnesota Electric Jurisdiction
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2016 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

		Base			Data Update	Adjustment		Amortization		Rider Removals		Secondary Calculations				
Line No.	Description	Unadjusted w/o NOL & 199	Unadjusted NOL & 199	Total Unadjusted	Black Dog Screenhouse	Like Kind Exchange Program	Remaining Life Study: NSPM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss & 199	2016 Test Year
	Work Paper Reference		**WP A-41**		**WP A-1**	**WP A-20**	**WP A-25**	**WP A-31**	**WP A-33**	**WP A-35**	**WP A-36**	**WP A-38**	**WP A-39**	**WP A-40**	**WP A-41**	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Plant as booked															
2	Production	9,293,468		9,293,468	2,676					(103,361)						9,192,783
3	Transmission	2,906,669		2,906,669						(5,371)	(210,336)					2,690,961
4	Distribution	3,272,959		3,272,959												3,272,959
5	General	727,748		727,748												727,748
6	Common	540,996		540,996												540,996
7	Total Utility Plant in Service	16,741,841		16,741,841	2,676					(108,733)	(210,336)					16,425,447
8																
9	Reserve for Depreciation															
10	Production	4,947,014		4,947,014	136		630			(190)						4,947,590
11	Transmission	554,837		554,837						(31)	(3,482)					551,324
12	Distribution	1,231,334		1,231,334		1,660										1,232,993
13	General	266,556		266,556		1,204										267,760
14	Common	267,994		267,994		97										268,091
15	Total Reserve for Depreciation	7,267,735		7,267,735	136	2,961	630			(221)	(3,482)					7,267,758
16																
17	Net Utility Plant															
18	Production	4,346,455		4,346,455	2,540		(630)			(103,171)						4,245,193
19	Transmission	2,351,832		2,351,832						(5,341)	(206,854)					2,139,637
20	Distribution	2,041,625		2,041,625		(1,660)										2,039,966
21	General	461,192		461,192		(1,204)										459,988
22	Common	273,002		273,002		(97)										272,905
23	Net Utility Plant in Service	9,474,106		9,474,106	2,540	(2,961)	(630)			(108,512)	(206,854)					9,157,689
24																
25	Utility Plant Held for Future Use															
26																
27	Construction Work in Progress	541,694		541,694	(2,814)					(33,002)	(61,466)					444,412
28																
29	Less: Accumulated Deferred Income Taxes	1,989,557	54,005	2,043,563	(2)		(257)	21,026	3,799	(7,398)	(26,865)	(57,910)			3,818	1,979,773
30																
31	Other Rate Base Items															
32	Cash Working Capital	(121,170)		(121,170)									13,041			(108,129)
33	Materials and Supplies	135,797		135,797												135,797
34	Fuel Inventory	73,476		73,476												73,476
35	Non Plant Assets and Liabilities	(3,716)		(3,716)												(3,716)
36	Customer Advances	(5,562)		(5,562)												(5,562)
37	Customer Deposits	(28,127)		(28,127)												(28,127)
38	Prepayments	89,307		89,307												89,307
39	Regulatory Amortizations							51,433	9,308							60,741
40	Total Other Rate Base	140,005		140,005				51,433	9,308				13,041			213,787
41																
42	Total Average Rate Base	8,166,248	(54,005)	8,112,243	(272)	(2,961)	(373)	30,407	5,509	(134,116)	(241,455)	57,910	13,041		(3,818)	7,836,115

Northern States Power Company
State of Minnesota Electric Jurisdiction
INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2016 Unadjusted Test Year versus 2016 Adjusted Test Year
($000's)

		Base			Data Update	Precedential											
Line No.	Description	Unadjusted w/o NOL & 199	Unadjusted NOL & 199	Total Unadjusted	Black Dog Screenhouse	Advertising	Customer Deposits Expense	Dues: Chamber of Commerce	Dues: Professional Associations	Economic Development Admin	Economic Development Donations	Foundation Admin	Foundation and Other Donations	Incentive Compensation	Investor Relations	Monticello LCM/EPU Return	Nobles Amounts over CON
	Work Paper Reference		WP A-41		WP A-1	WP A-2	WP A-3	WP A-4	WP A-5	WP A-6	WP A-7	WP A-8	WP A-9	WP A-10	WP A-11	WP A-12	WP A-13
1		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
2	Operating Revenues																
3	Retail Revenue	3,113,282		3,113,282													
4	Interdepartmental	798		798													
5	Other Operating	766,339		766,339	106											19,708	288
6	Total Revenue	3,880,419		3,880,419	106											19,708	288
7																	
8	Expenses																
9	Operating Expenses																
10	Fuel & Purchased Energy	1,078,508		1,078,508										(589)			
11	Power Production	689,903		689,903										(2,502)			
12	Transmission	311,312		311,312													
13	Distribution	108,023		108,023													
14	Customer Accounting	50,044		50,044													
15	Customer Service and Information	87,584		87,584		(43)											
16	Sales, Econ Dev, & Other	6		6						8	54						
17	Administrative and General	225,485		225,485		(2,647)	1	220	(19)			(273)	1,625	(9,554)	(469)		
18	Total Operating Expenses	2,550,866		2,550,866		(2,690)	1	220	(19)	8	54	(273)	1,625	(12,645)	(469)		
19																	
20	Depreciation	473,932		473,932	287												
21	Amortization	46,148		46,148													
22																	
23	Taxes																
24	Property	189,976		189,976													
25	Deferred Income Tax and ITC	117,336	86,395	203,731	(4)												
26	Federal and State Income Tax	11,562	(88,000)	(76,438)	(104)	1,113	(0)	(91)	8	(3)	(22)	116	(672)	5,231	197	8,153	119
27	Payroll and Other	27,599		27,599								(8)			(6)		
28	Total Taxes	346,473	(1,605)	344,868	(107)	1,113	(0)	(91)	8	(3)	(22)	108	(672)	5,231	191	8,153	119
29																	
30	Total Expenses	3,417,418	(1,605)	3,415,813	180	(1,577)	0	129	(11)	5	32	(165)	953	(7,414)	(278)	8,153	119
31																	
32	Allowance for Funds Used During Construction	33,560		33,560	(276)												
33																	
34	Total Operating Income	496,561	1,605	498,165	(350)	1,577	(0)	(129)	11	(5)	(32)	165	(953)	7,414	278	11,555	169
35																	
36	Calculation of Revenue Requirements																
37	Rate Base	8,166,248	(54,005)	8,112,243	(272)												
38	Required Operating Income	599,403	(3,964)	595,439	(20)												
39	Operating Income	496,561	1,605	498,165	(350)	1,577	(0)	(129)	11	(5)	(32)	165	(953)	7,414	278	11,555	169
40	Income Deficiency	102,842	(5,568)	97,274	330	(1,577)	0	129	(11)	5	32	(165)	953	(7,414)	(278)	(11,555)	(169)
41	**Revenue Deficiency**	**175,409**	**(9,498)**	**165,911**	**563**	**(2,690)**	**1**	**220**	**(19)**	**8**	**54**	**(281)**	**1,625**	**(12,645)**	**(475)**	**(19,708)**	**(288)**
42																	
43	Calculation of Income Taxes																
44	Operating Revenue	3,880,419		3,880,419	106											19,708	288
45	-Operating Expense	2,550,866		2,550,866		(2,690)	1	220	(19)	8	54	(273)	1,625	(12,645)	(469)		
46	-Amortization	46,148		46,148													
47	-Taxes Other then Income	217,575		217,575								(8)			(6)		
48	Operating Income Before Adjs	1,065,830		1,065,830	106	2,690	(1)	(220)	19	(8)	(54)	281	(1,625)	12,645	475	19,708	288
49	Additions to Income	183,981		183,981	(165)												
50	Deductions from Income	933,933	301,410	1,235,343	198												
51	Debt Synchonization	182,924	(1,210)	181,714	(6)												
52	State Taxable Income	132,954	(300,200)	(167,246)	(250)	2,690	(1)	(220)	19	(8)	(54)	281	(1,625)	12,645	475	19,708	288
53	State Income Tax Before Credits	13,030	(29,420)	(16,390)	(25)	264	(0)	(22)	2	(1)	(5)	28	(159)	1,239	47	1,931	28
54	State Tax Credits	559	559	1,118													
55	Federal Tax Deductions		1,748	1,748													
56	Federal Taxable Income	120,484	(271,970)	(151,486)	(226)	2,427	(0)	(198)	17	(7)	(49)	253	(1,466)	11,406	428	17,777	260
57	Federal Income Tax Before Credits	42,169	(95,189)	(53,020)	(79)	849	(0)	(69)	6	(3)	(17)	89	(513)	3,992	150	6,222	91
58	Federal Tax Credits	43,078	(37,168)	5,910													
59	Total Income Taxes	11,562	(88,000)	(76,438)	(104)	1,113	(0)	(91)	8	(3)	(22)	116	(672)	5,231	197	8,153	119

Northern States Power Company
State of Minnesota Electric Jurisdiction
INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2016 Unadjusted Test Year versus 2016 Adjusted Test Year
($000's)

		Adjustment															
Line No.	Description	Pension: Non Qualified	Aviation	Bad Debt Expense	CIP Approved Program Levels	CIP Incentive	Employee Expenses	Like Kind Exchange Program	Nuclear Retention	Other Revenue 3 Year Average	Retiree Medical: Discount Rate	Pension Smoothing	Remaining Life Study: NSPM	Remaining Life Study: NSPW	Trading: Asset-Based Margin	Trading: Non Asset-Based Admin	Trading: Non Asset-Based Margin
	Work Paper Reference	**WP A-14**	**WP A-15**	**WP A-16**	**WP A-17**	**WP A-18**	**WP A-19**	**WP A-20**	**WP A-21**	**WP A-22**	**WP A-23**	**WP A-24**	**WP A-25**	**WP A-26**	**WP A-27**	**WP A-28**	**WP A-29**
1		(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)
2	Operating Revenues																
3	Retail Revenue				(41,090)												
4	Interdepartmental				11												
5	Other Operating					21,227				1,123			195		(74,696)		(17,770)
6	Total Revenue				(41,080)	21,227				1,123			195		(74,696)		(17,770)
7																	
8	Expenses																
9	Operating Expenses																
10	Fuel & Purchased Energy														(57,476)		(14,671)
11	Power Production								(793)					(4,215)			
12	Transmission																
13	Distribution																
14	Customer Accounting			(729)													
15	Customer Service and Information				(41,080)	44,897											
16	Sales, Econ Dev, & Other																
17	Administrative and General	(1,410)	(1,906)				(1,613)				(376)	18				(985)	
18	Total Operating Expenses	(1,410)	(1,906)	(729)	(41,080)	44,897	(1,613)		(793)		(376)	18		(4,215)	(57,476)	(985)	(14,671)
19																	
20	Depreciation												1,261				
21	Amortization																
22																	
23	Taxes																
24	Property																
25	Deferred Income Tax and ITC												(515)				
26	Federal and State Income Tax	583	797	302	(0)	(9,792)	667	27	328	465	156	(7)	84	1,744	(7,124)	407	(1,282)
27	Payroll and Other		(19)														
28	Total Taxes	583	777	302	(0)	(9,792)	667	27	328	465	156	(7)	(430)	1,744	(7,124)	407	(1,282)
29																	
30	Total Expenses	(827)	(1,129)	(427)	(41,080)	35,104	(946)	27	(465)	465	(220)	11	831	(2,471)	(64,600)	(577)	(15,953)
31																	
32	Allowance for Funds Used During Construction																
33																	
34	Total Operating Income	827	1,129	427	(0)	(13,878)	946	(27)	465	658	220	(11)	(635)	2,471	(10,097)	577	(1,817)
35																	
36	Calculation of Revenue Requirements																
37	Rate Base							(2,961)					(373)				
38	Required Operating Income							(217)					(27)				
39	Operating Income	827	1,129	427	(0)	(13,878)	946	(27)	465	658	220	(11)	(635)	2,471	(10,097)	577	(1,817)
40	Income Deficiency	(827)	(1,129)	(427)	0	13,878	(946)	(190)	(465)	(658)	(220)	11	608	(2,471)	10,097	(577)	1,817
41	**Revenue Deficiency**	**(1,410)**	**(1,925)**	**(729)**	**0**	**23,670**	**(1,613)**	**(324)**	**(793)**	**(1,123)**	**(376)**	**18**	**1,037**	**(4,215)**	**17,221**	**(985)**	**3,099**
42																	
43	Calculation of Income Taxes																
44	Operating Revenue				(41,080)	21,227				1,123			195		(74,696)		(17,770)
45	-Operating Expense	(1,410)	(1,906)	(729)	(41,080)	44,897	(1,613)		(793)		(376)	18		(4,215)	(57,476)	(985)	(14,671)
46	-Amortization																
47	-Taxes Other then Income		(19)														
48	Operating Income Before Adjs	1,410	1,925	729	(0)	(23,670)	1,613		793	1,123	376	(18)	195	4,215	(17,221)	985	(3,099)
49	Additions to Income																
50	Deductions from Income																
51	Debt Synchonization							(66)					(8)				
52	State Taxable Income	1,410	1,925	729	(0)	(23,670)	1,613	66	793	1,123	376	(18)	204	4,215	(17,221)	985	(3,099)
53	State Income Tax Before Credits	138	189	71	(0)	(2,320)	158	6	78	110	37	(2)	20	413	(1,688)	97	(304)
54	State Tax Credits																
55	Federal Tax Deductions																
56	Federal Taxable Income	1,272	1,737	657	(0)	(21,351)	1,455	60	715	1,013	339	(16)	184	3,802	(15,533)	888	(2,795)
57	Federal Income Tax Before Credits	445	608	230	(0)	(7,473)	509	21	250	355	119	(6)	64	1,331	(5,437)	311	(978)
58	Federal Tax Credits																
59	Total Income Taxes	583	797	302	(0)	(9,792)	667	27	328	465	156	(7)	84	1,744	(7,124)	407	(1,282)

Northern States Power Company
State of Minnesota Electric Jurisdiction
INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES
2016 Unadjusted Test Year versus 2016 Adjusted Test Year
($000's)

Line No.	Description	XES Allocation on Labor Hours	Amortization: PI EPU Recovery	Amortization: Rate Case Expenses	Amortization: Sherco 3 Depr Deferral	Amortization: Transco Costs	Rider Removals: Rider: RES	Rider Removals: Rider: TCR	Rider Removals: Windsource	Secondary Calculations: ADIT Prorate for IRS	Secondary Calculations: Cash Working Capital	Secondary Calculations: Change in Cost of Capital	Secondary Calculations: Net Operating Loss & 199	2016 Test Year
	Work Paper Reference	WP A-30	WP A-31	WP A-32	WP A-33	WP A-34	WP A-35	WP A-36	WP A-37	WP A-38	WP A-39	WP A-40	WP A-41	
1		(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)
2	Operating Revenues													
3	Retail Revenue						(17,262)	(21,646)						3,033,285
4	Interdepartmental													809
5	Other Operating		2,694					(127,085)	(5,145)					586,984
6	Total Revenue		2,694				(17,262)	(148,730)	(5,145)					3,621,078
7														
8	Expenses													
9	Operating Expenses													
10	Fuel & Purchased Energy								(4,676)					1,001,096
11	Power Production						(872)							681,521
12	Transmission						(201)	(105,925)						205,186
13	Distribution													108,023
14	Customer Accounting													49,315
15	Customer Service and Information								(248)					91,110
16	Sales, Econ Dev, & Other													69
17	Administrative and General	(1,461)				(46)			(9)					206,579
18	Total Operating Expenses	(1,461)				(46)	(1,072)	(105,925)	(4,932)					2,342,900
19														
20	Depreciation						(441)	(3,752)						471,286
21	Amortization		2,884	1,113	503		(1,355)	(9,708)						39,585
22														
23	Taxes													
24	Property							(3,225)						186,751
25	Deferred Income Tax and ITC		(1,179)		(205)		(15,200)	(2,651)					3,013	186,991
26	Federal and State Income Tax	610	833	(461)	(51)	19	10,723	(5,882)	(87)	(537)	(121)		(3,534)	(73,527)
27	Payroll and Other	(14)							(2)					27,550
28	Total Taxes	596	(346)	(461)	(256)	19	(4,477)	(11,758)	(89)	(537)	(121)		(520)	327,766
29														
30	Total Expenses	(865)	2,538	653	247	(27)	(7,346)	(131,144)	(5,021)	(537)	(121)		(520)	3,181,537
31														
32	Allowance for Funds Used During Construction													33,283
33														
34	Total Operating Income	865	156	(653)	(247)	27	(9,916)	(17,586)	(123)	537	121		520	472,824
35														
36	Calculation of Revenue Requirements													
37	Rate Base		30,407		5,509		(134,116)	(241,455)		57,910	13,041		(3,818)	7,836,115
38	Required Operating Income		2,232		404		(9,844)	(17,723)		4,251	957	11,754	(280)	586,925
39	Operating Income	865	156	(653)	(247)	27	(9,916)	(17,586)	(123)	537	121		520	472,824
40	Income Deficiency	(865)	2,075	653	651	(27)	72	(136)	123	3,714	836	11,754	(800)	114,101
41	**Revenue Deficiency**	**(1,475)**	**3,540**	**1,113**	**1,110**	**(46)**	**122**	**(233)**	**210**	**6,335**	**1,427**	**20,048**	**(1,365)**	**194,612**
42														
43	Calculation of Income Taxes													
44	Operating Revenue		2,694				(17,262)	(148,730)	(5,145)					3,621,078
45	-Operating Expense	(1,461)				(46)	(1,072)	(105,925)	(4,932)					2,342,900
46	-Amortization		2,884	1,113	503		(1,355)	(9,708)						39,585
47	-Taxes Other then Income	(14)						(3,225)	(2)					214,302
48	Operating Income Before Adjs	1,475	(190)	(1,113)	(503)	46	(14,834)	(29,872)	(210)					1,024,290
49	Additions to Income		2,884		503		(4,897)	(2,054)						180,252
50	Deductions from Income						(42,585)	(12,299)					(5,664)	1,174,993
51	Debt Synchonization		681		123		(3,004)	(5,409)		1,297	292		(86)	175,529
52	State Taxable Income	1,475	2,013	(1,113)	(123)	46	25,858	(14,219)	(210)	(1,297)	(292)		5,749	(145,980)
53	State Income Tax Before Credits	145	197	(109)	(12)	5	2,534	(1,393)	(21)	(127)	(29)		563	(14,306)
54	State Tax Credits													1,118
55	Federal Tax Deductions												1,678	3,426
56	Federal Taxable Income	1,330	1,816	(1,004)	(111)	42	23,324	(12,826)	(190)	(1,170)	(263)		3,508	(133,982)
57	Federal Income Tax Before Credits	466	636	(351)	(39)	15	8,163	(4,489)	(66)	(410)	(92)		1,228	(46,894)
58	Federal Tax Credits						(26)						5,325	11,209
59	Total Income Taxes	610	833	(461)	(51)	19	10,723	(5,882)	(87)	(537)	(121)		(3,534)	(73,527)

Wholesale Customer Study

Purpose

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

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

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

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

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

Historic Wholesale Cost Assignment Method

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

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

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

Changes in Wholesale Market and Test Year Wholesale Customers

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

However, excess capacity and energy on a short to mid-term basis has increased competition and put downward pressure on pricing. Given the market dynamics, the Company's wholesale customers determined it was in their best interest to purchase energy on the open market rather than continuing service under cost based contracts. Where in the past, these customers mitigated energy cost volatility risk by entering into full requirements agreements with the Company, they now prefer to take on that risk themselves, given the current market environment. Therefore, the Company no longer has any cost-based requirements wholesale customers in the 2016 test year or the 2017 and 2018 plan years.

Services Provided to Wholesale Customers in 2016

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

Asset based transactions involve the sale of excess energy and capacity available from Company owned generation assets. Both costs and revenues associated with asset-based energy and capacity transactions are included in the unadjusted retail rate case cost of service, and all margins resulting from asset-based energy sales are excluded from the 2016 test year as they are returned to the ratepayers through the Fuel Clause Adjustment pursuant the Company's 2005 electric rate case (Docket No. E002/GR-05-1428).

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

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

Attachment A to this schedule provides a list of the types of services provided, and the ratemaking treatment for each type of service. Attachment B to this schedule provides a wholesale customer summary including all current agreements by customer and the expected revenues for the years 2016-2018.

Test Year Wholesale Transactions

During 2016, the Company expects to engage in wholesale transactions in the following categories: asset based energy sales, asset based capacity sales, non-asset based sales and other wholesale transactions including MISO interface and scheduling services, energy services agreements, and pass through charges. These transactions and their impact on the test year are discussed below.

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

Table 1 below shows the asset based energy sales margins for 2014 and 2016. In addition, Volume 4 Test Year Workpapers, Section VIII Adjustments, Tab A27 includes all calculations related to asset based transactions and their impact on the test year. The revenues associated with these trades flow through to Other Electric

Revenues in the income statement as shown in Workpapers Vol 4, Tab R2 : "SALES FOR RESALE – BILED MKT ASSET REV."

Table 1

Asset Based Energy Sales Transactions

State of Minnesota Jurisdiction	2014	2016 Budget
Revenues	$67.4M	$65.6M
COGS *	($50.6M)	($48.4M)
Margin	**$16.9M**	**$17.2M**

*COGS Information includes Revenue Sharing Thru the FCA

Asset Based Capacity Sales Transactions
Revenues for asset based capacity sales are included in the cost of service and are not included in the asset based margin adjustment (which includes only the net margin for asset based energy sales). These capacity sales revenues, labeled "OTHER ELEC REV – Zonal Resource Credits (ZRC)" and totaling $883,180 are included in Other Electric Revenues in the income statement as shown in Workpapers Vol 4, Tab R2.

Non-Asset Based Transactions
Non-asset based transactions are not included in the retail rate case: revenues and their associated fully allocated embedded costs are removed from the cost of service, and all margins are retained by the Company pursuant to the settlement in the Company's 2011 rate case (Docket No. E002/GR-10-971) . These adjustments are discussed by Company witness Ms. Anne E. Heuer in her Direct Testimony, Section VII, Adjustments to the Test Year.

Other Wholesale Transactions
This category includes the three types of wholesale customer agreements not included in the asset based and non-asset based categories: MISO Interface/Scheduling, Energy Services Agreements, and Pass Through Charges (for a detailed explanation of each category, please see Attachment A to this schedule). In each case, revenues and costs associated with these transactions are included in the rate case, and no adjustment is made to the income statement or cost of service. As shown in Attachment B to this schedule, revenues from Other Wholesale Transactions are expected to be $549,440 in

2016. These revenues flow into Other Operating Revenue as shown in Workpapers Vol 4, Tab R2, labeled "OTHER ELEC REV – Transmission Sales."

Conclusions

After reviewing the services anticipated to be provided to wholesale customers in 2016 and the transactions associated with those services, the Company concludes that the ratemaking treatment of these transactions is consistent with existing regulatory practices:

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

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

PUBLIC DOCUMENT – TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

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

Wholesale Customer Study
as of August 3, 2015

Background information

Energy deals

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

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

Capacity deals

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

Non-Asset Based Capacity Sales — A deal in the non asset capacity deals column (i.e. Cargill capacity) is for the sale of MISO ZRCs that are backed by the purchase of a like product.

Other deals

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

Energy Services Agreement — The deal in the energy services agreement **TRADE SECRET BEGINS** **TRADE SECRET ENDS** is the fee paid to NSP for the preservation of transmission reservations, which improves **TRADE SECRET BEGINS** **TRADE SECRET ENDS** ability to import and export power. The annual service fee payments are payable to NSP in advance of the service year.

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

2016

Counterparty	Contract term	Energy: Asset based: partial requirements 3	Energy: Non Asset: bilateral or market based	Capacity: Asset Capacity	Capacity: Non-Asset capacity	Other: MISO Interface Svcs & Scheduling Fees	Other: Energy Services Agreement	Other: Pass Through Charges
Revenues		[TRADE SECRET BEGINS						
Ada	1/1/13 - 12/31/16		1			A		2
Ada	1/1/13 - 12/31/16			A				
Kasota	1/1/13 - 12/31/16		1			A		2
Kasota	1/1/13 - 12/31/16			A				
NWEC	1/1/11 - 4/30/15							
NWEC	5/1/15 - 12/31/20	B	1			A		
NWEC	6/1/15 - 5/31/17			A				
NWEC	6/1/15 - 5/31/16			A				
NCP	5/1/15 - 12/31/20	B	1			A		
NCP	6/1/15 - 5/31/17			A				
CMMPA	11/8/11 - 4/30/16	B						
Dahlberg Light & Power Co.	1/1/14 - 12/31/16					A		
Dahlberg Light & Power Co.	1/1/17 - 12/31/18							
Dahlberg Light & Power Co.	6/1/14 - 5/31/17			A				
Dahlberg Light & Power Co.	6/1/15 - 5/31/16			A				
Dahlberg Light & Power Co.	1/1/14 - 12/31/18	B	1					
Minnesota Power	6/1/14 - 5/31/16			A				
Alliant/IPL	6/1/15 - 5/31/16			A				
Missouri River Energy Services	6/1/15 - 5/31/16			A				
Basin Electric Power Co.	6/1/14 - 5/31/19				1			
[TRADE SECRET BEGINS								
	5/1/09 - 4/30/25						A	
	6/1/15 - 5/31/25						A	
TRADE SECRET ENDS]								

2017

Counterparty	Contract term	Energy: Asset based: partial requirements 3	Energy: Non Asset: bilateral or market based	Capacity: Asset Capacity	Capacity: Non-Asset Capacity	Other: MISO Interface Svcs & Scheduling Fees	Other: Energy Services Agreement	Other: Pass Through Charges
Ada	1/1/13 - 12/31/16							
Ada	1/1/13 - 12/31/16							
Kasota	1/1/13 - 12/31/16							
Kasota	1/1/13 - 12/31/16							
NWEC	1/1/11 - 4/30/15							
NWEC	5/1/15 - 12/31/20	B	1			A		
NWEC	6/1/15 - 5/31/17			A				
NWEC	6/1/15 - 5/31/16							
NCP	5/1/15 - 12/31/20	B	1			A		
NCP	6/1/15 - 5/31/17			A				
CMMPA	11/8/11 - 4/30/16							
Dahlberg Light & Power Co.	1/1/14 - 12/31/16					A		
Dahlberg Light & Power Co.	1/1/17 - 12/31/18					A		
Dahlberg Light & Power Co.	6/1/14 - 5/31/17			A				
Dahlberg Light & Power Co.	6/1/15 - 5/31/16							
Dahlberg Light & Power Co.	1/1/14 - 12/31/18	B	1					
Minnesota Power	6/1/14 - 5/31/16							
Alliant/IPL	6/1/15 - 5/31/16							
Missouri River Energy Services	6/1/15 - 5/31/16							
Basin Electric Power Co.	6/1/14 - 5/31/19				1			
	5/1/09 - 4/30/25						A	
	6/1/15 - 5/31/25						A	

2018

Counterparty	Contract term	Energy: Asset based: partial requirements 3	Energy: Non Asset: bilateral or market based	Capacity: Asset capacity	Capacity: Non-Asset capacity	Other: MISO interface svcs & Scheduling Fees	Other: Energy services agreement	Other: Pass through charges
Ada	1/1/13 - 12/31/16							
Ada	1/1/13 - 12/31/16							
Kasota	1/1/13 - 12/31/16							
Kasota	1/1/13 - 12/31/16							
NWEC	1/1/11 - 4/30/15							
NWEC	5/1/15 - 12/31/20	B	1			A		
NWEC	6/1/15 - 5/31/17							
NWEC	6/1/15 - 5/31/16							
NCP	5/1/15 - 12/31/20	B	1			A		
NCP	6/1/15 - 5/31/17							
CMMPA	11/8/11 - 4/30/16							
Dahlberg Light & Power Co.	1/1/14 - 12/31/16							
Dahlberg Light & Power Co.	1/1/17 - 12/31/18					A		
Dahlberg Light & Power Co.	6/1/14 - 5/31/17							
Dahlberg Light & Power Co.	6/1/15 - 5/31/16							
Dahlberg Light & Power Co.	1/1/14 - 12/31/18	B	1					
Minnesota Power	6/1/14 - 5/31/16							
Alliant/IPL	6/1/15 - 5/31/16							
Missouri River Energy Services	6/1/15 - 5/31/16							
Basin Electric Power Co.	6/1/14 - 5/31/19				1			
	5/1/09 - 4/30/25						A	
	6/1/15 - 5/31/25						A	
								TRADE SECRET ENDS]

		2016							2017							2018						
		Energy		Capacity		Other			Energy		Capacity		Other			Energy		Capacity		Other		
Counterparty	Contract term	Asset based: partial requirements 3	Non Asset: bilateral or market based	Asset Capacity	Non-Asset capacity	MISO Interface Svcs & Scheduling Fees	Energy Services Agreement	Pass Through Charges	Asset based: partial requirements 3	Non Asset: bilateral or market based	Asset Capacity	Non-Asset Capacity	MISO Interface Svcs & Scheduling Fees	Energy Services Agreement	Pass Through Charges	Asset based: partial requirements 3	Non Asset: bilateral or market based	Asset capacity	Non-Asset capacity	MISO interface svcs & Scheduling Fees	Energy services agreement	Pass through charges
Costs																						
Ada	1/1/13 - 12/31/16		1			5		2														
Ada	1/1/13 - 12/31/16			4																		
Kasota	1/1/13 - 12/31/16		1			5		2														
Kasota	1/1/13 - 12/31/16			4																		
NWEC	1/1/11 - 4/30/15																					
NWEC	5/1/15 - 12/31/20	3	1			5			3	1			5			3	1			5		
NWEC	6/1/15 - 5/31/17			4							4											
NWEC	6/1/15 - 5/31/16			4																		
NCP	5/1/15 - 12/31/20	3	1			5			3	1			5			3	1			5		
NCP	6/1/15 - 5/31/17			4							4											
CMMPA	11/8/11 - 4/30/16	3																				
Dahlberg Light & Power Co.	1/1/14 - 12/31/16					5																
Dahlberg Light & Power Co.	1/1/17 - 12/31/18												5							5		
Dahlberg Light & Power Co.	6/1/14 - 5/31/17			4							4											
Dahlberg Light & Power Co.	6/1/15 - 5/31/16			4																		
Dahlberg Light & Power Co.	1/1/14 - 12/31/18	3	1						3	1						3	1					
Minnesota Power	6/1/14 - 5/31/16			4																		
Alliant/IPL	6/1/15 - 5/31/16			4																		
Missouri River Energy Services	6/1/15 - 5/31/16			4																		
Basin Electric Power Co.	6/1/14 - 5/31/19				1							1							1			
[TRADE SECRET BEGINS																						
	5/1/09 - 4/30/25						6							6							6	
	6/1/15 - 5/31/25						6							6							6	
TRADE SECRET ENDS]																						
Total Revenues Flowing to Other Electric Revenue																						

1 NSPM's proprietary book budget after joint operating agreement is targeted at an approximate $3.5 million trade margin for each year shown above. This transaction is part of the proprietary budget target however we do not specifically identify the revenue and cost of the deals that fall within the $3.5M, therefore this information is not presented within this analysis. The margin of this transaction is not shared with Minnesota.

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

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

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

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

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

A This amount agrees to either the "NSP Capacity ZRC Revenue" or "NSP Service Fee Revenue" budget file without exception.

B The budgeted gen book margin for 2016 - 2018 is $27.1M, $22.8M, and $23.3M, respectively. The budgeted amounts are a subset of this budget and are not budgeted on a contract by contract basis.

C The amounts are not included in the 2017 and 2018 budget due to timing of deal execution (i.e. deal was executed after preparation of 2016-2020 budget)

CAPACITY COST STUDY
NSP Summary

Long-Term Purchased Power Capacity Cost Forecast by Contract - Minnesota 2016 Rate Case Filing

	Byllesby 1	Byllesby 2	Hastings	HERC*	LSP	MH.Part	MPC.Coy**	Neshonoc	Rapidan***	St.Cloud	Mankato	Mankato II****	Cannon Falls	Total $000
	[TRADE SECRET BEGINS													
2016 Jan														
2016 Feb														
2016 Mar														
2016 Apr														
2016 May														
2016 Jun														
2016 Jul														
2016 Aug														
2016 Sep														
2016 Oct														
2016 Nov														
2016 Dec														
2017 Jan														
2017 Feb														
2017 Mar														
2017 Apr														
2017 May														
2017 Jun														
2017 Jul														
2017 Aug														
2017 Sep														
2017 Oct														
2017 Nov														
2017 Dec														
2018 Jan														
2018 Feb														
2018 Mar														
2018 Apr														
2018 May														
2018 Jun														
2018 Jul														
2018 Aug														
2018 Sep														
2018 Oct														
2018 Nov														
2018 Dec														
2016														154,140
2017														149,256
2018														144,685
													TRADE SECRET ENDS]	

*The contract with HERC terminates December 31, 2017
**The contract with MPC terminated in 2015
***The contract with Rapidan terminates April 30, 2017
****The contract with Makato II begins in 2018

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

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

Calculation Maps are included for each following page.

