

Direct Testimony and Schedules
Anne E. Heuer

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-12-____
Exhibit__(AEH-1)

Overall Revenue Requirements
Rate Base
Income Statement

December 18, 2012

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1 **I. INTRODUCTION**

2
3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Anne E. Heuer. I am Manager of Revenue Analysis for Xcel
5 Energy Services Inc. (XES or the Service Company).

6
7 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

8 A. I have over 25 years of experience at XES and Northern States Power
9 Company (NSPM or the Company) in the areas of corporate budgeting, cost
10 accounting, financial operations, and revenue requirements. In my current
11 role, I am responsible for the development of jurisdictional revenue
12 requirements for all NSPM jurisdictions. My resume is provided as
13 Exhibit___(AEH-1), Schedule 1.

14
15 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

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

- 19 • the overall retail revenue requirement of \$199.624 million and revenue
20 deficiency of \$16.900 million, determined by the cost of service for the
21 2013 budget test year; and
- 22 • the interim increase of \$14.704 million as discussed in our Petition for
23 Interim Rates.

24
25 I relied on and incorporated information provided by other witnesses in this
26 proceeding to develop many of the test year revenue requirement adjustments
27 discussed in my testimony. My testimony includes several schedules with

1 financial information related to the 2013 test year revenue requirements and
2 deficiency. These schedules were prepared by me or under my supervision.
3 Exhibit___(AEH-1), Schedule 2 provides an index of the schedules to my
4 testimony.

5
6 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

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

- 8 • Section II Data Provided and Selection of Test Year
- 9 • Section III Test Year Budget Development
- 10 • Section IV Test Year Revenue Deficiency
- 11 • Section V Description of Cost Changes
- 12 • Section VI Jurisdictional Cost of Service Study
- 13 • Section VII Compliance Issues and Applications
- 14 • Section VIII Utility and Jurisdictional Allocations
- 15 • Section IX Rate Base Components
- 16 • Section X Adjustments to Rate Base And Associated Income
- 17 Statement Adjustments
- 18 • Section XI Income Statement
- 19 • Section XII Adjustments to the Income Statement
- 20 • Section XIII Proposed Transmission Cost Recovery Rider
- 21 • Section XIV Conclusion

22
23 **II. DATA PROVIDED AND SELECTION OF TEST YEAR**

24
25 Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS
26 PROVIDED IN THIS PROCEEDING.

1 A. Financial data is provided for the most recent fiscal year (calendar year 2011),
2 and the test year (calendar year 2013).

3
4 Financial data for the most recent fiscal year and the test year are adjusted for
5 traditional regulatory adjustments (*e.g.*, advertising expenses, economic
6 development, etc.). The test year on which the Notice is based starts with
7 financial data included in the Company's 2013 projected fiscal year budget and
8 includes ratemaking adjustments deemed necessary, along with refinements
9 and corrections to 2013 budgeted data to reflect any subsequent changes to
10 our costs that have become better known. These changes to the base data
11 were made to assure the test year provides a normalized level of rate base and
12 expenses to establish just and reasonable rates. Separate rate base and income
13 statement bridge schedules that identify these adjustments are provided with
14 my testimony.

15
16 Q. WHY DID THE COMPANY PROPOSE CALENDAR YEAR 2013 FOR THE TEST YEAR
17 FOR THIS PROCEEDING?

18 A. Calendar year 2013 was selected as the test year because it uses the most recent
19 available budget information and is a reasonable representation of the costs
20 and expenses the Company will incur when the interim and final rates take
21 effect.

22
23 Q. DOES THE 2013 PROJECTED TEST YEAR MEET THE COMMISSION'S
24 REQUIREMENTS?

25 A. Yes. The use of a projected test year is consistent with the intent of North
26 Dakota Century Code (N.D.C.C.) § 49-05-04.1, subd. 1, which allows a utility
27 to select a future test year. N.D.C.C. § 49-05-04.1, subd. 2, then requires the

1 Company to present:

- 2 a) a comparison of forecast data to historical period data to demonstrate
3 the reliability and accuracy of the utility's forecast, including a
4 comparison of the prior years' forecast or budgeted data to actual data
5 for those periods;
- 6 b) a statement that the test-year budget data is reasonable, reliable, and
7 made in good faith and all basic assumptions used in making or
8 supporting the forecast are reasonable, evaluated, identified, and
9 justified to allow the Commission to test the appropriateness of the
10 forecast; and
- 11 c) the accounting treatment applied to anticipated events and transactions
12 in the budget is the same as the accounting treatment to be applied in
13 recording the events once they have occurred.

14

15 I provide a comparison of past budgets to actual costs later in my testimony in
16 compliance with the first requirement of this statute. The 2013 Company
17 budget data, after the adjustments I discuss below, is a reasonable
18 representation of the costs and expenses the Company will incur to provide
19 electric service in the State of North Dakota, and complies with N.D.C.C. §
20 49-05-04.1, subd. 2. Thus, the 2013 test-year data is reasonable, reliable and
21 made in good faith and is appropriate for setting rates in this proceeding. In
22 addition, the accounting treatment applied to anticipated events and
23 transactions in the budget is the same as the accounting treatment applied in
24 recording the events once they have occurred.

25

26 Q. N.D.C.C. § 49-05-04.1, subd. 1(c) REQUIRES A UTILITY TO FILE CERTAIN
27 FINANCIAL DATA FOR COMPARISON WITH THE TEST YEAR DATA. IS THE

1 COMPANY COMPLYING WITH THIS REQUIREMENT?

- 2 A. Yes. Exhibit___(AEH-1), Schedule 3 is the Company's 2011 actual
3 jurisdictional summary data. This information, providing the most recent
4 calendar year of actual data, is consistent with the approach we took in our last
5 electric rate case (Case No. PU-10-657) and with the financial statements in
6 our May 9, 2012 jurisdictional annual report filed with the Commission.

7
8 **III. TEST-YEAR BUDGET DEVELOPMENT**

9
10 **A. Budget Development Process**

- 11 Q. IS THERE A GROUP WITHIN XCEL ENERGY INC. (XEI) WITH OVERALL
12 RESPONSIBILITY FOR FINANCIAL GOVERNANCE?

- 13 A. Yes. The Xcel Energy Financial Council is responsible for approving the five-
14 year Operation and Maintenance (O&M) Budget and Capital Expenditure
15 Budget for each of the operating utility subsidiaries, as well as monitoring the
16 monthly financial performance of the operating companies and XEI during
17 the course of each year.

- 18
19 Q. PLEASE DESCRIBE IN GENERAL TERMS THE FINANCIAL BUDGET PROCESS.

- 20 A. Electric and natural gas utilities are long-term, capital intensive businesses. As
21 such, each year we prepare a five-year financial forecast that is used by
22 executive management to anticipate the Company's financial needs, make
23 major strategic decisions, and develop supportable and attainable financial
24 plans. Key components of the financial forecast are the O&M and capital
25 expenditure budgets.

1 The O&M and capital budgeting processes can generally be divided into three
2 phases: corporate instructions and guidelines; business area budget creation;
3 and senior management review and approval.
4

5 Q. PLEASE EXPLAIN THE PURPOSE OF THE BUDGET INSTRUCTIONS.

6 A. The Budget Instructions are the primary resource the business areas use in
7 developing the budgets for their organizations. The Budget Instructions
8 articulate the guiding principles of the budget process, as well as the
9 development expectations for both the O&M and Capital budgets. Because it
10 is necessary for the business areas to factor their strategic priorities and annual
11 plans into their budgets, each business area may also provide instructions
12 specific to its organization.
13

14 Q. HOW ARE THESE BUDGET GUIDELINES DEVELOPED?

15 A. The starting point for developing the budget guidelines is the most recent five-
16 year financial forecast. In developing the guidelines, the Financial Council
17 reviews this information, considering business plans and a number of other
18 factors, including updated sales forecasts, fuel costs, and other significant
19 revenue and expenses that may have a significant impact on financial results.
20 Of particular importance are the five-year capital spending levels, which drive
21 the amount of financing needed.
22

23 Q. WHO IS RESPONSIBLE FOR PREPARING THE O&M AND CAPITAL EXPENDITURE
24 BUDGETS FOR EACH BUSINESS AREA?

25 A. Each business area within XES or NSPM has an assigned finance
26 representative who works with the designated employees in the business area
27 to prepare the budget. This includes the gathering of data and supporting

1 assumptions. The information is consolidated and reviewed at various levels
2 within the functional groups, including review and approval by the senior
3 business area executive before being presented to the Company's President.
4 The Finance Council makes the final review.

5
6 Q. IS THE SAME PROCESS USED TO DEVELOP THE FIVE-YEAR CAPITAL
7 EXPENDITURE BUDGET?