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

CAPACITY COST STUDY
NSP Summary

[TRADE SECRET BEGINS

	A	B	C	D = A+B+C	E	F	D*E*F/1000
2016 Jan							
2016 Feb							
2016 Mar							
2016 Apr							
2016 May							
2016 Jun							
2016 Jul							
2016 Aug							
2016 Sep							
2016 Oct							
2016 Nov							
2016 Dec							
2017 Jan							
2017 Feb							
2017 Mar							
2017 Apr							
2017 May							
2017 Jun							
2017 Jul							
2017 Aug							
2017 Sep							
2017 Oct							
2017 Nov							
2017 Dec							
2018 Jan							
2018 Feb							
2018 Mar							
2018 Apr							
2018 May							
2018 Jun							
2018 Jul							
2018 Aug							
2018 Sep							
2018 Oct							
2018 Nov							
2018 Dec							

TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = A+B+C	E	F	D*E*F/1000
	[TRADE SECRET BEGINS						
2016 Jan							
2016 Feb							
2016 Mar							
2016 Apr							
2016 May							
2016 Jun							
2016 Jul							
2016 Aug							
2016 Sep							
2016 Oct							
2016 Nov							
2016 Dec							
2017 Jan							
2017 Feb							
2017 Mar							
2017 Apr							
2017 May							
2017 Jun							
2017 Jul							
2017 Aug							
2017 Sep							
2017 Oct							
2017 Nov							
2017 Dec							
2018 Jan							
2018 Feb							
2018 Mar							
2018 Apr							
2018 May							
2018 Jun							
2018 Jul							
2018 Aug							
2018 Sep							
2018 Oct							
2018 Nov							
2018 Dec							
							TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

[TRADE SECRET BEGINS

	A	B	C = A+B	D	F	C*D*F/1000
2016 Jan						
2016 Feb						
2016 Mar						
2016 Apr						
2016 May						
2016 Jun						
2016 Jul						
2016 Aug						
2016 Sep						
2016 Oct						
2016 Nov						
2016 Dec						
2017 Jan						
2017 Feb						
2017 Mar						
2017 Apr						
2017 May						
2017 Jun						
2017 Jul						
2017 Aug						
2017 Sep						
2017 Oct						
2017 Nov						
2017 Dec						
2018 Jan						
2018 Feb						
2018 Mar						
2018 Apr						
2018 May						
2018 Jun						
2018 Jul						
2018 Aug						
2018 Sep						
2018 Oct						
2018 Nov						
2018 Dec						

TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

	A	B	C	D	E = (A+B+C)*(1+D)	F	RCF	E*F/1000*(RCF/70%)
	[TRADE SECRET BEGINS							
2016 Jan								
2016 Feb								
2016 Mar								
2016 Apr								
2016 May								
2016 Jun								
2016 Jul								
2016 Aug								
2016 Sep								
2016 Oct								
2016 Nov								
2016 Dec								
2017 Jan								
2017 Feb								
2017 Mar								
2017 Apr								
2017 May								
2017 Jun								
2017 Jul								
2017 Aug								
2017 Sep								
2017 Oct								
2017 Nov								
2017 Dec								
Contract ends								Contract ends
								TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = B*C	E	F	G	H	I	J	K	L = (A*(D+E+F)*G*H*I*K+J)/12/1000	M	L-M
	[TRADE SECRET BEGINS													
2016 Jan														
2016 Feb														
2016 Mar														
2016 Apr														
2016 May														
2016 Jun														
2016 Jul														
2016 Aug														
2016 Sep														
2016 Oct														
2016 Nov														
2016 Dec														
2017 Jan														
2017 Feb														
2017 Mar														
2017 Apr														
2017 May														
2017 Jun														
2017 Jul														
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2018 Apr														
2018 May														
2018 Jun														
2018 Jul														
2018 Aug														
2018 Sep														
2018 Oct														
2018 Nov														
2018 Dec														

TRADE SECRET ENDS]

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

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

[TRADE SECRET BEGINS

	A	B	C	D	A*B*C*D/1000
2016 Jan					
2016 Feb					
2016 Mar					
2016 Apr					
2016 May					
2016 Jun					
2016 Jul					
2016 Aug					
2016 Sep					
2016 Oct					
2016 Nov					
2016 Dec					
2017 Jan					
2017 Feb					
2017 Mar					
2017 Apr					
2017 May					
2017 Jun					
2017 Jul					
2017 Aug					
2017 Sep					
2017 Oct					
2017 Nov					
2017 Dec					
2018 Jan					
2018 Feb					
2018 Mar					
2018 Apr					
2018 May					
2018 Jun					
2018 Jul					
2018 Aug					
2018 Sep					
2018 Oct					
2018 Nov					
2018 Dec					

TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

[TRADE SECRET BEGINS

	A	B	C	D = A+B+C	E	F = D*E/1000	G	H	I = G*H/1000	F+I
2016 Jan										
2016 Feb										
2016 Mar										
2016 Apr										
2016 May										
2016 Jun										
2016 Jul										
2016 Aug										
2016 Sep										
2016 Oct										
2016 Nov										
2016 Dec										
2017 Jan										
2017 Feb										
2017 Mar										
2017 Apr										
Contract ends										Contract ends

TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

[TRADE SECRET BEGINS

	A	B	C	D = A+B+C	E	F	D*E*F/1000-4.16667
2016 Jan							
2016 Feb							
2016 Mar							
2016 Apr							
2016 May							
2016 Jun							
2016 Jul							
2016 Aug							
2016 Sep							
2016 Oct							
2016 Nov							
2016 Dec							
2017 Jan							
2017 Feb							
2017 Mar							
2017 Apr							
2017 May							
2017 Jun							
2017 Jul							
2017 Aug							
2017 Sep							
2017 Oct							
2017 Nov							
2017 Dec							
2018 Jan							
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2018 Mar							
2018 Apr							
2018 May							
2018 Jun							
2018 Jul							
2018 Aug							
2018 Sep							
2018 Oct							
2018 Nov							
2018 Dec							

TRADE SECRET ENDS]

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

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

[TRADE SECRET BEGINS
Contracted Capacity (Net Capability) - KW: **A**

TRADE SECRET ENDS]

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	2006	2007	2008	2009	2010	2011	2012	2013	2014	**2015**	**2016**	**2017**	**2018**	2019	2020

[TRADE SECRET BEGINS
B
C
TRADE SECRET ENDS]

Contract Capacity Payment Factors:
[TRADE SECRET BEGINS
D
E
TRADE SECRET ENDS]

2016 Fixed Charges:		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
[TRADE SECRET BEGINS														
	=A*B*D													
	=A*C*E													

2017 Fixed Charges:		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
[TRADE SECRET BEGINS														
	=A*B*D													
	=A*C*E													

2018 Fixed Charges:		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
[TRADE SECRET BEGINS														
	=A*B*D													
	=A*C*E													

TRADE SECRET ENDS]

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

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

[TRADE SECRET BEGINS

Contracted Capacity (Net Capability) - KW: **A**

TRADE SECRET ENDS]

		1	2	3	4	5	6	7	8	9	10	11	12	13
		2018	2019	2020	2021	2022	2023	2024	2025	2026	**2027**	**2028**	**2029**	**2030**
[TRADE SECRET BEGINS														
	B													
	C													

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

TRADE SECRET ENDS]

Contract Capacity Payment Factors:
[TRADE SECRET BEGINS

D
E

TRADE SECRET ENDS]

2018 Fixed Charges:		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
[TRADE SECRET BEGINS														
	=A*B*D													
	=A*C*E													

TRADE SECRET ENDS]

CAPACITY COST STUDY
NSP Summary

Purchaser: **Northern States Power**
Seller: **Invenergy Cannon Falls, LLC - Cannon Falls Energy Center**

[TRADE SECRET BEGINS

Expected Start Date:
Expected Termination Date:

TRADE SECRET ENDS]

[TRADE SECRET BEGINS

Contracted Capacity (Net Capability) - KW: A

Net Dependable Capability:

TRADE SECRET ENDS]

Fixed Charge Prices:	2008	2009	2010	2011	2012	2013	2014	**2015**	**2016**	**2017**	**2018**	2019	2020

[TRADE SECRET BEGINS

B
C

TRADE SECRET ENDS]

Fixed Charge Factors:

[TRADE SECRET BEGINS

D
E

TRADE SECRET ENDS]

Fixed Charges - 2016:	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total

[TRADE SECRET BEGINS

=A*B*D
=A*C*E

Fixed Charges - 2017:	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total

[TRADE SECRET BEGINS

=A*B*D
=A*C*E

Fixed Charges - 2018:	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total

[TRADE SECRET BEGINS

=A*B*D
=A*C*E

TRADE SECRET ENDS]

Northern States Power Company
State of Minnesota Electric Juristiction
NUCLEAR OUTAGE ACCOUNTING
2016 Rate Case Test Year
Amortizations, Unamortized Balances
and Test Year Revenue Requirements

MN/WS IA	MN Ratio	Weight
Demand	87.35%	46.09%
Energy	83.64%	51.46%
Composite Interchange Rate		83.30%
MN Composite Tax Rate		0.4137

Capital Structure	Rate	Ratio	Cost
Long Term Debt	4.8100%	46.2400%	2.2200%
Short Term Debt	1.8400%	1.2600%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.7200%	52.5000%	5.1000%
Required Rate of Return			7.3400%

	BOY Balance	Annual Amortization	New Deferral	EOY Balance	BOY/EOY Average
Annualized Costs					
Deferred Outage Costs	$ 80,427,062	$ (60,902,205)	$ 39,735,841	$ 59,260,698	**$ 69,843,880**
Deferred Taxes	$ (32,858,396)	$ 24,881,535	$ (16,234,038)	$ (24,210,899)	**$ (28,534,647)**
Rate Base	$ 47,568,666	$ (36,020,670)	$ 23,501,803	$ 35,049,799	**$ 41,309,232**

Total Rate Base	**$ 41,309,232**
Return Requirement	$ 3,032,098
RR Tax on Equity Return	$ 1,486,562
Rate Base Revenue Requirement	**$ 4,518,659**
Expense Amortization	$ 60,902,205
Deferred Taxes	$ (8,647,497)
Current Taxes	$ 8,833,456
Income Statement Revenue Requirement	**$ 61,088,164**
Total Test Year Revenue Requirement before IA	**$ 65,606,824**
Interchange Agreement Revenue Offset	**$ (10,955,468)**
Net Test Year Revenue Requirement	**$ 54,651,356**
Previous Expense Method Total Test Year Revenue Req before IA	**$ 39,735,841**
Interchange Agreement Revenue Offset	**$ (6,635,358)**
Net Previous Expense Method Total Test Year Revenue Req	**$ 33,100,484**
Difference before IA	**$ 25,870,982**
Interchange Offset	**$ (4,320,110)**
Net Difference	**$ 21,550,872**

ADVERTISING
Test Year Ending 12-31-16

INCLUDABLE	FERC	Minnesota Jurisdiction
General Advertising	930.1	$ 144,272
Diversity Recruiting Ads		
Supplier Diversity Ads		
Job Postings		
Energy Update		
Online Information		
Mandatory Notices	928.0	$ 10,146
Conservation (General)	909.1	$ 27,943
Customer Programs	909.1	$ 311,744
Bill Inserts / Direct mailings		
InfoSmart		
Billwise		
Paysmart		
BudgetSmart		
Energy Solutions		
Energy Update		
Online Information		
Safety Advertising	909.1	$ 536,423
Billboards/Inserts		
TV, Radio Advertising		
Newspapers		
Online Information		
TOTAL INCLUSION		**$ 1,030,528**

EXCLUDABLE	FERC	Minnesota Jurisdiction
Brand/Image and Sponsorship	930.1	(2,647,370)
Branding	921	-
Customer Program	909.1	-
Non-Recoverable DSM	908	(42,990)
TOTAL EXCLUSION		**$ (2,690,360)**

Northern States Power Company
State of Minnesota Electric Jurisdiction

Docket No. E002/GR-15-826
Exhibit___(AEH-1), Schedule 16

ORGANIZATIONAL DUES
Test Year Ending December 31, 2016

		Minnesota Jurisdiction
INCLUDABLE		
Association Dues		
Professional Association Dues	$	581,778
Electric Utility Association Dues	$	1,674,787
Chamber of Commerce Dues	$	219,807
TOTAL INCLUSION	**$**	**2,476,372**

		Minnesota Jurisdiction
EXCLUDABLE		
Association Dues		
Professional Association Dues	$	(17,759)
Electric Utility Association Dues	$	(1,205)
TOTAL EXCLUSION	**$**	**(18,964)**

Economic Development Analysis - Commercial Inputs

2016 Economic Development

Average Cost for Inductrial/Commercial installation of 500KVA Txfs.	34,000	Schedule 17, Attachment B, Line 1
Annual Revenue per Customer	138,391	Schedule 17, Attachment B, Line 23
Total Economic Development Expenses in Test Year	62,231	Schedule 17, Attachment B, Line 18
Other Revenue Requirements Associated with Additional ED Customer	19,238	Schedule 17, Attachment B, Lines 16, 18, 19, 20, 21
Total Revenue Requirements	81,469	Schedule 17, Attachment B, Line 22
Potential Customer Benefit in Year 1	56,922	Schedule 17, Attachment B, Line 24
Potential Cumulative Customer Benefit over Life of Investment	1,314,759	Schedule 17, Attachment B, Line 26

2016 Economic Development Program Cost Benefit Analysis
Attachment A

Growth Program Cost Only	Yes	Enter "Yes" for Growth Program Cost Only Analysis
Total Economic Development Costs	No	

Present Commercial Distribution Rates:

Annual Revenue per Customer	$ 138,391	Margin & Customer charge only, no fuel, no rider revenues

ED Program Customer results	1	customers
Average Annual Use per Customer	2,190,000	kWh
kWh Monthly demand billing unit	500	kW
Assumed Total ED Program Result	2,190,000	kWh

Ave Cost for Inductrial/Commercial Jobs involving the installation of 500KVA Txfs.
$ 34,000

Book Life - transformers	32	years
Negative Salvage	-10.0%	cost of removal
Book Depreciation Rate	3.438%	
Tax Depreciation Rate	MACRS Depreciation Tables - 20 year recovery	

Composite Tax Rate 41.37%

Total Economic Development Costs	$ 62,231
Total ED Costs for all Customers	$ 62,231
Cumulative NPV Revenue Requirement	$ 1,314,759

2016 Economic Development Program Cost Benefit Analysis
Attachment A

Growth Program Cost Only	Yes	Enter "Yes" for Growth Program Cost Only Analysis
Total Economic Development Costs	No	

Preliminary Cost of Capital - Electric Case Filing	Cost	Weight	Weighted Cost of Capital	
Equity	9.72%	52.50%	5.10%	Last Authorized Cost of Capital per E002/GR-13-868
Preferred Stock	0.00%	0.00%	0.00%	Last Authorized Cost of Capital per E002/GR-13-868
Long-term Debt	4.94%	45.61%	2.25%	Last Authorized Cost of Capital per E002/GR-13-868
Short-term Debt	1.12%	1.89%	0.02%	Last Authorized Cost of Capital per E002/GR-13-868
		100.00%	7.37%	

MN Composite Income Tax Rate	41.37%	
Pre-tax Rate of Return		10.97%
Extension Operating & Maintenance Factor Global Insights O&M Escalation Factor FERC 912		2.34%

Annual Escalation Rate - Chained Price Index-Gross Domestic Product (source: biennual CIP Recovery Factor Filing
(BENCOST) MN Office of Energy Security "OES") 3.59%

Property Tax Rate 2.010%
Hennepin County Electric Rate: Pay 2011

Societal Perception:
Electric environmental damage based on environmental damage factor of $6.00 / MWh from Xcel Energy Resource Planning.

MWh/kWh	0.001	$ 6.00	MWh
		3.59%	

Net Present Value of Cash Flows
Attachment B

Line No.		Year Placed in Service 1	Extension Year No. 2	Extension Year No. 3	Extension Year No. 4
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost	$ 34,000			
2					
3					
4	Total cost:	$ 34,000			
5	Beginning Balance	$ 34,000			
6	Depreciation Expense (including negative salvage)	$ 1,169	$ 1,169	$ 1,169	$ 1,169
7	Ending Balance - Net Plant	$ 32,831	$ 31,663	$ 30,494	$ 29,325
8	Average Net Plant	$ 33,416	$ 32,247	$ 31,078	$ 29,909
9	Tax Depreciation Rate	3.750%	7.219%	6.677%	6.177%
10	Tax Depreciation Amount	$ 1,275	$ 2,454	$ 2,270	$ 2,100
11	Book - Tax Depreciation Difference	$ (106)	$ (1,286)	$ (1,101)	$ (931)
12	Cumulative Difference	$ (106)	$ (1,392)	$ (2,493)	$ (3,425)
13	Accumulated Deferred Income Taxes (ADIT)	$ (44)	$ (576)	$ (1,032)	$ (1,417)
14	Average ADIT	$ (22)	$ (310)	$ (804)	$ (1,224)
15	Rate Base	$ 33,394	$ 31,937	$ 30,274	$ 28,685
16	Return Requirement @ Pre-tax cost of capital	$ 3,663	$ 3,503	$ 3,321	$ 3,147
17	Distribution Costs:				
18	Economic Development Net Donations	$ 62,231			
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 13,612	$ 14,100	$ 14,607	$ 15,131
19	System Operating and Maintence Costs	$ 794	$ 823	$ 852	$ 883
20	Depreciation Expense	$ 1,169	$ 1,169	$ 1,169	$ 1,169
21	Property Taxes	$ -	$ 683	$ 708	$ 733
22	Total Revenue Requirement	$ 81,469	$ 20,279	$ 20,657	$ 21,063
23	Customer Non-Energy Revenues at proposed rates	$ 138,391	$ 138,391	$ 138,391	$ 138,391
24	Revenue Excess (Deficiency)	$ 56,922	$ 118,112	$ 117,734	$ 117,328
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 53,015	$ 102,454	$ 95,116	$ 88,282
26	Cumulative NPV	$ 53,015	$ 155,469	$ 250,585	$ 338,867

Net Present Value of Cash Flows
Attachment B

Line No.		Extension Year No. 5	Extension Year No. 6	Extension Year No. 7	Extension Year No. 8
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost				
2					
3					
4	Total cost:				
5	Beginning Balance				
6	Depreciation Expense (including negative salvage)	$ 1,169	$ 1,169	$ 1,169	$ 1,169
7	Ending Balance - Net Plant	$ 28,156	$ 26,988	$ 25,819	$ 24,650
8	Average Net Plant	$ 28,741	$ 27,572	$ 26,403	$ 25,234
9	Tax Depreciation Rate	5.713%	5.285%	4.888%	4.522%
10	Tax Depreciation Amount	$ 1,942	$ 1,797	$ 1,662	$ 1,537
11	Book - Tax Depreciation Difference	$ (774)	$ (628)	$ (493)	$ (369)
12	Cumulative Difference	$ (4,198)	$ (4,827)	$ (5,320)	$ (5,689)
13	Accumulated Deferred Income Taxes (ADIT)	$ (1,737)	$ (1,997)	$ (2,201)	$ (2,353)
14	Average ADIT	$ (1,577)	$ (1,867)	$ (2,099)	$ (2,277)
15	Rate Base	$ 27,164	$ 25,705	$ 24,304	$ 22,957
16	Return Requirement @ Pre-tax cost of capital	$ 2,980	$ 2,820	$ 2,666	$ 2,518
17	Distribution Costs:				
18	Economic Development Net Donations				
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 15,674	$ 16,237	$ 16,820	$ 17,424
19	System Operating and Maintence Costs	$ 915	$ 947	$ 981	$ 1,017
20	Depreciation Expense	$ 1,169	$ 1,169	$ 1,169	$ 1,169
21	Property Taxes	$ 760	$ 787	$ 815	$ 844
22	Total Revenue Requirement	$ 21,497	$ 21,960	$ 22,451	$ 22,972
23	Customer Non-Energy Revenues at proposed rates	$ 138,391	$ 138,391	$ 138,391	$ 138,391
24	Revenue Excess (Deficiency)	$ 116,894	$ 116,431	$ 115,940	$ 115,419
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 81,918	$ 75,993	$ 70,478	$ 65,345
26	Cumulative NPV	$ 420,784	$ 496,777	$ 567,254	$ 632,600

Net Present Value of Cash Flows
Attachment B

Line No.		Extension Year No. 9	Extension Year No. 10	Extension Year No. 11	Extension Year No. 12
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost				
2					
3					
4	Total cost:				
5	Beginning Balance				
6	Depreciation Expense (including negative salvage)	$ 1,169	$ 1,169	$ 1,169	$ 1,169
7	Ending Balance - Net Plant	$ 23,481	$ 22,313	$ 21,144	$ 19,975
8	Average Net Plant	$ 24,066	$ 22,897	$ 21,728	$ 20,559
9	Tax Depreciation Rate	4.462%	4.461%	4.462%	4.461%
10	Tax Depreciation Amount	$ 1,517	$ 1,517	$ 1,517	$ 1,517
11	Book - Tax Depreciation Difference	$ (348)	$ (348)	$ (348)	$ (348)
12	Cumulative Difference	$ (6,037)	$ (6,385)	$ (6,733)	$ (7,081)
13	Accumulated Deferred Income Taxes (ADIT)	$ (2,497)	$ (2,641)	$ (2,786)	$ (2,929)
14	Average ADIT	$ (2,425)	$ (2,569)	$ (2,713)	$ (2,858)
15	Rate Base	$ 21,640	$ 20,327	$ 19,015	$ 17,702
16	Return Requirement @ Pre-tax cost of capital	$ 2,374	$ 2,230	$ 2,086	$ 1,942
17	Distribution Costs:				
18	Economic Development Net Donations				
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 18,049	$ 18,697	$ 19,368	$ 20,064
19	System Operating and Maintence Costs	$ 1,053	$ 1,091	$ 1,130	$ 1,171
20	Depreciation Expense	$ 1,169	$ 1,169	$ 1,169	$ 1,169
21	Property Taxes	$ 875	$ 906	$ 939	$ 972
22	Total Revenue Requirement	$ 23,520	$ 24,093	$ 24,692	$ 25,317
23	Customer Non-Energy Revenues at proposed rates	$ 138,391	$ 138,391	$ 138,391	$ 138,391
24	Revenue Excess (Deficiency)	$ 114,871	$ 114,298	$ 113,699	$ 113,074
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 60,571	$ 56,132	$ 52,005	$ 48,169
26	Cumulative NPV	$ 693,171	$ 749,302	$ 801,307	$ 849,476

Net Present Value of Cash Flows
Attachment B

Line No.		Extension Year No. 13	Extension Year No. 14	Extension Year No. 15	Extension Year No. 16
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost				
2					
3					
4	Total cost:				
5	Beginning Balance				
6	Depreciation Expense (including negative salvage)	$ 1,169	$ 1,169	$ 1,169	$ 1,169
7	Ending Balance - Net Plant	$ 18,806	$ 17,638	$ 16,469	$ 15,300
8	Average Net Plant	$ 19,391	$ 18,222	$ 17,053	$ 15,884
9	Tax Depreciation Rate	4.462%	4.461%	4.462%	4.461%
10	Tax Depreciation Amount	$ 1,517	$ 1,517	$ 1,517	$ 1,517
11	Book - Tax Depreciation Difference	$ (348)	$ (348)	$ (348)	$ (348)
12	Cumulative Difference	$ (7,430)	$ (7,778)	$ (8,126)	$ (8,474)
13	Accumulated Deferred Income Taxes (ADIT)	$ (3,074)	$ (3,218)	$ (3,362)	$ (3,506)
14	Average ADIT	$ (3,002)	$ (3,146)	$ (3,290)	$ (3,434)
15	Rate Base	$ 16,389	$ 15,076	$ 13,764	$ 12,451
16	Return Requirement @ Pre-tax cost of capital	$ 1,798	$ 1,654	$ 1,510	$ 1,366
17	Distribution Costs:				
18	Economic Development Net Donations				
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 20,784	$ 21,530	$ 22,303	$ 23,104
19	System Operating and Maintence Costs	$ 1,213	$ 1,256	$ 1,301	$ 1,348
20	Depreciation Expense	$ 1,169	$ 1,169	$ 1,169	$ 1,169
21	Property Taxes	$ 1,007	$ 1,043	$ 1,081	$ 1,120
22	Total Revenue Requirement	$ 25,971	$ 26,652	$ 27,364	$ 28,106
23	Customer Non-Energy Revenues at proposed rates	$ 138,391	$ 138,391	$ 138,391	$ 138,391
24	Revenue Excess (Deficiency)	$ 112,420	$ 111,738	$ 111,027	$ 110,285
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 44,603	$ 41,290	$ 38,211	$ 35,350
26	Cumulative NPV	$ 894,079	$ 935,369	$ 973,580	$ 1,008,930

Net Present Value of Cash Flows
Attachment B

Line No.		Extension Year No. 17	Extension Year No. 18	Extension Year No. 19	Extension Year No. 20
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost				
2					
3					
4	Total cost:				
5	Beginning Balance				
6	Depreciation Expense (including negative salvage)	$ 1,169	$ 1,169	$ 1,169	$ 1,169
7	Ending Balance - Net Plant	$ 14,131	$ 12,963	$ 11,794	$ 10,625
8	Average Net Plant	$ 14,716	$ 13,547	$ 12,378	$ 11,209
9	Tax Depreciation Rate	4.462%	4.461%	4.462%	4.461%
10	Tax Depreciation Amount	$ 1,517	$ 1,517	$ 1,517	$ 1,517
11	Book - Tax Depreciation Difference	$ (348)	$ (348)	$ (348)	$ (348)
12	Cumulative Difference	$ (8,822)	$ (9,170)	$ (9,518)	$ (9,866)
13	Accumulated Deferred Income Taxes (ADIT)	$ (3,650)	$ (3,794)	$ (3,938)	$ (4,082)
14	Average ADIT	$ (3,578)	$ (3,722)	$ (3,866)	$ (4,010)
15	Rate Base	$ 11,138	$ 9,825	$ 8,512	$ 7,200
16	Return Requirement @ Pre-tax cost of capital	$ 1,222	$ 1,078	$ 934	$ 790
17	Distribution Costs:				
18	Economic Development Net Donations				
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 23,933	$ 24,792	$ 25,682	$ 26,604
19	System Operating and Maintence Costs	$ 1,396	$ 1,447	$ 1,499	$ 1,552
20	Depreciation Expense	$ 1,169	$ 1,169	$ 1,169	$ 1,169
21	Property Taxes	$ 1,160	$ 1,202	$ 1,245	$ 1,289
22	Total Revenue Requirement	$ 28,880	$ 29,687	$ 30,528	$ 31,405
23	Customer Non-Energy Revenues at proposed rates	$ 138,391	$ 138,391	$ 138,391	$ 138,391
24	Revenue Excess (Deficiency)	$ 109,511	$ 108,704	$ 107,863	$ 106,986
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 32,692	$ 30,224	$ 27,932	$ 25,803
26	Cumulative NPV	$ 1,041,622	$ 1,071,846	$ 1,099,777	$ 1,125,580

Net Present Value of Cash Flows
Attachment B

Line No.		Extension Year No. 21	Extension Year No. 22	Extension Year No. 23	Extension Year No. 24
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost				
2					
3					
4	Total cost:				
5	Beginning Balance				
6	Depreciation Expense (including negative salvage)	$ 1,169	$ 1,169	$ 1,169	$ 1,169
7	Ending Balance - Net Plant	$ 9,456	$ 8,288	$ 7,119	$ 5,950
8	Average Net Plant	$ 10,041	$ 8,872	$ 7,703	$ 6,534
9	Tax Depreciation Rate	2.231%			
10	Tax Depreciation Amount	$ 759			
11	Book - Tax Depreciation Difference	$ 410	$ 1,169	$ 1,169	$ 1,169
12	Cumulative Difference	$ (9,456)	$ (8,288)	$ (7,119)	$ (5,950)
13	Accumulated Deferred Income Taxes (ADIT)	$ (3,912)	$ (3,429)	$ (2,945)	$ (2,462)
14	Average ADIT	$ (3,997)	$ (3,670)	$ (3,187)	$ (2,703)
15	Rate Base	$ 6,044	$ 5,202	$ 4,516	$ 3,831
16	Return Requirement @ Pre-tax cost of capital	$ 663	$ 571	$ 495	$ 420
17	Distribution Costs:				
18	Economic Development Net Donations				
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 27,559	$ 28,549	$ 29,574	$ 30,635
19	System Operating and Maintence Costs	$ 1,608	$ 1,666	$ 1,726	$ 1,788
20	Depreciation Expense	$ 1,169	$ 1,169	$ 1,169	$ 1,169
21	Property Taxes	$ 1,336	$ 1,384	$ 1,433	$ 1,485
22	Total Revenue Requirement	$ 32,335	$ 33,338	$ 34,397	$ 35,497
23	Customer Non-Energy Revenues at proposed rates	$ 138,391	$ 138,391	$ 138,391	$ 138,391
24	Revenue Excess (Deficiency)	$ 106,056	$ 105,053	$ 103,994	$ 102,894
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 23,823	$ 21,978	$ 20,263	$ 18,672
26	Cumulative NPV	$ 1,149,403	$ 1,171,381	$ 1,191,644	$ 1,210,316

Net Present Value of Cash Flows
Attachment B

Line No.		Extension Year No. 25	Extension Year No. 26	Extension Year No. 27	Extension Year No. 28
	REVENUE REQUIREMENTS ANALYSIS:				
1	Total Cost				
2					
3					
4	Total cost:				
5	Beginning Balance				
6	Depreciation Expense (including negative salvage)	$ 1,169	$ 1,169	$ 1,169	$ 1,169
7	Ending Balance - Net Plant	$ 4,781	$ 3,613	$ 2,444	$ 1,275
8	Average Net Plant	$ 5,366	$ 4,197	$ 3,028	$ 1,859
9	Tax Depreciation Rate				
10	Tax Depreciation Amount				
11	Book - Tax Depreciation Difference	$ 1,169	$ 1,169	$ 1,169	$ 1,169
12	Cumulative Difference	$ (4,781)	$ (3,613)	$ (2,444)	$ (1,275)
13	Accumulated Deferred Income Taxes (ADIT)	$ (1,978)	$ (1,494)	$ (1,011)	$ (527)
14	Average ADIT	$ (2,220)	$ (1,736)	$ (1,253)	$ (769)
15	Rate Base	$ 3,146	$ 2,461	$ 1,775	$ 1,090
16	Return Requirement @ Pre-tax cost of capital	$ 345	$ 270	$ 195	$ 120
17	Distribution Costs:				
18	Economic Development Net Donations				
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$ 31,735	$ 32,874	$ 34,055	$ 35,277
19	System Operating and Maintence Costs	$ 1,852	$ 1,918	$ 1,987	$ 2,058
20	Depreciation Expense	$ 1,169	$ 1,169	$ 1,169	$ 1,169
21	Property Taxes	$ 1,538	$ 1,593	$ 1,651	$ 1,710
22	Total Revenue Requirement	$ 36,639	$ 37,825	$ 39,056	$ 40,334
23	Customer Non-Energy Revenues at proposed rates	$ 138,391	$ 138,391	$ 138,391	$ 138,391
24	Revenue Excess (Deficiency)	$ 101,752	$ 100,566	$ 99,335	$ 98,057
25	NPV of annual revenue excess (deficiency) @ Overall Return	$ 17,198	$ 15,831	$ 14,563	$ 13,389
26	Cumulative NPV	$ 1,227,514	$ 1,243,344	$ 1,257,908	$ 1,271,297

Net Present Value of Cash Flows
Attachment B

Line No.			Extension Year No. 29		Extension Year No. 30		Extension Year No. 31		Extension Year No. 32
	REVENUE REQUIREMENTS ANALYSIS:								
1	Total Cost								
2									
3									
4	Total cost:								
5	Beginning Balance								
6	Depreciation Expense (including negative salvage)	$	1,169	$	1,169	$	1,169	$	1,169
7	Ending Balance - Net Plant	$	106	$	(1,063)	$	(2,231)	$	(3,400)
8	Average Net Plant	$	691	$	(478)	$	(1,647)	$	(2,816)
9	Tax Depreciation Rate								
10	Tax Depreciation Amount							$	3,400
11	Book - Tax Depreciation Difference	$	1,169	$	1,169	$	1,169	$	(2,231)
12	Cumulative Difference	$	(106)	$	1,063	$	2,231	$	0
13	Accumulated Deferred Income Taxes (ADIT)	$	(44)	$	440	$	923	$	0
14	Average ADIT	$	(286)	$	198	$	681	$	462
15	Rate Base	$	405	$	(280)	$	(966)	$	(2,354)
16	Return Requirement @ Pre-tax cost of capital	$	44	$	(31)	$	(106)	$	(258)
17	Distribution Costs:								
18	Economic Development Net Donations								
	Societal Perspective - Net Benefit (Envrio Damage Costs - externalities)	$	36,544	$	37,856	$	39,215	$	40,622
19	System Operating and Maintence Costs	$	2,132	$	2,209	$	2,288	$	2,370
20	Depreciation Expense	$	1,169	$	1,169	$	1,169	$	1,169
21	Property Taxes	$	1,771	$	1,835	$	1,901	$	1,969
22	Total Revenue Requirement	$	41,660	$	43,037	$	44,466	$	45,872
23	Customer Non-Energy Revenues at proposed rates	$	138,391	$	138,391	$	138,391	$	138,391
24	Revenue Excess (Deficiency)	$	96,731	$	95,354	$	93,925	$	92,519
25	NPV of annual revenue excess (deficiency) @ Overall Return	$	12,302	$	11,294	$	10,361	$	9,506
26	Cumulative NPV	$	1,283,599	$	1,294,893	$	1,305,254	$	1,314,759

Non-Asset Based Trading Cost Study

Introduction

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

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

> "…would remove non-asset based margins and their associated embedded costs from the revenue requirement…"[2]

This report summarizes the cost study undertaken by the Company to determine the fully allocated cost of non-asset based trading activity.

Background

There are two main categories of short-term wholesale trading; asset based transactions and non-asset based transactions. Asset based transactions involve the sales of excess energy or capacity from Company owned generation assets. Non-asset based transactions are undertaken as energy market opportunities to make revenues and are unrelated to meeting the needs of the Native Load customers (retail customers and requirements wholesale customers taking service at cost-based rates).

Non-asset based trading transactions are those in which:

- Energy or capacity is purchased from a third party but is unrelated to serving native load
- That energy or capacity is resold for profit

The costs that are being examined in this study are related exclusively to non-asset based trading.

Prior to the 2010 Rate Case, the Company shared non-asset based margins with customers. In its 2009 test year general electric rate case (Docket No. E002/GR-08-

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[1] Docket No. E002/GR-10-971 ALJ Report, Findings of Fact, February 22, 2012; ALJ Findings 278 &315

[2] Docket No. E002/GR-10-971 PUC Findings of Fact, Conclusions and Order, May 14, 2012; page 9

1065 or 2008 Rate Case), the Company committed to perform both an incremental and fully distributed cost study of non-asset based trading activities as part of its next general electric rate case application. Therefore, the 2010 Rate Case included the first such study.

In the settlement of the 2010 Rate Case proceedings, the Company agreed to change the ratemaking treatment of non-asset based trading margins: the fully allocated cost of non-asset based trading activity is now excluded from the Company's revenue requirements, and the non-asset based trading margins are retained by the Company. This study provides support for the fully allocated cost adjustment made for the 2016 test year.

In compliance with the requirements of the 2010 Rate Case order, an incremental cost study is also provided as a part of this report. However, as the Company no longer requests incremental cost treatment pursuant to the Settlement Agreement, the Company proposes that the incremental cost study requirement be terminated after this rate case.

Definitions

Incremental Costs

In developing these studies, the Company has defined incremental costs as those costs that would cease to be incurred if the Company stopped performing non-asset based trading transactions.

Fully Allocated Costs

The definition that the Company is using to determine fully distributed costs includes the incremental costs along with a reasonable contribution of common overhead costs.

Incremental Costs

The first step taken to identify the incremental costs was to identify all expenses that are booked to the non-asset based trading account. Each cost has been reviewed to determine if it is directly incurred as a result of non-asset based trading activities.

The amounts in these accounts fall into three categories:

1. Exclusively related labor
2. Labor-related overhead
3. Non-exclusively related

Exclusively Related Labor

The most obvious of these direct costs are exclusively related productive labor and associated payroll taxes. These human resource costs directly related to the non-asset trading function.

Labor-Related Overhead

Labor overhead costs are not as clearly definable as "direct" compared to production labor. Labor overhead charges reflect the allocation of nonproductive labor costs (for example labor loadings such as pension and insurance). For non-asset based trading activities, the overhead costs are allocated from the Service Company to NSPM in the same manner that margins are shared under the Xcel Energy Operating Companies Joint Operating Agreement (JOA). Only if there is a one-to-one correlation between productive labor and hypothetical employee reductions are all the non-productive labor costs considered incremental. At the same time, it would not be reasonable to assume that there would be zero non-productive labor savings.

Therefore, we developed allocation factors, by business groups, to identify a reasonable amount of non-productive labor costs that should be included as incremental. The three business groups that are involved with non-asset based trading are Trading, Risk Management and Accounting. These groups represent the functions that are required for non-asset based trading activities. As part of this study, we analyzed time reports for employees involved in each activity (trading, risk management, and accounting) to determine the percentage of total possible hours that were spent supporting non-asset based trading for NSPM. We then utilized this percentage as the allocation factor to be applied to that group's non-productive labor costs. This methodology allowed us to capture the incremental costs associated with each activity, or looking at it another way, if we were to eliminate non-asset based trading activities for NSPM, we could reduce our workforce by the calculated percentage.

For example, within the Trading group, time spent on activities related to NSPM non-asset based trading amounted to 1.5 full time employees (FTEs). Therefore, we assume that if non-asset based trading were eliminated at NSPM, we would be able to reduce headcount by 1.5 FTEs out of a total of 16 employees. To determine the incremental costs associated with this activity, we then divide 1.5 into 16 and allocate 9.4 percent of associated Trading labor overheads to non-asset based trading and define that share as incremental. The table below shows the allocation percentages used to assign non-productive labor to incremental costs for each category:

Department	**Allocator**
Trading (1.5 FTE's out of 16 employees)	9.4%
Risk Management (0.9 FTE's out of 51 employees)	1.8%
Accounting (0. 8 FTE's out of 40 employees)	2.0%

Non-Exclusively Related

There are a number of other costs that are allocated to non-asset based trading, for example billing and payment tracking systems that are also used by other functions within the Company. For these costs, there is no direct cost causation nexus that suggests that such costs would be eliminated if non-asset based trading ceased and, therefore, they were not considered incremental.

No capital costs were considered incremental – such costs are sunk and therefore would not be eliminated if NSPM discontinued non-asset based trading activities.

Conclusion

As shown in Attachment A, using the above assumptions and methodology, the 2016 NSPM electric utility O&M budget includes $517,396 in annual incremental costs attributed to non-asset based trading activity, or $451,830 when allocated to the State of Minnesota electric retail jurisdiction.

<u>Fully Allocated Cost Analysis</u>

There are two components of fully allocated costs – 1) expenses and 2) a share of capital costs. All expenses recorded as non-asset based trading are considered fully distributed costs (i.e., an allocation percentage has not been applied to non-productive labor costs – for example labor loadings such as pension and insurance – as was done in the incremental cost study). In addition, IT systems costs that are necessary to support these activities are included in the fully allocated costs. In total, the fully allocated O&M costs include the following components: Labor, indirect labor overheads (which includes rents), and IT system costs.

Labor

The labor itself is directly recorded as being non-asset based trading. However, the Company has also included labor overhead allocations (for example pension and insurance) to the directly assigned labor in the fully allocated section of the study.

Labor Overhead

In addition to the labor overhead costs identified in the labor section above, a labor overhead rate of 14.69% percent was also applied to non-asset based trading labor. This is the same rate applied to total labor and labor loadings for charges to the non-regulated businesses within NSPM and for third party billings.

Attachment B shows the fully allocated labor and overhead costs associated with non-asset based trading for 2012-2014 actuals and 2016 budget.

IT Systems

In addition to the labor and labor overhead expenses, the Company identified IT systems used to facilitate non-asset based trading. The table below summarizes the computer systems identified which support non-asset based trading activities:

System	**Description**
JDE	General ledger system used to account for trade activity for financial reporting
Bookrunner	Repository system used in calculating Value-at-Risk (VAR) and forward MTM transactions
PCI	Bid-to-bill transaction management tool used for MISO activity
Passport	Records payments made by Accounts Payable
XRT	Records payment made by Cash Management
Documentum	Storage of contract documentation
CXL	Manage commodity trading logistics and risk management
Business Objects	Query tool

IT System O&M Expense – An analysis was conducted to determine the amount of IT System O&M expense is related to non-asset based trading. First, for each IT system listed above, the amount of O&M expense assigned to NSPM was identified. Then the portion of the NSPM IT system O&M expense allocated to non-asset based trading was calculated based upon the Non-Asset Revenue Percent (a ratio of NSPM non-asset based trading revenue to NSPM Electric Utility revenue). Please see the top half of Attachment C for the IT system O&M expense assigned to non-asset based trading for 2013 and 2014 actual and the 2015 and 2016 budgets.

IT System Capital Revenue Requirements – An analysis was also conducted to determine the IT system capital revenue requirements associated with non-asset based trading. First, the rate base associated with the above listed IT systems was determined and the total 2016 budget rate base and depreciation expense (capital costs) for the above listed IT systems was calculated. Second, the Non-Asset Revenue Percent was applied to the capital costs to calculate the IT system capital costs attributable to non-asset based trading. (See the bottom half of Attachment C.) Third, the resulting rate base and depreciation expense was used to calculate the 2016 test year revenue requirements related to non-asset based trading. Attachment D shows the 2016 IT systems capital revenue requirement calculation.

Conclusion

As shown in Attachment E, using the above described assumptions and methodology, the 2016 budget includes $1,127,831 in annual fully allocated costs attributed to non-asset based trading activity for NSPM and $984,910 associated with the State of Minnesota electric retail jurisdiction.

Northern States Power Company
Summary of Non-Asset Based Trading Costs Attachment A
Incremental Costs

NSPM Incremental O&M Expenses	**2012**	**2013**	**2014**	**Three Year Avg**	**2016 Budget**
Trading	$ 365,231	$ 376,554	$ 431,790	$ 391,192	$ 311,593
Risk	$ 89,919	$ 124,614	$ 146,791	$ 120,442	$ 148,585
Accounting	$ 34,997	$ 52,845	$ 32,334	$ 40,059	$ 57,218
Total Incremental O&M Expenses	$ 490,147	$ 554,014	$ 610,916	$ 551,692	$ 517,396

Minnesota Jurisdiction Incremental O&M Expenses	**2012**	**2013**	**2014**	**Three Year Avg**	**2016 Budget**
Trading	$ 320,947	$ 330,298	$ 377,987	$ 343,077	$ 272,107
Risk	$ 79,017	$ 109,307	$ 128,500	$ 105,608	$ 129,756
Accounting	$ 30,753	$ 46,353	$ 28,305	$ 35,137	$ 49,967
Total Incremental O&M Expenses	$ 430,716	$ 485,958	$ 534,792	$ 483,822	$ 451,830

State of MN Jurisdictional Allocation					
Energy MN Jurisdictional Allocator	87.8749%	87.7158%	87.5394%		87.3278%

Northern States Power Company
Summary of Non-Asset Based Trading Costs
Fully Allocated Costs

Attachment B

NSPM O&M Expenses	**2012**	**2013**	**2014**	**Three Year Avg**	**2016 Budget**
Trading	$ 773,176	$ 737,274	$ 787,449	$ 765,966	$ 514,992
Risk	$ 159,852	$ 207,912	$ 245,305	$ 204,356	$ 255,125
Accounting	$ 59,675	$ 79,227	$ 52,045	$ 63,649	$ 228,720
Indirect Labor Overhead	$ 98,689	$ 100,819	$ 177,587	$ 125,699	$ 109,196
Total Fully Allocated O&M Expenses	**$ 1,091,393**	**$ 1,125,232**	**$ 1,262,387**	**$ 1,159,671**	**$ 1,108,033**

State of Minnesota O&M Expenses	**2012**	**2013**	**2014**	**Three Year Avg**	**2016 Budget**
Trading	$ 679,428	$ 646,705	$ 689,328	$ 671,821	$ 449,731
Risk	$ 140,470	$ 182,372	$ 214,739	$ 179,193	$ 222,795
Accounting	$ 52,440	$ 69,494	$ 45,560	$ 55,831	$ 199,736
Indirect Labor Overhead	$ 86,723	$ 88,434	$ 155,459	$ 110,205	$ 95,358
Total Fully Allocated O&M Expenses	**$ 959,061**	**$ 987,006**	**$ 1,105,086**	**$ 1,017,051**	**$ 967,621**

State of Minnesota Jurisdictional Allocation					
Energy MN Jurisdictional Allocator	87.8749%	87.7158%	87.5394%		87.3278%

NSP - System Cost Relating to Non-Asset Trading Activity

Attachment C

	2013	2014	2015 F	2016 B	
Proration of costs based on revenue ratio					
Total Non-Asset (Prop book) Trading Rev	22,841,160	39,774,850	42,338,492	23,999,998	
Total NSP-MN Revenue	4,076,481,845	4,243,218,256	4,089,758,327	4,088,894,818	
Non-Asset Revenue % **	**0.56%**	**0.94%**	**1.04%**	**0.59%**	
O&M Costs					
JDE	28,617	28,367	29,297	23,440	
Bookrunner	-	-	-	-	
PCI	396,002	463,053	345,117	133,854	
Passport	308,494	258,660	150,642	184,997	
Business Objects		427,860	486,515	427,128	
Total O&M	733,113	1,177,940	1,011,571	769,419	
Non-Asset Revenue % **			1.04%	0.59%	
IT O&M related to Non-Asset trading	**-**	**-**	**10,472**	**4,516**	
** Non-Asset revenue percentage is the percentage of total Prop revenues to total NSP MN electric operating revenues					
					Undepreciated Balance 12/31/2016
Depreciation (Capital Costs)					
JDE	54,077	54,077	45,064	-	-
Bookrunner	340,482	340,482	56,747	-	-
PCI	323,296	90,047	75,726	75,726	145,142
Passport	465,551	343,312	343,312	171,656	-
XRT					-
Documentum	282,699	216,130	128,212	128,218	309,875
CXL	-	669,850	1,290,648	1,284,933	5,149,824
Business Objects	-	28,846	177,121	176,514	497,635
Total Depreciation	1,466,105	1,742,744	2,116,831	1,837,048	6,102,477
Non-Asset Revenue % **			1.04%	0.59%	0.59%
IT Dep'n related to Non-Asset trading	**-**	**-**	**21,914**	**10,783**	**35,819**

Northern States Power Company, a Minnesota corporation
Non-Asset Based Trading Study Revenue Requirement

Attachment D

	Total NSPM		
Rate Analysis	**2016**	**2017**	**2018**
Rate Base			
EOY Net Plant	35,819	25,601	15,842
Depreciation	10,783	9,609	9,461
BOY Net Plant	46,601	35,210	25,304
Average Rate Base	**41,210**	**30,405**	**20,573**
Revenue Requirements			
Debt Return	900	700	500
Equity Return	2,100	1,600	1,000
Current Income Tax Requirement	1,500	1,100	700
Book Depreciation	10,783	9,609	9,461
Annual Deferred Tax	-	-	-
ITC Flow Thru	-	-	-
Tax Depreciation & Removal Expense	10,783	9,609	9,461
AFUDC Expenditure	-	-	-
Book Depreciation Cleared to Operating	-	-	-
Avoided Tax Interest	-	-	-
Property Tax	-	-	-
Total Revenue Requirements	**15,283**	**13,009**	**11,661**

Cap structure from GR-13-868

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	**4.9000%**	**45.6000%**	**2.2300%**
Short Term Debt	**0.6200%**	**1.9000%**	**0.0100%**
Preferred Stock	**0.0000%**	**0.0000%**	**0.0000%**
Common Equity	**9.7200%**	**52.5000%**	**5.1000%**
Required Rate of Return			**7.3400%**
Tax Rate (MN)	**41.3700%**		

Northern States Power Company
2016-2018 Non-Asset Based Trading Cost Adjustment

Attachment E

Line		2016 NSPM Electric	2016 MN Jurisdiction
1	**O&M from cost study**		
2	Allocation Method	EEnergy	87.33%
3	Fully Allocated O&M Expenses	1,108,033	967,621
4	**Associated IT costs**		
5	Allocation Method	EDemandProd	87.35%
6	IT O&M costs	4,516	3,944
7	Revenue requirement on IT in rate base	15,283	13,346
8	Total associated IT costs	19,799	17,290
9	**TOTAL EXPENSE CREDIT (Line 3 + Line 8)**	**1,127,831**	**984,910**

Northern States Power Company
State of Minnesota Electric Jurisdiction
Production Tax Credits (PTCs)
Test Year Ending December 31, 2016
($000's)

MWH	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Grand Meadow	38,717	24,139	28,880	29,537	29,137	21,606	19,155	13,616	21,061	31,863	32,165	26,473	316,349
Nobles	64,785	52,683	59,944	61,990	66,994	48,811	40,240	33,275	48,130	67,902	70,805	57,206	672,765
Pleasant Valley	79,411	53,850	59,265	61,628	60,963	45,289	40,997	29,174	46,369	65,950	66,303	54,327	663,526
Boarder Winds	46,361	41,423	40,691	52,582	47,822	35,404	29,700	24,338	34,293	48,188	51,386	38,365	490,553
Courtenay	-	-	-	-	-	-	-	-	-	-	-	1,503	1,503
Total	229,274	172,095	188,780	205,737	204,916	151,110	130,092	100,403	149,853	213,903	220,659	177,874	2,144,696
PTC Rate/Mwh	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00	$ 23.00
PTCs													
Grand Meadow	890	555	664	679	670	497	441	313	484	733	740	609	7,275
Nobles	1,490	1,212	1,379	1,426	1,541	1,123	926	765	1,107	1,562	1,629	1,316	15,476
Pleasant Valley	1,826	1,239	1,363	1,417	1,402	1,042	943	671	1,066	1,517	1,525	1,250	15,261
Boarder Winds	1,066	953	936	1,209	1,100	814	683	560	789	1,108	1,182	882	11,282
Courtenay	-	-	-	-	-	-	-	-	-	-	-	35	35
Total	$ 5,272	$ 3,959	$ 4,342	$ 4,731	$ 4,713	$ 3,476	$ 2,993	$ 2,309	$ 3,446	$ 4,920	$ 5,076	$ 4,092	49,329

State of MN Energy Allocator	87.3278%
State of MN PTCs	**$ 43,078**
Revenue Requirement Conversion Factor	1.70561
State of MN Revenue Requirements	**$ (73,474)**
Interchange Agreement Energy Allocation	16.3554%
Interchange Agreement Revenue Offset	$ (12,017)
State of MN Revenue Requirements (Net of IA)	**$ (61,457)**

Annual Revenue Requirement
Monticello LCM/EPU Project Return

2016 Capital Structure	Rates	Ratios	Weighted Costs
Long Term Debt	4.81%	46.24%	2.22%
Short Term Debt	1.84%	1.26%	0.02%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	10.00%	52.50%	5.25%
Required Rate of Return			7.49%

Tax Rate (MN)	41.3700%
IRS Pro-Rate Method Avg Bal Factor	26.8379%
Minnesota Demand Allocation	87.3461%

	Cost	
Full Return Portion	415,000	
Zero Return Portion	335,718	44.7196% = Pro Rate Factor
	750,718	

2016 Revenue Requirements	Full Project RR		Zero Return Adjustment	
(000's)	Company Total	MN Jur	Company Total	MN Jur
Plant Investment	723,210	631,696	323,417	282,492
RWIP	27,508	24,027	12,302	10,745
Total Project Spend	**750,718**	**655,723**	**335,718**	**293,237**
Depreciation Reserve	162,155	141,636	72,515	63,339
CWIP	-	-	-	-
Accumulated Deferred Taxes	137,846	120,403	61,644	53,844
Total Rate Base	450,718	393,684	201,559	176,054
				-
Average Rate Base	450,718	393,684	201,559	176,054
			-	-
Tax Preferenced Items:		-		-
Tax Depreciation & Removal Expense	26,528	23,171	-	-
Avoided Tax Interest	-	-	-	-
		-	-	-
Debt Return	10,096	8,819	4,515	3,944
Equity Return	23,663	20,668	10,582	9,243
Current Income Tax Requirement	23,757	20,751	7,467	6,522
		-	-	-
Book Depreciation	41,303	36,076	-	-
Annual Deferred Tax	(4,769)	(4,165)	-	-
AFUDC Expenditure	-	-	-	-
Property Taxes		-	-	-
Total Revenue Requirements	94,050	82,149	22,563	19,708

Wisconsin Company Demand	**15.8651%**
IA Revvenue Offset	3,127
Total Revenue Requirements (Net of IA)	16,582

Annual Revenue Requirement
Prairie Island EPU Amortization and Debt Only Return

	As Filed		Weighted	Last Authorized ROE		Weighted
2016 Capital Structure	**Rates**	**Ratios**	**Costs**	**Rates**	**Ratios**	**Costs**
Long Term Debt	**4.81%**	**46.24%**	**2.22%**	**4.81%**	**46.24%**	**2.22%**
Short Term Debt	**1.84%**	**1.26%**	**0.02%**	**1.84%**	**1.26%**	**0.02%**
Preferred Stock	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Common Equity	**10.00%**	**52.50%**	**5.25%**	**9.72%**	**52.50%**	**5.10%**
Required Rate of Return			**7.49%**			**7.34%**

Tax Rate (MN)	**41.3700%**
IRS Pro-Rate Method Avg Bal Factor	**26.8379%**
Minnesota Demand Allocation	**74.3399%**

2016 Revenue Requirements	**Full Project RR**		**Zero Equity Return Adj**	
(000's)	Company Total	MN Jur	Company Total	MN Jur
Plant Investment	78,885	58,643	78,885	58,643
Depreciation Reserve	9,699	7,210	9,699	7,210
CWIP	-	-	-	-
Accumulated Deferred Taxes	28,283	21,026	28,709	21,342
Total Rate Base	40,903	30,407	40,477	30,091
		-		
Average Rate Base	40,903	30,407	40,477	30,091
				-
Tax Preferenced Items:		-		-
Tax Depreciation & Removal Expense	-		-	-
Avoided Tax Interest	-	-	-	-
		-		-
Debt Return	916	681	-	-
Equity Return	2,086	1,551	2,125	1,580
Current Income Tax Requirement	3,090	2,297	1,499	1,115
		-		-
Book Depreciation	3,880	2,884	-	-
Annual Deferred Tax	(1,586)	(1,179)	-	-
AFUDC Expenditure	-	-	-	-
Property Taxes		-		-
Total Revenue Requirements	8,386	6,234	3,625	2,694
Net Revenue Requirement			**4,762**	**3,540**

Northern States Power Company
State of Minnesota Electric Jurisdiction
RATE CASE EXPENSE AMORTIZATION
Test Year Ending December 31, 2016

2016 MN Electric Rate Case Expenses		Minnesota Jurisdiction
Consulting Fees		$696,000
Outside Legal Fees		2,040,000
State Agency Fees and Administrative Law Judge		1,007,000
Administrative Costs (transcripts, admin)		458,605
Sub - TOTAL		**$4,201,605**
Remove percent for unregulated business		($21,739)
Remove percent for proposed write-off		($840,321)
TOTAL Rate Case Expense	**A**	**$3,339,545**
Requested Amortization (3 year period)		3
TOTAL Annual Amortization	**A/3**	**$1,113,182**

NSPM Minnesota Retail - Electric
IRS Pro-Rate Method Accumulated Deferred Tax Adjustment
Including NOL Annual Deferred at Last Authorized Rate of Return
Test Year Ending December 31, 2016

	Days to Prorate	Prorate Factor	Total Company Plant Deferred *	Total Company Prorated Plant Deferred *	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	2016 Monthly Expense	2016 Prorated Monthly Expense
RIS Annual Deferred Tax Expense			111,135,327		95,083,231		120,693,096		215,776,327	
January	335	91.78%	9,261,277	8,500,076	7,923,603	7,272,348	10,057,758	9,231,093	17,981,361	16,503,441
February	307	84.11%	9,261,277	7,789,622	7,923,603	6,664,510	10,057,758	8,459,539	17,981,361	15,124,049
March	276	75.62%	9,261,277	7,003,048	7,923,603	5,991,546	10,057,758	7,605,318	17,981,361	13,596,864
April	246	67.40%	9,261,277	6,241,847	7,923,603	5,340,291	10,057,758	6,778,653	17,981,361	12,118,944
May	215	58.90%	9,261,277	5,455,273	7,923,603	4,667,328	10,057,758	5,924,433	17,981,361	10,591,760
June	185	50.68%	9,261,277	4,694,072	7,923,603	4,016,073	10,057,758	5,097,768	17,981,361	9,113,840
July	154	42.19%	9,261,277	3,907,498	7,923,603	3,343,109	10,057,758	4,243,547	17,981,361	7,586,656
August	123	33.70%	9,261,277	3,120,924	7,923,603	2,670,146	10,057,758	3,389,327	17,981,361	6,059,472
September	93	25.48%	9,261,277	2,359,723	7,923,603	2,018,891	10,057,758	2,562,662	17,981,361	4,581,552
October	62	16.99%	9,261,277	1,573,148	7,923,603	1,345,927	10,057,758	1,708,441	17,981,361	3,054,368
November	32	8.77%	9,261,277	811,948	7,923,603	694,672	10,057,758	881,776	17,981,361	1,576,448
December	1	0.27%	9,261,277	25,373	7,923,603	21,709	10,057,758	27,556	17,981,361	49,264
Total Days	365								Total	99,956,659

Pro-Rate Method BOY/EOY Average	49,978,330
BOY/EOY Average	107,888,164
Rate Base Adjustment	57,909,834
Composite Tax Rate	41.37%
Weighted Cost of STD	0.02%
Weighted Cost of LTD	2.22%
Weighted Cost of Debt	2.24%
Weighted Cost of Equity	5.10%
Required Rate of Return	**7.34%**
Equity Return Tax RR	**3.60%**
RB Revenue Requirement Factor	10.94%
Annual Revenue Requirement Impact	6,334,536

* Tie to Exhibit__(LHP-1), Schedule 11

($000's)

Impact of Unused/(Utilized) Tax Deductions on Rate Base	2014 Annual Report EOY Balances	2015 Bridge Annual Utilization Amounts	2015 Bridge EOY Balances	2016 Test Year Annual Utilization Amounts	2016 Test Year EOY Balances
1. Unused/(Utilized) Deductions	393,087,231	(97,341,132)	295,746,100	(295,746,100)	0
2. Deferred Tax Effect of Unused/(Utilized) Deductions	160,267,315	(39,724,624)	120,542,691	(120,693,096)	(150,405)
3. Unused/(Utilized) Credits State	0	558,701	558,701	(558,701)	0
4. Unused/(Utilized) Credits Federal	97,562,520	26,047,263	123,609,783	31,842,924	155,452,707
5. Accumulated Deferred Income Taxes (ADIT)	**257,829,835**	**(13,118,660)**	**244,711,175**	**(89,408,873)**	**155,302,302**

Impact of Unused/(Utilized) Tax Deductions on Revenue Requirements	2015 Bridge Year Utilization Adjustment	2016 Test Year Utilization Adjustment	Comment
6. Deferred Tax Asset BOY	0	0	Zero since adjustment reflects current year utilization
7. Deferred Tax Asset EOY	(13,118,660)	(89,408,873)	From Utilization columns on Line 4
8. Average Rate Base	(6,559,330)	(44,704,436)	(BOY + EOY)/2
9. Return Requirement	(481,455)	(3,281,306)	Rate Base * Req Rate of Return
10. RR Tax on Equity Return	(236,045)	(1,608,742)	(T/(1-T))*RB*Equity Return
11. Rate Base Revenue Requirement	(717,500)	(4,890,048)	Line 9 + Line 10
12. Deferred Tax	13,118,660	89,408,873	From Utilization columns on Line 5
13. Current Tax Rev Req [1]	(14,382,429)	(91,901,658)	From Line 19
14. Total Revenue Requirements	**(1,981,269)**	**(7,382,833)**	Line 10+11+12
RR on beg balance from 2015		(1,435,000)	
Total for validation	(1,981,269)	(8,817,833)	
RIS COSS	(1,981,269)	(8,817,833)	
Difference	(0)	0	
[1] *Current Income Tax Rev Req Calculation*			
15. Utilized Deductions	97,341,132	295,746,100	Unused Annual Deductions
16. Deferred Taxes	13,118,660	89,408,873	Line 12
17. Unused State Tax Credits	558,701	(558,701)	From Utilization columns on Line 3
18. Unused Federal Tax Credits	26,047,263	31,842,924	From Utilization columns on Line 4
19. Current Income Tax Revenue Requirement	(14,382,429)	(91,901,658)	(T/(1-T))*(-Line 15+.65xLine16+Line17)+.65xLine 16+Line 17

Weighted Cost of Capital	2015	2016
Active Rates and Ratios Version	Last Authorized	Last Authorized
Cost of Short Term Debt	0.98%	1.84%
Cost of Long Term Debt	4.84%	4.81%
Cost of Common Equity	9.72%	9.72%
Ratio of Short Term Debt	1.61%	1.26%
Ratio of Long Term Debt	45.89%	46.24%
Ratio of Common Equity	52.50%	52.50%
Weighted Cost of STD	0.02%	0.02%
Weighted Cost of LTD	2.22%	2.22%
Weighted Cost of Debt	2.24%	2.24%
Weighted Cost of Equity	5.10%	5.10%
Required Rate of Return	**7.34%**	**7.34%**
Corp Composite Tax Rate	40.81%	40.81%
MN Composite Tax Rate	41.37%	41.37%

2016 TEST YEAR BASE COST OF FUEL RECONCILIATION

Category		Minnesota Amount (000s)	Comments
Fuel and Purchased Power	$	1,078,508	Docket GR-15-826, AEH-1, Sch. 11, line 6, col. 1
Costs Not Recoverable in Fuel Clause:			
Less Fuel Handling O&M Expenses	$	(9,833)	
Less Non-Fuel Variable Interchange Expenses	$	(5,001)	
Less Non-Asset Based Trading Expenses	$	(14,671)	
Less Off-System Sales Net of Interchange	$	(55,510)	
Less Windsource Fuel Costs	$	(5,258)	
Subtotal	$	(90,273)	
Interchange Agreement Impacts			
Less Minnesota Fuel Costs Offset by Interchange Revenue	$	(162,202)	
Total Minnesota Fuel Costs included in Cost of Service	$	826,033	
Minnesota Fuel Costs in Base Cost of Fuel Filing	$	829,073	Docket MR-15-827, Base Fuel Cost, line 30, col. “Total"
Difference in Fuel Costs	$	(3,040)	Difference due to different Allocation Process*
Process Check using Difference in Allocators			
Net System Fuel Costs		$1,120,558	Line 20 of Base Cost of Fuel
Energy Allocator Net of Interchange used in Cost of Service		73.47%	
Sales Allocator used in Base Cost of Fuel		73.18%	
Fuel Costs due to difference in Allocator	$	(3,295)	Difference due to different Allocation Process*
Unexplained Difference	$	255	
Percent of Total Fuel and Purchased Power		0.02%	

* Fuel Costs check using the difference in Sales and Energy allocators is slightly different than the reconciliation above due to a monthly calculation of the Base Cost of Fuel and an annual calculation of the Cost of Service.

Northern States Power Company
State of Minnesota Electric Jurisdiction
Annual Revenue Requirement
Minnesota Remaining Life
2016 Test Year Minnesota Electric Rate Case
($'s)

	2016	2017	2018
Weighted Cost of Debt	2.24%	2.26%	2.26%
Weighted Cost of Equity (Last Authorized ROE)	5.10%	5.10%	5.10%
Required Rate of Return	7.34%	7.36%	7.36%
Composite Tax Rate	41.37%	41.37%	41.37%
Jurisdictional Demand	87.3461%	87.3461%	87.3461%
Wisconsin IA Demand	15.8651%	15.8651%	15.8651%

Total Company

Rate Analysis	2015 Bridge	2016	2017	2018
Plant Investment				
Depreciation Reserve		(5,602,267)	(16,880,749)	(30,113,866)
CWIP				
Accumulated Deferred Taxes		2,286,267	6,888,982	12,289,379
	-	3,316,000	9,991,767	17,824,487
Average Rate Base	-	3,316,000	9,991,767	17,824,487
Debt Return	-	74,278	225,814	402,833
Equity Return	-	169,116	509,580	909,049
Current Income Tax Requirement	-	(4,560,282)	(4,381,820)	(5,670,895)
Book Depreciation		(11,204,532)	(11,352,437)	(15,113,797)
Annual Deferred Tax		4,572,536	4,632,895	6,167,895
ITC Flow Thru				
Tax Depreciation & Removal Expense				
AFUDC Expenditure				
Avoided Tax Interest				
Property Taxes				
Total Revenue Requirements	-	(10,948,884)	(10,365,967)	(13,304,915)

MN Jurisdiction

Rate Analysis	2015 Bridge	2016	2017	2018
Plant Investment	-	-	-	-
Depreciation Reserve	-	(4,893,362)	(14,744,676)	(26,303,288)
CWIP	-	-	-	-
Accumulated Deferred Taxes	-	1,996,965	6,017,257	10,734,293
	-	2,896,397	8,727,419	15,568,994
Average Rate Base	-	2,896,397	8,727,419	15,568,994
Debt Return	-	64,879	197,240	351,859
Equity Return	-	147,716	445,098	794,019
Current Income Tax Requirement	-	(3,983,229)	(3,827,349)	(4,953,306)
Book Depreciation	-	(9,786,721)	(9,915,911)	(13,201,312)
Annual Deferred Tax	-	3,993,932	4,046,653	5,387,416
ITC Flow Thru	-	-	-	-
Tax Depreciation & Removal Expense	-	-	-	-
AFUDC Expenditure	-	-	-	-
Avoided Tax Interest	-	-	-	-
Property Taxes	-	-	-	-
Total Revenue Requirements	-	(9,563,423)	(9,054,268)	(11,621,324)
Other Revenues (Interchange)		(1,517,247)	(1,436,469)	(1,843,735)
Total Revenue Requirements Net of Interchange		(8,046,176)	(7,617,799)	(9,777,589)

	2016 Test Year	Jan - Mar 2017***	Apr 2017 - Dec 2018***
Base Rates			
TCR Rider Projects			
CapX2020 Brookings*	✓	✓	X
CapX2020 Fargo*	✓	✓	X
CapX2020 La Crosse**	✓	✓	✓
Big Stone - Brookings**	✓	✓	✓
La Crosse - Madison**	✓	✓	✓
MISO RECB Sch 26 and 26A net revenues**	✓	✓	✓
Interim rates - No TCR Projects in 2016 or 2017			

* Included in 2016 to 2018 Plan Years with 2016 and 2017 Interim rate adjustments to exclude from Interim rates; to be recovered in base rates and removed from the TCR Rider at conclusion of the case.

** Removed from 2016 to 2018 Plan Year revenue requirement calculations (revenues and expenses), projects continue recovery in the TCR Rider after the conclusion of the rate case.

*** Projects "Rolled In" to final rates would be recovered for all of 2016 and 3 months (Jan - Mar) of 2017 through TCR Rider and 9 months (Apr - Dec) of 2017 through base rates. Date of recovery through base rates subject to change based on procedural schedule.

**** The TCR Rider Roll-In Timeline is based on the Compliance Activities identified in the Direct Testimony of Mr. Burdick.

<u>**Note:**</u> At the close of the rate case TCR Rider revenues are to be trued-up back to Jan 1, 2016 to reflect rate case decisions (e.g. Cost of Capital).

Procedural Key Milestones from Nov 2015 to Mar 2017 (tentative subject to change based on procedural schedule)

- November 2, 2015: 2015 Rate case filed
- Week of November 2, 2015: 2016 TCR Rider Supplement filed
- January 1, 2016: 2016 Interim Rates and 2016 TCR rate effective
- October 1, 2016: 2017 TCR Rider petition filed
- January 1, 2017: 2017 Interim Rates and TCR rate effective
- March 1st, 2017: MPUC Multi-Year Rate Plan Order
- April 1, 2017: Final Rates Implemented and TCR Tariff modification to remove CapX2020 Brookings and CapX2020 Fargo

Northern States Power Company

Revenue Requirements Discovery - 2016 TY Electric Rate Case
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Docket No.	Party	IR No.	Description	Addressed in 2016 TY Case
12-961	DOC	106	Subject: Affiliated Interests Please provide a statement in writing setting forth: A. Any and all business affiliations or common business interest between any of Xcel Energy's officers, directors or major stockholders (5 percent or more) and any of the following concerns: contractors, engineering firms, consultants, financial institutions, service and material suppliers, or other persons or companies doing business with Xcel Energy. B. The general nature and amount of any and all transactions with such person or companies. C. A complete description of the basis for pricing any materials and/or services involved in these transactions. D. Please identify any affiliated interest transactions and the amounts included in the current electric rate case.	Appendix A
12-961	DOC	128	In the initial filing of its next rate case, the Company shall expand upon the information filed under Minnesota Rules 7825.4000(b) and 7825.4100(B), including balance sheet and income statement reconciliations between its FERC Form 1 and its general ledger accounts, for each of the three most recent calendar years relative to the rate case test year. The schedules provided shall be produced in like manner as requested and illustrated in the Department's Information Request 128-Revised, marked in the record as Exhibit 163, DOC Attachment ACB-15. The Company shall also include explanations of the accounts that have large differences in amounts when compared between actuals and its test-year request (change of ±10 percent or more).	Volume 3 Section IV
12-961	DOC	144	Subject: NSPM's Non-Regulated Business Activities Please discuss why the Customer-Owned Street Lighting Maintenance and the Sherco Steam Sales to Liberty Paper activities are classified as non-regulated activities and how these activities are treated for rate-making (Stitt, IV. Cost Assignment Allocation and Framework, C. Allocation Methods and Factors, 3. Utility Allocations, E. Non-Regulated Business Activity Allocations).	Appendix A
12-961	DOC	155	Subject: Below-the-line charges Reference: No specific reference A. Please indicate if any charges from Service Company, Xcel Corporate, or any charges from an entity assigned to NSP from below-the-line accounts (such as FERC Accounts 426.1 to 426.5) have been included in the test year. If yes, please provide a description of type of charge and amount of the charge in the test year. B. Please describe the Company's policy to ensure below-the-line charges are not included in the test year.	Testimony Section V. Income Statement, Part B
12-961	DOC	170	Subject: Foundation Expense A. Please provide all 2014 test year amounts included in rate base and/or the revenue requirement, as well as any other financial implications from Xcel's Foundation. Please include on a Total Company and Minnesota jurisdictional basis.	Testimony Section IV Part i & Section XI Part C
12-961	DOC	187	Subject: Rate Case Expenses Reference: Testimony of Anne E. Heuer, Exhibit___(AEH-1), Schedule 20. Please provide a comparison of the total requested rate case expenses and the actual rate case expenses incurred in each of the following rate cases: (1) E002/GR-05-1428; (2) E002/GR-08-1065; (3) E002/GR-10-971 and (4) E002/GR-12-961.	AEH-1, Schedule 22 Rate Case Expense
12-961	DOC	603	Volume III, Part III, Tab 4 has some spreadsheets showing research expenses for the test year. However, the spreadsheets neither show total contributions nor the amount allocated to Xcel's Minnesota jurisdiction. Please provide a spreadsheet that shows totals and amounts allocated to Xcel's Minnesota Jurisdiction.	Volume 3, Section III Commission Policy Information, Item 4 Research Expenses
12-961	DOC	702	Subject: Revenue Requirement Determination 1) Please express Xcel Energy's proposed revenue requirements in mathematical terms, using a breakdown of the revenue requirements similar to the one provided on page 26 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners: tax rate, operating expenses excluding income and revenue taxes, rate base, rate of return, federal and state income taxes, other operating revenues, and any other items used by Xcel Energy. 2) Please quantify each item identified under your response to question 1 above.	Testimony Section II. Case Overview, Part A
12-961	DOC	703	Subject: Rate Base Determination 1) Please express Xcel Energy's proposed rate base in mathematical terms, using a breakdown of the rate base similar to the one provided on page 27 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners: accumulated depreciation reserves, accumulated provision for deferred income taxes, operating reserves, electric plant held for future use, construction work in progress, working capital, and any other items used by Xcel Energy. 2) Please quantify each item identified under your response to question 1 above.	Testimony Section IV. Rate Base
12-961	DOC	704	Subject: Operating Expenses Determination 1) Please express Xcel Energy's proposed operating expenses in mathematical terms, using a breakdown of the operating expenses similar to the one provided on page 30 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners: operation and maintenance expenses, depreciation expense, miscellaneous amortization expenses, taxes other than income taxes, and any other items used by Xcel Energy. 2) Please quantify each item identified under your response to question 1 above.	Testimony Section V. Income Statement, Part B
12-961	DOC	1108	Subject: MISO Schedules and Attachments Reference: No specific reference A. For each MISO Schedule, please provide a brief description of the MISO charge (both revenues and expenses), how this charge is reflected in retail rates through rate cases, riders, or any other recovery mechanisms. Please include charges by MISO Schedule. If not reflected in retail rates, please provide a brief explanation for why this appropriate. B. For each MISO Attachment, please provide a brief description of the MISO charge (both revenues and expenses), how this charge is reflected in retail rates through rate cases, riders, or any other recovery mechanisms. Please include charges by MISO Attachment. If not reflected in retail rates, please provide a brief explanation for why this appropriate.	Appendix A
12-961	DOC	1120	Subject: Net Operating Loss and Bonus Tax Depreciation Reference: Anne Heuer Direct Testimony on page 92 A. Please confirm the Company's continued requirement to follow the resolution of the "Tax Normalization and Allowance for Net Operating Losses" – Exhibit 105 in Xcel's last rate case (Docket E002/GR-10-971). Specifically, will the Company continue to give back to ratepayers annually the estimated $60.2 million over 2012 and 2015 in the last rate case in Exhibit 105 Attachment 1 and $85.4 million over 2013 to 2016 in the May 31, 2012 Rate Compliance Report for Regulatory Treatment of Net Operating Loss (Docket E002/GR-10-971)? Please explain your response. B. DOC is concerned that by including the utilization of the 2013 deferred tax normalization into the rate case rather than through an annual refund filing, the Company is attempting to change the intent of the resolution in Exhibit 105 to give back the updated $85.4 million on a continuing annual basis. Please explain why DOC should not be concerned by confirming the Company's requirement to give the full no estimated $85.4 million as the amount is utilized for tax purposes.	Testimony Section V. Income Statement, Part D
12-961	DOC	1134	Subject: Study of Wholesale Customers	AEH-1, Schedule 12 Wholesale Customer Study
12-961	DOC	1138	Subject: Production Tax Credits Reference: Please clearly show where the $18.8 million production tax credit which results in a $32.1 million reduction in test year revenue requirements is included in the 2014 test year. B. Please provide the allocator used in determining the Minnesota Jurisdictional amount for production tax credit and support why the allocator is reasonable.	AEH-1, Schedule 19 Production Tax Credits
12-961	MCC	100	Income tax: Please show the quantified results of calculating Xcel's total MN income tax liability for the 2014 test year. If because of zero taxes some deductions are unutilized, please explain how the unused tax credits are returned to retail ratepayers after 2014.	Testimony Section VII. Adjustments to Test Year, Part F