8 A. No. The process for developing the five-year capital expenditure budget is
9 slightly different. The capital budget is a comprehensive listing of major
10 projects and "routine" project construction work. Many of the major projects
11 are planned and completed over multiple calendar years. Accordingly, each
12 business area develops its capital budget from a starting Construction Work In
13 Progress (CWIP) balance, where applicable, and forecasts future capital
14 expenditures for the current bridge year (the remainder of the current year in
15 which the budget is prepared) and for the next five years.

16
17 Capital projects must identify in-service dates or, in the case of routine
18 projects, request that a "project closing" pattern be applied. Once the five-
19 year capital expenditure budget has been approved by the Financial Council,
20 we perform all of the plant-related accounting activities needed to prepare a
21 forecast cost of service.

22
23 In terms of governance, new major projects with spending that begins in the
24 upcoming year must be brought forward for review by the Investment Review
25 Council (IRC). The IRC reviews each project, ensures that the project
26 assumptions are understood and properly analyzed, and indicates when the
27 project can be brought to the Financial Council for final review and approval.

1 NSPM projects greater than \$25 million are also approved by the XEI and
2 NSPM Boards of Directors. These project approvals are a key part of the
3 annual capital budget governance process.

4
5 Q. WHAT HAPPENS AFTER THE BUSINESS AREAS HAVE COMPLETED THEIR
6 RECOMMENDED O&M AND CAPITAL BUDGETS?

7 A. After the business areas review and approve their “bottom-up” budgets, the
8 President of NSPM is responsible for reviewing the total budgets for his or
9 her operating company across all business areas.

10
11 Since budget guidelines are also developed on an operating company basis, the
12 President of NSPM has a foundation on which to evaluate business area
13 budgets that are either above or below the budget guidelines, and can evaluate
14 the reasons for each business area coming in over or under the budget
15 guidelines.

16
17 After incorporating any modifications requested by the President of NSPM,
18 the O&M and capital expenditure budgets are presented to the Financial
19 Council. The same iterative process used up to this point is repeated at the
20 Financial Council, meaning additional research and analysis may be required
21 and adjustments made as necessary.

22
23 Q. PLEASE DESCRIBE THE PROCESS IN PLACE FOR CAPITAL EXPENDITURE AND
24 PROJECT OVERSIGHT.

25 A. As business areas assess their operating needs and identify potential capital
26 projects, the scope, cost, and timing of these projects are evaluated and
27 prioritized within the business area, resulting in a projection of recommended

1 capital expenditures for the next several years.

2
3 Corporate management, supported by the Financial Performance and
4 Planning group, reviews the aggregate forecast of capital spending on a
5 periodic basis. These corporate capital reviews consider strategic priorities,
6 resource planning requirements, overall funding capability, and capital
7 allocation priorities and constraints.

8
9 With input from corporate management, the business areas continually
10 manage their planned level of capital spending, taking into account changing
11 business priorities, new operating and regulatory requirements, vendor or
12 equipment cost changes, and funding constraints. The highest prioritized
13 capital projects are identified, and those satisfying established approval criteria
14 then require corporate governance approval.

15
16 In addition, a quarterly capital review process takes place to review the current
17 year's capital forecast, all previously-approved capital projects greater than \$25
18 million, and the updated five-year capital spending forecast. As discussed
19 previously, the Financial Council oversees the process for approval and
20 authorization of major capital projects, based on corporate governance
21 guidelines.

22
23 Q. WAS THE BUDGETING PROCESS FOR THE 2013-2017 O&M AND CAPITAL
24 BUDGET MODIFIED FROM PAST BUDGETING PROCESSES FOR THE PURPOSE OF
25 IMPROVING THEIR ACCURACY?

26 A. Yes. While the overall budgeting process is primarily the same, in 2012 we
27 added an additional three years of detailed O&M budgeting to our

1 requirements. In previous years, while capital was budgeted for a full five
2 years, a detailed O&M budget was only developed for a two-year period due
3 to budget system limitations. In 2012, an information technology solution was
4 identified that allowed us to expand detailed O&M budgeting to five years (an
5 additional three years), consistent with the capital budget.

6
7 Other changes we made were to the compilation and review of budget
8 documentation and related summary information to drive further
9 improvements in the process. These changes were the result of annual
10 debriefing meetings held with internal budget process stakeholders and
11 Financial Council members in order to continually improve the efficiency and
12 accuracy of our process.

13
14 Q. HAVE THERE BEEN ANY CHANGES IN ORGANIZATIONAL STRUCTURE SINCE
15 THE LAST RATE CASE, AND, IF SO, DID THOSE HAVE ANY IMPACT ON THE USE
16 OF HISTORICAL INFORMATION IN THE BUDGETING PROCESS?

17 A. There was a corporate reorganization in 2011 that became effective for budget
18 purposes in 2012. However, we are able to “map” the associated expenses for
19 each activity from before the reorganization to after the reorganization.
20 Consequently, the reorganization had no effect on our ability to use historical
21 costs to identify trends and variances when developing the 2013 budget.

22
23 **B. Reliability of Test-Year Budget**

24 Q. WHY DOES THE COMPANY PLACE SUCH EMPHASIS ON BUDGETING ACCURACY?

25 A. A key factor in maintaining the Company’s credibility with customers,
26 regulators, and the investment community is our ability to accurately forecast
27 its results from operations. That, in turn, requires a budget process that is

1 transparent and accurately reflects the O&M and capital expenditures NSPM
 2 expects to incur during the budget period. The budgeting process must be
 3 accurate because the Company uses the same budget for financial
 4 management purposes and development of rate case test year costs. This
 5 ensures processes are in place that facilitate regular and consistent monitoring
 6 and forecast updates of actual spending compared to budgets to reflect the
 7 dynamic nature of the business.

8
 9 Q. NDCC § 49-05-04.1, SUBD. 2, REQUIRES THE COMPANY TO PRESENT A
 10 COMPARISON OF FORECAST DATA TO HISTORICAL PERIOD DATA TO
 11 DEMONSTRATE THE RELIABILITY AND ACCURACY OF THE UTILITY’S FORECAST.
 12 HAVE YOU PREPARED SUCH AN ANALYSIS?

13 A. Yes. Tables 1 and 2 summarize the actual versus budget comparisons for
 14 NSPM Total Company and for NSPM Electric. Table 2 summarizes the most
 15 recent five years of actual versus budget comparisons for O&M expenses by
 16 FERC account for the NSPM electric utility.

17 **Table 1**
 18 **Total NSPM Company Actual v. Budget O&M**
 19 **(\$ in Thousands)**

Year	Budget Amount	Actual Amount	\$ Variance	% Variance
2011	\$1,070.3	\$1,064.8	(\$5.5)	-0.5%
2010	\$1,033.9	\$1,038.0	\$4.1	0.4%
2009	\$1,006.4	\$970.9	(\$35.5)	-3.5%
2008	\$903.2	\$875.8	(\$27.4)	-3.0%
2007	\$862.0	\$885.1	\$23.1	2.7%
5-Yr. Total	\$4,875.8	\$4,834.6	(\$41.2)	-0.8%

20

Table 2
NSPM Company Electric Utility Actual v. Budget O&M
(\$ in thousands)

Year	Budget Amount	Actual Amount	\$ Variance	% Variance
2011	\$979.8	\$980.7	\$0.9	0.1%
2010	\$944.1	\$955.3	\$11.3	1.2%
2009	\$921.0	\$886.0	(\$35.0)	-3.8%
2008	\$823.5	\$796.3	(\$27.2)	-3.3%
2007	\$780.0	\$800.9	\$20.9	2.7%
5-Year Total	\$4,448.4	\$4,419.2	(\$29.2)	-0.7%

Q. PLEASE DISCUSS THE VARIANCES IN BUDGETED AND ACTUAL O&M EXPENSES OVER THE PAST FIVE YEARS?

A. The results for the NSPM Total Company are similar to those for the NSPM electric operations. Therefore, I will only discuss the Total Company results. On average, actual results were within 0.8 percent of the budget over the five year period, and there was less than a 1 percent deviation for 2010 and 2011. In 2009, actual O&M expenses were less than the budget by 3.5 percent due primarily to the economic downturn, which happened in late 2008, after the original budget was approved. As a result of the changed economic conditions and resulting lost revenues, the Company took actions to reduce costs, which resulted in actual spending in 2009 that was lower than the original budget.

In 2008, expenses were lower than the budget due to cost savings from the integration of Nuclear Management Company into NSPM, and management actions to reduce costs due to the economic conditions that occurred late in the year, including elimination of the Annual Incentive Plan payment. These reductions were partially offset by higher bad debt expense and active employee healthcare costs. In 2007, expenses were 2.7 percent higher than the budget, largely driven by higher nuclear operating costs than budgeted.

1 **C. Sales Forecast**

2 Q. WHEN WAS THE SALES FORECAST THAT WAS INCORPORATED INTO THE TEST
3 YEAR REVENUE REQUIREMENT DEVELOPED?

4 A. The sales forecast was developed in July 2012 based on actual data through
5 June 2012. For 2012 statistics presented in this testimony, the forecast values
6 for July through October have been replaced with actual values.

7
8 Q. HAS THE COMPANY CHANGED ITS FORECASTING METHODOLOGY FOR NORTH
9 DAKOTA SINCE THE LAST RATE CASE?

10 A. No. We believe that our existing methodology is appropriate for estimating
11 annual electric sales in North Dakota.

12
13 Q. WHAT IS THE COMPANY'S FORECAST OF ELECTRIC SALES AND CUSTOMERS FOR
14 THE TEST YEAR ENDING DECEMBER 31, 2013?

15 A. Summaries of the monthly test-year MWh sales and number of customers for
16 each customer class are included in the Test Year Workpapers at Section VII,
17 Tab B1, Customers, and Tab B2, Energy (Sales) and Demand.

18
19 Q. WHAT HAS BEEN THE HISTORICAL CUSTOMER GROWTH IN NORTH DAKOTA?

20 A. The total number of electric retail customers in the Company's North Dakota
21 service territory increased at an average annual rate of 0.5 percent from 2000
22 through 2011, or 390 customers per year on average. This average growth is
23 negatively impacted by unusual events occurring in 2005 and 2011. In 2005,
24 the Company implemented a new billing system, and the associated customer-
25 count definitional changes resulted in a reduction in the count of customers
26 following the billing system conversion. In 2011, the Company lost a
27 significant number of customers due to the Minot flood in June. While most

1 of those customers were reconnected by the end of the year, the average
2 customer count for that year declined from 2010 levels. Excluding 2005 and
3 2011 from the calculation of average annual growth shows an increase of 0.8
4 percent per year or 720 customers on average.

5
6 The largest class of customers is the Residential class, which represents 86
7 percent of total customers and has an average growth rate of 0.8 percent or
8 600 additions per year during the period from 2000 through 2011 (excluding
9 2005 and 2011 as previously discussed).

10
11 Q. HOW DOES THE TEST-YEAR CUSTOMER GROWTH COMPARE WITH HISTORICAL
12 GROWTH?

13 A. We expect 2012 and 2013 retail customer additions to be stronger than the
14 2000 to 2011 historical growth (excluding 2005 and 2010), and average 1,060
15 customer additions per year, or 1.2 percent. The 2012 customer forecast
16 reflects actual customer data through October 2012.

17
18 Table 3 provides the historical and forecast annual customer growth rate by
19 class for the time period 2000-2013.

20 **Table 3**
21 **2000-2013 Average Annual Percent Change in Customers**

Customer Class	2000-2011 Average (excluding 2005 & 2011)	2012 Forecast	2013 Test Year
Residential	0.8%	1.4%	1.0%
Commercial & Industrial	1.0%	0.7%	1.5%
Street Lighting	2.5%	22.8%	5.4%
Public Authority	0.0%	1.3%	1.7%
Total Retail	0.8%	1.3%	1.1%

22
23 Q. WHY IS THE PROJECTED CUSTOMER COUNT GROWTH STRONGER THAN THE

1 HISTORICAL AVERAGE GROWTH?

2 A. The historical average includes several years of slower growth than average.

3
4 Q. WHAT HAS BEEN THE HISTORICAL WEATHER-NORMALIZED SALES GROWTH IN
5 NORTH DAKOTA?

6 A. After normalizing for weather, the Company's North Dakota service territory
7 total electric retail sales have increased an average of 1.0 percent per year
8 during the period of 2000 through 2011. Residential sales have averaged
9 growth of 0.8 percent, while total Commercial and Industrial sales have
10 increased at an average annual rate of 1.2 percent during the period of 2000
11 through 2011.

12
13 In 2008, retail sales growth slowed from the 2000-2007 historical average
14 annual rate of 1.4 percent to only 0.7 percent. In 2009, retail sales declined 0.6
15 percent from 2008 levels. The 2008 slowdown was seen primarily in sales to
16 the Commercial and Industrial sector, which increased by only 0.7 percent in
17 2008, followed by a decline of 2.0 percent in 2009, when our service area in
18 Fargo experienced a major flood. Growth in the Commercial and Industrial
19 class was only 0.6 percent in 2010. Table 4 provides the sales by customer
20 class and the sales forecast for 2012 and 2013.

21 **Table 4**
22 **2000-2013 Average Annual Percent Change in Sales**

Customer Class	2000-2011 Average	2012 Forecast	2013 Test Year
Residential	0.8%	-0.1%	1.9%
Commercial & Industrial	1.2%	0.4%	1.3%
Street Lighting	1.2%	-1.1%	2.5%
Public Authority	0.6%	-5.8%	0.1%
Total Retail	1.0%	0.2%	1.5%

23
24 Q. HOW DO 2013 TEST-YEAR SALES COMPARE TO HISTORICAL SALES?

1 A. The total retail sales 2013 test-year growth rate of 1.5 percent is higher than
2 the historical average annual growth rate for the time period 2000-2011, which
3 reflects the lower growth during 2008 and 2009. The 2012 projection
4 incorporates actual sales data through October 2012. The sales projections for
5 2013 reflect stronger growth for the Residential class, while the Commercial
6 and Industrial class shows slightly stronger growth.

7

8 Q. PLEASE EXPLAIN THE RESIDENTIAL GROWTH PROJECTIONS RELATIVE TO
9 HISTORICAL GROWTH.

10 A. The test-year sales growth in the Residential class is due to improving
11 customer additions combined with growth in use per customer. While use per
12 customer is expected to decline in 2012, it is projected to increase in 2013.

13

14 Q. PLEASE EXPLAIN THE COMMERCIAL AND INDUSTRIAL GROWTH PROJECTIONS
15 RELATIVE TO HISTORICAL GROWTH.

16 A. The Commercial and Industrial sector experienced sales growth slowing in
17 2008, and declining in 2009. This sector is expected to grow modestly again in
18 2012, and then grow at a stronger rate in the 2013 test-year as the economy
19 continues to improve.

20

21 Q. HOW DID THE 2011 WEATHER-NORMALIZED SALES COMPARE TO THE 2011
22 TEST-YEAR SALES FORECAST FILED IN THE COMPANY'S PREVIOUS ELECTRIC
23 RATE CASE (PU-10-657 AND PU-11-55)?

24 A. A comparison of the weather-normalized 2011 actual sales and the 2011 test-
25 year forecasted sales filed in the Company's previous electric rate cases is
26 provided in Table 4. The 2011 overall sales forecast was very close to the
27 2011 weather-normalized actual sales. Weather-normalized 2011 actual sales

1 were lower (-18,512 MWh or -0.8 percent) than predicted for the test year.
 2 The lower-than-expected sales were seen in the Residential sector, and were
 3 partially offset by higher-than expected sales in the Commercial and Industrial
 4 sales sector.

5 **Table 5**
 6 **2011 Weather-Normalized Sales by Class (MWh)**

Customer Class	2011 Test-Year Forecast	2011 Actual	Variance	Percentage
Residential	806,310	770,827	-35,483	-4.4%
Commercial & Industrial	1,417,205	1,432,150	14,946	1.1%
Street Lighting	15,856	16,067	212	1.3%
Public Authority	11,910	13,723	1,813	15.2%
Total Retail	2,251,280	2,232,768	-18,512	-0.8%

7
 8 **D. Test-Year Budget Adjustments**

9 Q. YOU MENTIONED THAT ADJUSTMENTS WERE MADE TO THE ORIGINAL 2013
 10 BUDGET. PLEASE DESCRIBE THE TYPES OF ADJUSTMENTS MADE.

11 A. The Company made four types of adjustments to the base data for the
 12 purpose of improving the appropriateness of the test year:

- 13 • *Forecast Updates.* Three rate base and six income statement updates were
 14 made to the budgeted data to reflect known reductions and additions to
 15 the 2013 projected year budgeted data.
- 16 • *Traditional rate case adjustments.* Five traditional rate case adjustments
 17 were made to the income statement.
- 18 • *Rate Case Adjustments.* Five rate base and seventeen income statement
 19 adjustments were made to ensure the test year accurately reflects past
 20 Commission orders and is an accurate representation of future
 21 anticipated costs.
- 22 • *Amortizations.* Of the seventeen income statement adjustments, five are
 23 amortizations, including amortization of our proposed 2013 rate case

1 expenses.