Revenue Requirements Discovery - 2016 TY Electric Rate Case
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Docket No.	Party	IR No.	Description	Addressed in 2016 TY Case
12-961	MCC	115	Follow-up to IR 100 response: Zero income tax liability for 2014. Carry forward of deferred tax liability. How much impact will this have on 2014 rates. Please explain the impact and how it is calculated.	Testimony Section VII. Adjustments to Test Year, Part F
12-961	MCC	500	With respect to test year or outside of test year adjustments, please identify the following: A. Adjustments made to known and measurable changes in other accounts associated with the increases (such as affects or impacts on CWIP, sales or other accounts that will be directly affected). B. Provide explanation of how assets are being added (for example, are they being added and rates affected from the start-up period, going forward, or are they mid-year increases that are annualized and charged for the entire). If explanations are contained in testimony, please provide specific citations.	Testimony Section VII. Adjustments to Test Year
12-961	MCC	704	For Jurisdictional Cost of Service allocation purposes, A. Please explain the methodology used to classify fixed production plant as demand and energy related and provide relevant workpapers. B. Please explain the basis of allocating fixed production costs classified as demand to jurisdictions. C. Please explain the basis of allocating fixed production costs classified as energy to jurisdictions. D. Please explain the basis of allocating energy costs to classes. E. Please provide the demand and energy allocators by jurisdiction for fixed production plant in Excel spreadsheet format. F. Please explain the methodology used to allocate base energy costs to jurisdictions. G. Please explain the methodology used to allocate fuel and purchased power costs to jurisdictions.	Testimony Section VI. Utility and Jurisdictional Allocations
12-961	OAG	0023	Provide a summary explaining the accounting and regulatory treatment for current and deferred income taxes related to the net operating loss and ITC along with the associated dollars for each year since the special accounting began. For each year end show the unused NOL and ITC credits and the related impact on current and deferred taxes. Explain whether these amounts reflect the Commission's decision to not recognize deferred taxes that are normally recognized due to differences between tax and financial reporting of depreciation.	Testimony Section VII. Adjustments to Test Year, Part F
12-961	OAG	0026	Provide the calculations for current and deferred income taxes for each year that NOL and ITCs were unrecognized for tax purposes as if the Commission had not approved the special accounting treatment for income taxes related to the NOL and ITC. Also explain and show the calculation of the accounting treatment for this item that resulted from the settlement and Commission approval in NSP's last case.	Testimony Section VII. Adjustments to Test Year, Part F
12-961	OAG	0030	Explain the tax treatment of PTCs, e.g. are the credits included in taxable income. Explain why there is a revenue conversion factor used to calculate the revenue requirement for PTCs. Provide the calculation of the revenue conversion factor of 1.70561 on AEH - Sch. 22.	AEH-1, Schedule 19 Production Tax Credits
12-961	OAG	0035	Explain why NSP did not provide 2013 financial data as the most recent fiscal year in accordance with Minnesota rules.	Testimony Section III. Supporting Information, Part A
12-961	OAG	0039	Provide a summary of the amount authorized for recovery for each year from 2005 through 2012 and projected for 2013 and 2014 and the total return or carrying charge for the test year.	AEH-1, Schedule 14 Nuclear Outage Accounting and Volume 4, P4-1
12-961	OAG	0039.1	Reference response to OAG IR 39. Response did not provide the amount of authorized return or carrying charge for each year that was authorized. Provide this information for the test year.	AEH-1, Schedule 14 Nuclear Outage Accounting
12-961	OAG	0041	Reference Heuer Direct AEH-1, Sch. 14. Provide explanations/descriptions for the table information including the demand rate, FOM rate, and capacity factor adjustment and how these are calculated.	AEH-1, Schedule 13 Capacity Cost Study
12-961	OAG	0053	Explain how NSP will "…remove all amounts to be included in the TCR Rider from the test year to isolate the remaining cost of service used to set base rates."	Testimony Section VIII. Costs Recovered in Riders
12-961	OAG	0053.1	Response indicates that there will be double recovery for some rider projects until there is a later true-up. Identify each project and over what period for each project double recovery will occur.	Testimony Section VIII. Costs Recovered in Riders
12-961	OAG	0057	Explain how rider revenue requirements are developed in light of the approval in NSP's last case to not recognize deferred income taxes due to the inability of NSP/Xcel to obtain tax refunds for net operating loss carrybacks. Explain whether and to what extent the NOL and deferred tax issue has an impact on previous rider projects and on current rider projects.	Testimony Section VIII. Costs Recovered in Riders
12-961	OAG	0057.1	Reference NSP response to OAG IR 57. Explain how NSP recordkeeping will assure proper cost recovery for NOL and tax recognition if NSP does not separately segregate the NOL and tax impacts for setting base rates and setting rider recovery. In addition, provide an explanation of situations where the rider recovery is modified by the Commission.	Testimony Section VII. Adjustments to Test Year, Part F
12-961	OAG	0060	Explain and show where the $32.1 million reduction in revenue requirements for production tax credits are reflected in the test year financial statements.	AEH-1, Schedule 19 Production Tax Credits
12-961	OAG	0076	Reference Heuer Direct, Schedule 12, and Volume 4, Workpapers tab P4-2B. Explain why the cost of capital summary on Schedule 12 does not reflect the cost of capital proposed for setting rates in this case.	AEH-1, Schedule 14 Nuclear Outage Accounting
12-961	OAG	0077	Reference Volume 4, Workpapers tab P4-2B. Explain whether the amounts for 2008 through 2012 on the workpaper reflect actual amounts or estimated amounts. For the years 2009 and 2010 provide the actual amounts for current "Outage Costs" and the amounts used to set rates.	/olume 4A, P4-1 Actual thru 201
12-961	OAG	0081	Explain whether the test year revenue requirement calculation for the deferred recognition of deferred taxes includes the recognition of prior period utilization of deferred taxes and tax credits. Explain whether the deferred tax credits will be ultimately utilized and if there are any limitations under the tax code that might limit their utilization.	Testimony Section V. Income Statement, Part D
12-961	OAG	0082	Reference Heuer Direct, and Schedule 11, Change in cost of capital. Provide the calculation. Explain further if and how this adjustment reflects the impact of using an overall rate of return of 7.45% versus 7.64% for all items included in the revenue requirement.	Testimony Section VII. Adjustments to Test Year, Part F
12-961	OAG	0085.2	Reference NSP response to OAG IR 85.1. Explain whether and how the assets, revenues and expenses referred to in IR 85.1 have been separated for wholesale and retail jurisdictions. Discuss the jurisdictional separation separately for assets, revenues and expenses.	Testimony Section IX. Compliance with Prior Commission Orders
12-961	OAG	0104	Provide the summary financial schedules required by Minnesota rules when a utility files for a general rate increase using 2013 actual financial information compared to the 2014 test year. Provide this information as soon as it becomes available.	Testimony Section III. Supporting Information, Part A
12-961	XLI	305	Please provide a schedule showing production O&M expense by FERC account separated between labor and non-labor expenses for the test year.	Volume 4A, Section V. O&M
13-868	DOC	117	Reference: Direct Testimony of Anne Heuer at Pages 22-23. A. Please identify specifically where the 2014 SEP costs are included in the rate case. B. Please provide the detailed work papers that support the test-year SEP costs. If the work papers were filed with the rate case, please provide the appropriate reference.	Testimony Section II. Case Overview, Part B

Revenue Requirements Discovery - 2016 TY Electric Rate Case
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Docket No.	Party	IR No.	Description	Addressed in 2016 TY Case
13-868	DOC	160	Reference: Mr. Robinson Direct Testimony page 13, Border Winds & Ms. Heuer Schedule 22. Please calculate the production tax credit amounts (PTCs) for Borders Wind for 2015 and 2016 assuming correct tax PTC rate and mwh based on the capacity factor the Company used in Docket No. E002/M-13-716. (Format consistent with Schedule 22).	AEH-1, Schedule 19 Production Tax Credits
13-868	DOC	2148	Reference: DOC July 2, 2014 Direct Testimony of Campbell in Docket No. E002/CI-13-754. Please calculate and show all calculations for the rate base, income statement and overall revenue requirement impacts for the following Monticello EPU prudency adjustment recommended by the Department for 2015: The Department recommended a disallowance of $71.42 million on a Minnesota jurisdictional basis (including AFUDC), which is estimated to be less than a $10.713 million annual revenue requirement reduction on a Minnesota jurisdictional basis for 2015 based on our investigation of Monticello LCM and EPU projects. The Department will include the final revenue requirement reduction for Monticello CI investigation docket in the revenue requirements of DOC witness Dale Lusti in his Surrebuttal Testimony (Schedules DVL-S-4 and DVL-S-7) in this rate case proceeding.	AEH-1, Schedule 20 Monticello LCM/EPU Return
13-868	DOC	1119	Reference: Anne Heuer Direct Testimony, Page 18, Other Amortization: For the $5 million increase in Other Amortizations, please explain why this amount should be recoverable in the current rate case and provide all supporting calculations and assumptions.	Testimony Section II. Case Overview, Part B
13-868	DOC	1172	Subject: Interest on Customer Deposits. Reference: Heuer Direct, Page 129 and Adjustment A22. Please provide support for the adjustment to reduce test-year rate base by the average balance of customer deposits.	Testimony Section VII. Adjustments to Test Year, Adjustment 3
13-868	DOC	1173	Subject: Donations. Reference: Heuer Direct, Pages 124-125, Adjustment A18 Volume 4, Tab A18, Workpaper A18-3: A. Please reproduce the workpaper A18-3 for actual donations for 2011, 2012 and 2013, test year requested and authorized donations for the 2011 and 2013 test years. B. Regarding the Corporate Contributions and Focus Area Grants categories on the A18-3 workpaper, please answer the following questions: 1. What is the general purpose of these two categories of contributions? 2. What types of organizations are typical recipients of the contributions in each category?	Volume 4B, Section VIII. Adjustments
13-868	DOC	2132	Subject: 2015 Forecast Cost of Service Study Reference: Exhibit_____(AEH-1), Schedule 3 Exhibit_____(AEH-1), Schedule 4 Exhibit_____(AEH-1), Schedule 8 Exhibit_____(AEH-1), Schedule 9 Exhibit_____(AEH-1), Schedule 10 Exhibit_____(AEH-1), Schedule 11 Exhibit_____(AEH-1), Schedule 27 Please provide schedules that support the 2015 forecast $134,975,000 revenue deficiency as identified in Schedule 27, Page 5 of 6, Line 21 that are similar in nature to how schedules 3, 8, 9, 10 and 11 support Schedule 4. As it relates to schedules 8 and 9, only the 2015 numbers are requested.	Volume 3, Section II. Required Financial Information, Part 2. Jurisdictional Financial Summary Schedules.
13-868	MCC	4	When the Company grosses up a cost for tax purposes there is a multiplier used for assumed tax liability. Please provide calculation and any supporting documentation for how the tax percentage is developed.	Volume 3, Section II. Required Financial Information, Part 7. Other Supplemental Information
13-868	MCC	6	The Chamber understands, with respect to income taxes as discussed in witness Heuer's testimony, the difference between: • income taxes of ($76,304) as described on Schedule 4, pps. 3 and 4 of 6; and • total company income tax credit of ($79 ,228) as identified for the total jurisdiction credit on Schedule 21, p. 2 of 8, • is income tax credits of approximately $3 million returned to ratepayers through riders. Please provide a bridge schedule illustrating and identifying the credits and which riders they flow through.	Testimony Section VII. Adjustments to Test Year, Part F
13-868	MCC	110	Witness Heuer's testimony provides the revenue requirement associated with the CIP incentive at $27.577 million for 2014 (see page 133). Were any such adjustments made for 2015? Please explain.	Testimony Section VII. Adjustments to Test Year, Part C
13-868	MCC	151	Please provide the revenue requirements for Pleasant Valley and Borders if this investment were to be recovered from the Rider when the plants go in service in 2015? Please provide a narrative response along with the quantitative information in live Excel format with formulae intact.	Testimony Section II. Case Overview, Part B
13-868	MCC	152	Can Xcel use the PTC offset (Department's recommendation) associated with Pleasant Valley and Borders in the current case if it has net operating losses? Or does Xcel already have sufficient carryover deductions and PTC so that there is no practical current impact of adding Pleasant Valley and Borders' PTC offset? Please explain.	Testimony Section V. Income Statement, Part D
13-868	MCC	156	Please explain what method is used to allocate Other Production O&M on a jurisdictional basis and also provide the resulting % classification of demand/capacity related versus energy related. By Other Production O&M, we mean non fuel and non PP A related.	Testimony Section VI. Utility and Jurisdictional Allocations
13-868	MCC	208	For Xcel's recently announced Transco, please provide: a. Business structure of organization, ownership, and organization diagram b. Required regulatory approvals, FERC plus state by state plus schedule c. Projects to be included, capital investments, and revenue requirements d. Projected impact on NSP-M and MN jurisdiction revenue requirements at least through 2018.	Appendix A
13-868	OAG	196.1	Reference: Response to OAG IR 196 – DOE settlements. Attachment A shows the total payments received of $181,931,289. The total allocated to the Minnesota and Wisconsin jurisdictions total $178,360,326. Provide the reconciliation of these two amounts.	Volume 4A, P4-5
13-868	OAG	105	For all responses show amounts for Total Company and the Minnesota jurisdictional electric unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations. Reference: NOL and deferred taxes. Provide the historical (by year) and most recent status of tax NOL carryforwards and carrybacks and identify the deferred taxes that have and have not been utilized for the benefit of ratepayers.	Appendix A AEH-1, Schedule 24 Net Operating Loss
13-868	OAG	117	For all responses show amounts for Total Company and the Minnesota jurisdictional electric unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations. Reference: Sparby Direct, pg. 5. Explain and quantify the investments in transmission owned by NSP. Provide the total cost, the Minnesota retail jurisdictional cost, other state's retail jurisdictional costs, and the wholesale jurisdictional costs that are represented in the test year. Provide the amount of revenues for 2012, 2013, and projected 2014 for transmission services in total and for the Minnesota jurisdiction. Provide a summary of transmission revenues that are included in the test year cost of service and the revenues that are not included in the test year, and explain the basis for not including revenues in the test year.	Appendix A

Revenue Requirements Discovery - 2016 TY Electric Rate Case
Index

Docket No.	Party	IR No.	Description	Addressed in 2016 TY Case
13-868	OAG	133	For all responses show amounts for Total Company and the Minnesota jurisdictional electric unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations. Reference: Clark Direct, pg. 15. For each year 2009 through 2013 and the test year provide the level of interchange agreement revenues to Minnesota coming from Wisconsin and revenues to Wisconsin coming from Minnesota. Also identify the level of rate base or investments in each state that contribute to the revenues for Minnesota and Wisconsin due to the interchange agreement. Explain whether any of the revenues are billed on a MWH or kWh basis and if so identify the level of revenues that are billed based MWH or kWh covering this period.	Appendix A
13-868	OAG	158	Reference Heuer Direct, pg. 13 – amortizations and depreciation. Explain the distinction between amortization and depreciation as used in the testimony for capital related costs. Identify the items and the level of amortization and depreciation expense that include the $70 million depreciation increase.	Testimony Section II. Case Overview, Part B
13-868	OAG	160	Reference Heuer Direct, pg. 18 - amortization. Provide a comparison schedule showing amortization amounts by item that were approved in NSP's last rate case along with amortizations included in the current rate case.	Testimony Section II. Case Overview, Part B
13-868	OAG	167	Reference Heuer Direct, pg. 39. Provide a summary of revenues and cross-charges, if any, for shared services with Home Smart. Provide a revenue and expense summary for Home Smart operations for 2012 and 2013.	Appendix A and IX. Compliance With Prior Commission Orders
13-868	OAG	184	Reference Heuer Direct, Schedule 21, pg. 1 – NOL. Provide a revised Schedule 21, pg. 1 that includes the description for line 2. Explain what the 2013 Bridge Annual Utilization Amount column represents. Explain how the Bridge column is different than the 2013 EOY Balances. Provide the calculations that produce the Accumulated Deferred Income Taxes on line 4.	Testimony Section VII. Adjustments to Test Year, Part F
13-868	OAG	185	Reference Heuer Direct, pg. 94 – NOL Deferred Taxes. Testimony states that the revenue requirement will change for the level of NOL included in the test based on the final approved revenues and costs. Explain why estimated test year revenues and expenses will impact the NOL and deferred tax revenue requirement given that actual revenues and expenses are used to file income taxes.	Testimony Section VII. Adjustments to Test Year, Part F
13-868	OAG	191	Reference Heuer Direct, pg 143, table 7 – rate case expense. Provide a schedule showing the amount, by category , e.g. consulting, legal, etc., for each of the rate cases shown. Explain whether these amounts are test year amounts (amortizations) or total. Explain why the 08-1065 expenses were substantially less than the other cases.	AEH-1, Schedule 22 Rate Case Expense

Docket No. E002/GR-12-961
Information Request No. DOC-106

Question:

Subject: Affiliated Interests

Please provide a statement in writing setting forth:

A. Any and all business affiliations or common business interest between any of Xcel Energy's officers, directors or major stockholders (5 percent or more) and any of the following concerns: contractors, engineering firms, consultants, financial institutions, service and material suppliers, or other persons or companies doing business with Xcel Energy.

B. The general nature and amount of any and all transactions with such person or companies.

C. A complete description of the basis for pricing any materials and/or services involved in these transactions.

D. Please identify any affiliated interest transactions and the amounts included in the current electric rate case.

Response:

Xcel Energy Inc. owns 100 percent of the common stock of NSPM. All officers and directors of the Company (NSPM) are employees of Xcel Energy Inc. or Xcel Energy Services Inc.

A. The Company submits annual reports of affiliate relationships by April 1st of each year pursuant to Minnesota Public Utilities Commission (MPUC) Rule 7825.2200. The 2014 report was filed on April 1, 2015 and is included as Attachments A to this response.

Xcel Energy Inc. also submits interlocking directorate reports to the Federal Energy Regulatory Commission (FERC) to show any "interlocking" relationship between officers or directors of NSPM (or Xcel Energy Inc.) and entities doing business with NSPM or Xcel Energy Inc. Attachment B to this response provides a copy of the currently-effective Interlocking Directorate reports submitted in April 2015 to FERC for all NSPM officers and directors. Please note that the interlocking report is an annual report as required, and the status reflected is that as of the date of filing.

B. & C. The Company submits an annual report of transactions with affiliates pursuant to the MPUC Order in Docket No. G,E999/CI-90-1008. The 2014 annual report was submitted to the MPUC with the Company's 2014 jurisdictional annual financial report on May 1, 2015, and is included as Attachment C with this response. The annual reports discuss the goods or services provided by or to affiliates and the consideration.

D. The current electric rate case 2016 test year includes expenses from Xcel Energy Service Company (XES), Northern States Power Company - Wisconsin (NSPW), Public Service of Colorado (PSCo), and Southwestern Public Service Co (SPS). Additionally, under the terms of the Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy (Interchange Agreement), the Company budgets revenues expected to be received from NSPW and expenses expected to be billed from NSPW associated with the NSP Companies' production and transmission systems. The table below summarizes transactions between the above-listed companies.

Affiliate	NSPM Electric	State of MN Electric Jurisdiction
XES	$ 284,286,966	$ 248,725,886
NSPW	$ 6,807	$ 5,946
PSCo	$ 1,279	$ 1,117
Interchange Agreement with NSPW Exp.	$185,280,489	$161,831,603
Interchange Agreement with NSPW Rev.	$515,013,396	$449,806,807

Preparer: Tara Heine / Mary Pope
Title: Assistant Corporate Secretary / Senior Rate Analyst
Department: Corporate Compliance / Revenue Requirements North

414 Nicollet Mall
Minneapolis, Minnesota 55401

April 1, 2015

--Via Electronic Filing--

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: ANNUAL REPORT
AFFILIATED INTEREST
DOCKET NO. E,G999/PR-15-___

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Annual Report of Affiliated Interests as of March 31, 2015.

Minn. R. 7825.2200(A) requires public utilities providing electric or natural gas service in the State of Minnesota to submit a report to the Commission on April 1 of each year containing a description of various types of companies or persons who are affiliates of the utility as defined in Minn. Stat. §216B.48.

Northern States Power Company (NSPM) is a utility operating company subsidiary of Xcel Energy Inc. NSPM provides electric and natural gas service in the State of Minnesota. NSPM is registered with the Minnesota Secretary of State to do business under the trade name Xcel Energy. Xcel Energy Services Inc. (XES) is the service company within the Xcel Energy Inc. holding company structure.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list.

Please contact me at paul.lehman@xcelenergy.com or (612) 330-7529 if you have any questions regarding this filing.

Sincerely,

/s/

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL AFFILIATED INTEREST REPORT IN COMPLIANCE WITH MINN. RULE 7825.2200(A).

DOCKET NO. E,G999/PR-15-___

ANNUAL REPORT

ANNUAL REPORT

Minn. R. 7825.2200(A) requires that the Company submit certain information to the Commission on an annual basis. We provide the required information below:

A. Minnesota Rule Requirements

1. Minn. R. 7825.2200(A)(1)

Minn. R. 7825.2200(A), subd. 1 requires:

> A list of all corporations and persons which own or hold, directly or indirectly, five percent or more of the voting securities of the reporting public utility. Such list shall show the number of units of each class of voting securities held, the percent which the individual holding of each class is to the total outstanding of that class, and the state of incorporation of each corporation.

Xcel Energy Inc. owns and holds 100 percent of the voting securities of Northern States Power Company, a Minnesota corporation (NSPM). The voting securities of NSPM consist of 1,000,000 shares of issued common stock. NSPM's common stock is not publicly traded.

Xcel Energy Inc. was originally incorporated under the laws of the State of Minnesota as Northern States Power Company (NSP) in 1909. Xcel Energy

Inc. as it exists today was formed as a result of a merger in August 2000 between New Century Energies Inc. (NCE) and NSP, with the surviving entity being NSP. When the merger was completed the company name was changed to Xcel Energy Inc. As described in the Docket No. E,G002/PA-99-1031, the common and preferred stock of NSP became preferred stock of Xcel Energy Inc. upon completion of the NSP/NCE merger in August 2000.

2. Minn. R. 7825.2200(A)(2)

Minn. R. 7825.2200(A), subd. 2 requires:

> A list of all corporations and persons which own or hold, directly or indirectly, five percent or more of the voting securities of any corporation in a chain or successive ownership of five percent or more of the voting securities of the reporting public utility. Such list will show the number of units of each class of securities held, the percent which the individual holding of each class is to the total outstanding of that class, and the state of incorporation of each corporation.

Xcel Energy Inc. owns 100 percent of the issued common stock of NSPM. The following table sets forth certain information as to each person or entity known to us to be the beneficial owner of more than 5 percent of Xcel Energy Inc.'s common stock:

Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percent of Class
BlackRock, Inc. 55 East 52nd Street New York, NY 10022	35,320,178[1]	7.00%
Franklin Resources, Inc. Charles B. Johnson Rupert H. Johnson, Jr. Franklin Advisers, Inc. Fiduciary Trust Company International One Franklin Parkway San Mateo, CA 94403	27,841,700[2]	5.50%
State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	26,153,296[3]	5.20%
The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, PA 19355	27,888,108[4]	5.51%

(1) The information contained in the table and this footnote with respect to BlackRock, Inc. is based solely on a Schedule 13G filed by the listed person with the SEC on February 9, 2015. The filing

indicates that as of December 31, 2014, BlackRock, Inc. had sole voting power for 30,973,237 shares and sole dispositive power for 35,320,178 shares.

(2) The information contained in the table and this footnote with respect to Franklin Resources, Inc. is based solely on a Schedule 13G filed by each of the listed persons with the SEC on February 10, 2015. The filing indicates that as of December 31, 2014, (a) the shares are held by investment companies and institutional accounts that are advised by subsidiaries of Franklin Resources, Inc. pursuant to advisory contracts which grant to such subsidiaries all investment and voting power over the shares, (b) Charles B. Johnson and Rupert H. Johnson, Jr. are the principal stockholders of Franklin Resources, Inc., (c) Franklin Advisers, Inc. one of the subsidiaries of Franklin Resources, Inc., had sole voting power for 27,626,014 shares and sole dispositive power for 27,826,014 shares and (d) Fiduciary Trust Company International, one of the subsidiaries of Franklin Resources, Inc., had sole voting power for 15,686 shares and sole dispositive power for 15,686 shares.

(3) The information contained in the table and this footnote with respect to State Street Corporation is based solely on a Schedule 13G filed by the listed person with the SEC on February 13, 2015. The filing indicates that as of December 31, 2014, State Street Corporation had sole voting power for 0 shares, shared voting power for 26,153,296 shares, sole dispositive power for 0 shares and shared dispositive power for 26,153,296 shares.

(4) The information contained in the table and this footnote with respect to The Vanguard Group, Inc. is based solely on a Schedule 13G filed by the listed person with the SEC on February 10, 2015, The filing indicates that as of December 31, 2014, The Vanguard Group, Inc. reported that it had sole voting power for 897,683 shares, sole dispositive power for 27,076,418 shares and shared dispositive power for 811,690 shares. The Vanguard Group, Inc. also reported that (i) Vanguard Fiduciary Trust Company, a wholly-owned subsidiary of The Vanguard Group, Inc., is the beneficial owner of 680,890 shares as a result of its serving as investment manager of collective trust accounts and (ii) Vanguard Investments Australia, Ltd., a wholly-owned subsidiary of The Vanguard Group, Inc., is the beneficial owner of 347,593 shares as a result of its serving as investment manager of Australian investment offerings.

3. Minn. R. 7825.2200(A)(3)

Minn. R. 7825.2200(A), subd. 3 requires:

> A list of all corporations five percent or more of whose voting securities are owned by any corporation or person owning five percent or more of the voting securities of the reporting public utility, or by any corporation or person in any chain of successive ownership, of each public utility, as defined in sub-item (2). Such list should indicate the name of the affiliated corporation or person which owns five percent or more of the voting securities of each corporation listed.

See chart above.

4. Minn. R. 7825.2200(A)(4)

Minn. R. 7825.2200(A), subd. 4 requires:

> A list identifying all corporations operating a public utility or servicing organization furnishing management, supervisory, construction,

> engineering, accounting, financial, legal, and similar approved in the services to the reporting public utility, which have one or more officers or one or more directors in common with the reporting public utility; and every other organization which has directors in common with the public utility where the number of common directors is more than one-third of the total number of directors of the reporting public utility.

Xcel Energy Services Inc. (XES) provides the Company with management, supervisory, construction, engineering, accounting, financial, legal, and similar services pursuant to a Utility Service Agreement previously approved by the Securities and Exchange Commission.[1] The most recent standard form service and cost allocation agreement was approved by the Commission in Docket No. E,G002/AI-08-760 on January 29, 2009. In Docket No. E,G002/AI-10-690, Order dated March 15, 2011, the Commission directed the Company to change the formula for the general allocator used in allocating corporate expenses to substitute Allocated Labor Hours with Overtime in place of Number of Employees. The allocation of XES costs to the Company's regulated utility operations in Minnesota under the Utility Service Agreement was also reviewed in the Company's 2008, 2010 and 2012 electric general rate cases (Docket Nos. E002/GR-08-1065, E002/GR-10-971 and E002/GR-12-961), and 2009 natural gas general rate case (Docket No. G002/GR-09-1153).

The allocation of XES costs to the Company's regulated utility are currently under review in the Company's 2013 electric rate case (Docket No. E002/GR-13-868). In addition, on March 24, 2014, the Company filed a petition (Docket No. E002/AI-14-234) with the Commission to update the Utility Service Agreement to reflect allocations consistent with the Company's Cost Assignment and Allocation Manual as filed in the Company's 2013 electric rate case. The Commission approved the Second Amendment to the Service Agreement in its November 20, 2014 Order.

We provide a Legal Structure Chart as Attachment A to this filing. The Chart shows the utility operating company and intermediate holding company subsidiaries of Xcel Energy Inc. effective as of December 31, 2014, including percentage ownership.

Attachment B to this filing provides the names of the principal officers and directors of NSPM. Certain of these officers and directors are also officers and/or directors of the other Xcel Energy operating companies (described

[1] Effective February 8, 2006, federal jurisdiction over the Utility Service Agreement transferred from the SEC to the Federal Energy Regulatory Commission under the Public Utility Holding Company Act of 2005 (PUHCA 2005).

below) or other Xcel Energy Inc. subsidiaries. Attachment C provides the names of the officers and directors of Xcel Energy Inc., XES, the subsidiary or utility operating company affiliates of the Company, the intermediate holding company subsidiaries of Xcel Energy Inc., and the Xcel Energy Foundation.

B. Company Legal Structure

In this Section, we provide discussion of the NSPM subsidiaries.

NSPM directly owns 100 percent of the voting securities of the following subsidiaries:

- NSP Nuclear Corporation
- United Power and Land Company

NSP Nuclear Corporation, in turn, owns 100 percent of the voting securities of Nuclear Management Company, LLC (NMC). NMC is the legal entity created to provide management services to NSPM's Prairie Island and Monticello nuclear power plants. In September 2008, the nuclear operating license and operations management of both nuclear power plants were transferred to NSPM.[2] Currently, NSP Nuclear Corporation is a shell company with no ongoing nuclear operations.

NSPM also directly owns 32.8 percent of the voting securities of Private Fuel Storage LLC. Private Fuel Storage LLC is an entity created to pursue development of an interim spent nuclear fuel storage facility, until the United States Department of Energy establishes a permanent spent fuel storage facility as required by federal law.

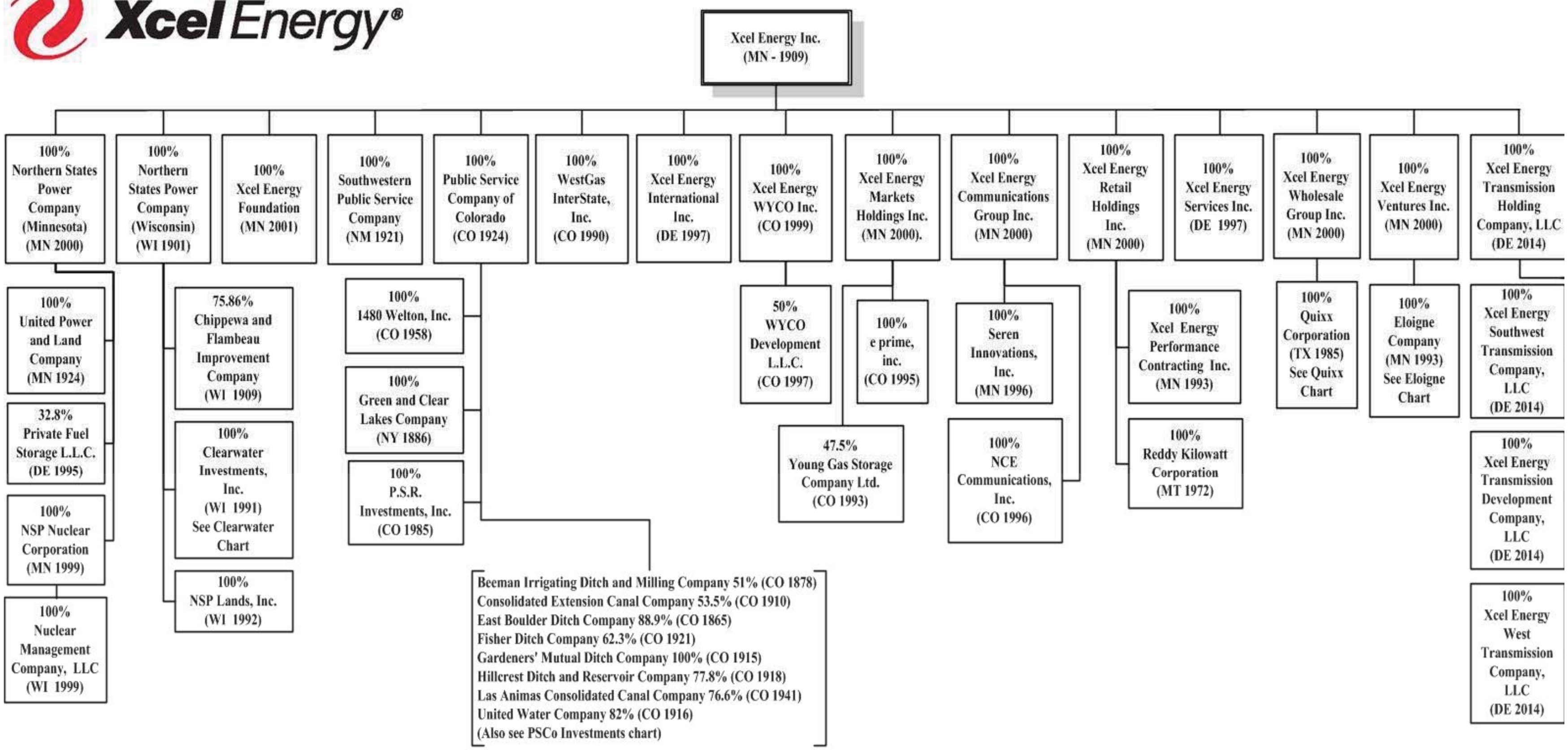
C. NSPM Affiliates

In addition to NSPM, Xcel Energy Inc. owns 100 percent of the voting securities (common stock) of several utility operating company subsidiaries, which provide regulated electric and/or natural gas service. These companies are: Northern States Power Company, a Wisconsin corporation (NSPW); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. also owns 100 percent of the common stock of WestGas InterState, Inc., a small FERC-regulated interstate gas pipeline serving portions of Wyoming; and Xcel Energy WYCO Inc., which owns 50

[2] The Company submitted an informational filing regarding this integration on April 14, 2008 in Docket No. E002/AI-99-1652. We also submitted a status report concerning NMC on February 26, 2010 in the same docket.

percent of a regulated natural gas storage facility in Colorado through WYCO Development LLC. In 2013, the regulated operations of the utility operating company subsidiaries, WestGas and WYCO comprised approximately 99 percent of all Xcel Energy Inc. operating revenue.

Xcel Energy Inc. also owns 100 percent of the voting securities of certain intermediate holding company subsidiaries: Xcel Energy Communications Group Inc.; Xcel Energy International Inc.; Xcel Energy Markets Holdings Inc.; Xcel Energy Retail Holdings Inc.; Xcel Energy Services Inc.; Xcel Energy Ventures Inc.; Xcel Energy Wholesale Group Inc. and Xcel Energy Transmission Holding Company L.L.C. The intermediate holding company subsidiaries of Xcel Energy Inc. in turn own (subject to limited exceptions) 100 percent of the voting securities of various second tier subsidiaries of Xcel Energy Inc. Xcel Energy Inc. also owns 100 percent of Xcel Energy Foundation, a Minnesota non-profit corporation.



Xcel Energy Inc. Legal Structure Chart
Last update: November 24, 2014
Effective as of: December 31, 2014

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION ("NSPM")

Directors:
Ben Fowke
Teresa S. Madden
Christopher B. Clark
Marvin E. McDaniel, Jr.

Officers:

Chairman, CEO	Ben Fowke
President	Christopher B. Clark
Executive Vice President, General Counsel	Scott M. Wilensky
Executive Vice President, CFO	Teresa S. Madden
Executive Vice President	Kent T. Larson
Executive Vice President	Marvin E. McDaniel, Jr.
Senior Vice President, Treasurer	George E. Tyson, II
Senior Vice President, Chief Nuclear Officer	Timothy J. O'Connor
Senior Vice President, Corporate Secretary	Judy M. Poferl
Senior Vice President, Controller	Jeffrey S. Savage
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

XCEL ENERGY INC. (HOLDING COMPANY PARENT OF NSPM)

Directors:[1]
Gail K. Boudreaux
Richard K. Davis
Ben Fowke
Albert F. Moreno
Richard T. O'Brien
Christopher J. Policinski
A. Patricia Sampson
James J. Sheppard
David A. Westerlund
Kim Williams
Timothy V. Wolf

Officers:

Chairman, President and CEO	Ben Fowke
Executive Vice President and Group President, Operations	Kent T. Larson
Executive Vice President, General Counsel	Scott M. Wilensky
Senior Vice President, Corporate Secretary and Executive Services	Judy M. Poferl
Executive Senior Vice President, CFO	Teresa S. Madden
Executive Vice President, Group President, Utilities and CAO	Marvin E. McDaniel, Jr.
Senior Vice President, Treasurer	George E. Tyson, II
Senior Vice President, Controller	Jeffrey S. Savage
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

[1] With the exception of Mr. Fowke, all Xcel Energy Inc. directors are independent.

II. XCEL ENERGY SERVICES INC. (SERVICE COMPANY)

Directors:
Ben Fowke
Teresa S. Madden
Scott M. Wilensky

Officers:

Chairman, President and CEO	Ben Fowke
Executive Vice President, CFO	Teresa S. Madden
Executive Vice President, General Counsel	Scott M. Wilensky
Executive Vice President, Group President, Utilities and CAO	Marvin E. McDaniel, Jr.
Executive Vice President and Group President, Operations	Kent T. Larson
Senior Vice President & Chief Nuclear Officer	Timothy J. O'Connor
Senior Vice President, Corporate Secretary and Executive Services	Judy M. Poferl
Senior Vice President and Treasurer	George E. Tyson, II
Senior Vice President and Controller	Jeffrey S. Savage
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

III. SUBSIDIARIES OF THE COMPANY

NSP NUCLEAR CORPORATION

Directors:
Ben Fowke
Timothy J. O'Connor
Christopher B. Clark

Officers:

Chairman	Ben Fowke
President & CEO	Ben Fowke
Vice President & CFO	Teresa S. Madden
Vice President	Timothy J. O'Connor
Vice President & Secretary	Judy M. Poferl
Vice President & Treasurer	George E. Tyson, II
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

UNITED POWER AND LAND COMPANY

Directors:
Lawrence A. Bick
Dan Nygaard
Christopher B. Clark

Officers:

Chairman & President	Christopher B. Clark
Vice President	Lawrence A. Bick
Vice President & Secretary	Judy M. Poferl
Vice President & Treasurer	Mary P. Schell
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Eric V. Gray

IV. Utility Operating Company Affiliates of Company

Northern States Power Company, a Wisconsin corporation

Directors:
Ben Fowke
Teresa S. Madden
Marvin E. McDaniel, Jr.
Mark E. Stoering

Officers:

Chairman and CEO	Ben Fowke
President	Mark E. Stoering
Executive Vice President, General Counsel	Scott M. Wilensky
Executive Vice President, CFO	Teresa S. Madden
Executive Vice President	Marvin E. McDaniel, Jr.
Executive Vice President	Kent T. Larson
Senior Vice President, Treasurer	George E. Tyson, II
Senior Vice President, Corporate Secretary	Judy M. Poferl
Senior Vice President, Controller	Jeffrey S. Savage
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Jean C. Fox
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

PUBLIC SERVICE COMPANY OF COLORADO

Directors:
David L. Eves
Ben Fowke
Teresa S. Madden
Marvin E. McDaniel, Jr.

Officers:

Chairman, CEO	Ben Fowke
President	David L. Eves
Executive Vice President, CFO	Teresa S. Madden
Executive Vice President, General Counsel	Scott M. Wilensky
Executive Vice President	Marvin E. McDaniel, Jr.
Executive Vice President	Kent T. Larson
Senior Vice President, Treasurer	George E. Tyson, II
Senior Vice President, Controller	Jeffrey S. Savage
Senior Vice President, Corporate Secretary	Judy M. Poferl
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

SOUTHWESTERN PUBLIC SERVICE COMPANY

Directors:
Ben Fowke
David T. Hudson
Teresa S. Madden
Marvin E. McDaniel, Jr.

Officers:

Chairman, CEO	Ben Fowke
President	David T. Hudson
Executive Vice President, General Counsel	Scott M. Wilensky
Executive Vice President, CFO	Teresa S. Madden
Executive Vice President	Marvin E. McDaniel, Jr.
Executive Vice President	Kent T. Larson
Senior Vice President, Secretary	Judy M. Poferl
Senior Vice President, Treasurer	George E. Tyson, II
Senior Vice President, Controller	Jeffrey S. Savage
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

WESTGAS INTERSTATE, INC.

Directors:
Cheryl F. Campbell
Ben Fowke

Principal Officers:

Chairman, President & CEO	Cheryl F. Campbell
Vice President	Gary Lakey
Vice President & Treasurer	George E. Tyson, II
Vice President & Secretary	Judy M. Poferl
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

V. Intermediate Holding Company Affiliates of Company

Xcel Energy Communications Group Inc.

Directors:
Ben Fowke

Officers:

Chairman, President & CEO	Ben Fowke
Vice President & CFO	Teresa S. Madden
Vice President & Secretary	Judy M. Poferl
Vice President & Treasurer	George E. Tyson, II
Vice President	Marvin E. McDaniel, Jr.
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

Xcel Energy International Inc.

Director:
Ben Fowke

Officers:

Chairman, President & CEO	Ben Fowke
Vice President & Secretary	Judy M. Poferl
Vice President & Treasurer	George E. Tyson, II
Vice President & CFO	Teresa S. Madden
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

XCEL ENERGY MARKETS HOLDINGS INC.

Directors:
Ben Fowke

Officers:

President & CEO	Ben Fowke
Vice President & CFO	Teresa S. Madden
Vice President & Secretary	Judy M. Poferl
Vice President & Treasurer	George E. Tyson, II
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

XCEL ENERGY RETAIL HOLDINGS INC.

Directors:
Ben Fowke

Officers:

Chair, President & CEO	Ben Fowke
Vice President & CFO	Teresa S. Madden
Vice President & Treasurer	George E. Tyson, II
Vice President & Secretary	Judy M. Poferl
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

XCEL ENERGY VENTURES INC.

Director:
Ben Fowke

Officers:

Chairman, President & CEO	Ben Fowke
Vice President & CFO	Teresa S. Madden
Vice President & Secretary	Judy M. Poferl
Vice President & Treasurer	George E. Tyson, II
Vice President	Marvin E. McDaniel, Jr.
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

XCEL ENERGY WHOLESALE GROUP INC.

Directors:
Ben Fowke

Officers:

Chairman, President & CEO	Ben Fowke
Vice President & CFO	Teresa S. Madden
Vice President & Secretary	Judy M. Poferl
Vice President & Treasurer	George E. Tyson, II
Vice President	Marvin E. McDaniel, Jr.
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

XCEL ENERGY WYCO INC.

Directors:
George E. Tyson, II
Ben Fowke

Officers:

Chairman, President & CEO	Ben Fowke
Vice President	George E. Tyson, II
Vice President & Treasurer	Renaldo Baucom
Vice President & Secretary	Judy M. Poferl
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

XCEL ENERGY FOUNDATION

Directors:
Christopher B. Clark
David L. Eves
Ben Fowke
David T. Hudson
Marvin E. McDaniel, Jr.
Mark E. Stoering

Officers:

Chairman and President	Ben Fowke
Treasurer	George E. Tyson, II
Secretary	Judy M. Poferl

XCEL ENERGY TRANSMISSION HOLDING COMPANY, LLC

Managers:
Ben Fowke
Teresa S. Madden
George E. Tyson, II

Officers:

Chairman, President & CEO	Ben Fowke
Executive Vice President, CFO	Teresa S. Madden
Executive Vice President	Kent T. Larson
Executive Vice President	Marvin E. McDaniel, Jr.
Executive Vice President, General Counsel	Scott M. Wilensky
Senior Vice President, Secretary	Judy M. Poferl
Senior Vice President, Controller	Jeffrey S. Savage
Senior Vice President, Treasurer	George E. Tyson, II
Assistant Secretary	Patricia K. Drury
Assistant Secretary	Tara M. Heine
Assistant Secretary	Wendy B. Mahling
Assistant Treasurer	Paul A. Johnson
Assistant Treasurer	Mary P. Schell
Assistant Treasurer	Brian J. Van Abel

Certificate of Service

I, Tiffany Hughes, hereby certify that I have this day served copies of the foregoing document or a summary thereof on the attached lists of persons:

<u>xx</u> by depositing a true and correct copy or summary thereof, properly enveloped with postage paid, in the United States Mail at Minneapolis, Minnesota; or

<u>xx</u> via electronic filing

Xcel Energy's Miscellaneous Gas and Electric Service List

Dated this 1st day of April 2015

/s/
____
Tiffany Hughes
Records Analyst

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
James J.	Bertrand	james.bertrand@leonard.com	Leonard Street & Deinard	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Jeffrey A.	Daugherty	jeffrey.daugherty@centerpointenergy.com	CenterPoint Energy	800 LaSalle Ave Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 554021425	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Sandra	Hofstetter	N/A	MN Chamber of Commerce	7261 County Road H Fremont, WI 54940-9317	Paper Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tiffany	Hughes	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Thomas G.	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Byron E.	Starns	byron.starns@leonard.com	Leonard Street and Deinard	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric and Gas

30-Apr-15

FERC Form 561 is being filed on behalf of the following individuals:

	Docket Number
Patricia K. Drury	ID-7290-000
Benjamin G.S. Fowke III	ID-4171-000
Tara M. Heine	ID-5588-000
Paul A. Johnson	ID-5635-000
Kent T. Larson	ID-6245-000
Teresa S. Madden	ID-3073-000
Wendy B. Mahling	ID-7213-000
Marvin E. McDaniel	ID-6150-000
Timothy J. O'Connor	ID-7087-000
Judy M. Poferl	ID-7148-000
Jeffrey S. Savage	ID-6680-000
Mary P. Schell	ID-5593-000
George E. Tyson, II	ID-4175-000
Brian J. Van Abel	ID-7433-000
Scott M. Wilensky	ID-6679-000

FERC Form 561 is being filed on behalf of the following individuals who do not currently have a docket number assigned:
Mark E. Stoering
Jean C. Fox

FERC Form 561 is not being filed on behalf of the following individuals who previously filed informational reports due to retirement or resignation:

David M. Sparby	ID-5160-000 (retirement)

The utility contact is:
Tara M. Heine
Assistant Corporate Secretary
Xcel Energy Inc.
414 Nicollet Mall, Suite 500
Minneapolis, MN 55401
612-215-5391
e mail: tara.m.heine@xcelenergy.com

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

This report is mandatory under Section 305(c)(1) of the Federal Power Act. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law.
The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
Drury Patricia K				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-7290	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
1480 Welton Inc	OEP	305B	$ -
Clearwater Investments Inc	OEP	305B	$ -
e prime inc	OEP	305B	$ -
Eloigne Company	OEP	305B	$ -
Green and Clear Lakes Company	OEP	305B	$ -
NCE Communications Inc	OEP	305B	$ -
NSP Lands Inc	OEP	305B	$ -
NSP Nuclear Corporation	OEP	305B	$ -
Nuclear Management Company LLC	OEP	305B	$ -
PSR Investments Inc	OEP	305B	$ -
Quixx Carolina Inc	OEP	305B	$ -
Quixx Corporation	OEP	305B	$ -
Quixxlin Corp	OEP	305B	$ -
Reddy Kilowatt Corporation	OEP	305B	$ -
Seren Innovations Inc	OEP	305B	$ -
United Power and Land Company	OEP	305B	$ -
WestGas Interstate Inc	OEP	305B	$ -
Xcel Energy Communications Group Inc	OEP	305B	$ -
Xcel Energy Inc.	OEP	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy Markets Holdings Inc	OEP	305B	$ -
Xcel Energy Performance Contracting Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel energy Southwest Transmission Company	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -
Xcel Energy WYCO Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/9/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

This report is mandatory under Section 305(c)(1) of the Federal Power Act. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
FOWKE III BENJAMIN G S				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-4171	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	DIR		
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	DIR		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	DIR		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	DIR		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Cod	(5) Type Code	(6) Total Revenue ($)
e prime inc	DIR	305B	$ -
e prime inc	OEP	305B	$ -
e prime inc	CEO	305B	$ -
e prime inc	PRES	305B	$ -
Eloigne Company	DIR	305B	$ -
Eloigne Company	OEP	305B	$ -
Eloigne Company	PRES	305B	$ -
NCE Communications Inc	PRES	305B	$ -
Nuclear Management Company	DIR	305B	$ -
NSP Nuclear Corporation	OEP	305B	$ -
NSP Nuclear Corporation	CEO	305B	$ -
NSP Nuclear Corporation	DIR	305B	$ -
NSP Nuclear Corporation	PRES	305B	$ -
PSR Investments Inc	DIR	305B	$ -
PSR Investments Inc	OEP	305B	$ -
PSR Investments Inc	PRES	305B	$ -
Quixx Carolina, Inc.	DIR	305B	$ -
Quixx Carolina, Inc.	CEO	305B	$ -
Quixx Carolina, Inc.	PRES	305B	$ -
Quixx Carolina, Inc.	OEP	305B	$ -
Quixx Corporation	DIR	305B	$ -
Quixx Corporation	OEP	305B	$ -
Quixx Corporation	CEO	305B	$ -
Quixx Corporation	PRES	305B	$ -
Quixxlin Corp.	DIR	305B	$ -
Quixxlin Corp.	OEP	305B	$ -
Quixxlin Corp.	CEO	305B	$ -
Quixxlin Corp.	PRES	305B	$ -
Reddy Kilowatt Corporation	DIR	305B	$ -
Reddy Kilowatt Corporation	OEP	305B	$ -
Reddy Kilowatt Corporation	PRES	305B	$ -
Safe Haven Homes LLC	OEP	305B	$ -
Seren Innovations Inc	DIR	305B	$ -
Seren Innovations Inc	OEP	305B	$ -
Seren Innovations Inc	CEO	305B	$ -
Seren Innovations Inc	PRES	305B	$ -
WestGas Interstate Inc	DIR	305B	$ -
Xcel Energy Communications Group Inc	DIR	305B	$ -
Xcel Energy Communications Group Inc	OEP	305B	$ -
Xcel Energy Communications Group Inc	CEO	305B	$ -
Xcel Energy Communications Group Inc	PRES	305B	$ -
Xcel Energy Foundation	DIR	305B	$ -
Xcel Energy Foundation	OEP	305B	$ -
Xcel Energy Foundation	PRES	305B	$ -
Xcel Energy Inc	DIR	305B	$ -
Xcel Energy Inc	OEP	305B	$ -
Xcel Energy Inc	CEO	305B	$ -
Xcel Energy Inc	PRES	305B	$ -
Xcel Energy International Inc	DIR	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy International Inc	CEO	305B	$ -
Xcel Energy International Inc	PRES	305B	$ -
Xcel Energy Markets Holdings Inc	DIR	305B	$ -
Xcel Energy Markets Holdings Inc	CEO	305B	$ -
Xcel Energy Markets Holdings Inc	PRES	305B	$ -
Xcel Energy Performance Contracting Inc	DIR	305B	$ -
Xcel Energy Performance Contracting Inc	OEP	305B	$ -
Xcel Energy Performance Contracting Inc	PRES	305B	$ -
Xcel Energy Retail Holdings Inc	CEO	305B	$ -
Xcel Energy Retail Holdings Inc	PRES	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	DIR	305B	$ -
Xcel Energy Services Inc	DIR	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel Energy Services Inc	CEO	305B	$ -
Xcel Energy Services Inc	PRES	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	OEP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	CEO	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	PRES	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	CEO	305B	$ -
Xcel Energy Transmission Development Company, LLC	PRES	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	CEO	305B	$ -
Xcel Energy Transmission Holding Company, LLC	PRES	305B	$ -
Xcel Energy Ventures Inc	DIR	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Ventures Inc	CEO	305B	$ -
Xcel Energy Ventures Inc	PRES	305B	$ -
Xcel Energy Wholesale Group Inc	DIR	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	CEO	305B	$ -
Xcel Energy Wholesale Group Inc	PRES	305B	$ -
Xcel Energy WYCO Inc	DIR	305B	$ -
Xcel Energy WYCO Inc	OEP	305B	$ -
Xcel Energy WYCO Inc	CEO	305B	$ -
Xcel Energy WYCO Inc	PRES	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/24/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 07/31/2011)

This report is mandatory under Section 305(c)(1) of the Federal Power Act. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law.
The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
Fox Jean C				**1414 West Hamilton Ave.**		
FERC USE:		**3. Report Year Ending**	2014	**Eau Claire**	WI	54701
4. Docket #	ID-0000	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (WI)	OEP		
Northern States Power Company (WI)	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
Clearwater Investments Inc	OEP	305B	$ -
NSP Lands Inc	OEP	305B	$ -

Signature: Signed **Date:** 4/23/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

This report is mandatory under Section 305(c)(1) of the Federal Power Act. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
HEINE TARA M				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-5588	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position C	(5) Type Co	(6) Total Revenue ($)
1480 Welton Inc	OEP	305B	$ -
Clearwater Investments Inc	OEP	305B	$ -
e prime inc	OEP	305B	$ -
Eloigne Company	OEP	305B	$ -
Green and Clear Lakes Company	OEP	305B	$ -
NCE Communications Inc	OEP	305B	$ -
NSP Lands Inc	OEP	305B	$ -
NSP Nuclear Corporation	OEP	305B	$ -
Nuclear Management Company LLC	OEP	305B	$ -
PSR Investments Inc	OEP	305B	$ -
Quixx Carolina Inc	OEP	305B	$ -
Quixx Corporation	OEP	305B	$ -
Quixxlin Corp	OEP	305B	$ -
Reddy Kilowatt Corporation	OEP	305B	$ -
Seren Innovations Inc	OEP	305B	$ -
United Power and Land Company	OEP	305B	$ -
WestGas Interstate Inc	OEP	305B	$ -
Xcel Energy Communications Group Inc	OEP	305B	$ -
Xcel Energy Inc.	OEP	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy Markets Holdings Inc	OEP	305B	$ -
Xcel Energy Performance Contracting Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel energy Southwest Transmission Company	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -
Xcel Energy WYCO Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/8/2015

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

›rm Approved
›o. 1902-0099
(Expires 08/31/2014)

as provided by law.
The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
JOHNSON PAUL A				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapoli**	MN	55401
4. Docket #	ID-5635	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code	(1) Name of Public Utili	(2) Position Code(s)
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position	(5) Type Co	(6) Total Revenue ($)
1480 Welton Inc	OEP	305B	$ -
e prime inc	OEP	305B	$ -
Eloigne Company	OEP	305B	$ -
Green and Clear Lakes Company	OEP	305B	$ -
NCE Communications Inc	OEP	305B	$ -
NSP Nuclear Corporation	OEP	305B	$ -
PSR Investments Inc	OEP	305B	$ -
Quixx Carolina Inc	OEP	305B	$ -
Quixx Corporation	OEP	305B	$ -
Quixxlin Corp	OEP	305B	$ -
Reddy Kilowatt Corporation	OEP	305B	$ -
Seren Innovations Inc	OEP	305B	$ -
United Power and Land Company	OEP	305B	$ -
WestGas Interstate Inc	OEP	305B	$ -
Xcel Energy Communications Group Inc	OEP	305B	$ -
Xcel Energy Inc	OEP	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy Markets Holdings Inc	OEP	305B	$ -
Xcel Energy Performance Contracting Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -
Xcel Energy WYCO Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/9/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

This report is mandatory under Section 305(c)(1) of the Federal Power Act. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law.
The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**	
LARSON KENT T.				**414 Nicollet Mall**	
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-6245-000	**5. Latest Date Authorized**			
6. Mail to Company		Xcel Energy Inc.			

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	VP		
Northern States Power Company (WI)	VP		
Public Service Company of Colorado	VP		
Southwestern Public Service Co	VP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
Nuclear Management Company LLC	DIR	305B	$ -
Quixx Corporation	OEP	305B	$ -
Xcel Energy Services Inc.	VP	305B	$ -
Xcel Energy Services Inc.	OEP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	VP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	VP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/9/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				2. Business Address (Street, City, State, and Zip Code)		
MADDEN TERESA S				414 Nicollet Mall		
FERC USE:		3. Report Year Ending	2014	Minneapolis	MN	55401
4. Docket #	ID-3073	5. Latest Date Authorized				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	DIR		
Northern States Power Company (MN)	OEP		
Northern States Power Company (MN)	VP		
Northern States Power Company (WI)	DIR		
Northern States Power Company (WI)	OEP		
Northern States Power Company (WI)	VP		
Public Service Company of Colorado	DIR		
Public Service Company of Colorado	OEP		
Public Service Company of Colorado	VP		
Southwestern Public Service Co	DIR		
Southwestern Public Service Co	OEP		
Southwestern Public Service Co	VP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
NSP Nuclear Corporation	OEP	305B	$ -
NSP Nuclear Corporation	VP	305B	$ -
Nuclear Management Company LLC	VP	305B	$ -
Nuclear Management Company LLC	OEP	305B	$ -
PSR Investments Inc	DIR	305B	$ -
Seren Innovations Inc.	VP	305B	$ -
Seren Innovations Inc.	OEP	305B	$ -
Xcel Energy Communications Group, Inc.	VP	305B	$ -
Xcel Energy Communications Group, Inc.	OEP	305B	$ -
Xcel Energy Inc	VP	305B	$ -
Xcel Energy Inc	OEP	305B	$ -
Xcel Energy International Inc	VP	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy Markets Holdings Inc	VP	305B	$ -
Xcel Energy Markets Holdings Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	VP	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Services Inc	VP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel Energy Services Inc	DIR	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	OEP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	VP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	VP	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	VP	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/13/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
MAHLING WENDY B				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-7213	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
1480 Welton Inc	OEP	305B	$ -
Clearwater Investments Inc	OEP	305B	$ -
e prime inc	OEP	305B	$ -
Eloigne Company	OEP	305B	$ -
Green and Clear Lakes Company	OEP	305B	$ -
NCE Communications Inc	OEP	305B	$ -
NSP Lands Inc	OEP	305B	$ -
NSP Nuclear Corporation	OEP	305B	$ -
Nuclear Management Company LLC	OEP	305B	$ -
PSR Investments Inc	OEP	305B	$ -
Quixx Carolina Inc	OEP	305B	$ -
Quixx Corporation	OEP	305B	$ -
Quixxlin Corp	OEP	305B	$ -
Reddy Kilowatt Corporation	OEP	305B	$ -
Seren Innovations Inc	OEP	305B	$ -
United Power and Land Company	OEP	305B	$ -
WestGas Interstate Inc	OEP	305B	$ -
Xcel Energy Communications Group Inc	OEP	305B	$ -
Xcel Energy Inc.	OEP	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy Markets Holdings Inc	OEP	305B	$ -
Xcel Energy Performance Contracting Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel energy Southwest Transmission Company	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -
Xcel Energy WYCO Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/23/2015

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
MCDANIEL JR MARVIN E				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-6150	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	VP		
Northern States Power Company (WI)	VP		
Public Service Company of Colorado	VP		
Southwestern Public Service Co	VP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
NCE Communications Inc	DIR	305B	$ -
NCE Communications Inc	VP	305B	$ -
Xcel Energy Communications Group Inc	VP	305B	$ -
Xcel Energy Foundation	DIR	305B	$ -
Xcel Energy Inc.	VP	305B	$ -
Xcel Energy Inc.	OEP	305B	$ -
Xcel Energy Services Inc	VP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	VP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	VP	305B	$ -
Xcel Energy Ventures Inc	VP	305B	$ -
Xcel Energy Wholesale Group Inc	VP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/17/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
OCONNOR TIMOTHY J				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-7087	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	OEP		
Northern States Power Company (MN)	VP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
NSP Nuclear Corporation	DIR	305B	$ -
NSP Nuclear Corporation	VP	305B	$ -
Nuclear Management Company, LLC	DIR	305B	$ -
Nuclear Management Company, LLC	PRES	305B	$ -
Xcel Energy Services Inc	VP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/11/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
Poferl Judy M				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-7148	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	DIR		
Northern States Power Company (MN)	VP		
Northern States Power Company (MN)	SEC		
Northern States Power Company (WI)	VP		
Northern States Power Company (WI)	SEC		
Public Service Company of Colorado	VP		
Public Service Company of Colorado	SEC		
Southwestern Public Service Co	VP		
Southwestern Public Service Co	SEC		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
1480 Welton Inc	SEC	305B	$ -
1480 Welton Inc	VP	305B	$ -
Clearwater Investments Inc	VP	305B	$ -
Clearwater Investments Inc	SEC	305B	$ -
e prime inc	SEC	305B	$ -
e prime inc	VP	305B	$ -
e prime inc	DIR	305B	$ -
Eloigne Company	SEC	305B	$ -
Eloigne Company	VP	305B	$ -
Eloigne Company	DIR	305B	$ -
Green and Clear Lakes Company	SEC	305B	$ -
Green and Clear Lakes Company	VP	305B	$ -
NCE Communications Inc	SEC	305B	$ -
NCE Communications Inc	VP	305B	$ -
NSP Lands Inc	SEC	305B	$ -
NSP Lands Inc	VP	305B	$ -
NSP Nuclear Corporation	VP	305B	$ -
NSP Nuclear Corporation	SEC	305B	$ -
Nuclear Management Company LLC	VP	305B	$ -
Nuclear Management Company LLC	SEC	305B	$ -
PSR Investments Inc	SEC	305B	$ -
PSR Investments Inc	VP	305B	$ -
Quixx Carolina Inc	VP	305B	$ -
Quixx Carolina Inc	SEC	305B	$ -
Quixx Corporation	VP	305B	$ -
Quixx Corporation	SEC	305B	$ -
Quixxlin Corp	VP	305B	$ -
Quixxlin Corp	SEC	305B	$ -
Reddy Kilowatt Corporation	SEC	305B	$ -
Reddy Kilowatt Corporation	VP	305B	$ -
Seren Innovations Inc	SEC	305B	$ -
Seren Innovations Inc	VP	305B	$ -
United Power and Land Company	VP	305B	$ -
United Power and Land Company	SEC	305B	$ -
WestGas Interstate Inc	VP	305B	$ -
WestGas Interstate Inc	SEC	305B	$ -
Xcel Energy Communications Group Inc	SEC	305B	$ -
Xcel Energy Communications Group Inc	VP	305B	$ -
Xcel Energy Inc	VP	305B	$ -
Xcel Energy Inc	SEC	305B	$ -
Xcel Energy International Inc	SEC	305B	$ -
Xcel Energy International Inc	VP	305B	$ -
Xcel Energy Markets Holdings Inc	SEC	305B	$ -
Xcel Energy Markets Holdings Inc	VP	305B	$ -
Xcel Energy Performance Contracting Inc	VP	305B	$ -
Xcel Energy Performance Contracting Inc	SEC	305B	$ -
Xcel Energy Retail Holdings Inc	VP	305B	$ -
Xcel Energy Retail Holdings Inc	SEC	305B	$ -
Xcel Energy Services Inc	SEC	305B	$ -
Xcel Energy Services Inc	VP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	SEC	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	SEC	305B	$ -
Xcel Energy Transmission Development Company, LLC	VP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	SEC	305B	$ -
Xcel Energy Transmission Holding Company, LLC	VP	305B	$ -
Xcel Energy Ventures Inc	VP	305B	$ -
Xcel Energy Ventures Inc	SEC	305B	$ -
Xcel Energy Wholesale Group Inc	VP	305B	$ -
Xcel Energy Wholesale Group Inc	SEC	305B	$ -
Xcel Energy WYCO Inc	VP	305B	$ -
Xcel Energy WYCO Inc	SEC	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/21/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**	
SAVAGE JEFFREY S				**414 Nicollet Mall**	
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-6680	**5. Latest Date Authorized**			
6. Mail to Company		Xcel Energy Inc			

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	VP		
Northern States Power Company (MN)	COMP		
Northern States Power Company (WI)	VP		
Northern States Power Company (WI)	COMP		
Public Service Company of Colorado	VP		
Public Service Company of Colorado	COMP		
Southwestern Public Service Co	VP		
Southwestern Public Service Co	COMP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
Clearwater Investments, Inc.	COMP	305B	$ -
Clearwater Investments, Inc.	VP	305B	$ -
Eloigne Company	COMP	305B	$ -
Nuclear Management Company, LLC	VP	305B	$ -
Nuclear Management Company, LLC	COMP	305B	$ -
P.S.R. Investments, Inc.	VP	305B	$ -
P.S.R. Investments, Inc.	COMP	305B	$ -
Quixx Corporation	VP	305B	$ -
Quixx Corporation	COMP	305B	$ -
Xcel Energy Inc.	VP	305B	$ -
Xcel Energy Inc.	COMP	305B	$ -
Xcel Energy Services Inc	VP	305B	$ -
Xcel Energy Services Inc	COMP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	VP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	COMP	305B	$ -
Xcel Energy Transmission Development Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	COMP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	VP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	COMP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/15/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

This report is mandatory under Section 305(c)(1) of the Federal Power Act. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law.
The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
SCHELL MARY P				**414 Nicollet Mall**		
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-5593	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
1480 Welton Inc	OEP	305B	$ -
Clearwater Investments Inc	OEP	305B	$ -
e prime inc	OEP	305B	$ -
Eloigne Company	OEP	305B	$ -
Green and Clear Lakes Company	OEP	305B	$ -
NCE Communications Inc	OEP	305B	$ -
NSP Lands Inc	OEP	305B	$ -
NSP Nuclear Corporation	OEP	305B	$ -
PSR Investments Inc	OEP	305B	$ -
Quixx Carolina Inc	OEP	305B	$ -
Quixx Corporation	OEP	305B	$ -
Quixxlin Corp	OEP	305B	$ -
Reddy Kilowatt Corporation	OEP	305B	$ -
Seren Innovations Inc	OEP	305B	$ -
United Power and Land Company	TREA	305B	$ -
United Power and Land Company	VP	305B	$ -
WestGas Interstate Inc	OEP	305B	$ -
Xcel Energy Communications Group Inc	OEP	305B	$ -
Xcel Energy Inc	OEP	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy Markets Holdings Inc	OEP	305B	$ -
Xcel Energy Performance Contracting Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -
Xcel Energy WYCO Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/13/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

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RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**		
Stoering Mark E				**1414 West Hamilton Ave**		
FERC USE:		**3. Report Year Ending**	2014	**Eau Claire**	WI	54701
4. Docket #	ID-0000	**5. Latest Date Authorized**				
6. Mail to Company		Xcel Energy Inc				

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (WI)	DIR		
Northern States Power Company (WI)	CEO		
Northern States Power Company (WI)	PRES		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
Chippewa and Flambeau Improvement Company	DIR	305B	$ -
Chippewa and Flambeau Improvement Company	PRES	305B	$ -
Clearwater Investments Inc	DIR	305B	$ -
Clearwater Investments Inc	PRES	305B	$ -
NSP Lands Inc	DIR	305B	$ -
NSP Lands Inc	PRES	305B	$ -
Xcel Energy Foundation	DIR	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/23/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
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Docket No. E002/GR-15-826
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ANNUAL REPORT OF INTERLOCKING POSITIONS

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RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**	
TYSON II GEORGE E				**414 Nicollet Mall**	
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis** MN	55401
4. Docket #	ID-4175	**5. Latest Date Authorized**			
6. Mail to Company		Xcel Energy Inc			

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	VP		
Northern States Power Company (MN)	TREA		
Northern States Power Company (WI)	VP		
Northern States Power Company (WI)	TREA		
Public Service Company of Colorado	VP		
Public Service Company of Colorado	TREA		
Southwestern Public Service Co	VP		
Southwestern Public Service Co	TREA		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
1480 Welton Inc	VP	305B	$ -
1480 Welton Inc	TREA	305B	$ -
Clearwater Investments Inc	DIR	305B	$ -
Clearwater Investments Inc	VP	305B	$ -
Clearwater Investments Inc	TREA	305B	$ -
e prime inc	DIR	305B	$ -
e prime inc	VP	305B	$ -
e prime inc	TREA	305B	$ -
Eloigne Company	DIR	305B	$ -
Eloigne Company	VP	305B	$ -
Eloigne Company	TREA	305B	$ -
Green and Clear Lakes Company	VP	305B	$ -
Green and Clear Lakes Company	TREA	305B	$ -
NCE Communications Inc	VP	305B	$ -
NCE Communications Inc	TREA	305B	$ -
NSP Nuclear Corporation	VP	305B	$ -
NSP Nuclear Corporation	TREA	305B	$ -
PSR Investments Inc	VP	305B	$ -
PSR Investments Inc	TREA	305B	$ -
Quixx Carolina Inc	VP	305B	$ -
Quixx Carolina Inc	TREA	305B	$ -
Quixx Corporation	VP	305B	$ -
Quixx Corporation	TREA	305B	$ -
Quixxlin Corp	VP	305B	$ -
Quixxlin Corp	TREA	305B	$ -
Reddy Kilowatt Corporation	TREA	305B	$ -
Reddy Kilowatt Corporation	VP	305B	$ -
Seren Innovations Inc	VP	305B	$ -
Seren Innovations Inc	TREA	305B	$ -
WestGas Interstate Inc	VP	305B	$ -
WestGas Interstate Inc	TREA	305B	$ -
WYCO Development LLC	OEP	305B	$ -
Xcel Energy Communications Group Inc	TREA	305B	$ -
Xcel Energy Communications Group Inc	VP	305B	$ -
Xcel Energy Foundation	TREA	305B	$ -
Xcel Energy Inc	VP	305B	$ -
Xcel Energy Inc	TREA	305B	$ -
Xcel Energy International Inc	TREA	305B	$ -
Xcel Energy International Inc	VP	305B	$ -
Xcel Energy Markets Holdings Inc	TREA	305B	$ -
Xcel Energy Markets Holdings Inc	VP	305B	$ -
Xcel Energy Performance Contracting Inc.	TREA	305B	$ -
Xcel Energy Performance Contracting Inc.	VP	305B	$ -
Xcel Energy Retail Holdings Inc	VP	305B	$ -
Xcel Energy Retail Holdings Inc	TREA	305B	$ -
Xcel Energy Services Inc	TREA	305B	$ -
Xcel Energy Services Inc	VP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	TREA	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	TREA	305B	$ -
Xcel Energy Transmission Development Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	TREA	305B	$ -
Xcel Energy Transmission Holding Company, LLC	VP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	VP	305B	$ -
Xcel Energy Ventures Inc	TREA	305B	$ -
Xcel Energy Wholesale Group Inc	VP	305B	$ -
Xcel Energy Wholesale Group Inc	TREA	305B	$ -
Xcel Energy WYCO Inc	VP	305B	$ -
Xcel Energy WYCO Inc	DIR	305B	$ -
Young Gas Storage Company Ltd	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/10/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

PLEASE READ THE INSTRUCTIONS ATTACHED BEFORE COMPLETING THIS FORM.

RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**	
VAN ABEL BRIAN J				**414 Nicollet Mall**	
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN	55401
4. Docket #	ID-7433	**5. Latest Date Authorized**			
6. Mail to Company		Xcel Energy Inc			

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
1480 Welton Inc	OEP	305B	$ -
Clearwater Investments, Inc.	OEP	305B	$ -
e prime inc	OEP	305B	$ -
Eloigne Company	OEP	305B	$ -
Green and Clear Lakes Company	OEP	305B	$ -
NCE Communications Inc	OEP	305B	$ -
NSP Nuclear Corporation	OEP	305B	$ -
NSP Lands, Inc.	OEP	305B	$ -
PSR Investments Inc	OEP	305B	$ -
Quixx Carolina Inc	OEP	305B	$ -
Quixx Corporation	OEP	305B	$ -
Quixxlin Corp	OEP	305B	$ -
Reddy Kilowatt Corporation	OEP	305B	$ -
Seren Innovations Inc	OEP	305B	$ -
United Power and Land Company	OEP	305B	$ -
WestGas Interstate Inc	OEP	305B	$ -
Xcel Energy Communications Group Inc	OEP	305B	$ -
Xcel Energy Inc	OEP	305B	$ -
Xcel Energy International Inc	OEP	305B	$ -
Xcel Energy Markets Holdings Inc	OEP	305B	$ -
Xcel Energy Performance Contracting Inc	OEP	305B	$ -
Xcel Energy Retail Holdings Inc	OEP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -
Xcel Energy Ventures Inc	OEP	305B	$ -
Xcel Energy Wholesale Group Inc	OEP	305B	$ -
Xcel Energy WYCO Inc	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/23/2015

Northern States Power Company

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment B

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

FEDERAL ENERGY REGULATORY COMMISSION
ANNUAL REPORT OF INTERLOCKING POSITIONS

Form Approved
OMB No. 1902-0099
(Expires 08/31/2014)

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RESPONDENT INFORMATION

1. Full name (Last, First, Middle Initial)				**2. Business Address (Street, City, State, and Zip Code)**	
WILENSKY SCOTT M				**414 Nicollet Mall**	
FERC USE:		**3. Report Year Ending**	2014	**Minneapolis**	MN 55401
4. Docket #	ID-6679	**5. Latest Date Authorized**			
6. Mail to Company		Xcel Energy Inc			

PUBLIC UTILITY DATA

(1) Name of Public Utility	(2) Position Code(s)	(1) Name of Public Utility	(2) Position Code(s)
Northern States Power Company (MN)	VP		
Northern States Power Company (MN)	OEP		
Northern States Power Company (WI)	VP		
Northern States Power Company (WI)	OEP		
Public Service Company of Colorado	VP		
Public Service Company of Colorado	OEP		
Southwestern Public Service Co	VP		
Southwestern Public Service Co	OEP		

INTERLOCKING ENTITY DATA

(3) Name of Entity	(4) Position Code(s)	(5) Type Code	(6) Total Revenue ($)
NCE Communications, Inc.	DIR	305B	$ -
Nuclear Management Company, LLC	VP	305B	$ -
Nuclear Management Company, LLC	OEP	305B	$ -
Xcel Energy Inc.	OEP	305B	$ -
Xcel Energy Inc.	VP	305B	$ -
Xcel Energy Services Inc	VP	305B	$ -
Xcel Energy Services Inc	OEP	305B	$ -
Xcel Energy Services Inc	DIR	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	VP	305B	$ -
Xcel Energy Southwest Transmission Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Development Company, LLC	VP	305B	$ -
Xcel Energy Transmission Development Company, LLC	OEP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	VP	305B	$ -
Xcel Energy Transmission Holding Company, LLC	OEP	305B	$ -

Signature: Signed **Reason for not having a signature:** **Date:** 4/24/2015

Format Number FERC 561 (REVISED 01/2010)

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment C

ELECTRIC UTILITY

JURISDICTIONAL ANNUAL REPORT

For Calendar Year 2014
(Minnesota Jurisdiction)

MINNESOTA DEPARTMENT OF COMMERCE

TABLE OF CONTENTS

Company Northern States Power Company

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For Calendar Year 2014
(Minnesota Jurisdiction)

MINNESOTA DEPARTMENT OF COMMERCE

TRANSACTIONS WITH AFFILIATES ANNUAL REPORTING

Regulated Operating Companies	Provided For	Provided By
Administrative Agreement with Xcel Operating Subsidiaries (1)		
NSP Wisconsin	19,070,216	620,425
Public Service Co. of Colorado	314,550	77,629
Southwestern Public Service Co.	52,894	14,559
Hayden Joint Venture	2,371	
Sub-total Regulated Operating Companies	**19,440,031**	**712,614**
NSP Minnesota Agreements from Prior to Xcel Merger (2)		
NSP Wisconsin Interchange Agreement (3)	474,541,853	145,101,746
NSP Wisconsin SCADA Agreement (4)	96,284	-
Total Previously Existing Agreement Transactions	**474,638,137**	**145,101,746**
Total Regulated Operating Companies	**$ 494,078,168**	**$ 145,814,360**

NOTES:

(1) This section includes transactions directed by E002/AI-01-493 Compliance Filing only.
Beginning in 2005, totals include inventory transfers not previously available for reporting

(2) This section includes transactions which fall under agreements between NSPM and NSPW that allowed to continue to operate under after the formation of Xcel Energy in August 2000.