2
3 I discuss each of these adjustments later in my testimony, more specifically in
4 Section X Adjustments to Rate Base and Associated Income Statement
5 Adjustments and Section XII Adjustments to the Income Statement. A list of
6 adjustments, some of which apply to both rate base and income statements, is
7 shown on Exhibit____(AEH-1), Schedule 4.
8

9 Q. HAVE YOU PREPARED SCHEDULES THAT IDENTIFY THE ADJUSTMENTS TO THE
10 PROJECTED YEAR BUDGET DATA?

11 A. Yes. The bridge schedules Exhibit____(AEH-1), Schedule 5, 2013 Test Year
12 Bridge Schedule - Rate Base and Exhibit____(AEH-1), Schedule 6, 2013 Test
13 Year Bridge Schedule - Income Statement, show all test period adjustments.
14 Column 1 of the Rate Base bridge schedule shows the 2013 unadjusted rate
15 base by each component of rate base. Each adjustment to rate base is
16 contained within a column that shows its effect on each rate base component.
17 Likewise, Column 1 of the Income Statement bridge schedule shows the 2013
18 unadjusted income statement by each component of the income statement.
19 As with rate base, each adjustment to the income statement is contained
20 within a column that shows its effect on each income statement component.
21 In addition, the Income Statement bridge schedule shows the impact of each
22 rate base and income statement adjustment on the revenue requirement.
23

24 Q. IS THE 2013 O&M EXPENSE BUDGET FOR THE COMPANY'S ELECTRIC UTILITY
25 OPERATIONS AN ACCURATE AND RELIABLE PROJECTION?

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

1 **IV. TEST-YEAR REVENUE DEFICIENCY**

2
3 Q. WHAT IS THE AMOUNT OF THE JURISDICTIONAL REVENUE REQUIREMENT FOR
4 NORTH DAKOTA?

5 A. The jurisdictional retail revenue requirement for North Dakota electric utility
6 operations is \$199.624 million based on average rate base and projected net
7 operating income for the 2013 test year, the average capital structure, short-
8 term debt, long-term debt, and 10.60 percent return on equity (ROE) and 7.90
9 percent overall Rate of Return (ROR) recommended by Ms. Ann E. Bulkley in
10 her Direct Testimony filed with this Application.

11
12 Q. WHAT IS THE AMOUNT OF THE REVENUE DEFICIENCY FOR THE TEST YEAR?

13 A. The revenue deficiency for the test year is \$16.900 million. A summary of the
14 revenue deficiency for 2013 is shown in Exhibit___(AEH-1), Schedule 7.
15 Schedule 7 is a comparison of the jurisdictional revenue requirement amount
16 for the test year with the forecasted revenues for the same period under
17 present rates, which were approved by the Commission in Case No. PU-10-
18 657. The level of North Dakota retail electric rates must be increased by this
19 amount in 2013 in order for the Company to earn an overall return on rate
20 base of 7.90 percent as developed in Exhibit___(AEH-1), Schedule 8, Page 5.

21
22 Q. WHAT IS THE PERCENTAGE INCREASE IN BASE RATE REVENUES PROPOSED IN
23 THIS CASE?

24 A. The test-year revenue deficiency amount represents a 9.25 percent overall
25 increase in retail revenues from base rates compared to projected 2013 retail
26 revenues at present rates.

27

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

3 A. Yes, under my direction, a cost of service study was prepared.
4 Exhibit___(AEH-1), Schedule 8 contains a copy of the jurisdictional cost of
5 service study for the test year.

6

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

9 A. The capital structure employed in this case represents the Company's 2013
10 budgeted amounts. The costs and ratios associated with this capital structure
11 are found in Exhibit___(AEH-1), Schedule 8, Page 5, and are as follows:

12

	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	
13				
14	Long Term Debt	5.14%	44.96%	2.31%
15	Short Term Debt	0.75%	2.48%	0.02%
16	Common Equity	10.60%	52.56%	<u>5.57%</u>
17	Weighted Cost			7.90%

18

19 These capital structure ratios and the cost rates are based on the 2013 budget
20 for the Company's capital structure.

21

22 V. DESCRIPTION OF COST CHANGES

23

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

25 A. Consistent with the analysis provided in prior rate cases, my explanation of the
26 key deficiency cost drivers uses a comparison to the Commission ordered
27 results from our last electric rate case (Case Nos. PU-10-657 and PU-11-55)

1 which used a test year based on the 2011 budget. I will refer to the
2 comparison year as the 2011 rate case.

3
4 **A. Overview of Key Cost Drivers**

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

6 A. A summary of the cost elements to which the revenue deficiency can be
7 attributed is provided in Exhibit____(AEH-1), Schedule 9, Page 1 of 2. The
8 major cost elements driving the revenue deficiency are related to:

- 9 1) the growth in rate base and the capital recovery requirements associated
10 with the additional rate base investments made since the 2011 rate case;
11 and
12 2) increases in operating and maintenance costs due to higher production
13 expense (primarily nuclear) and increases in transmission, and higher
14 pension expenses reflected in Administrative and General expenses.

15
16 These cost elements are partially offset by retail sales growth and higher
17 wholesale transmission margins in the North Dakota jurisdiction. Lower cost
18 of debt has also reduced the cost of capital incurred on rate base.

19
20 Q. WHAT HAVE BEEN THE MAIN REASONS FOR GROWTH IN THE COMPANY'S
21 GENERATION PLANT INVESTMENT?

22 A. As described in Ms. Laura McCarten's Direct Testimony, the Company has
23 made significant investments in nuclear plants and modernization of
24 transmission and distribution assets for reliability, including:

- 25 • Power uprate at the Monticello nuclear power plant;
26 • Extension of the operating lives at the Monticello and Prairie Island
27 nuclear power plants, including replacement of a Prairie Island steam

1 generator, granted an Advanced Determination of Prudence (ADP) in
2 Case No. PU-10-127;

- 3 • CapX 2020 regional transmission backbone infrastructure (ADP Notice
4 filings were submitted for the Fargo, Bemidji and La Crosse projects);
5 and
- 6 • Reliability, extension, rebuilds, and reinforcements of the North Dakota
7 distribution system, both overhead and underground.

8
9 Total transmission, distribution, and nuclear production investments account
10 for approximately \$9.7 million of the \$10.1 million of capital related cost
11 drivers shown on Exhibit___(AEH-1), Schedule 9, Page 1 of 2, Row 1, and
12 Table 6.

13 **Table 6**
14 **Capital Recovery by Functional Class**

Functional Class	2013 Test-Year Revenue Requirement (\$M)
Nuclear Production	4.9
Non-Nuclear Production	0.2
Transmission	2.0
Distribution	2.5
Other Capital	1.5
Change in Cost of Capital	(1.3)
Total Capital Recovery	10.1

15
16
17 Q. WHAT ARE THE ELEMENTS OF CAPITAL RECOVERY?

18 A. The elements of capital recovery are: (i) depreciation, which is the ratable
19 return of investment over its estimated service life; (ii) return on investment;
20 and (iii) related income taxes.

21
22 Q. PLEASE DISCUSS THE REVENUE DEFICIENCY RELATED TO OPERATING
23 EXPENSES.

1 A. Exhibit___(AEH-1), Schedule 9, Page 2 of 2, shows a summary of the change
2 in operating expenses by functional class between the 2011 and the 2013 test
3 periods. The schedule also shows a calculation of the average annual percent
4 of increase over the same period.

5

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

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

11

12 Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE
13 COMPARABLE BETWEEN THE 2013 TEST-YEAR BUDGET AND THOSE
14 CONTAINED IN 2013 RATE CASE TEST YEAR?

15 A. Yes. Both categorizations conform to the FERC Uniform System of
16 Accounts.

17

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

20 A. Yes, but with the following three exceptions:

21 1) Power production expenses that are part of the fixed Interchange
22 Agreement costs between NSPM and Northern States Power
23 Company-Wisconsin (NSPW) are reclassified to margin. This allows
24 the net effect of Interchange Agreement billings to be treated more like
25 purchased (or sold) power.

26 2) Transmission revenues associated with the provision of transmission
27 service are included in other electric operation revenues in the Cost of

1 Service. Expense related to the transmission of energy by others is
2 included in O&M expense, FERC 565. For Schedule 9, we reclassified
3 the transmission revenue as a negative transmission expense.

4 3) Transmission Interchange Agreement expenses billed from NSPW to
5 NSPM have been reclassified to margin on Schedule 9.

6
7 Q. WHAT IS THE AMOUNT OF CHANGE IN O&M COSTS SINCE THE 2011 RATE
8 CASE?

9 A. Excluding the cost of fuel and purchased energy, and reflecting the three
10 reclassifications discussed above, operating expenses have increased in total by
11 \$6.3 million since the 2011 rate case. Most of this change reflects higher
12 O&M costs associated with power production (\$3.0 million); transmission
13 (\$0.7 million); and administrative and general expenses (\$2.1 million).