(3) In accordance with FERC Docket No. ER14-1325-000, NSPM and NSPW Interchange Agreement , the cost sharing of electric transmission and production costs for 2014.

(4) NSPM and NSPW SCADA and gas dispatch Agreement, Docket G-002/AI-94-831, regarding sharing of SCADA costs

(5) "Provided By" represents service provided by the affiliate/nonregulated to NSPM
"Provided For" represents service provided by NSPM to affiliate/nonregulated

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment C

Company Northern States Power Company

Page E-13-2

For Calendar Year 2014
(Minnesota Jurisdiction)

MINNESOTA DEPARTMENT OF COMMERCE

	Provided For		Provided By
Parent Company			
Xcel Energy Services Inc.	835,136,859		1,254,445,783
Xcel Energy Inc.	-		167,557,531
Total Parent Company	**835,136,859**		**1,422,003,314**
Nonregulated Affiliates			
United Power & Land	352		-
NSP Nuclear	1,459		(240,000)
Xcel Energy Inc.	21,894		-
Total Nonregulated Affiliates	**23,705**		**(240,000)**
Nonregulated Activity			
Connect Smart	-		-
Homesmart	414,260		-
Infowise	534		-
Non-Regulated Street Lighting Maint.	29,939		-
Propane Gas	(204,306)	(2)	-
Sherco Steam to LPI	456,220		-
Other Non Utility	10,491		-
Other Non Regulated	2,077		-
Total Nonregulated Activity	**$ 709,214**		**$ -**

NOTES:

(1) "Provided By" represents service provided by the affiliate/nonregulated to NSPM
"Provided For" represents service provided by NSPM to affiliate/nonregulated

(2) Reflects propane provided by NSPM to non-jurisdictional customers. All of these propane revenues are included in FERC account 495, Other Gas Revenues. These revenues are included as an offset to retail revenues requirements in the state of Minnesota Gas Utility cost of service study. The cost of propane is recorded in FERC account 728.

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment C

Company Northern States Power Company

Page E-13-3

For Calendar Year 2014
(Minnesota Jurisdiction)

MINNESOTA DEPARTMENT OF COMMERCE

TRANSACTIONS WITH AFFILIATES ANNUAL REPORTING *

Service Company Charges to NSPM Utility Operating Company for 2014

Functional Class	Indirect Charges	Direct Charges	Total
Administrative and General	$ 148,880,948	$ 43,230,141	$ 192,111,089
Customer Accounting	22,116,364	141,181	22,257,545
Customer Service and Information	598,732	1,425,516	2,024,249
Distribution	4,120,763	5,797,447	9,918,210
Gas Production		309,098	309,098
Gas Storage		18,363	18,363
Power Production	3,174,089	22,902,731	26,076,819
Regional Markets		260,839	260,839
Customer Sales		2,336	2,336
Transmission	6,114,613	13,695,845	19,810,458
Utility Plant		131,804,357	131,804,357
Non-Utility Plant		1,122,876	1,122,876
Receivable		477,668	477,668
Clearing		20,674,676	20,674,676
Regulatory Assets		15,830,433	15,830,433
Regulatory Liabilities		408,790	408,790
Taxes	3,989,832	3,432,461	7,422,292
Other Income	14,957	(49,637)	(34,680)
Other Income Deductions	5,703,279	370,094	6,073,372
Interest Charges	276	190,701	190,977
Money Pool Activity	-		34,000,000
Insurance Premiums			25,686,014
Shared Asset Credit	-		(29,136,859)
Grand Total	$ 194,713,853	$ 262,045,916	$ 487,308,924

* Information provided based on Company's FERC Form 1 filing, page 429.

Company: Northern States Power Company

For Calendar Year 2014
(Minnesota Jurisdiction)

MINNESOTA DEPARTMENT OF COMMERCE

Administrative Services Agreement between Northern States Power Company and other Xcel Energy Inc. Utility Operating Company Subsidiaries Reporting Requirements Stipulated in MPUC Docket No. E-002/AI-01-493

As a condition of approval of the Administrative Services Agreement ("Agreement") between Northern States Power Company d/b/a Xcel Energy ("Xcel Energy" or "the Company") and its utility operating company affiliates, MPUC Docket No. E-002/AI-01-493 (order dated June 22, 2001), Xcel Energy agreed to provide the following annual reporting recommended by the Department of Commerce. By order dated April 10, 2002, the Commission authorized the Company to provide the information contemporaneous with affiliate transaction portion of the May 1st jurisdictional financial report.

A Heading that identifies the type of transactions
The transactions included in the amounts shown on page E-13-1 are made up of costs associated with providing incidental services, lease arrangements, use of equipment, and other goods provided at cost by the Company to an operating company affiliate, or by the affiliate to the Company.

The identity of the affiliated parties in the first sentence
The other utility operating company parties to the Agreement are Northern States Power Company (Wisconsin) ("NSPW"), Public Service Company of Colorado ("PSCO") and Southwestern Public Service Company. Page E-13-1 lists the Xcel Energy affiliate included in the Agreement and the dollars charged to the affiliate by the Company or to the Company by the affiliate under the Agreement.

A general description of the nature and terms of the agreement, including the effective date of the contract or arrangement and the length of the contract or arrangement
The Agreement allows the operating utilities to share a limited amount of services, leasing arrangements, equipment, and other goods between them when it is mutually beneficial to the operating utilities involved. The Agreement allows these transactions to occur on an "at-cost" basis, consistent with U.S. Securities and Exchange Commission rules applicable to registered holding company systems. This costing methodology is also consistent with the fully allocated costing principles adopted by the MPUC in Docket No. G,E999/CI-90-1008.

Company Northern States Power Company

For Calendar Year 2014
(Minnesota Jurisdiction)

Administrative Services Agreement between Northern States Power Company and other Xcel Energy Inc.
Utility Operating Company Subsidiaries Reporting Requirements Stipulated in MPUC Docket No. E-002/AI-01-493

A list and the past history of all current contracts or agreements between the utility and the affiliate, the consideration received by the affiliate for such contracts or agreements, and a summary of the relevant costs records related to these ongoing transactions.
Page E-13-1 shows the additional agreements under which Xcel Energy and NSPW currently provide services (see footnote 2). The gas SCADA and gas dispatch cost sharing agreement was approved in MPUC Docket No. G002/AI-94-831. The "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy" between the Company and NSPW was accepted for filing in FERC Docket No. ER14-1325-000 effective January 1, 2014, restating the similar 1984 "Interchange Agreement", and allocates electric production and transmission costs for the integrated electric system. Both agreements existed prior to the formation Xcel Energy Inc. and were assigned to the Company as part of the August 2000 merger transactions.

The amount of compensation and, if applicable, a brief description of the cost allocation methodology or market information used to determine cost or price.
The price or cost of the goods or services was based on the actual cost to the operating utility company providing the goods or services.

If the service or good acquired from an affiliate is competitively available, an explanation must be included stating whether competitive bidding was used, and if it was used, a copy of the proposal or a summary must be included. If it is not competitively bid, an explanation must be included stating why bidding was not used.
For 2014, the goods and services provided were billed at cost to the operating utility company affiliate and were provided on a limited "as available" basis. For this reason, there were no situations were competitive bidding was warranted.

If the arrangement is in writing, a copy of that document must be attached.
Other than the Agreement, there were no arrangements made in writing for 2014.

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
DOC Information Request No. 106
Attachment C

Company Northern States Power Company

For Calendar Year 2014
(Minnesota Jurisdiction)

XCEL ENERGY COMPLIANCE REPORTING RELATED TO DOCKET NO. G,E-999/CI-90-1008

Introduction

Pursuant to the Commission's order setting filing requirements, Northern States Power Company d/b/a Xcel Energy ("Xcel Energy") responded to the Commission's ordering paragraph (3) in Docket No. G, E-999/CI-90-1008, the investigation into the competitive impact of appliance sales and service practices of Minnesota gas and electric utilities:

> "Within 60 days of the date of this order, each utility party to this proceeding shall submit a filing explaining: 1) whether its method of allocation is a fully allocated costing approach; 2) whether it complies with the recommended cost allocation principles; and 3) if it does not comply with the recommended cost allocation principles, whether its methods would accomplish similar results."

Xcel Energy had multiple non-regulated services and subsidiaries. We follow the same cost allocation process for both of these types of activities. The cost allocation approach is a fully allocated costing method as approved by the Commission in our electric and gas rate cases (E002/GR-92-1185 and G002/GR-92-1186).

The Commission's stated hierarchical cost allocation principles are:

1. Tariffed rate shall be used to value tariffed services provided to the non-regulated activity.

2. Costs shall be directly assigned to either regulated or non-regulated activities whenever possible.

3. Costs that cannot be directly assigned are common costs, which shall be grouped into 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-causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available.

4. Whenever neither direct nor indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator computed by using the ratio of all expenses directly assigned or attributed to regulated and non-regulated activities.

Xcel Energy follows this basic approach. Our process accomplishes the proper separation of costs between Xcel Energy's regulated utility business and non-regulated operations. Each activity that can be considered outside of Xcel Energy's core electric and gas business is reviewed for regulated/non-regulated treatment. If the activity is identified as non-regulated operations, the non-regulated cost allocation process is followed.

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

Xcel Energy Non-regulated Cost Allocation Process

Xcel Energy's approach includes the following steps of analysis: business profiles, direct charging, cost causation allocation, corporate residual allocation, overhead allocations, and the working capital fee.

Business Profile

The allocation process begins by reviewing for each non-regulated business the services they anticipate Xcel Energy's utility business will be providing.

Direct Charges (Addresses Principle #2)

Budgeted cross charges between Xcel Energy service providers and non-regulated businesses are reviewed with the business. Any process, project or service performed for the direct benefit of a non-regulated business is directly charged to the business. The business area providing service to the non-regulated business communicates the anticipated level of service and what the cost will be for the upcoming year.

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Actual charges for labor are assigned to the non-regulated business by either setting up a fixed labor distribution or though exception time reporting. The non-labor charges are directly charged. This process enables charging for all service that is provided; including what may not have been anticipated at budget time.

Cost Causation Allocations (Addresses Principle #2)
If no direct charge has been established for a service expected it be provided, a cost causation allocation is developed. Direct charging is preferred, however, if a service is expected to be provided and was not budgeted as a direct charge, an estimate of the cost of the service is made and allocated to the non-regulated business. An example of this would be, when a service is being provided, but it is at such a minimal level that it would be very difficult or cost prohibitive to charge on a direct basis.

Overhead Costs (Addresses Principle #3)
The overhead allocation factor captures indirect costs associated with providing services to others. Xcel Energy currently uses separate rates for labor and non-labor costs. The labor overhead rate was developed based on employee related expenses (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 non-labor overhead rate is developed based on procurement and material-related costs. The overhead factor is applied to all direct charges.

Corporate Residual Allocation
For non-regulated services wholly contained within the NSP Minnesota, a portion of NSP Minnesota's corporation costs are assigned based on the relative size of the non-regulated business.

Working Capital Fee (Addresses Principle #3)
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 the non-regulated businesses.

Summary
Xcel Energy's process has been reviewed in a number of dockets including our most recent general rate cases and complies with the common objective stated in the instant docket.

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Xcel Energy Services Cost Allocations
Summary of Review and Monitoring of Indirect Cost Allocations

As a condition of approval of the Service Agreement, between Xcel Energy Services, Inc. (“XLS” or “Service Company”) and Northern States Power Company d/b/a Xcel Energy, MPUC Docket No. G,E002/AI-00-1251, Xcel Energy agreed to provide, with our Minnesota jurisdictional annual report, a summary of the review and monitoring done to ensure appropriate allocation of service company costs. In addition, the report was required to identify any changes in cost allocators or changes to companies that are allocated such costs. On August 1, 2000, XLS began operating as the Service Company of Xcel Energy Inc. The indirect cost allocators implemented at that time were those approved by the MPUC in the above docket.

Changes to Indirect Cost Allocators - Methods
The indirect cost allocation methods approved in the MPUC Docket No. E,G002/AI-14-0234 were used in the 2014 costs allocations included in this filing.

Changes to Indirect Cost Allocators – Companies Added/Deleted
For the year ended December 31, 2014, some minor changes were made in the Xcel Energy Inc. affiliate companies included in the XLS indirect cost allocators. A summary of these changes is included on 13-10 through 13-15 of this report.

Changes to Indirect Cost Allocators – Updated Base Data
For the year ended December 31, 2014, no updates were made to the base data used to develop the indirect cost allocators.

Summary of Review and Monitoring of Indirect Cost Allocators
For the year ended December 31, 2014, monthly detailed statements were sent to the affiliate company financial organizations These statements included all billings (both direct billings and indirect cost allocations) to them from XLS for their review and approval. In addition, detailed statements were also provided to the service function service providers for their review. As a result, both service receivers (affiliate companies) and service providers (service functions) initiated discussions with XLS which, in some cases, resulted in adjustments to billings and changes in indirect cost allocators. The changes included on 13-10 through 13-15 of this report is a log of the changes that were made to the indirect cost allocators as a result of this process.

Northern States Power Company

Docket No. E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Docket No. E002/GR-12-961
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MINNESOTA DEPARTMENT OF COMMERCE

XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes

Description	JDE Subledger	Status	Effective Jan-14	Effective Apr-14	Effective Dec-14
Executive - Corp Governance	110				
Executive (exclusive)	111	**Inactive 8-04**			
Board of Directors - Corp Gov	114			Updated Statistics	
Shareholder - Corp Gov	115			Updated Statistics	
Investor Relations - Corp Gov	116			Updated Statistics	
Acctg, Reporting, & Taxes	120			Updated Statistics	
Acctg. & Reporting - Corp Gov	121			Updated Statistics	
Taxes - Corp Gov	122	**Inactive 4-14**		Inactive	
Accounting - Op Co's	123			Updated Statistics	
Accting PSCo & SPS	124			Updated Statistics	
Accounting NSPM & NSPW	125			Updated Statistics	
Acctg NSPM & NSPW Electric	126			Updated Statistics	
Accounting OPCos Elec	127			Updated Statistics	
Prop Trad NSPM, PSCo &SPS	128		Updated Statistics	Updated Statistics	
Gen Prop Tradg OPCos	129		Updated Statistics	Updated Statistics	
Audit Services	130			Updated Statistics	
Audit Services - Corp Gov	131			Updated Statistics	
AUDIT Serv OPCos	132			Updated Statistics	
AUDIT OPCos Electric	133			Updated Statistics	
AUDIT OPCos Gas	134			Updated Statistics	
CA ACCTG	135			Updated Statistics	
Finance & Treasury	140			Updated Statistics	
Finance & Treasury - Corp Gov	141			Updated Statistics	
Risk Management	142			Updated Statistics	
Risk Management - Corp Gov	143			Updated Statistics	
Prop Tradg FERC 557	144		Updated Statistics	Updated Statistics	
Prop Gen Tradg FERC 557	145		Updated Statistics	Updated Statistics	
Risk OPCos	146			Updated Statistics	
Captive Insurance	147			Updated Statistics	
Corporate Strategy & Bus Dev	160	**Inactive 4-14**		Inactive	
Corporate Strategy & Bus Dev - Corp Gov	161			Updated Statistics	
CORP STRAT OPCo	162			Updated Statistics	

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MINNESOTA DEPARTMENT OF COMMERCE

XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-14	Effective Apr-14	Effective Dec-14
Legal OPCo Elec	163			Updated Statistics	
Legal OPCo Gas	164			Updated Statistics	
Legal	170			Updated Statistics	
Legal - Corp Governance	171			Updated Statistics	
LEGAL NSPM & NSPW	172			Updated Statistics	
LEGAL NSPM & NSPW Electric	173			Updated Statistics	
LEGAL OPCos	174			Updated Statistics	
Communications - Corp Gov	180			Updated Statistics	
Employee Communications	181			Updated Statistics	
Xcel Foundation	182			Updated Statistics	
Employee Communications - exclusive	183	**Inactive 4-07**			
Branding	184			Updated Statistics	
Customer Safety Advertising/Information Costs	185			Updated Statistics	
HR Corp Governance	189			Updated Statistics	
HR (Diversity/Safety/Emp Relations)	190			Updated Statistics	
HR - Energy Supply	191	**Inactive 4-13**			
HR - Energy Delivery	192	**Inactive 4-13**			
HR - Retail	193	**Inactive 4-13**			
Payroll - South	194	**Inactive 8-04**			
Payroll - North	195	**Inactive 8-04**			
HR - Energy Markets	196	**Inactive 1-14**	Inactive		
HR - Op Co's	197			Updated Statistics	
Payroll	198			Updated Statistics	
HR - Recruitment	199			Updated Statistics	
Facilities	200	**Inactive 5-11**			
Facilities - Admin	201	**Inactive 5-11**			
Supply Chain Special Programs	220	**Inactive 1-08**			
HR - Benefits	240	**Inactive 8-04**			
Customer Service (inclusive)	400	**Inactive 12-04**			
Customer Service - South	401	**Inactive 12-04**			
Customer Service - North	402	**Inactive 12-04**			
Customer Service IT - FERC 903	403			Updated Statistics	

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XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-14	Effective Apr-14	Effective Dec-14
Customer Service IT FERC 903 - South	404			Updated Statistics	
Customer Service IT FERC 903 - North	405			Updated Statistics	
Energy Deliv Fin Svcs (inclusive)	406	**Inactive 12-04**			
Federal Lobbying	409			Updated Statistics	
Governmental Affairs	410			Updated Statistics	
Marketing & Sales (use 412)	411	**Inactive 1-08**			
Marketing & Sales	412			Updated Statistics	
Payment and Reporting	413			Updated Statistics	
ES A&G FERC 921	414			Updated Statistics	
Energy Markets - Fuel	415			Updated Statistics	
Supply Chain	416			Updated Statistics	
Rates & Regulation	417			Updated Statistics	
Rates Electric	418			Updated Statistics	
Rates & Regulation - all	418	**Inactive 5-05**			
Customer Service - 903	419	**Inactive 10-08**			
Customer Service - South - 903	420	**Inactive 10-08**			
Customer Service - North - 903	421	**Inactive 4-08**			
C&FO Constr, Oper & Maint	423			Updated Statistics	
Receipts Processing	428	**Inactive 1-08**			
Energy Markets - Regulated Trading	429			Updated Statistics	
Energy Supply Asset Management	430			Updated Statistics	
Energy Markets - Business Services	431			Updated Statistics	
C&FO Financial Services	432	**Inactive 1-10**			
Enterprises Financial Services	433	**Inactive 12-04**			
Shared Services Financial Services	434	**Inactive 2-10**			
Customer Care 903	435			Updated Statistics	
Customer Care 902	436			Updated Statistics	
Customer Care 901	437			Updated Statistics	
Customer Care South 903	438			Updated Statistics	
Customer Care North 903	439			Updated Statistics	
Utilities Group A&G FERC 921	440			Updated Statistics	
Distribution Electric FERC 580	441			Updated Statistics	

Northern States Power Company

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For Calendar Year 2014
(Minnesota Jurisdiction)

Minnesota Department of Commerce

XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-14	Effective Apr-14	Effective Dec-14
Transmission Electric FERC 560	442			Updated Statistics	
Distribution Gas FERC 870 (E&S)	443			Updated Statistics	
Transmission Gas FERC 850	444			Updated Statistics	
Distribution Gas FERC 880 (Misc)	445			Updated Statistics	
CC Low Income Assistance 908	446			Updated Statistics	
Customer Billing FERC 903	447			Updated Statistics	
Transm Elec 560 PSCo & SPS	448	**Inactive 4-14**		Inactive	
Transm Elec 560 NSPM & NSPW	449			Updated Statistics	
Transm Elec FERC 566	450	**Inactive 4-14**		Inactive	
Transm Elec FERC 561.5	451			Updated Statistics	
Transm Elec FERC 561.2	452	**Inactive 4-14**		Inactive	
Distribution Elec FERC 586	453			Updated Statistics	
Distribution Gas FERC 878	454			Updated Statistics	
ES Misc Power Expense Op Co's	455			Updated Statistics	
ES Misc Power Expense North	456			Updated Statistics	
ES Misc Power Expense South	457			Updated Statistics	
ES Operations Management OPCo's	458			Updated Statistics	
ES Operations Management North	459			Updated Statistics	
ES Operations Management South	460			Updated Statistics	
ES Engineering & Construction OPCo's	461			Updated Statistics	
ES Engineering & Construction North	462			Updated Statistics	
ES Engineering & Construction South	463			Updated Statistics	
ES Environmental Policy & Services OPCo's	464			Updated Statistics	
ES Environmental Policy & Services North	465			Updated Statistics	
ES Environmental Policy & Services South	466			Updated Statistics	
Transm Elec FERC 561.5 North	467	**Inactive 4-14**		Inactive	
Transm Elec FERC 566	468			Updated Statistics	
Elec Dist FERC 588	469			Updated Statistics	
Gas Dist FERC 813	470			Updated Statistics	
Elec Dist FERC 588 North	471			Updated Statistics	
Elec Dist FERC 588 South	472			Updated Statistics	
Gas Dist FERC 813 North	473			Updated Statistics	
Gas Dist/Elec Dist/Gas Trans Finance FERC 588, 880, 859	474			Updated Statistics	

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XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-14	Effective Apr-14	Effective Dec-14
Non-labor alloc. following labor	910	**Inactive 1-10**			
Labor allocator	920	**Inactive 3-07**			
Business Systems	500				
CIS (Customer Information System) (use 503)	501	**Inactive 4-07**			
CSS (use 503)	502	**Inactive 4-07**			
CRS (Customer Resource System)	503			Updated Statistics	
Maximo	504			Updated Statistics	
JDE (J.D. Edwards)	505			Updated Statistics	
GIS (Geographic Information System) Distribution	506			Updated Statistics	
OMS (Outage Management System)	507			Updated Statistics	
e-Business	508			Updated Statistics	
Passport - all modules	509			Updated Statistics	
Passport - Accounts Payable	510			Updated Statistics	
Passport - Inventory	511	**Inactive 3-11**			
Passport - Work Management	512			Updated Statistics	
Passport - Purchasing	513			Updated Statistics	
Misc. Applications	514			Updated Statistics	
PeopleSoft	515			Updated Statistics	
PowerPlant	516			Updated Statistics	
GMS (Gas Management System)	517			Updated Statistics	
MDMS (Monitoring Devise Management System)	518			Updated Statistics	
CL/QM (Call Logging and Quality Management)	519			Updated Statistics	
IVR (Interactive Voice Response)	520			Updated Statistics	
Time/PTRS	521			Updated Statistics	
ERS (Electric Reliability System)	522	**Inactive 1-12**			
Network	523			Updated Statistics	
DSS Support	524			Updated Statistics	
Utility Innovations	525			Updated Statistics	
EMS-Transmission (Energy Mgmt System-SCADA)	526			Updated Statistics	
EMS-Distribution (Energy Mgmt System-SCADA)	527			Updated Statistics	
EMS-Shared (Energy Mgmt System-SCADA)	528			Updated Statistics	
Mercury Interactive	529			Updated Statistics	
DAMS (Delivery Asset Management System)	530	**Inactive 3-11**			
Gas SCADA	531			Updated Statistics	
Utility Innovations - Advertising	532	**Inactive 1-12**			
CBS/ALS/CFM	533			Updated Statistics	
CES	534			Updated Statistics	
Altra Power (ACES)	535			Updated Statistics	

Company Northern States Power Company

For Calendar Year 2014
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XLS JDE Indirect Allocations
Log of Additions/Deletions/Changes (Cont'd)

Description	JDE Subledger	Status	Effective Jan-14	Effective Apr-14	Effective Dec-14
Design Tool	536			Updated Statistics	
Eclipse	537			Updated Statistics	
Electronic Deal Ticketing	538	**Inactive 3-11**			
Flipper	539			Updated Statistics	
Meter Reading Acquisition System (MRAS)	540			Updated Statistics	
Panorama	541	**Inactive 3-11**			
PCI	542			Updated Statistics	
Transmission Accounting and Billing System(TABS)	543	**Inactive 3-11**			
EAI/ESB (Enterprise Application Integration/Enterprise Service Bus)	544			Updated Statistics	
CBS Municipal Billing System	545	**Inactive 3-11**			
CFO Systems	549			Updated Statistics	
HR Systems	550			Updated Statistics	
Corporate Systems	551			Updated Statistics	
Security Systems	552			Updated Statistics	
Energy Supply Systems	553			Updated Statistics	
Business Objects	554			Updated Statistics	
Revenue Reporting System (RRS)	555			Updated Statistics	
FARRMS REC	556	**Inactive 3-11**			
Mobile Computing	559			Updated Statistics	
GIS (Geographic Information System) Transmission	560	**Inactive 1-12**			
Enterprise Continuity	561			Updated Statistics	
Mainframe Charges From IBM	562			Updated Statistics	
SAP General Ledger	563				New

Reviews (Non IT)	**Jan-14**	**Apr-14**	**May-14**
Input/update data in Matrix	Jim Foland	Carrie Authier	Carrie Authier
Verified Matrix links to allocations sheets	Jim Foland	Carrie Authier	Carrie Authier
Reviewed input for keying errors	Carrie Authier	Jim Foland	Jim Foland
Serivce Company Acctg verified and approved input data for reasonableness	Olga Odell	Olga Odell	Olga Odell
Reviewed report (R55VNUA)- verified all total 100%	Carrie Authier	Carrie Authier	Carrie Authier
These reviews should be done and signed off on after every update to the allocations.			

Reviews (IT)	**Jan-14**	**Apr-14**	**May-14**
Input/update data in Matrix	Jim Foland	Carrie Authier	Carrie Authier
Verified Matrix links to allocations sheets	Jim Foland	Carrie Authier	Carrie Authier
Reviewed input for keying errors	Carrie Authier	Jim Foland	Jim Foland
Serivce Company Acctg verified and approved input data for reasonableness	Olga Odell	Olga Odell	Olga Odell
Reviewed report (R55VNUA)- verified all total 100%	Carrie Authier	Carrie Authier	Carrie Authier
These reviews should be done and signed off on after every update to the allocations.			

Docket No. E002/GR-12-961
Information Request No. DOC-144

Question:

Subject: NSPM's Non-Regulated Business Activities

Please discuss why the Customer-Owned Street Lighting Maintenance and the Sherco Steam Sales to Liberty Paper activities are classified as non-regulated activities and how these activities are treated for rate-making (Stitt, IV. Cost Assignment Allocation and Framework, C. Allocation Methods and Factors, 3. Utility Allocations, E. Non-Regulated Business Activity Allocations).

Response:

Customer-Owned Street Lighting Maintenance

Customers that own their own lighting systems (such as municipal government entities) take regulated energy-only service from the Company. The Company provides two energy-only rate schedules for street lighting in Section No. 5 of the Minnesota Electric Rate Book:

- Street Lighting Energy Service (Closed), Rate Code A32, Rate Sheet Nos.76-77, and
- Street Lighting Energy Service – Metered, Rate Code A34, Rate Sheet Nos.78-78.1.

The optional maintenance service available to these customers is non-regulated.

In the Company's 1991 general rate case (Docket No. E002/GR-91-1), the Commission decided that maintenance for customer-owned street lighting was a competitive service and should be deregulated. The November 27, 1991 Order found:

> NSP's maintenance service for customer-owned equipment is deregulated herewith. Within 60 days of this Order, NSP shall file its proposed accounting and allocation procedures for removing this service from regulated operations. Any proposals that the Company may wish to file regarding standards for customer-owned equipment maintenance contractors shall be filed within 60 days of this Order.

In compliance, the Company filed a compliance plan regarding street lighting services. The Commission approved the compliance plan in its October 26, *1992 Order Accepting Plan and Requiring Notice* in Docket No. E-002/M-92-614:

> The Commission finds that NSP's proposed deregulation plan for its street lighting maintenance and repair service fulfills the requirements of the Commission's directive in its November 27, 1991 Order. The Company's proposed accounting system will properly allocate costs between NSP's regulated and nonregulated entities, and will provide a sufficient basis for monitoring possible cross-subsidization.

Regarding the treatment in rate-making, no customer-owned equipment was included in rate base. The costs and revenues associated with the provision of maintenance services for customer-owned lighting are not included in the test year. However, the regulated energy service costs and revenues related to providing electric service to customer-owned equipment are included in the test year.

Sherco Steam Sales to Liberty Paper

Liberty Paper operates a facility on land adjoining the Sherco generation plant. A steam line was constructed to the Liberty Paper facility to meet its thermal energy needs. In Docket No. E002/M-93-1253, the Company petitioned the Commission for permission to treat the construction and operation of the steam supply system as a non-regulated venture. The Commission approved the Company's proposed accounting treatment for steam sales to Liberty Paper in its February 14, 1995 ORDER in Docket No. E002/M-93-1253.

Regarding the treatment in rate-making, costs associated with construction were segregated from rate base for ratemaking purposes with O&M expenses being recorded in nonutility operating accounts on an incremental basis. The corresponding revenue associated with the Liberty Paper facility is also recorded in FERC 417, a nonutility operating account.

Preparer:	Steven V. Huso / Shari Cardille
Title:	Pricing Consultant / Principal Rate Analyst
Department:	Regulatory Analysis / Revenue Requirements – North

Docket No. E002/GR-12-961
Information Request No. DOC-1108

Question:

Subject: MISO Schedules and Attachments

A. For each MISO Schedule, please provide a brief description of the MISO charge (both revenues and expenses), how this charge is reflected in retail rates through rate cases, riders, or any other recovery mechanisms. Please include charges by MISO Schedule. If not reflected in retail rates, please provide a brief explanation for why this is appropriate.

B. For each MISO Attachment, please provide a brief description of the MISO charge (both revenues and expenses), how this charge is reflected in retail rates through rate cases, riders, or any other recovery mechanisms. Please include charges by MISO Attachment. If not reflected in retail rates, please provide a brief explanation for why this appropriate.

Response:

A. Attachment A to this response includes a brief description of each MISO schedule, how the charge is reflected in retail rates, and the budgeted 2016 charges by MISO schedule. A reference to Volume 4 Workpapers of the Application has also been included. The detailed schedules are available at: https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx

B. With the exception of Attachment O, the MISO Attachments do not have charges directly associated with them; any charges are recovered through an accompanying MISO Schedule. Attachment O provides the rate formulas for determining a MISO member's Annual Transmission Revenue Requirement (ATRR). Like other vertically-integrated MISO members, NSP imputes expenses associated with its own ATRR, as these costs are recovered in base rates, and pays a share of expenses associated with other MISO members who own transmission facilities in the NSP pricing zone. NSP receives revenues from wholesale transmission customers in the NSP zone (based on the rates calculated in Attachment O). These revenues are credited against the retail cost of service. A brief description of the MISO Attachments is available at the website listed in part A of our response.

Preparer:	Thomas Kramer / Nick Morlan
Title:	Principal Rate Analyst / Principal Financial Consultant
Department:	Revenue Requirements – North / Transmission Accounting

Docket No. E002/GR-12-961
Information Request No. DOC-1108, Attachment A

Docket E002/GR-15-826
Exhibit___(AEH-1), Appendix A

Northern States Power Company-Minnesota

MISO Schedules

Schedule #	Brief Description	Rate Recovery Mechanism	2016 Expense	Rate Case Work Paper	2016 Revenue	Rate Case Work Paper
1	Scheduling, System Control and Dispatch Service	Electric Base Rates	$307,635	W/P O2-2	$1,154,354	W/P R2-2
2	Reactive Supply and Voltage	Electric Base Rates	$9,273,067	W/P O2-2	$8,408,509	W/P R2-2
3	Regulating Reserve	FCA				
4	Energy Imbalance Service	FCA				
5	Spinning Reserve	FCA				
6	Supplemental Reserve	FCA				
7	Long-Term and Short-Term Firm Point-To-Point Service	Electric Base Rates	$71,111	W/P O2-2	$8,872,056	W/P R2-2
8	Non-Firm Point to Point Transmission Service	Electric Base Rates	$0		$561,206	W/P R2-2
9	Network Integration Transmission Service	Electric Base Rates	$9,398,907	W/P O2-2	$31,772,307	W/P R2-2
10	ISO Cost Recovery Adder	Electric Base Rates	$7,112,580	(A)	$0	
10-FERC	Annual Charges Recovery	Electric Base Rates	$3,150,784	W/P O2-2	$0	
16	FTR Administrative Service Cost Recovery	Electric Base Rates		(B)	$0	
17	Energy Market Support Cost Recovery	Electric Base Rates	$5,943,474	(B)	$0	
23	Recovery of Schedule 10 and Schedule 17 Costs from GFAs	Electric Base Rates		(C)	$0	
24	Local Balancing Authority Cost Recovery	Electric Base Rates	$884,729	W/P O2-2	$1,277,970	W/P R2-2
26	Network Upgrade from Transmission Expansion Plan	MN TCR Rider	$86,849,041	W/P O2-2	$90,285,317	W/P R2-2
26-A	Multi-Value Project Usage Rate	MN TCR Rider	$34,421,748	(D)	$58,031,388	W/P R2-2
37	MTEP Project Cost Recovery for ATSI Zone	MN TCR Rider	$0		$0	
38	MTEP Project Cost Recovery for DEO and DEK Version	MN TCR Rider	$0		$0	
			$157,413,075		$200,363,106	

(A) on W/P O2-2 This is the sum of BU 371120 Object 637262, 637264, and 637266

(B) Sum of amounts = 7,129,549 agrees with Schedule 16 & 17 total on W/P O2-2

(C) on W/P O2-2 This is the sum of BU 371121 Object 637260, 637262, 637264, and 637266

(D) on W/P O2-2 This is the sum of BU 371120 Object 637245

Energy related MISO charges flow through the Fuel Clause Adjustment (FCA).

Docket No. E002/GR-15-826
Exhibit___(AEH-1), Appendix A

Docket No. E002/GR-13-868
Information Request No. MCC-208

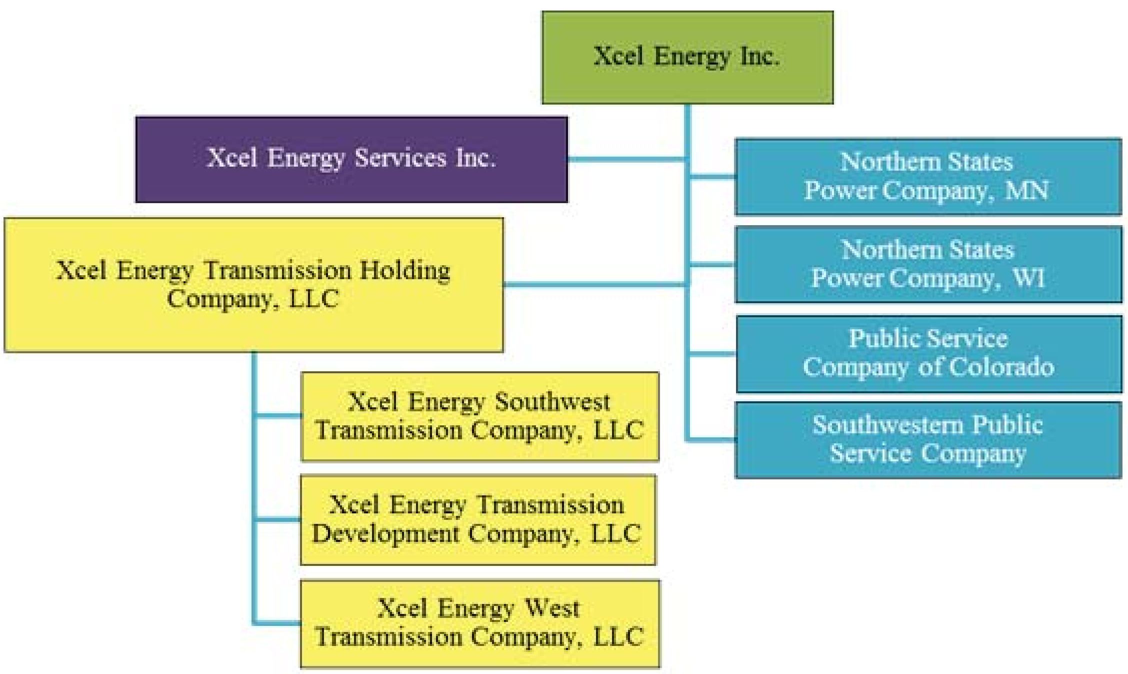
Question:

For Xcel's recently announced Transco, please provide:

a. Business structure of organization, ownership, and organization diagram
b. Required regulatory approvals, FERC plus state by state plus schedule
c. Projects to be included, capital investments, and revenue requirements
d. Projected impact on NSP-M and MN jurisdiction revenue requirements at least through 2018.