14
15 Q. WHAT ARE THE MAIN REASONS FOR INCREASE IN O&M COSTS ASSOCIATED
16 WITH POWER PRODUCTION?

17 A. For the State of North Dakota, \$2.6 million of the \$3.0 million increase in
18 O&M for power production (generating facilities) is nuclear related. Within
19 the \$2.6 million of nuclear, \$1.7 million is related to security contracts,
20 compliance program activities in the wake of the Fukushima event, nuclear
21 fees, and other compliance-related contracts. The other \$0.8 million in nuclear
22 increases are due to amortization of refueling outages. The reasons for the
23 nuclear increases are discussed in more detail, on a Total Company basis, in
24 the Direct Testimony of Mr. Timothy O'Connor.

25
26 Q. PLEASE BRIEFLY DISCUSS THE MAIN REASON FOR THE INCREASE IN
27 TRANSMISSION EXPENSE.

1 A. Transmission expense (adjusted to include transmission revenues and exclude
2 transmission Interchange Agreement expense as discussed earlier) for the
3 North Dakota electric retail jurisdiction has increased by \$0.7 million. As
4 discussed by Mr. Stephen R. Foss in his Direct Testimony, this increase is due
5 to additional O&M costs associated with new transmission infrastructure
6 added to the system, and increased O&M for aging infrastructure.

7

8 Q. PLEASE DISCUSS THE REASONS FOR THE INCREASE IN ADMINISTRATIVE AND
9 GENERAL EXPENSE.

10 A. Administrative and General expense for the North Dakota electric retail
11 jurisdiction has increased by \$2.1 million. This increase is largely due to
12 increases in pension expense accounted in FERC 926 (\$1.4 million) and a
13 reallocation of nuclear IT equipment (\$0.5 million).

14

15 Q. WHY DID PENSION EXPENSE INCREASE?

16 A. The pension expense increase resulted from a combination of three factors:
17 (i) the 2008 market losses, which are phased-in over 5 years (which means that
18 the full amount of the 2008 loss is not included in pension expense calculation
19 until 2013); (ii) a reduction in the discount rate used to calculate pension
20 expense; and (iii) a reduction in the expected return on pension assets that is
21 also used to calculate pension expense.

22

23 Q. WAS ANY PART OF THE PENSION EXPENSE INCREASE RELATED TO AN
24 INCREASE IN PENSION BENEFITS?

25 A. No. The increase in 2013 pension expense is not related to any increase in
26 pension benefit levels. Pension benefits have in fact been reduced over a
27 number of years.

1 Q. PLEASE EXPLAIN THE REASON FOR THE \$500,000 INCREASE DUE TO NUCLEAR
2 IT EQUIPMENT ALLOCATION.

3 A. In 2012 we discovered a need for a correction in the assignment of costs for
4 computers and phones as a result of assigning certain Service Company
5 employees supporting only Nuclear operations to NSPM. These are not
6 changes to the allocation process, but rather, corrections necessary to properly
7 align costs to the operating company (i.e., NSPM) for which the computer and
8 phone costs are incurred.

9

10 In 2011, XES reassigned employees that only support a single operating
11 company to that operating company. Because these employees had been
12 charging all of their labor to the respective operating companies to which they
13 were reassigned, there is no impact to the labor allocations. However, in the
14 process of implementing the direct assignments, we discovered that the
15 computers and phones used by employees in Nuclear operations had been
16 assigned to XES employees. As a result, these computers and phones have
17 not been included in the statistical information used in previous information
18 technology allocations to NSPM.

19

20 The resulting shift in property that occurred when these employees were
21 assigned from XES to NSPM brought this prior misalignment in allocation to
22 light in 2012. The allocation has been corrected for the 2013 budget.

23

24 Q. WHAT IS THE IMPACT OF THIS PROPERTY ASSIGNMENT CORRECTION ON THE
25 TEST YEAR?

26 A. Because the error was corrected in 2012, there is no adjustment to the test
27 year. However, the change in the percentage of costs allocated to NSPM as a

1 result of this correction increases the test year revenue requirement by
2 approximately \$500,000 compared to our 2011 budget used in the 2011 rate
3 case.

4
5 Q. PLEASE DISCUSS THE COMPONENTS OF YOUR CALCULATION OF “NET SALES
6 AND GROWTH IN MARGIN” SHOWN ON EXHIBIT____(AEH-1), SCHEDULE 9,
7 PAGE 1, LINE 12.

8 A. This line item shows the change in operating revenues and other margins from
9 the 2011 rate case to the 2013 test year. The level of kilowatt-hour sales has
10 increased since the 2011 rate case, generating an increase in retail revenues,
11 which has provided a partial offset to some of the effects of increasing costs
12 of operations. This change results from the addition of new customers, as
13 well as any changes in use per customer. Specifically, the gross margin was
14 calculated by using total revenues excluding the following costs, which are
15 recovered separately for purposes of this analysis: (1) city franchise fees; (2)
16 cost of fuel and purchased energy; and (3) transmission of energy by others.

17
18 **VI. JURISDICTIONAL COST OF SERVICE STUDY**

19
20 Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF
21 SERVICE STUDY FOR THE 2013 TEST YEAR.

22 A. The complete jurisdictional cost of service study, in addition to the summary
23 schedules described below, includes the following financial data input sections,
24 for both Total Company and the North Dakota Jurisdiction:

- 25 i) capital structure;
26 ii) cost of capital;
27 iii) income tax rates;

- 1 iv) rate base;
- 2 v) income statement;
- 3 vi) income tax calculations; and
- 4 vii) cash working capital computation.

5
6 Summary schedules taken from the complete jurisdictional cost of service are
7 included in Exhibit____(AEH-1), Schedule 8 for the 2013 test year. The
8 jurisdictional cost of service study reflects all the adjustments discussed in my
9 testimony.

10
11 Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY
12 SCHEDULES.

13 A. The jurisdictional cost of service summary for the 2013 test year is included in
14 Exhibit____(AEH-1), Schedule 8, Pages 1-6.

- 15 • The cover page identifies the North Dakota Retail jurisdiction
16 requested ROE, and shows the earned ROE under current rates (5.35
17 percent), the revenue deficiency (\$16.900 million), and the percent of
18 increase (9.25 percent) that would result if rates were increased to earn
19 the requested ROE (10.60 percent).
- 20 • The “Rate Base Summary” for total Company electric operations and
21 the North Dakota jurisdiction is shown on Schedule 8, Page 2.
- 22 • An “Income Statement Summary” for total Company electric
23 operations and the North Dakota jurisdiction is shown on Schedule 8,
24 Page 3. The income statement includes the total operating income at
25 present authorized retail rates.
- 26 • The “Income Tax Summary” for total Company electric operations and
27 the North Dakota jurisdiction is shown on Schedule 8, Page 4. The

1 schedule shows adjustments to book income necessary to determine
2 state and federal taxable income. The federal and state income tax
3 calculations are carried back to the income statement on Schedule 8,
4 Page 3.

- 5 • The “Revenue Requirement and Return Summary” for total Company
6 electric operations and the North Dakota jurisdiction is shown on
7 Schedule 8, Page 5. Specifically, the schedule shows: (i) the earned
8 overall rate of return on rate base; (ii) the earned ROE; (iii) the revenue
9 deficiency that needs to be recovered to enable the North Dakota
10 jurisdiction electric operations to earn the requested ROE; and (iv) the
11 total revenue requirements and the percent of increase that would result
12 by increasing retail billing rates by the amount of the revenue
13 deficiency.
- 14 • The computation of cash working capital is shown on Schedule 8, Page
15 6, and is carried back to the rate base on Schedule 8, Page 2.

16
17 Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE NORTH
18 DAKOTA COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?

19 A. Yes. The revenue conversion factor calculation is included in
20 Exhibit___(AEH-1), Schedule 10; and composite income tax rates are
21 included in Exhibit___(AEH-1), Schedule 8, Page 5.

22
23 Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING
24 TAXABLE INCOME IS CALCULATED.

25 A. The interest deduction applicable to the income tax calculation is the result of
26 a calculation commonly referred to as “interest synchronization.” The amount
27 of interest deducted for income tax purposes is the weighted cost of debt

1 capital multiplied by the average rate base.

2
3 Q. DESCRIBE THE SCHEDULE IN YOUR EXHIBITS THAT IS RELATED TO THE
4 INCOME STATEMENT.

5 A. Exhibit___(AEH-1), Schedule 11 consists of comparative income statements
6 for the test year. Schedule 11, Page 1 is a comparative income statement for
7 the 2013 test year, showing the income effect of present authorized rates and
8 proposed rates. This comparative income statement was prepared from the
9 results of the jurisdictional cost of service study and includes the revenue
10 deficiency in the North Dakota Jurisdiction electric utility operations.
11 Schedule 11, Page 2 shows an electric utility comparative income statement for
12 the North Dakota jurisdiction and total Company for the 2013 test year before
13 making test period adjustments and also after making test period adjustments.

14
15 **VII. COMPLIANCE ISSUES AND APPLICATIONS**

16
17 Q. DID YOU REVIEW PRIOR COMMISSION ORDERS AS PART OF THE DEVELOPMENT
18 OF THE TEST-YEAR REVENUE REQUIREMENT?

19 A. Yes. I describe below the various Commission Orders that were reviewed and
20 addressed in preparing the test year. I will discuss required adjustments related
21 to each of these items later in my testimony. The Filing Requirements
22 Compliance Table included in the testimony of Ms. McCarten,
23 Exhibit___(LM-1), Schedule 2, documents how our rate case filing includes
24 information submitted in compliance with these prior Commission orders.

25
26 **1) Long Term Incentive**

27 In Case No. PU-400-92-399, the Commission determined that the costs of the

1 Company's long term incentive plan should be excluded from retail rates.
2 Long term incentive, except for certain nuclear employees, has been excluded
3 from the test year as part of our incentive adjustment, which is discussed in
4 Section XII of my testimony. However, because the Commission has
5 previously denied recovery of all long term incentive, we have excluded costs
6 related to long term incentive for certain nuclear employees in our
7 determination of interim rate levels as outlined in our Interim Rate Petition.

8
9 The Company has also removed all expenses associated with the Company's
10 Supplemental Executive Retirement Plan (SERP) from its base data, which is
11 consistent with prior Commission practice.

12
13 **2) Organizational Dues**

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

19
20 **3) Nuclear Refueling Costs**

21 In Case No. PU-07-774, the Commission determined that nuclear refueling
22 costs should be amortized over the life of the installed fuel. In our last two
23 rate cases, the Commission determined an appropriate level for recovery using
24 the deferral and amortization methodology. The Company is amortizing its
25 nuclear refueling costs as ordered and has included an amortization expense in
26 the 2013 test year reflecting the levelized accounting. The amortization is
27 recognized in the budget. However, the 2013 test year includes an adjustment

1 to recognize an update of the nuclear fuel outage costs, as discussed in Section
2 XII of my testimony.

3
4 **4) Depreciation Lives**

5 The 2013 budget for depreciation expense was based on the depreciation
6 principles approved by the Commission in Case No. PU-07-776, as
7 implemented in our last rate case. There are several changes to the approved
8 lives, net salvage rates, and accruals that the Company is proposing in this
9 proceeding for Steam Production, Other Production, and transmission,
10 distribution, and general plant for electric and common assets. The basis of
11 the 2013 budget as well as the adjustments the Company is proposing in this
12 case are further discussed by Ms. Lisa H. Perkett in her Direct Testimony.
13 The related test year adjustments are discussed in Section X of my testimony.

14
15 **5) Expense Exclusions**

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

- 18 • Expenses related to Renewable Development Fund (RDF) Research
19 and Development grants and disbursements.
20 • Costs associated with 50 percent of test-year charitable contributions.
21 • The amount of incentive compensation above the 15 percent cap
22 included as part of the settlement in our last rate case.

23
24 The Company is adhering to the above items as follows:

- 25 • The Company has not included any RDF amortization expense in the
26 test year.
27 • The Company has requested recovery of 50 percent of charitable

1 contributions in the test year. Because these costs were budgeted below
2 the line, we made an adjustment to include 50 percent of this expense,
3 as discussed in Section XII of my testimony. However, since the
4 authorization to recover 50 percent of this expense was the result of a
5 settlement, we have excluded these costs in our determination of
6 interim rate levels as outlined in our Interim Rate Petition.

- 7 • In this case, the Company requests approval to cap the recovery of
8 Annual Incentive Plan (AIP) compensation at 25 percent of any
9 individual employee's base salary. Therefore, our test year incentive
10 compensation adjustment made in Section XII of my testimony reflects
11 recovery of these costs up to the 25 percent cap. However, since the
12 Commission has previously only allowed recovery of annual incentive
13 compensation up to 15 percent of any individual's base salary, we
14 excluded the incremental difference from our determination of interim
15 rate levels as outlined in our Interim Rate Petition.

16 17 **6) Demand Side Management**

18 In Case No. PU-08-171, the Commission authorized NSP to record
19 expenditures implementing its existing Savers Switch and Energy Control
20 Service load management programs in a deferred account for amortization in
21 the Company's next general rate case. The amount deferred was limited to
22 \$266,904 per year. In our last rate case, the Commission approved a three year
23 amortization of the anticipated December 31, 2010 deferred DSM balance.
24 Since the current general rate case was filed two years later, we estimate the
25 unrecovered balance to be \$168,486. Our test year proposes a new three-year
26 amortization of the 2012 year end balance. This test year amortization is
27 further discussed in Section XII of my testimony.

1
2 **7) Asset Based and Non-Asset Based Margin Sharing**

3 In Case No. PU-07-776, the Commission approved 85 percent of all asset-
4 based wholesale margins and 50 percent of non-asset based margins being
5 provided to ratepayers through the Fuel Cost Recovery (FCR) Rider. Asset-
6 based margins will be passed to customers each month through the true-up
7 provisions of the monthly FCR. The non-asset based margins, if any, will be
8 passed through the FCR in the subsequent year. In Section XII of my
9 testimony, I provide an adjustment to remove all asset based and non-asset
10 based margins from the base budget data in recognition of this sharing
11 arrangement.

12
13 **VIII. UTILITY AND JURISDICTIONAL ALLOCATIONS**

14
15 Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS TO THE
16 COMPANY'S ELECTRIC UTILITY OPERATIONS.

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

23
24 Cost allocation and assignment principals have not changed since our last
25 North Dakota electric rate case. O&M cost assignments and allocations are
26 also consistent with the Company's recent Minnesota electric rate case filed on
27 November 2, 2012 with the Minnesota Public Utilities Commission (MPUC

1 Docket No. E002/GR-12-961). Non-O&M costs include such items as book
2 depreciation expense, deferred income taxes, and property taxes. All of the
3 investments common to the electric and natural gas utilities, and their related
4 costs (e.g., software or other common investments and expenses), are
5 evaluated as to whether the cost should be direct assigned to electric or natural
6 gas, or allocated based on appropriate allocators such as: Customers,
7 Customer Bills, Transportation Studies, or the three factor general allocator
8 (the average of Revenue Ratio, Employee Ratio, and Asset Ratio).

9
10 Additional information regarding this process and the reason for selecting a
11 particular allocator is also included in the Cost Assignment and Allocation
12 Manual (CAAM) which I have included as Exhibit___(AEH-1), Schedule 12.

13
14 Q. HAVE THERE BEEN ANY CHANGES SINCE THE LAST ELECTRIC RATE CASE THAT
15 WOULD SIGNIFICANTLY IMPACT THE PERCENTAGE OF COSTS THAT GET
16 ASSIGNED TO NORTH DAKOTA FROM ANY OF THE ALLOCATION
17 METHODOLOGIES DESCRIBED IN THE CAAM?

18 A. Yes. As I discussed in Section V, a correction was made to the underlying
19 computer and telephone statistics used to allocate certain Service Company
20 costs to operating company. Although this change occurred in 2012 and was
21 reflected in the 2013 O&M budget, it did result in a \$500,000 increase in the
22 allocation of Property Management costs to the North Dakota jurisdiction.

23
24 Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR THE
25 COMPANY'S ELECTRIC UTILITY OPERATIONS IN NORTH DAKOTA.

26 A. O&M cost assignments and allocations are summarized on Exhibit___(AEH-
27 1), Schedule 13. The expense budgets relied upon to develop test-year income

1 statement items were generally prepared on a functional basis (*i.e.*, Production,
2 Transmission, Distribution, Customer Accounts, Customer Information, Sales,
3 Administrative and General). These functional amounts are directly assigned
4 to North Dakota jurisdiction electric operations or allocated to the electric
5 operations based on cost causation.

6
7 Q. PLEASE EXPLAIN THE PROCESS FOR ASSIGNING THE COMPANY'S INVESTMENT
8 IN ELECTRIC PLANT TO THE NORTH DAKOTA JURISDICTION.