Response:

a. The following chart shows the organizational structure for the Transco.



b. In November 2014, FERC approved the transmission formula rate filings of XETD and Xcel Energy Southwest Transmission Company, LLC (XEST) under Section 205 of the Federal Power Act, subject to submission of certain compliance filings. The compliance filings were submitted in January 2015. *Xcel Energy Transmission Development Co., LLC* 149 FERC ¶ 61,181 (2014); *Xcel Energy Southwest Transmission Company, LLC,* 149 FERC ¶ 61,182 (2014). The

XEST formula rate filing, to be included in the Southwest Power Pool, Inc. OATT, was set for settlement judge procedures after certain parties protested the filing, and remains in settlement judge procedures. The parties have reached a settlement in principle and expect to file a settlement before October 30, 2015.

FERC also approved the FPA Section 204 financing filing submitted by XETD and XEST. *Xcel Energy Southwest Transmission Company, LLC et al,* 150 FERC ¶ 61,169 (2015).

On September 22, 2015, FERC issued deficiency letters asserting the January 2015 XETD and XEST compliance filings describing the allocations of costs by Xcel Energy Services Inc. (XES) to XETD and XEST were deficient and requiring submission of additional information. On October 16, 2015, FERC granted extensions of time to submit the responses, and XETD and XEST will submit further compliance filings in November 2015. The XETD and XEST formula rate compliance filings are pending FERC action.

In July, 2015, the Minnesota PUC issued an order approving the August 2014 affiliated interest agreement filing submitted by NSPM in Docket No. E002/AI-14-759. No other state filings have been submitted. No other state pre-approvals were required.

It is expected that Transco opportunities in the MISO region would be largely defined by the MISO Order No. 1000 competitive process tariff. Order No. 1000 was upheld on appeal by the D.C. Circuit Court of Appeals. The appeals of the MISO and SPP regional compliance filings are pending in the 7th Circuit Court of Appeals and D.C. Circuit Court of Appeals, respectively.

c. There are no Projects, and therefore neither capital investment nor revenue requirements. The first proposed competitive project is a $17.5 million (SPP cost estimate) investment in SPP that is scheduled to be bid at the same time as the MN Electric Rate Case 15-826. The second proposed project is $58M (MISO cost estimate) investment in MISO that is scheduled to be bid in the first half of 2016.

d. Xcel Energy Inc.'s Transco initiative is not expected to have any impact on the NSPM and State of Minnesota electric jurisdiction revenue requirements in the 2016 test year or years 2017 – 2018 of our current electric rate case.

The Company proposed, and the MPUC approved, a "true-up" mechanism to address test year impacts of Transco activities in the affiliated interest filing in Docket No. E002/AI-14-759.

Preparer: Cheryl A. Bredenbeck
Title: Director, Transmission Investment Development
Department: Transmission Investment

Docket No. E002/GR-13-868
Information Request No. OAG-105

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional electric unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations.

Reference: NOL and deferred taxes.

Provide the historical (by year) and most recent status of tax NOL carryforwards and carrybacks and identify the deferred taxes that have and have not been utilized for the benefit of ratepayers.

Response:

Attachment A to this response provides the annual activity and ongoing balances associated with the deferred tax asset generated by income tax net operating loss and unused tax credits. This schedule covers the complete history as reported in the Company's May 31, 2015, Annual Compliance Filing, the 2015 rate case bridge year, the 2016 rate case test year, and the long range forecast associated with this data. Year by year balance buildup and utilization is also indicated on the schedule.

As noted on the schedule, the 2016 test year and subsequent forecast data assumes the Company has sufficient revenues to earn the requested return on rate base in the filed case. Based on these assumptions, the deferred tax asset balance associated with these items will be complete utilized by the end of 2019.

Witness:	Anne E. Heuer
Preparer:	Jeffrey C. Robinson
Title:	Regulatory Consultant
Department:	Revenue Requirements - North

Docket No. E002/GR-13-868
Information Response No. OAG-105 Attachment A

Docket No. E002/GR-15-826
Exhibit___(AEH-1), Appendix A

Northern States Power Co. Minnesota
Minnesota Retail Electric Jurisdiction
Net Operating Loss (NOL) Related Deferred Tax Asset Balance Reporting
Prior Period Reported Results and Rate Case Forecast
Dollars in thousands

	History Period								
	2010 YE Ann Rpt Balance	**2011 Annual Activity**	**2011 YE Ann Rpt Balance**	**2012 Annual Activity**	**2012 Ann Rpt Balance**	**2013 Annual Activity**	**2013 Ann Rpt Balance**	**2014 Annual Activity**	**2014 Ann Rpt Balance**
EOY Unused Deduction Balance	232,103	356,584	588,687	(173,629)	415,058	210,670	625,729	(232,642)	393,087
Tax Effect of Deduction Balance	94,853	145,369	240,222	(70,890)	169,332	86,037	255,369	(95,102)	160,267
EOY Unused Credit Balance	9,958	17,078	27,036	18,482	45,518	25,188	70,706	26,857	97,563
Total (EOY Rate Base)	**104,812**	**162,447**	**267,258**	**(52,408)**	**214,850**	**111,225**	**326,075**	**(68,245)**	**257,830**
	Initial Build-up	Build-up		Utilization		Build-up		Utilization	

	Rate Case Bridge Year			Rate Case Test Year (1)		Forecast (1)						
	2014 Ann Rpt Balance	**2015 Annual Activity**	**2015 RC Bridge Yr Balance**	**2016 Annual Activity**	**2016 RC Test Yr Balance**	**2017 Annual Activity**	**2017 Forecast Balance**	**2018 Annual Activity**	**2018 Forecast Balance**	**2019 Annual Activity**	**2019 Forecast Balance**	
EOY Unused Deduction Balance	393,087	(97,341)	295,746	(295,746)	(0)	0	(0)	0	(0)	0	(0)	
Tax Effect of Deduction Balance	160,267	(39,725)	120,543	(120,693)	(150)	0	(150)	0	(150)	0	(150)	
Total (EOY Rate Base)	**257,830**	**(13,119)**	**244,711**	**(89,409)**	**155,302**	**(52,982)**	**102,320**	**(62,136)**	**40,184**	**(40,335)**	**(150)**	(2)

(1) Assumes Company has sufficient revenue to earn the requested cost of capital.
(2) Minor residual balance due to changing annual composite tax rates.

Docket No. E002/GR-13-868
Information Request No. OAG-117

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional electric unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations.

Reference: Sparby Direct, pg. 5.

Explain and quantify the investments in transmission owned by NSP. Provide the total cost, the Minnesota retail jurisdictional cost, other state's retail jurisdictional costs, and the wholesale jurisdictional costs that are represented in the test year. Provide the amount of actual revenues for 2012, 2013, 2014 and projected revenues for 2016, 2017, and 2018 for transmission services in total and for the Minnesota jurisdiction. Provide a summary of transmission revenues that are included in the test year cost of service and the revenues that are not included in the test year, and explain the basis for not including revenues in the test year.

Response:

As described by Company witness Ian Benson in his Direct Testimony, NSPM and Northern States Power Company, a Wisconsin corporation (NSPW) own and operate electric transmission facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin and the upper peninsula of Michigan. The two companies operate an integrated transmission system comprised of approximately 7,700 miles of transmission facilities operating at voltages between 23.9 kilovolts (kV) and 500 kV, and approximately 557 transmission and distribution substations.

Specific transmission plant-in-service 2016 test year ending balances for Total Company, the Minnesota jurisdiction, and other jurisdictions are shown in the table below:

$000s	**Total Company**	**MN Retail Electric**	**All Other**
Plant in Service	$3,150,683	$2,719,980	$430,704
Depreciation Reserve	662,526	558,878	103,648
Net Plant in Service	$2,488,157	$2,161,102	$327,055

The 2016 test year includes all revenues allocated to the State of Minnesota electric jurisdiction associated with base rate recovery. The total transmission revenues included in base rates for Minnesota Company in the 2016 test year are displayed in Attachment A to this response. The transmission revenues include revenue recovered from MISO for Schedule 1 (Scheduling, System Control and Dispatch Services), Schedule 2 (Reactive Supply and Voltage), Network Transmission and Transmission Expansion Plan Revenues. The revenues in the attachment are provided at a Minnesota Company level and allocated to all other state jurisdictions.

The only transmission revenues not included in the test year are transmission revenues allocated to the North and South Dakota jurisdictions and those recovered through the rider.

The transmission revenues in Attachment A also include all Interchange Agreement Transmission revenues. The Interchange Agreement revenues are also provided at a Minnesota Company level and allocated to all other state jurisdictions. Attachment A also includes actual revenues for 2012, 2013, 2014 and test year for 2016, 2017, 2018.

Witness:	Ian Benson
Preparer:	Shari Cardille/Jeff Hafner
Title:	Principal Rate Analyst/Senior Rate Analyst
Department:	Revenue Requirements/Revenue Requirements

Docket No. E002/GR-13-868
Information Request No. OAG-117, Attachment A
Data obtained from ElecRev12 tie to FF1 Pg 300 Line 22

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Object Account		JDE Description	Associated FERC Acct	12/31/2012 Yearly Total	
801699	517210.1010	PTP Firm - Tsmn RTO	456.05	10,135,538.72	801699.517210.1010
801699	517220.1010	PTP Non-Firm - Tsmn RT	456.06	618,216.66	801699.517220.1010
801699	517220.1000	Grandfathered TM1	456.07	0.00	801699.517220.1000
801699	517230.1000	Network - Tsmn - OATT	456.07	0.00	801699.517230.1000
801699	517230.1010	Network - Tsmn RTO	456.07	14,041,476.05	801699.517230.1010
801699	517231.0000	Network - Whls	456.07	2,974,360.73	801699.517231.
801699	517232.0000	Network - GFA	456.07	7,993,172.61	801699.517232.
801699	517240.1000	Joint Pricing Zone - G	456.07	32,190,783.22	801699.517240.1000
801699	517240.2000	Joint Pricing Zone - S	456.07	5,749,882.11	801699.517240.2000
881100	517250.1130	Contracts-SD State Pen	456.09	185,535.64	881100.517250.1130
801699	517250.1160	Contracts-WPPI Meter S	456.09	37,440.00	801699.517250.1160
801699	517250.1170	Contracts-UPA	456.09	8,040,000.00	801699.517250.1170
801699	517250.1190	Contracts-UND	456.09	56,722.84	801699.517250.1190
801699	517250.1210	Contracts-Granite Fall	456.09	14,631.48	801699.517250.1210
801699	517250.1220	Contracts-E Grand Fork	456.09	46,268.40	801699.517250.1220
881100	517250.1500	Contracts - Miscellane	456.09	0.00	881100.517250.1500
801699	517270.1000	Sch 1 - Tsmn OATT	456.12	0.00	801699.517270.1000
801699	517270.1010	Sch 1. - Tsmn RTO	456.12	68,194.94	801699.517270.1010
801699	517270.1020	Sch 1. - Tsmn RTO Firm	456.12	183,207.75	801699.517270.1020
801699	517270.1030	Sch 1. - Tsmn RTO Non-Firm	456.12	34,080.98	801699.517270.1030
801699	517271.0000	Sch 1-Sch,Sys Ctrl&Disp	456.12	48,637.25	801699.517271.
801699	517272.1000	Sch 1-Sch, Sys Ctrl Int	456.12	204,012.08	801699.517272.1000
200107	517280.1000	Sch 2 - Tsmn-OATT	456.14	0.00	200107.517280.1000
200107	517280.1010	Sch 2 - Tsmn-RTO	456.14	9,021,415.92	200107.517280.1010
200107	517280.1240	Sch 2-PTP	456.14	116,401.12	200107.517280.1240
200107	517281.1010	Sch 2-Rctve Supp	456.14	69,427.63	200107.517281.1010
200107	517282.0000	Sch 2-Reactive Supply -	456.14	134,424.57	200107.517282
200107	517290.1000	Sch 3 - Tsmn-OATT	456.16	0.00	200107.517290.1000
200107	517310.1000	Sch 5 - Tsmn-OATT	456.22	0.00	200107.517310.1000
200107	517320.1000	Sch 6 - Tsmn-OATT	456.24	0.00	200107.517320.1000
801699	517328.0000	FERC Assmt Passthrough	456.26	0.00	801699.517328.
801699	517329.1000	RTO-Passthrough Rev -	456.26	303,999.57	801699.517329.1000
801699	517322.0000	Sch 24 - Bal Auth	456.27	1,750,847.85	801699.517322.0000
801699	517322.1000	Other RTO GFA Revenue	456.27	95,390.16	801699.517322.1000
801699	517323.1010	Sch 14 Reg Thru & Out-	456.55	0.00	801699.517323.1010
801699	517324.1010	Trans Expans Plan-SPP	456.56	17,694,246.86	801699.517324.1010
801699	517245.1010	Sch 26a-MVP NSP 1203	456.56	8,221,703.35	801699.517245.1010
801699	517246.0000	Sch 37-Trans Exp Plan C	456.56	303,253.92	801699.517246
801699	517325.1020	Trans Expansion Plan - Whls	456.56	17,205.63	801699.517325.1020
881100	517355.0000	RTO-Passthrough Rev -	456.56		881100.517355
				$120,350,478.04	
		Total amount from FF1 Page 300 Line 22		**120,350,478.00**	
			check	**$0.04**	

Docket No. E002/GR-13-868
Information Request No. OAG-117, Attachment A
Data obtained from ElecRev13 tie to FF1 Pg 300 Line 22

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Object Account		JDE Description	Associated FERC Acct	12/31/2013 Yearly Total	
801699	517210.1010	PTP Firm - Tsmn RTO	456.05	8,519,808.07	801699.517210.1010
801699	517220.1010	PTP Non-Firm - Tsmn RT	456.06	777,167.26	801699.517220.1010
801699	517220.1000	Grandfathered TM1	456.07	0.00	801699.517220.1000
801699	517230.1000	Network - Tsmn - OATT	456.07	0.00	801699.517230.1000
801699	517230.1010	Network - Tsmn RTO	456.07	18,181,385.49	801699.517230.1010
801699	517231.0000	Network - Whls	456.07	1,376.75	801699.517231.
801699	517232.0000	Network - GFA	456.07	9,946,672.20	801699.517232.
801699	517240.1000	Joint Pricing Zone - G	456.07	33,447,842.50	801699.517240.1000
801699	517240.2000	Joint Pricing Zone - S	456.07	5,957,935.04	801699.517240.2000
881100	517250.1130	Contracts-SD State Pen	456.09	184,597.09	881100.517250.1130
801699	517250.1160	Contracts-WPPI Meter S	456.09	37,440.00	801699.517250.1160
801699	517250.1170	Contracts-UPA	456.09	8,040,000.00	801699.517250.1170
801699	517250.1190	Contracts-UND	456.09	57,951.96	801699.517250.1190
801699	517250.1210	Contracts-Granite Fall	456.09	14,924.16	801699.517250.1210
801699	517250.1220	Contracts-E Grand Fork	456.09	46,268.40	801699.517250.1220
881100	517250.1500	Contracts - Miscellane	456.09	0.00	881100.517250.1500
801699	517270.1000	Sch 1 - Tsmn OATT	456.12	0.00	801699.517270.1000
801699	517270.1010	Sch 1. - Tsmn RTO	456.12	373,624.59	801699.517270.1010
801699	517270.1020	Sch 1. - Tsmn RTO Firm	456.12	519,313.74	801699.517270.1020
801699	517270.1030	Sch 1. - Tsmn RTO Non-Firm	456.12	86,656.37	801699.517270.1030
801699	517271.0000	Sch 1-Sch,Sys Ctrl&Disp	456.12	19.38	801699.517271.
801699	517272.1000	Sch 1-Sch, Sys Ctrl Int	456.12	218,650.22	801699.517272.1000
200107	517280.1000	Sch 2 - Tsmn-OATT	456.14	0.00	200107.517280.1000
200107	517280.1010	Sch 2 - Tsmn-RTO	456.14	8,856,666.74	200107.517280.1010
200107	517280.1240	Sch 2-PTP	456.14	126,983.04	200107.517280.1240
200107	517281.1010	Sch 2-Rctve Supp	456.14	34.05	200107.517281.1010
200107	517282.0000	Sch 2-Reactive Supply -	456.14	140,537.12	200107.517282
200107	517290.1000	Sch 3 - Tsmn-OATT	456.16	0.00	200107.517290.1000
200107	517310.1000	Sch 5 - Tsmn-OATT	456.22	0.00	200107.517310.1000
200107	517320.1000	Sch 6 - Tsmn-OATT	456.24	0.00	200107.517320.1000
801699	517328.0000	FERC Assmt Passthrough	456.26	0.00	801699.517328.
801699	517329.1000	RTO-Passthrough Rev -	456.26	265,529.82	801699.517329.1000
801699	517322.0000	Sch 24 - Bal Auth	456.27	2,090,409.04	801699.517322.0000
801699	517322.1000	Other RTO GFA Revenue	456.27	220,265.61	801699.517322.1000
801699	517323.1010	Sch 14 Reg Thru & Out-	456.55	0.00	801699.517323.1010
801699	517324.1010	Trans Expans Plan-SPP	456.56	40,064,827.19	801699.517324.1010
801699	517245.1010	Sch 26a-MVP NSP 1203	456.56	28,916,456.95	801699.517245.1010
801699	517246.2000	Sch 38-Trans Exp Plan C	456.56	661,082.07	801699.517246.2000
801699	517246.1000	Sch 37-Trans Exp Plan C	456.56	(17.63)	801699.517246.1000
801699	517325.1020	Trans Expansion Plan - Whls	456.56	7.28	801699.517325.1020
				$167,754,414.50	
		Total amount from FF1 Page 300 Line 22			
			check	**$167,754,414.50**	

Docket No. E002/GR-13-868 Docket E002/GR-15-826
Information Request No. OAG-117, Attachment A Exhibit__(AEH-1), Appendix A
Data obtained from ElecRev14 tie to FF1 Pg 300 Line 22

Object Account	JDE Description	Associated FERC Acct		
801699 517210.1010	PTP Firm - Tsmn RTO	456.05	8,725,178.05	801699.517210.1010
801699 517220.1010	PTP Non-Firm - Tsmn RT	456.06	764,679.01	801699.517220.1010
801699 517220.1000	Grandfathered TM1	456.07	0.00	801699.517220.1000
801699 517230.1000	Network - Tsmn - OATT	456.07	0.00	801699.517230.1000
801699 517230.1010	Network - Tsmn RTO	456.07	19,225,311.63	801699.517230.1010
801699 517231.0000	Network - Whls	456.07	0.00	801699.517231.
801699 517232.0000	Network - GFA	456.07	9,636,215.24	801699.517232.
801699 517240.1000	Joint Pricing Zone - G	456.07	33,259,633.09	801699.517240.1000
801699 517240.2000	Joint Pricing Zone - S	456.07	5,664,270.02	801699.517240.2000
881100 517250.1130	Contracts-SD State Pen	456.09	187,918.02	881100.517250.1130
801699 517250.1160	Contracts-WPPI Meter S	456.09	37,440.00	801699.517250.1160
801699 517250.1170	Contracts-UPA	456.09	8,040,000.00	801699.517250.1170
801699 517250.1190	Contracts-UND	456.09	58,998.45	801699.517250.1190
801699 517250.1210	Contracts-Granite Fall	456.09	15,222.60	801699.517250.1210
801699 517250.1220	Contracts-E Grand Fork	456.09	46,268.40	801699.517250.1220
881100 517250.1500	Contracts - Miscellane	456.09	0.00	881100.517250.1500
801699 517270.1000	Sch 1 - Tsmn OATT	456.12	0.00	801699.517270.1000
801699 517270.1010	Sch 1. - Tsmn RTO	456.12	405,764.21	801699.517270.1010
801699 517270.1020	Sch 1. - Tsmn RTO Firm	456.12	459,817.44	801699.517270.1020
801699 517270.1030	Sch 1. - Tsmn RTO Non-Firm	456.12	65,429.06	801699.517270.1030
801699 517271.0000	Sch 1-Sch,Sys Ctrl&Disp	456.12	0.00	801699.517271.
801699 517272.1000	Sch 1-Sch, Sys Ctrl Int	456.12	222,807.71	801699.517272.1000
200107 517280.1000	Sch 2 - Tsmn-OATT	456.14	0.00	200107.517280.1000
200107 517280.1010	Sch 2 - Tsmn-RTO	456.14	8,391,229.61	200107.517280.1010
200107 517280.1240	Sch 2-PTP	456.14	126,983.04	200107.517280.1240
200107 517281.1010	Sch 2-Rctve Supp	456.14	0.00	200107.517281.1010
200107 517282.0000	Sch 2-Reactive Supply -	456.14	138,869.66	200107.517282
200107 517290.1000	Sch 3 - Tsmn-OATT	456.16	0.00	200107.517290.1000
200107 517310.1000	Sch 5 - Tsmn-OATT	456.22	0.00	200107.517310.1000
200107 517320.1000	Sch 6 - Tsmn-OATT	456.24	0.00	200107.517320.1000
801699 517328.0000	FERC Assmt Passthrough	456.26	0.00	801699.517328.
801699 517329.1000	RTO-Passthrough Rev -	456.26	252,560.99	801699.517329.1000
801699 517322.0000	Sch 24 - Bal Auth	456.27	1,058,741.71	801699.517322.0000
801699 517322.1000	Other RTO GFA Revenue	456.27	1,961.91	801699.517322.1000
801699 517323.1010	Sch 14 Reg Thru & Out-	456.55	0.00	801699.517323.1010
801699 517324.1010	Trans Expans Plan-SPP	456.56	59,965,018.76	801699.517324.1010
801699 517245.1010	Sch 26a-MVP NSP 1203	456.56	47,573,012.17	801699.517245.1010
801699 517246.2000	Sch 38-Trans Exp Plan C	456.56	992,429.62	801699.517246.2000
801699 517246.1000	Sch 37-Trans Exp Plan C	456.56	1,264,109.02	801699.517246.1000
801699 517325.1020	Trans Expansion Plan - Whls	456.56	0.00	801699.517325.1020
			206,579,869	
	Total amount from FF1 Page 300 Line 22			
		check	**206,579,869**	

Docket No. E002/GR-13-868
Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Northern States Power Company- Minnesota
2016 Budget Transmission Revenue Budget

BU	Object	Sub	FERC	Description	Assumptions/Comments	2016 JAN	2016 FEB	2016 MAR	2016 APR	2016 MAY	2016 JUNE	2016 JULY	2016 AUGUST	2016 SEPT	2016 OCT	2016 NOV	2016 DEC	2016 TOTAL
MISO																		
801699	517210	1010	45605	PTP - Firm	MISO Tab -	$ 656,658	$ 603,281	$ 646,471	$ 627,824	$ 927,629	$ 902,849	$ 839,414	$ 848,310	$ 797,021	$ 819,216	$ 586,175	$ 617,209	$ 8,872,056
801699	517220	1010	45606	PTP - Non Firm	MISO Tab -	$ (49,977)	$ 89,468	$ 132,165	$ 36,723	$ 34,307	$ 19,855	$ 28,139	$ 36,623	$ 35,769	$ 28,313	$ 82,694	$ 87,128	$ 561,206
801699	517230	1010	45607	Network	MISO Tab -	$ 2,712,754	$ 2,554,780	$ 2,589,635	$ 2,126,860	$ 2,559,719	$ 2,673,202	$ 3,265,141	$ 3,055,967	$ 2,735,745	$ 2,320,300	$ 2,499,862	$ 2,678,342	$ 31,772,307
801699	517231		45607	Network - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517270	1010	45612	Sch 1 - Sch, Sys Ctrl & D	MISO Tab -	$ 91,795	$ 84,743	$ 87,962	$ 78,416	$ 107,538	$ 108,149	$ 115,220	$ 109,610	$ 100,994	$ 94,049	$ 85,185	$ 90,692	$ 1,154,354
801699	517271		45612	Sch 1 - Sch, Sys Ctrl & D - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200107	517280	1010	45614	Sch 2 - Reactive Supply	MISO Tab -	$ 700,210	$ 612,567	$ 645,690	$ 567,358	$ 705,116	$ 776,488	$ 915,375	$ 830,070	$ 747,985	$ 588,717	$ 633,527	$ 685,407	$ 8,408,509
200107	517281	1010	45614	Sch 2 - Reactive Supply - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517322		45627	Sch 24 - Bal Auth	MISO Tab -	$ 105,037	$ 105,037	$ 105,037	$ 105,037	$ 105,037	$ 107,541	$ 107,541	$ 107,541	$ 107,541	$ 107,541	$ 107,541	$ 107,541	$ 1,277,970
801699	517322	1000	45627	Other RTO GFA Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517324	1010	45656	Trans Expansion Plan		$ 6,621,692	$ 6,526,403	$ 6,972,059	$ 6,354,350	$ 7,075,701	$ 8,063,367	$ 9,500,792	$ 9,370,587	$ 8,397,502	$ 6,848,973	$ 7,279,516	$ 7,274,374	$ 90,285,317
801699	517245	1010	45656	Trans Exp Plan - Sch 26A - Brookings CapX2020		$ 5,309,971	$ 4,687,590	$ 4,791,963	$ 4,255,947	$ 4,588,654	$ 5,019,943	$ 5,783,275	$ 5,492,678	$ 4,611,824	$ 4,486,467	$ 4,599,849	$ 4,403,226	$ 58,031,388
801699	517245		45656	Trans Exp Plan - Sch 26A - Big Stone to Brookings		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517245		45656	Trans Exp Plan - Sch 26A - N LaCrosse to N Madison		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JPZ																		
801699	517240	1000	45607	Joint Pricing Zone - GRE	GRE	$ 3,295,394	$ 2,960,293	$ 3,048,088	$ 2,367,783	$ 3,242,532	$ 3,674,097	$ 3,875,383	$ 3,711,266	$ 3,489,463	$ 2,772,869	$ 3,055,258	$ 3,316,170	$ 38,808,595
801699	517240	2000	45607	Joint Pricing Zone - SMMPA		$ 562,682	$ 500,369	$ 511,315	$ 474,298	$ 574,935	$ 652,920	$ 725,737	$ 737,990	$ 621,148	$ 517,441	$ 514,431	$ 563,624	$ 6,956,890
801699	517240		45607	Joint Pricing Zone - MRES		$ 369,156	$ 318,186	$ 351,694	$ 334,088	$ 341,582	$ 367,448	$ 388,911	$ 387,417	$ 359,349	$ 346,085	$ 343,056	$ 366,092	$ 4,273,063
200107	517280	1240	45614	Sch 2 - Reactive Supply		$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 126,983
GFA's - TM1																		
801699	517232		45607	Network - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517272	1000	45612	Sch 1-Sch, Sys Ctrl & D - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200107	517282		45614	Sch 2 - Reactive Supply - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517329	1000	45626	Sch 10 - MISO Passthrough	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MISO Tariff																		
881100	517355		45632	Facilities	Charges budgeted	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 46,866
GFA's - Fixed Contracts																		
881100	517250	1130	45609	Facilities	Charges budgeted at	$ 15,473	$ 15,420	$ 14,079	$ 13,290	$ 15,929	$ 17,135	$ 16,854	$ 19,249	$ 16,073	$ 15,067	$ 14,567	$ 14,874	$ 188,010
801699	517250	1160	45609	Contracts - WPPI	Charges budgeted	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 37,440
801699	517250	1170	45609	Contracts - UPA	Charges budgeted at	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517250	1190	45609	Contracts - UND	Charges budgeted	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 5,125	$ 61,499
801699	517250	1210	45609	Contracts - Granite Falls	Charges budgeted	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 1,320	$ 15,838
801699	517250	1220	45609	Contracts - EGF	Charges budgeted	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 4,142	$ 49,709
801798	519390		45642	GRE Cr Lk Facilities	Charges budgeted	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 212,410
816200	519390		45642	GRE 500kV tsmn O&M	Charges budgeted	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 54,480
801699	519390			Marshall TOPS Agreement	Charges budgeted at	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 10,601	$ 127,208
				Total NSP		**$ 20,451,879**	**$ 19,119,174**	**$ 19,957,194**	**$ 17,403,009**	**$ 20,339,714**	**$ 22,444,030**	**$ 25,622,819**	**$ 24,768,343**	**$ 22,081,451**	**$ 19,006,073**	**$ 19,862,696**	**$ 20,265,715**	**$ 251,322,097**

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Docket E002/GR-15-826
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Northern States Power Company- Minnesota
2016 Budget Transmission Revenue Budget

BU	Object	Sub	FERC	Description	Assumptions/Comments	2016 JAN	2016 FEB	2016 MAR	2016 APR	2016 MAY	2016 JUNE	2016 JULY	2016 AUGUST	2016 SEPT	2016 OCT	2016 NOV	2016 DEC	2016 TOTAL
MISO																		
Other Revenue																		
801798	519302	1500	45653	Facilities - Shakopee Dist, Blue Lake	Charges budgeted	$ 8,369	$ 8,014	$ 7,898	$ 6,970	$ 10,039	$ 9,816	$ 11,813	$ 10,510	$ 11,592	$ 8,707	$ 7,836	$ 8,124	$ 109,688
801798	519302	105	45653	Distrib FacFxd Ch - Anoka	Charges budgeted	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 63,000
801798	519302	110	45653	Distrib FacFxd Ch - Arlington	Charges budgeted	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 1,061	$ 12,732
801798	519302	125	45653	Distrib FacFxd Ch - MN Valley	Charges budgeted	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 1,560
801798	519302	130	45653	Distrib FacFxd Ch - EGF	Charges budgeted	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801798	519302	120	45653	Distrib FacFxd Ch - Winthrop	Charges budgeted	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 16,496
801798	519302	1035	45653	Distrib Wheeling Ch - Twin Cities Hydro	Charges budgeted	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 354,816
801798	519302	1040	45653	Distrib FacFxd Ch - Eagle Creek	Charges budgeted	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 126,360
				Total Other Revenue		**$ 56,283**	**$ 55,928**	**$ 55,812**	**$ 54,884**	**$ 57,952**	**$ 57,729**	**$ 59,726**	**$ 58,424**	**$ 59,506**	**$ 56,621**	**$ 55,749**	**$ 56,038**	**$ 684,652**
				Grand Total		**$ 20,508,162**	**$ 19,175,102**	**$ 20,013,006**	**$ 17,457,893**	**$ 20,397,666**	**$ 22,501,759**	**$ 25,682,545**	**$ 24,826,767**	**$ 22,140,957**	**$ 19,062,694**	**$ 19,918,446**	**$ 20,321,752**	**$ 252,006,749**

Docket No. E002/GR-13-868
Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Northern States Power Company- Minnesota
2017 Budget Transmission Revenue Budget

BU	Object	Sub	FERC	Description	Assumptions/Comments	2017 JAN	2017 FEB	2017 MAR	2017 APR	2017 MAY	2017 JUNE	2017 JULY	2017 AUGUST	2017 SEPT	2017 OCT	2017 NOV	2017 DEC	2017 TOTAL
MISO																		
801699	517210	1010	45605	PTP - Firm	MISO Tab -	$ 656,658	$ 603,281	$ 646,471	$ 627,824	$ 927,629	$ 902,849	$ 839,414	$ 848,310	$ 797,021	$ 819,216	$ 586,175	$ 617,209	$ 8,872,056
801699	517220	1010	45606	PTP - Non Firm	MISO Tab -	$ (49,977)	$ 89,468	$ 132,165	$ 36,723	$ 34,307	$ 19,855	$ 28,139	$ 36,623	$ 35,769	$ 28,313	$ 82,694	$ 87,128	$ 561,206
801699	517230	1010	45607	Network	MISO Tab -	$ 2,746,996	$ 2,494,740	$ 2,619,836	$ 2,141,872	$ 2,588,938	$ 2,706,145	$ 3,317,514	$ 3,101,474	$ 2,770,742	$ 2,341,661	$ 2,675,195	$ 2,861,922	$ 32,367,034
801699	517231		45607	Network - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517270	1010	45612	Sch 1 - Sch, Sys Ctrl & D	MISO Tab -	$ 91,795	$ 84,743	$ 87,962	$ 78,416	$ 107,538	$ 108,149	$ 115,220	$ 109,610	$ 100,994	$ 94,049	$ 85,185	$ 90,692	$ 1,154,354
801699	517271		45612	Sch 1 - Sch, Sys Ctrl & D - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200107	517280	1010	45614	Sch 2 - Reactive Supply	MISO Tab -	$ 700,210	$ 612,567	$ 645,690	$ 567,358	$ 705,116	$ 776,488	$ 915,375	$ 830,070	$ 747,985	$ 588,717	$ 633,527	$ 685,407	$ 8,408,509
200107	517281	1010	45614	Sch 2 - Reactive Supply - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517322		45627	Sch 24 - Bal Auth	MISO Tab -	$ 107,541	$ 107,541	$ 107,541	$ 107,541	$ 107,541	$ 110,679	$ 110,679	$ 110,679	$ 110,679	$ 110,679	$ 110,679	$ 110,679	$ 1,312,456
801699	517322	1000	45627	Other RTO GFA Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517324	1010	45656	Trans Expansion Plan		$ 6,555,629	$ 6,462,432	$ 6,898,306	$ 6,294,155	$ 6,999,672	$ 7,965,659	$ 9,371,532	$ 9,244,185	$ 8,292,460	$ 6,777,922	$ 7,199,014	$ 7,193,985	$ 89,254,952
801699	517245	1010	45656	Trans Exp Plan - Sch 26A - Brookings CapX2020		$ 5,257,214	$ 4,683,722	$ 4,779,896	$ 4,285,987	$ 4,592,558	$ 4,989,968	$ 5,693,338	$ 5,425,569	$ 4,613,908	$ 4,498,398	$ 4,602,874	$ 4,421,696	$ 57,845,129
801699	517245		45656	Trans Exp Plan - Sch 26A - Big Stone to Brookings		$ 107,136	$ 95,449	$ 97,409	$ 87,344	$ 93,591	$ 101,690	$ 116,024	$ 110,567	$ 94,026	$ 91,672	$ 93,801	$ 90,109	$ 1,178,818
801699	517245		45656	Trans Exp Plan - Sch 26A - N LaCrosse to N Madison		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JPZ																		
801699	517240	1000	45607	Joint Pricing Zone - GRE	GRE Network	$ 3,403,221	$ 2,955,665	$ 3,147,797	$ 2,445,252	$ 3,348,685	$ 3,794,469	$ 4,002,301	$ 3,832,824	$ 3,603,779	$ 2,863,688	$ 3,155,317	$ 3,424,767	$ 39,977,764
801699	517240	2000	45607	Joint Pricing Zone - SMMPA		$ 581,150	$ 498,972	$ 528,097	$ 489,866	$ 593,805	$ 674,350	$ 749,557	$ 762,212	$ 641,535	$ 534,424	$ 531,316	$ 582,124	$ 7,167,408
801699	517240		45607	Joint Pricing Zone - MRES		$ 381,272	$ 317,297	$ 363,237	$ 345,053	$ 352,793	$ 379,509	$ 401,676	$ 400,133	$ 371,143	$ 357,444	$ 354,316	$ 378,108	$ 4,401,981
200107	517280	1240	45614	Sch 2 - Reactive Supply		$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 126,983
GFA's - TM1																		
801699	517232		45607	Network - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517272	1000	45612	Sch 1-Sch, Sys Ctrl & D - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200107	517282		45614	Sch 2 - Reactive Supply - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517329	1000	45626	Sch 10 - MISO Passthrough	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MISO Tariff																		
881100	517355		45632	Facilities	Charges budgeted	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 18,088
GFA's - Fixed Contracts																		
881100	517250	1130	45609	Facilities	Charges budgeted	$ 15,473	$ 15,420	$ 14,079	$ 13,290	$ 15,929	$ 17,135	$ 16,854	$ 19,249	$ 16,073	$ 15,067	$ 14,567	$ 14,874	$ 188,010
801699	517250	1160	45609	Contracts - WPPI	Charges budgeted	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 37,440
801699	517250	1170	45609	Contracts - UPA	Charges budgeted	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517250	1190	45609	Contracts - UND	Charges budgeted	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 5,227	$ 62,729
801699	517250	1210	45609	Contracts - Granite Falls	Charges budgeted	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 1,346	$ 16,154
801699	517250	1220	45609	Contracts - EGF	Charges budgeted	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 4,225	$ 50,703
801798	519390		45642	GRE Cr Lk Facilities	Charges budgeted	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 212,410
816200	519390		45642	GRE 500kV tsmn O&M	Charges budgeted	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 54,480
801699	519390			Marshall TOPS Agreement	Charges budgeted	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 10,866	$ 130,388
				Total NSP		**$ 20,613,431**	**$ 19,080,411**	**$ 20,127,602**	**$ 17,579,793**	**$ 20,527,217**	**$ 22,606,060**	**$ 25,736,738**	**$ 24,890,618**	**$ 22,255,230**	**$ 19,180,365**	**$ 20,183,773**	**$ 20,617,813**	**$ 253,399,053**