9 A. A summary and description of the allocation factors used to allocate capital
10 related items to the North Dakota jurisdictional electric operations income
11 statement and rate base is contained in Exhibit___(AEH-1), Schedule 14.
12 Plant investments are accounted for in the manner prescribed by the FERC
13 Uniform System of Accounts. Detailed records are maintained on a functional
14 basis (*e.g.*, Production, Transmission, Distribution). The capital budgets, from
15 which the projected plant balances in rate base were developed, are also
16 prepared on a functional basis. These functional amounts are assigned to the
17 appropriate jurisdiction directly, or allocated based on the use of such assets in
18 providing electric service in a particular jurisdiction and the underlying
19 elements of cost causation.

20
21 Q. PLEASE EXPLAIN THE NEED FOR JURISDICTIONALLY ALLOCATING THE
22 INVESTMENTS IN PRODUCTION AND TRANSMISSION FACILITIES.

23 A. The NSPM and NSPW production and transmission system (NSP System) is
24 designed, built, and operated to provide an integrated source of electricity for
25 all of their electric customers. Costs are allocated first between NSPM and
26 NSPW through the Interchange Agreement as approved by FERC, which I
27 discuss later in my testimony. NSPM's portion of costs is then allocated to

1 utility operations in North Dakota, Minnesota, and South Dakota, as well as to
2 the single remaining wholesale customer taking requirements service at rates
3 regulated by FERC.

4
5 To determine the level of investment associated with the provision of electric
6 service to North Dakota retail customers, it is necessary to assign or allocate a
7 portion of the total production and transmission investment to each
8 jurisdiction. We used each jurisdiction's respective coincident peak demands
9 for electricity as the basis for this allocation. It is reasonable to use coincident
10 peak demands as an allocation basis because these facilities are constructed to
11 meet peak requirements and operate as an integrated system across all
12 jurisdictions. This is consistent with the methodology accepted in the last
13 North Dakota electric rate case and reflects the fact that these facilities have
14 been designed to meet peak requirements. The exception to this are the
15 Company-owned wind projects (Grand Meadow and Nobles) are allocated to
16 jurisdiction on the basis of energy rather than coincident peak demands. We
17 believe this is a more reasonable allocation basis since wind farms are generally
18 constructed to meet energy needs, not to meet demand requirements.

19
20 Q. PLEASE DESCRIBE THE IMPACT OF FEWER WHOLESALERS TO THE
21 NORTH DAKOTA RETAIL JURISDICTION.

22 A. At the end of 2012, all of NSPW's wholesale customers are terminating their
23 supply agreements and they will no longer be served by NSPW as native
24 requirements customers. As a result of the loss of these wholesale customers
25 (approximately 100 MW of load), NSPM's percent of the total NSP System
26 load increases as NSPW's percent of total NSP System production and
27 transmission costs decreases. The result is a decrease in NSPM other revenue

1 of approximately \$0.8 million and an increase in Interchange Agreement
2 billings from NSPW of approximately \$0.1 million, a net increase of \$0.9
3 million in our revenue deficiency. However, the decrease in Interchange
4 Agreement revenues due to load shift is partially offset by the large increase in
5 NSP System production and transmission revenue requirements resulting in a
6 net revenue requirement increase of approximately \$0.5 million.

7
8 Q. HOW WERE THE DISTRIBUTION INVESTMENT AMOUNTS ASSIGNED TO THE
9 NORTH DAKOTA JURISDICTION?

10 A. The Company's electric distribution plant investment amounts have been
11 directly assigned based upon the jurisdiction(s) served by each of the
12 individual distribution facilities. Therefore, North Dakota distribution
13 investments are assigned directly to North Dakota.

14 15 **IX. RATE BASE COMPONENTS**

16
17 Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

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

22
23 Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED TEST-YEAR
24 RATE BASE.

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

- 27
- Net Utility Plant;

- 1 • Short-term Construction Work in Progress (CWIP);
- 2 • Accumulated Deferred Income Taxes (ADIT); and
- 3 • Other Rate Base Items.

4
5 Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR TESTIMONY THAT ARE RELATED
6 TO THE TEST-YEAR AVERAGE INVESTMENT IN RATE BASE.

7 A. Exhibit____(AEH-1), Schedule 15, Page 1 of 3, shows a detailed statement of
8 the Average Rate Base by component for the 2013 test year. Schedule 15,
9 Page 2 of 3, is a comparative statement of the 2013 Test Year Average Rate
10 Base for the North Dakota jurisdiction and total Company, before and after
11 making proposed test period adjustments. Schedule 15, page 3 of 3 provides
12 detailed information on CWIP and ADIT for the total Company and North
13 Dakota jurisdiction. Exhibit____(AEH-1), Schedule 3, Page 2 shows the
14 Company's actual 2011 Average Rate Base as provided in the May 3, 2012
15 jurisdictional annual report to the Commission. The annual jurisdictional
16 report rate base provided in Schedule 3 has been modified to included cash
17 working capital in rate base and a redetermination of the deferred tax asset
18 associated with the net operating loss.

19
20 **A. Net Utility Plant**

21 Q. WHAT DOES NET UTILITY PLANT REPRESENT?

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

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

27 A. The net utility plant is included in rate base at depreciated original cost

1 reflecting the simple average of projected net plant balances at the beginning
2 and end of the test year. Such treatment is consistent with the method
3 employed in our most recent North Dakota electric rate case.
4

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

8 A. The historical base used was the Company's actual net investment (Plant In
9 Service less Accumulated Depreciation) on the books and records of the
10 Company as of March 31, 2012. The budget projections for April through
11 December 2012 were then applied to the March 31, 2012 balance to arrive at a
12 beginning test-year net plant balance.
13

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

16 A. The ending net plant balances were determined by applying the data contained
17 in the 2013 capital budget to the above-described beginning test-year balances,
18 adjusted for plant additions, retirements, depreciation, salvage and removal
19 costs projected to occur during the test year.
20

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

23 A. The average net utility plant included in the test-year rate base is \$451.383
24 million, provided on Exhibit___(AEH-1), Schedule 8, Page 2. As shown on
25 this schedule, the average net utility plant is comprised of an average plant
26 balance of \$870.972 million minus an average depreciation reserve of
27 \$419.589 million.

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B. Construction Work in Progress

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

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

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

A. The beginning test-year balance for CWIP was the March 31, 2012 actual balance. Construction expenditures, and transfers to Plant in Service during the remaining months of 2012 were netted against the March 31, 2012 balance to derive a beginning test-year balance. The beginning test-year CWIP balance was adjusted to reflect projected construction expenditures, and transfers to Plant In Service during the 2013 test year to obtain the ending test-year CWIP balance. These projections were developed from the Company's 2013 capital budget.

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

A. As shown on Exhibit____(AEH-1), Schedule 8, Page 2, the average short-term CWIP included in rate base was \$2.037 million.

1 **C. Accumulated Deferred Income Taxes**

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

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

10
11 Q. WHY IS ADIT DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

12 A. To the extent deferred income taxes have been recovered in rates, they
13 represent a non-investor source of funds (because revenues have been
14 received for tax liabilities yet to be paid). Accordingly, the average projected
15 ADIT balance is deducted in arriving at total rate base to recognize such funds
16 are available for corporate use between the time they are collected in rates and
17 ultimately remitted to the respective taxing authorities.

18
19 Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE PROJECTED TEST-YEAR RATE
20 BASE?

21 A. As shown on Exhibit____(AEH-1), Schedule 8, Page 2, \$92.784 million was
22 deducted. This amount reflects a simple average of the beginning and
23 projected ending test-year ADIT balances.

24
25 **D. Other Rate Base**

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

27 A. Other Rate Base is comprised primarily of what is referred to as Working

1 Capital. It also includes certain unamortized balances that are the result of
2 specific ratemaking amortizations as discussed further in my testimony.

3
4 Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

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

10
11 Q. HOW HAVE TEST-YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY
12 REQUIREMENTS BEEN CALCULATED?

13 A. The Materials and Supplies and Fuel Inventory amounts shown on
14 Exhibit___(AEH-1), Schedule 8, Page 2, are based on the thirteen-month
15 average balances projected during the test year. Materials and Supplies average
16 balance included in the test-year rate base equals \$7.613 million. The test-year
17 average rate base amount for Fuel Inventory is \$5.899 million.

18
19 Q. HOW HAVE THE TEST-YEAR NON-PLANT ASSETS & LIABILITIES BEEN
20 DETERMINED?

21 A. These balances as shown on Exhibit___(AEH-1), Schedule 8, Page 2,
22 represent the 2013 calendar year estimate of these balances. Any book/tax
23 timing differences associated with these items have been reflected in the
24 determination of current and deferred income tax provision and ADIT
25 balances previously discussed. This group is primarily comprised of liabilities
26 that reduce test-year rate base by \$1.809 million.