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Northern States Power Company- Minnesota
2017 Budget Transmission Revenue Budget

BU	Object	Sub	FERC	Description	Assumptions/Comments	2017 JAN	2017 FEB	2017 MAR	2017 APR	2017 MAY	2017 JUNE	2017 JULY	2017 AUGUST	2017 SEPT	2017 OCT	2017 NOV	2017 DEC	2017 TOTAL
MISO																		
Other Revenue																		
801798	519302	1500	45653	Facilities - Shakopee Dist, Blue Lake	Charges budgeted	$ 8,796	$ 8,782	$ 8,084	$ 8,631	$ 7,392	$ 9,202	$ 12,936	$ 13,615	$ 11,666	$ 8,654	$ 7,876	$ 8,268	$ 113,902
801798	519302	105	45653	Distrib FacFxd Ch - Anoka	Charges budgeted	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 63,000
801798	519302	110	45653	Distrib FacFxd Ch - Arlington	Charges budgeted	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 1,082	$ 12,986
801798	519302	125	45653	Distrib FacFxd Ch - MN Valley	Charges budgeted	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 1,560
801798	519302	130	45653	Distrib FacFxd Ch - EGF	Charges budgeted	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801798	519302	120	45653	Distrib FacFxd Ch - Winthrop	Charges budgeted	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 16,500
801798	519302	1035	45653	Distrib Wheeling Ch - Twin Cities Hydro	Charges budgeted	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 354,816
801798	519302	1040	45653	Distrib FacFxd Ch - Eagle Creek	Charges budgeted	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 126,360
				Total Other Revenue		**$ 56.731**	**$ 56.717**	**$ 56.019**	**$ 56.567**	**$ 55.327**	**$ 57.137**	**$ 60.871**	**$ 61.550**	**$ 59.601**	**$ 56.589**	**$ 55.811**	**$ 56.203**	**$ 689.124**
				Grand Total		**$ 20,670,162**	**$ 19,137,128**	**$ 20,183,621**	**$ 17,636,360**	**$ 20,582,544**	**$ 22,663,198**	**$ 25,797,609**	**$ 24,952,168**	**$ 22,314,831**	**$ 19,236,955**	**$ 20,239,584**	**$ 20,674,017**	**$ 254,088,177**

Docket No. E002/GR-13-868
Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
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Northern States Power Company- Minnesota
2018 Budget Transmission Revenue Budget

BU	Object	Sub	FERC	Description	Assumptions/Comments	2018 JAN	2018 FEB	2018 MAR	2018 APR	2018 MAY	2018 JUNE	2018 JULY	2018 AUGUST	2018 SEPT	2018 OCT	2018 NOV	2018 DEC	2018 TOTAL
MISO																		
801699	517210	1010	45605	PTP - Firm	MISO Tab -	$ 656,658	$ 603,281	$ 646,471	$ 627,824	$ 927,629	$ 902,849	$ 839,414	$ 848,310	$ 797,021	$ 819,216	$ 586,175	$ 617,209	$ 8,872,056
801699	517220	1010	45606	PTP - Non Firm	MISO Tab -	$ (49,977)	$ 89,468	$ 132,165	$ 36,723	$ 34,307	$ 19,855	$ 28,139	$ 36,623	$ 35,769	$ 28,313	$ 82,694	$ 87,128	$ 561,206
801699	517230	1010	45607	Network	MISO Tab -	$ 2,975,819	$ 2,695,258	$ 2,835,482	$ 2,309,316	$ 2,727,600	$ 2,872,743	$ 3,483,114	$ 3,262,112	$ 2,968,491	$ 2,579,812	$ 2,755,450	$ 2,947,779	$ 34,412,976
801699	517231		45607	Network - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517270	1010	45612	Sch 1 - Sch, Sys Ctrl & D	MISO Tab -	$ 91,795	$ 84,743	$ 87,962	$ 78,416	$ 107,538	$ 108,149	$ 115,220	$ 109,610	$ 100,994	$ 94,049	$ 85,185	$ 90,692	$ 1,154,354
801699	517271		45612	Sch 1 - Sch, Sys Ctrl & D - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200107	517280	1010	45614	Sch 2 - Reactive Supply	MISO Tab -	$ 700,210	$ 612,567	$ 645,690	$ 567,358	$ 705,116	$ 776,488	$ 915,375	$ 830,070	$ 747,985	$ 588,717	$ 633,527	$ 685,407	$ 8,408,509
200107	517281	1010	45614	Sch 2 - Reactive Supply - Whls		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517322		45627	Sch 24 - Bal Auth	MISO Tab -	$ 110,679	$ 110,679	$ 110,679	$ 110,679	$ 110,679	$ 113,541	$ 113,541	$ 113,541	$ 113,541	$ 113,541	$ 113,541	$ 113,541	$ 1,348,181
801699	517322	1000	45627	Other RTO GFA Revenue		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517324	1010	45656	Trans Expansion Plan		$ 6,426,280	$ 6,334,922	$ 6,762,196	$ 6,169,966	$ 6,861,562	$ 7,808,490	$ 9,186,623	$ 9,061,788	$ 8,128,842	$ 6,644,187	$ 7,056,970	$ 7,052,041	$ 87,493,869
801699	517245	1010	45656	Trans Exp Plan - Sch 26A - Brookings CapX2020		$ 5,188,916	$ 4,622,874	$ 4,717,799	$ 4,230,306	$ 4,532,895	$ 4,925,142	$ 5,619,374	$ 5,355,084	$ 4,553,968	$ 4,439,958	$ 4,543,077	$ 4,364,252	$ 57,093,644
801699	517245		45656	Trans Exp Plan - Sch 26A - Big Stone to Brookings		$ 1,096,200	$ 976,619	$ 996,673	$ 893,686	$ 957,611	$ 1,040,476	$ 1,187,138	$ 1,131,305	$ 962,062	$ 937,977	$ 959,762	$ 921,983	$ 12,061,492
801699	517245		45656	Trans Exp Plan - Sch 26A - N LaCrosse to N Madison		$ 189,678	$ 168,987	$ 172,457	$ 154,637	$ 165,698	$ 180,036	$ 205,413	$ 195,752	$ 166,468	$ 162,300	$ 166,070	$ 159,533	$ 2,087,027
JPZ																		
801699	517240	1000	45607	Joint Pricing Zone - GRE	GRE Network Tab -	$ 3,505,317	$ 3,044,335	$ 3,242,231	$ 2,518,609	$ 3,449,146	$ 3,908,303	$ 4,122,370	$ 3,947,808	$ 3,711,892	$ 2,949,599	$ 3,249,977	$ 3,527,510	$ 41,177,097
801699	517240	2000	45607	Joint Pricing Zone - SMMPA		$ 598,585	$ 513,941	$ 543,940	$ 504,562	$ 611,619	$ 694,581	$ 772,044	$ 785,078	$ 660,782	$ 550,457	$ 547,255	$ 599,587	$ 7,382,430
801699	517240		45607	Joint Pricing Zone - MRES		$ 392,710	$ 326,816	$ 374,134	$ 355,405	$ 363,377	$ 390,894	$ 413,726	$ 412,137	$ 382,277	$ 368,167	$ 364,945	$ 389,451	$ 4,534,041
200107	517280	1240	45614	Sch 2 - Reactive Supply		$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 10,582	$ 126,983
GFA's - TM1																		
801699	517232		45607	Network - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517272	1000	45612	Sch 1-Sch, Sys Ctrl & D - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200107	517282		45614	Sch 2 - Reactive Supply - GFA	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517329	1000	45626	Sch 10 - MISO Passthrough	TM1 Tab -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MISO Tariff																		
881100	517355		45632	Facilities	Charges budgete	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 1,507	$ 18,088
GFA's - Fixed Contracts																		
881100	517250	1130	45609	Facilities	Charges budgete	$ 15,473	$ 15,420	$ 14,079	$ 13,290	$ 15,929	$ 17,135	$ 16,854	$ 19,249	$ 16,073	$ 15,067	$ 14,567	$ 14,874	$ 188,010
801699	517250	1160	45609	Contracts - WPPI	Charges budgete	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 3,120	$ 37,440
801699	517250	1170	45609	Contracts - UPA	Charges budgete	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801699	517250	1190	45609	Contracts - UND	Charges budgete	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 5,332	$ 63,984
801699	517250	1210	45609	Contracts - Granite Falls	Charges budgete	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 1,373	$ 16,477
801699	517250	1220	45609	Contracts - EGF	Charges budgete	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 4,310	$ 51,717
801798	519390		45642	GRE Cr Lk Facilities	Charges budgete	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 17,701	$ 212,410
816200	519390		45642	GRE 500kV tsmn O&M	Charges budgete	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 4,540	$ 54,480
801699	519390			Marshall TOPS Agreement	Charges budgete	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 11,137	$ 133,648

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Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Northern States Power Company- Minnesota
2018 Budget Transmission Revenue Budget

BU	Object	Sub	FERC	Description	Assumptions/Comments	2018 JAN	2018 FEB	2018 MAR	2018 APR	2018 MAY	2018 JUNE	2018 JULY	2018 AUGUST	2018 SEPT	2018 OCT	2018 NOV	2018 DEC	2018 TOTAL
MISO																		
				Total NSP		**$ 21,957,944**	**$ 20,259,513**	**$ 21,341,561**	**$ 18,630,378**	**$ 21,630,307**	**$ 23,818,283**	**$ 27,077,948**	**$ 26,168,068**	**$ 23,405,767**	**$ 20,350,963**	**$ 21,218,796**	**$ 21,630,590**	**$ 267,490,119**
Other Revenue																		
801798	519302	1500	45653	Facilities - Shakopee Dist, Blue Lake	Charges budgete	$ 8,796	$ 8,782	$ 8,084	$ 8,631	$ 7,392	$ 9,202	$ 12,936	$ 13,615	$ 11,666	$ 8,654	$ 7,876	$ 8,268	$ 113,902
801798	519302	105	45653	Distrib FacFxd Ch - Anoka	Charges budgete	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 5,250	$ 63,000
801798	519302	110	45653	Distrib FacFxd Ch - Arlington	Charges budgete	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 1,104	$ 13,246
801798	519302	125	45653	Distrib FacFxd Ch - MN Valley	Charges budgete	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 130	$ 1,560
801798	519302	130	45653	Distrib FacFxd Ch - EGF	Charges budgete	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
801798	519302	120	45653	Distrib FacFxd Ch - Winthrop	Charges budgete	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 1,375	$ 16,500
801798	519302	1035	45653	Distrib Wheeling Ch - Twin Cities Hydro	Charges budgete	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 29,568	$ 354,816
801798	519302	1040	45653	Distrib FacFxd Ch - Eagle Creek	Charges budgete	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 10,530	$ 126,360
				Total Other Revenue		**$ 56,753**	**$ 56,739**	**$ 56,041**	**$ 56,588**	**$ 55,349**	**$ 57,159**	**$ 60,893**	**$ 61,572**	**$ 59,623**	**$ 56,611**	**$ 55,833**	**$ 56,225**	**$ 689,384**
				Grand Total		**$ 22,014,697**	**$ 20,316,252**	**$ 21,397,601**	**$ 18,686,966**	**$ 21,685,656**	**$ 23,875,442**	**$ 27,138,841**	**$ 26,229,640**	**$ 23,465,390**	**$ 20,407,573**	**$ 21,274,629**	**$ 21,686,815**	**$ 268,179,503**

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Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Total Company and Minnesota State Transmission Revenues

				Total Company						MN State					
				12/31/2012	12/31/2013	12/31/2014	12/31/2016	12/31/2017	12/31/2018	12/31/2012	12/31/2013	12/31/2014	12/31/2016	12/31/2017	12/31/2018
Object Account		JDE Description	Associated FERC Acct	Yearly Total	Yearly Total	Yearly Total	2016 Budget	2017 Budget	2018 Budget	Yearly Total	Yearly Total	Yearly Total	2016 Budget	2017 Budget	2018 Budget
801699	517210.1010	PTP Firm - Tsmn RTO	456.05	10,135,538.72	8,519,808.07	8,725,178.05	8,872,055.53	8,872,055.53	8,872,055.53	8,929,713.68	7,473,217.81	7,637,008.74	7,749,394.50	7,749,394.50	7,749,394.50
801699	517220.1010	PTP Non-Firm - Tsmn RT	456.06	618,216.66	777,167.26	764,679.01	561,205.73	561,205.73	561,205.73	544,667.42	681,698.48	669,311.30	490,191.32	490,191.32	490,191.32
801699	517220.1000	Grandfathered TM1	456.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
801699	517230.1000	Network - Tsmn - OATT	456.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
801699	517230.1010	Network - Tsmn RTO	456.07	14,041,476.05	18,181,385.49	19,225,311.63	31,772,306.79	32,367,034.21	34,412,976.04	12,370,961.64	15,947,947.73	16,827,607.66	27,751,870.86	28,271,342.07	30,058,392.46
801699	517231.0000	Network - Whls	456.07	2,974,360.73	1,376.75	0.00	0.00	0.00	0.00	2,620,501.03	1,207.63	0.00	0.00	0.00	0.00
801699	517232.0000	Network - GFA	456.07	7,993,172.61	9,946,672.20	9,636,215.24	0.00	0.00	0.00	7,042,224.86	8,724,803.09	8,434,425.02	0.00	0.00	0.00
801699	517240.1000	Joint Pricing Zone - G	456.07	32,190,783.22	33,447,842.50	33,259,633.09	38,808,594.90	39,977,764.49	41,177,097.42	28,361,045.74	29,339,042.63	29,111,624.69	33,897,794.11	34,919,018.15	35,966,588.69
801699	517240.2000	Joint Pricing Zone - S	456.07	5,749,882.11	5,957,935.04	5,664,270.02	6,956,890.01	7,167,408.05	7,382,430.29	5,065,818.64	5,226,050.38	4,957,844.92	6,076,572.10	6,260,451.40	6,448,264.94
801699	517240.0000	Joint Pricing Zone - M	456.07	0.00	0.00	0.00	4,273,063.13	4,401,981.20	4,534,040.64	0.00	0.00	0.00	3,732,353.99	3,844,958.90	3,960,307.67
881100	517250.1130	Contracts-SD State Pen	456.09	185,535.64	184,597.09	187,918.02	188,009.54	188,009.54	188,009.54	163,462.46	161,920.81	164,481.64	164,219.00	164,219.00	164,219.00
801699	517250.1160	Contracts-WPPI Meter S	456.09	37,440.00	37,440.00	37,440.00	37,440.00	37,440.00	37,440.00	32,985.76	32,840.80	32,770.63	32,702.38	32,702.38	32,702.38
801699	517250.1170	Contracts-UPA	456.09	8,040,000.00	8,040,000.00	8,040,000.00	0.00	0.00	0.00	7,083,481.20	7,052,350.32	7,037,283.36	0.00	0.00	0.00
801699	517250.1190	Contracts-UND	456.09	56,722.84	57,951.96	58,998.45	61,499.08	62,729.07	63,983.65	49,974.52	50,833.03	51,640.40	53,717.05	54,791.39	55,887.22
801699	517250.1210	Contracts-Granite Fall	456.09	14,631.48	14,924.16	15,222.60	15,837.60	16,154.40	16,477.44	12,890.77	13,090.85	13,324.10	13,833.53	14,110.24	14,392.40
801699	517250.1220	Contracts-E Grand Fork	456.09	46,268.40	46,268.40	46,268.40	49,709.16	50,703.36	51,717.48	40,763.85	40,584.70	40,497.99	43,419.01	44,287.41	45,173.20
801798	519390.0000	GRE Cr Lk Facilities	456.42				212,410.44	212,410.44	212,410.44	0.00	0.00	0.00	185,532.24	185,532.24	185,532.24
816200	519390.0000	GRE 500kV tsmn O&M	456.42				54,480.00	54,480.00	54,480.00	0.00	0.00	0.00	47,586.16	47,586.16	47,586.16
801699	519390.0000	Marshall TOPS Agreement					127,207.71	130,387.90	133,647.60	0.00	0.00	0.00	111,110.97	113,888.74	116,735.96
881100	517250.1500	Contracts - Miscellane	456.09	0.00	0.00	0.00				0.00	0.00	0.00	0.00	0.00	0.00
801699	517270.1000	Sch 1 - Tsmn OATT	456.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
801699	517270.1010	Sch 1. - Tsmn RTO	456.12	68,194.94	373,624.59	405,764.21	1,154,354.29	1,154,354.29	1,154,354.29	60,081.79	327,727.80	355,158.92	1,008,283.46	1,008,283.46	1,008,283.46
801699	517270.1020	Sch 1. - Tsmn RTO Firm	456.12	183,207.75	519,313.74	459,817.44	0.00	0.00	0.00	161,411.52	455,520.20	402,470.85	0.00	0.00	0.00
801699	517270.1030	Sch 1. - Tsmn RTO Non-Firm	456.12	34,080.98	86,656.37	65,429.06	0.00	0.00	0.00	30,026.37	76,011.33	57,269.01	0.00	0.00	0.00
801699	517271.0000	Sch 1-Sch,Sys Ctrl&Disp	456.12	48,637.25	19.38	0.00	0.00	0.00	0.00	42,850.88	17.00	0.00	0.00	0.00	0.00
801699	517272.1000	Sch 1-Sch, Sys Ctrl Int	456.12	204,012.08	218,650.22	222,807.71	0.00	0.00	0.00	179,740.76	191,790.79	195,020.02	0.00	0.00	0.00
200107	517280.1000	Sch 2 - Tsmn-OATT	456.14	0.00	0.00	0.00				0.00	0.00	0.00	0.00	0.00	0.00
200107	517280.1010	Sch 2 - Tsmn-RTO	456.14	9,021,415.92	8,856,666.74	8,391,229.61	8,408,508.55	8,408,508.55	8,408,508.55	7,948,138.07	7,768,696.08	7,344,709.02	7,344,504.29	7,344,504.29	7,344,504.29
200107	517280.1240	Sch 2-PTP	456.14	116,401.12	126,983.04	126,983.04	126,983.04	126,983.04	126,983.04	102,552.88	111,384.19	111,146.22	110,914.73	110,914.73	110,914.73
200107	517281.1010	Sch 2-Rctve Supp	456.14	69,427.63	34.05	0.00	0.00	0.00	0.00	61,167.82	29.87	0.00	0.00	0.00	0.00
200107	517282.0000	Sch 2-Reactive Supply -	456.14	134,424.57	140,537.12	138,869.66	0.00	0.00	0.00	118,432.08	123,273.26	121,550.39	0.00	0.00	0.00
200107	517290.1000	Sch 3 - Tsmn-OATT	456.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
200107	517310.1000	Sch 5 - Tsmn-OATT	456.22	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0
200107	517320.1000	Sch 6 - Tsmn-OATT	456.24	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0
801699	517328.0000	FERC Assmt Passthrough	456.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
801699	517329.1000	RTO-Passthrough Rev -	456.26	303,999.57	265,529.82	252,560.99	0.00	0.00	0.00	267,832.74	232,911.61	221,062.59	0.00	0.00	0.00
801699	517322.0000	Sch 24 - Bal Auth	456.27	1,750,847.85	2,090,409.04	1,058,741.71	1,277,969.67	1,312,456.33	1,348,180.83	1,542,549.48	1,833,619.01	926,699.68	1,116,256.66	1,146,379.42	1,177,583.38
801699	517322.1000	Other RTO GFA Revenue	456.27	95,390.16	220,265.61	1,961.91	0.00	0.00	0.00	84,041.59	193,207.74	1,717.23	0.00	0.00	0.00
801699	517323.1010	Sch 14 Reg Thru & Out-	456.55	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0
801699	517324.1010	Trans Expans Plan-SPP	456.56	17,694,246.86	40,064,827.19	59,965,018.76	90,285,317.12	89,254,952.00	87,493,869.00	15,589,162.31	35,143,183.69	52,486,421.48	78,860,703.38	77,960,719.63	76,422,482.31
801699	517245.0000	Trans Exp Plan - Sch 26A - Bi	456.56			0.00	0.00	1,178,817.71	14,148,519.18	0.00	0.00	0.00	0.00	1,029,651.30	12,358,179.72
801699	517245.1010	Sch 26a-MVP NSP 1203	456.56	8,221,703.35	28,916,456.95	47,573,012.17	58,031,388.43	57,845,128.83	57,093,644.19	7,243,567.30	25,364,301.55	41,639,896.38	50,688,154.57	50,525,464.08	49,869,071.55
801699	517246.2000	Sch 38-Trans Exp Plan C	456.56		661,082.07	992,429.62	0.00	0.00	0.00	0.00	579,873.43	868,657.77	0.00	0.00	0.00
801699	517246.1000	Sch 37-Trans Exp Plan C	456.56	303,253.92	(17.63)	1,264,109.02	0.00	0.00	0.00	267,175.80	(15.46)	1,106,454.40	0.00	0.00	0.00
801699	517325.1020	Trans Expansion Plan - Whls	456.56	17,205.63	7.28	0.00	0.00	0.00	0.00	15,158.68	6.39	0.00	0.00	0.00	0.00
881100	517355.0000	RTO-Passthrough Rev -	456.56		0.00	0.00	46,866.48	18,087.84	18,087.84	0.00	0.00	0.00	40,936.04	15,799.02	15,799.02
				$120,350,478.04	**$167,754,414.50**	**$206,579,869.42**	**$251,322,097.19**	**$253,399,052.52**	**$267,490,118.73**	**$106,032,381.67**	**$147,147,126.71**	**$180,816,054.43**	**$219,520,050.33**	**$221,334,189.81**	**$233,642,186.60**
		Total amount from FF1 Page 300 Line 22		**120,350,478.00**	**167,754,415.00**	**206,579,869.00**									
			check	**$0.04**	**-$0.50**	**$0.42**									

Demand Allocation (MN State)

2012	88.1030%
2013	87.7158%
2014	87.5284%
2016/2017/2018	87.3461%

Interchange Transmission Revenues
MN Company

	2012 Act	2013 Act	2014 Act	2016 Bud	2017 Plan Year	2018 Plan Year
Interchange Transmission Reven	42,632,106	36,789,427	36,866,599	60,206,488	63,618,112	65,815,951

Docket No. E002/GR-13-868
Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Transmission Revenues

2014 Actual

	Total Company	**MN State**	**ND State**	**SD State**	**Wholesale**
Point to Point - Firm	8,725,178	7,637,009	550,803	537,366	0
Point to Point - NonFirm	764,679	669,311	48,273	47,095	0
Network Transmission	67,785,430	59,331,502	4,279,159	4,174,769	0
Contracts	8,385,847	7,339,998	529,382	516,468	0
Schedule 1	1,153,818	1,009,919	72,838	71,061	0
Schedule 2	8,657,082	7,577,406	546,504	533,172	0
RTO - PassThrough	252,561	221,063	15,944	15,555	0
Schedule 24	1,060,704	928,417	66,960	65,327	0
Transmission Expansion	109,794,570	96,101,430	6,931,112	6,762,028	0
Total Transmission	**206,579,869**	**180,816,054**	**13,040,974**	**12,722,841**	**0**
Interchange Transmission Rev	**36,866,599**	**32,268,744**	**2,327,315**	**2,270,540**	**0**
Total Transmission incl Interchang	**243,446,468**	**213,084,799**	**15,368,289**	**14,993,381**	**0**
Demand Allocation	100.0000%	87.5284%	6.3128%	6.1588%	0.0000%

Transmission Revenues

2013 Actual

	Total Company	**MN State**	**ND State**	**SD State**	**Wholesale**
Point to Point - Firm	8,519,808	7,473,218	520,262	521,770	4,558
Point to Point - NonFirm	777,167	681,698	47,458	47,595	416
Network Transmission	67,535,212	59,239,051	4,124,038	4,135,991	36,131
Contracts	8,381,182	7,351,620	511,797	513,280	4,484
Schedule 1	1,198,264	1,051,067	73,172	73,384	641
Schedule 2	9,124,221	8,003,383	557,171	558,786	4,881
RTO - PassThrough	265,530	232,912	16,215	16,262	142
Schedule 24	2,310,675	2,026,827	141,101	141,510	1,236
Transmission Expansion	69,642,356	61,087,350	4,252,710	4,265,037	37,259
Total Transmission	**167,754,415**	**147,147,127**	**10,243,923**	**10,273,616**	**89,749**
Interchange Transmission Rev	**36,789,427**	**32,270,140**	**2,246,546**	**2,253,058**	**19,682**
Total Transmission incl Interchang	**204,543,842**	**179,417,267**	**12,490,470**	**12,526,674**	**109,431**
Demand Allocation	100.0000%	87.7158%	6.1065%	6.1242%	0.0535%

Docket No. E002/GR-13-868
Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Transmission Revenues

2012 Actual

	Total Company	MN State	ND State	SD State	Wholesale
Point to Point - Firm	10,135,539	8,929,714	583,391	613,930	8,504
Point to Point - NonFirm	618,217	544,667	35,584	37,447	519
Network Transmission	62,949,675	55,460,552	3,623,320	3,812,988	52,815
Contracts	8,380,598	7,383,559	482,379	507,630	7,031
Schedule 1	538,133	474,111	30,974	32,596	451
Schedule 2	9,341,669	8,230,291	537,697	565,844	7,838
RTO - PassThrough	304,000	267,833	17,498	18,414	255
Schedule 24	1,846,238	1,626,591	106,268	111,830	1,549
Transmission Expansion	26,236,410	23,115,064	1,510,142	1,589,192	22,012
Total Transmission	**120,350,478**	**106,032,382**	**6,927,253**	**7,289,869**	**100,974**
Interchange Transmission Rev	**42,632,106**	**37,560,164**	**2,453,861**	**2,582,312**	**35,768**
Total Transmission incl Interchang	**162,982,584**	**143,592,546**	**9,381,115**	**9,872,181**	**136,742**
Demand Allocation	100.0000%	88.1030%	5.7559%	6.0572%	0.0839%

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Information Request No. OAG-117, Attachment A

Docket E002/GR-15-826
Exhibit__(AEH-1), Appendix A

Transmission Revenues

2016 Budget

	Total Company	**MN State**	**ND State**	**SD State**	**Wholesale**
Point to Point - Firm	8,872,056	7,749,394	550,972	571,689	0
Point to Point - NonFirm	561,206	490,191	34,852	36,162	0
Network Transmission	81,810,855	71,458,591	5,080,618	5,271,646	0
Contracts	746,594	652,120	46,365	48,108	0
Schedule 1	1,154,354	1,008,283	71,688	74,383	0
Schedule 2	8,535,492	7,455,419	530,071	550,001	0
RTO - PassThrough	0	0	0	0	0
Schedule 24	1,277,970	1,116,257	79,364	82,349	0
Transmission Expansion	148,363,572	129,589,794	9,213,675	9,560,103	0
Total Transmission	**251,322,097**	**219,520,050**	**15,607,605**	**16,194,442**	**0**
Interchange Transmission Rev	**60,206,488**	**52,588,019**	**3,738,943**	**3,879,525**	**0**
Total Transmission incl Intercha	**311,528,585**	**272,108,070**	**19,346,548**	**20,073,967**	**0**
Demand Allocation	100.0000%	87.3461%	6.2102%	6.4437%	0.0000%

2017 Plan Year

	Total Company	**MN State**	**ND State**	**SD State**	**Wholesale**
Point to Point - Firm	8,872,056	7,749,394	550,972	571,689	0
Point to Point - NonFirm	561,206	490,191	34,852	36,162	0
Network Transmission	83,914,188	73,295,771	5,211,239	5,407,179	0
Contracts	752,315	657,118	46,720	48,477	0
Schedule 1	1,154,354	1,008,283	71,688	74,383	0
Schedule 2	8,535,492	7,455,419	530,071	550,001	0
RTO - PassThrough	0	0	0	0	0
Schedule 24	1,312,456	1,146,379	81,506	84,571	0
Transmission Expansion	148,296,986	129,531,634	9,209,539	9,555,813	0
Total Transmission	**253,399,053**	**221,334,190**	**15,736,588**	**16,328,275**	**0**
Interchange Transmission Rev	**63,618,112**	**55,567,940**	**3,950,812**	**4,099,360**	**0**
Total Transmission incl Intercha	**317,017,165**	**276,902,130**	**19,687,400**	**20,427,635**	**0**

Transmission Revenues

2018 Plan Year

	Total Company	**MN State**	**ND State**	**SD State**	**Wholesale**
Point to Point - Firm	8,872,056	7,749,394	550,972	571,689	0
Point to Point - NonFirm	561,206	490,191	34,852	36,162	0
Network Transmission	87,506,544	76,433,554	5,434,331	5,638,659	0
Contracts	758,166	662,229	47,084	48,854	0
Schedule 1	1,154,354	1,008,283	71,688	74,383	0
Schedule 2	8,535,492	7,455,419	530,071	550,001	0
RTO - PassThrough	0	0	0	0	0
Schedule 24	1,348,181	1,177,583	83,725	86,873	0
Transmission Expansion	158,754,120	138,665,533	9,858,948	10,229,639	0
Total Transmission	**267,490,119**	**233,642,187**	**16,611,671**	**17,236,261**	**0**
Interchange Transmission Rev	**65,815,951**	**57,487,666**	**4,087,302**	**4,240,982**	**0**
Total Transmission incl Intercha	**333,306,070**	**291,129,853**	**20,698,974**	**21,477,243**	**0**

Docket No. E002/GR-13-868
Information Request No. OAG-133

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional electric unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations.

Reference: Clark Direct, pg. 15.

For each year 2010 through 2014 and the test year provide the level of interchange agreement revenues to Minnesota coming from Wisconsin and revenues to Wisconsin coming from Minnesota. Also identify the level of rate base or investments in each state that contribute to the revenues for Minnesota and Wisconsin due to the interchange agreement. Explain whether any of the revenues are billed on a MWH or kWh basis and if so identify the level of revenues that are billed based MWH or kWh covering this period.

Response:

Table 1 below provides the requested information for the Interchange Agreement billings from NSP-Minnesota to NSP-Wisconsin.

Table 2 below provides the requested information for the Interchange Agreement billings from NSP-Wisconsin to NSP-Minnesota.

The following provides a description of the amounts included in each column in Table 1 and Table 2.

- Column A provides the dollar amount of total billings for the year. This includes items such as production and transmission O&M expenses, fuel and purchased power expenses, production and transmission fixed charges and carrying charges on fuel inventory balances.
- Column B provides the total production and transmission fixed charges. Fixed charges are the revenue requirements related to the plant investment and include items such as return on rate base, current and deferred income taxes, book depreciation, property insurance, and property taxes.
- Column C provides the average rate base amounts in which the fixed charge amounts in column B are based. These are the levels of rate base in each

company that contribute to the revenues. The levels of rate base for NSP-Minnesota are reflected in Table 1 and the levels of rate base for NSP-Wisconsin are reflected in Table 2.

- Column D provides the amount of the total billings (revenues) that are based on monthly energy requirements (or the variable production costs) and that are billed on a MWH basis. In large part, this consists of fuel and purchased power expenses but also includes items such as variable production O&M expenses and carrying charges on fuel inventory balances.

TABLE 1

NSP-Minnesota Interchange Agreement Revenues (from Billings to NSP-Wisconsin)
($ in thousands) (Total Company)

	A	**B**	**C**	**D**
Year	Total Billings	Fixed Charge Component of Total Bilings	Average Rate Base	Total Billings based on MWH Requirements
2010	$ 416,076	$ 110,422	$ 3,245,693	$ 198,429
2011	$ 440,519	$ 129,339	$ 3,962,351	$ 202,289
2012	$ 449,958	$ 133,919	$ 4,161,115	$ 210,612
2013	$ 458,633	$ 135,235	$ 4,600,506	$ 217,364
2014	$ 474,542	$ 154,716	$ 5,372,806	$ 208,188
2016 Test Year	$ 515,013	$ 192,132	$ 6,129,907	$ 203,873

TABLE 2

NSP-Wisconsin Interchange Agreement Revenues (from Billings to NSP-Minnesota)
($ in thousands) (Total Company)

	A	**B**	**C**	**D**
	Total Billings	Fixed Charge Component of Total Bilings	Average Rate Base	Total Billings based on MWH Requirements
2010	$ 116,312	$ 67,777	$ 343,847	$ 21,327
2011	$ 124,334	$ 77,974	$ 377,747	$ 19,430
2012	$ 125,344	$ 77,381	$ 403,530	$ 20,220
2013	$ 136,917	$ 86,744	$ 447,415	$ 20,676
2014	$ 145,102	$ 94,510	$ 512,497	$ 21,335
2016 Test Year	$ 185,280	$ 134,007	$ 740,497	$ 20,100

Witness:	Anne E. Heuer
Preparer:	Karen Everson
Title:	Director
Department:	Utility Accounting

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED
– PUBLIC DATA –

Docket No. E002/GR-13-868
Information Request No. OAG-167

Question:

Provide a summary of revenues and cross-charges, if any, for shared services with Home Smart. Provide a revenue and expense summary for Home Smart operations for 2014.

Response:

Please see Attachment A to this response for a summary of actual HomeSmart revenues and cross-charges for 2014.

Attachment A is marked "NON-PUBLIC," as it contains information that is trade secret data as defined by Minn. Stat. §13.37(1)(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. Thus Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500.

Witness:	Anne E. Heuer
Preparer:	Don Reiter / Mary Pope
Title:	Operations Manager / Senior Rate Analyst
Department:	HomeSmart Minnesota / Revenue Requirements North

Northern States Power Company

Docket No. E002/GR-13-868
OAG Information Request No. 167
Attachment A - Page 1 of 1

HomeSmart Cross Charges: Revenues and Expense

	2014 Actual	Description
	[TRADE SECRET BEGINS	
Sales Revenues		Sales revenues (water heaters, furnaces, central AC etc) 90% of sales to service plan customers
Service Plan Revenues		Service plan revenues
Total Revenues		**Total revenues**
	TRADE SECRET ENDS]	

	2014 Actual	Description
	[TRADE SECRET BEGINS	
Cost Of Goods Sold (COGS)		**Equipment costs paid to suppliers and payments to subcontractors for service parts and service labor .**
Outside Services Customer Care		Fee billed to HomeSmart by customer care area of Xcel Energy
Consulting Prof Service Legal		Xcel Energy legal fees
Network Voice		Xcel Energy phone system fees
Network Data		Network data charges
Distributed System Services		IT system fees
App Dev & Maint		Fees paid to IT to maintain HomeSmart application
Non Energy		HomeSmart bad debt reserve fees
Space		Facility charges Rice Street rent
Cust Billing Services to Other		Costs for billing HomeSmart customers via CRS billing system
Shared Assets Costs		Shared asset costs
Operating Co Overheads		Company overheads
Other Deductions		After hours phone center call roll over charges (calls taken by Sky Park Center Point)
Total Cross Charges		**Total cross charges paid to Xcel**
Total Direct Charges		Direct expenses incurred by HomeSmart
Total Expenses		HomeSmart O&M expense total
Total Expenses and COGS		**HomeSmart Total Expense and COGS**
	TRADE SECRET ENDS]	