27

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

3 A. Items of Prepayments and Other Working Capital, such as customer advances
4 and deposits, are based on the actual thirteen-month average balances during
5 the period ended May 31, 2012, as a proxy for the test year. The unamortized
6 balances included in this section are based on the amortization schedules as
7 described later in my testimony on revenue requirements. The net impact of
8 these various items increase test-year rate base by \$6.235 million as shown on
9 Exhibit____(AEH-1), Schedule 8, Page 2.

10

11 Q. HOW HAVE THE TEST-YEAR CASH WORKING CAPITAL REQUIREMENTS BEEN
12 DETERMINED?

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

16

17 Q. HAVE THE COMPONENTS OF THE TEST-YEAR CASH WORKING CAPITAL BEEN
18 CALCULATED CONSISTENT WITH METHODS USED IN THE MOST RECENT NORTH
19 DAKOTA ELECTRIC RATE CASE?

20 A. Yes.

21

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

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

1 are incurred until the related disbursements are actually made.

2
3 Q. HAS THE COMPANY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST
4 NORTH DAKOTA ELECTRIC RATE CASE?

5 A. Yes. The Company has updated the study for the calculation of the lead and
6 lag days through December 2011. We conducted the studies to be used in
7 both Minnesota and South Dakota, and determined that the results were
8 nearly identical for both jurisdictions. Therefore, we used the study reflected
9 in our Minnesota application for this current proceeding. The methodology
10 for calculating the lead/lag days is consistent with the methodology used in
11 the Company's prior electric and gas regulatory filings. The results of the
12 updated lead/lag study for electric operations were incorporated into the
13 North Dakota jurisdiction cash working capital rate base component as shown
14 on Exhibit (AEH-1), Schedule 8, Page 2.

15
16 Q. WHAT IS THE TEST-YEAR CASH WORKING CAPITAL AMOUNT?

17 A. The amount included in the average rate base is a negative \$926,000. The
18 detailed components and calculations associated with this amount are
19 summarized in Exhibit____(AEH-1), Schedule 8, Page 6.

20
21 Q. WHAT IS INDICATED BY THE NEGATIVE CASH WORKING CAPITAL AMOUNT?

22 A. Negative cash working capital indicates overall revenue collections occur
23 sooner than the date when the associated costs of service are paid. In the
24 Company's circumstance, taxing authorities (property taxes) comprise the
25 largest source of cash working capital as offsets to working capital provided by
26 the Company's investors. Other sources of offsets may include customers,
27 creditors, and employees. The negative cash working capital reduces rate base

1 to compensate customers for funds provided to meet cash working capital
2 requirements.

3
4 Q. IS THE 2013 TEST-YEAR RATE BASE FOR THE COMPANY'S NORTH DAKOTA
5 JURISDICTION ELECTRIC OPERATIONS REASONABLE FOR PURPOSES OF
6 DETERMINING FINAL RATES IN THIS PROCEEDING?

7 A. Yes. The test-year rate base was developed on sound ratemaking principles in
8 a manner similar to prior Company electric rate cases.

9
10 **X. ADJUSTMENTS TO RATE BASE AND ASSOCIATED INCOME**
11 **STATEMENT ADJUSTMENTS**

12
13 Q. PLEASE IDENTIFY THE TEST-YEAR ADJUSTMENTS TO THE 2013 BUDGET FOR
14 RATE BASE.

15 A. We made rate base adjustments for forecast updates and rate case
16 adjustments. While we refer to these as rate base adjustments, the
17 adjustments discussed in this section also consider any income statement
18 impacts resulting from the rate base adjustment (annual book depreciation as
19 an example). These adjustments are listed below.

20 **A. Forecast Updates**

- 21 1) Bemidji CapX2020 Update
22 2) Brookings CapX2020 Update
23 3) Nuclear Fuel Inventory Update

24
25 **B. Rate Case Adjustments**

- 26 4) 2012 Depreciation Study for Transmission, Distribution, and
27 General Assets

- 1 5) 2012 Remaining Life Study for Production Assets
- 2 6) Black Dog Steam Plant Remediation Costs

3

4 **C. Other Ratemaking Adjustments**

- 5 7) Net Operating Loss
- 6 8) Cash Working Capital

7

8 Each of these adjustments to rate base, along with the associated adjustments

9 to the income statement, is discussed in more detail in this section of my

10 testimony. The detailed cost items related to each adjustment can be found on

11 the rate base bridge schedule (Exhibit___(AEH-1), Schedule 5), and the

12 income statement bridge schedule (Exhibit___(AEH-1), Schedule 6).

13

14 **A. Forecast Updates**

15 Q. DID YOU UPDATE THE 2013 CAPITAL BUDGET DATA IN THE PREPARATION OF

16 YOUR TEST-YEAR RATE BASE?

17 A. Yes. There were three adjustments identified during our review of the 2013

18 capital budget and preparation of testimony as necessary in order to present a

19 representative level of rate base for our proposed test year.

20

21 **1) Bemidji CapX2020 Update**

22 Q. PLEASE DESCRIBE THE UPDATE FOR THE BEMIDJI CAPX2020 TRANSMISSION

23 PROJECT.

24 A. The Bemidji Update adjustment recognizes material forecast changes in the

25 test year for the Bemidji CapX2020 project after the original capital budget

26 used in the test year was prepared. The budget was updated to reflect the

27 actual September 2012 in-service date for the Bemidji project.

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The result of this update to the test year budget is reflected on Exhibit__(AEH-1), Schedule 5, column 2 and increases test year rate base by \$1.2 million. The update is also reflected in Exhibit__(AEH-1), Schedule 6, Page 1, Column 2 and increases test year revenue requirements by \$0.2 million. Support for this adjustment can be found in Test Year Workpapers, Section VIII Adjustments, Tab A1.

2) Brookings CapX2020 Update

Q. PLEASE DESCRIBE THE UPDATE FOR THE BROOKINGS CAPX2020 TRANSMISSION PROJECT.

A. The Company received a revised capital expenditure forecast for the CapX2020 Brookings transmission project resulting from engineering updates that reflect more accurate and detailed cost estimates. The detailed cost estimates allowed the project to lock in on steel commodity pricing and material delivery timing. Siting and Land Rights easement acquisition activity has also been more productive than expected and the projected project contingency has been proportionately decreased to reflect the project’s current progress. As a result of the revised capital expenditure forecast, the projected balances for associated plant in service, reserve for depreciation and accumulated deferred income taxes were updated.

The result of this update to the test year budget is reflected on Exhibit__(AEH-1), Schedule 5, column 3 and increases rate base by \$171,000. The update is also reflected in Exhibit__(AEH-1), Schedule 6, Page 1, Column 3 and increases test year revenue requirements by \$22,000. Support for this adjustment can be found in Test Year Workpapers, Section

1 VIII Adjustments, Tab A2.

2
3 **3) Nuclear Fuel Inventory Update**

4 Q. PLEASE DESCRIBE THE UPDATE IN NUCLEAR FUEL INVENTORY.

5 A. Nuclear fuel inventory balances were updated to reflect the update in the
6 nuclear fuel forecast, which occurred after the summer 2012 sales forecast was
7 completed and after the capital budget was finalized.

8
9 The result of this update to the test year budget is reflected on
10 Exhibit____(AEH-1), Schedule 5, column 4 and increases test year rate base by
11 \$229,000. The update is also reflected in Exhibit____(AEH-1), Schedule 6,
12 Page 1, Column 5 and decreases test year revenue requirements by \$26,000.
13 Support for this adjustment can be found in Test Year Workpapers, Section
14 VIII Adjustments, Tab A4.

15
16 **B. Rate Case Adjustments**

17 Q. DID YOU MAKE RATE CASE ADJUSTMENTS TO THE 2013 CAPITAL BUDGET DATA
18 IN THE PREPARATION OF YOUR TEST-YEAR RATE BASE?

19 A. Yes. The three rate case adjustments discussed below were made to our test-
20 year rate base in order to present a representative level of rate base for our
21 proposed test year.

22
23 **4) 2012 Depreciation Study for Transmission, Distribution, and**
24 **General Assets**

25 Q. PLEASE DESCRIBE THE 2012 TRANSMISSION, DISTRIBUTION, AND GENERAL
26 FIVE YEAR DEPRECIATION STUDY ADJUSTMENT.

27 A. This adjustment updates the 2013 test year to include the impact of the

1 Company's 2012 Transmission, Distribution, and General Depreciation Five
2 Year Study. This adjustment is further supported by Ms. Lisa H. Perkett in
3 her Direct Testimony.

4
5 The result of including this adjustment in the test year is reflected on
6 Exhibit____(AEH-1), Schedule 5, Column 5 and decreases test year rate base
7 by \$308,000. The adjustment is also reflected in Exhibit____(AEH-1),
8 Schedule 6, Page 2, Column 21 and increases test year revenue requirements
9 by \$968,000. Support for this adjustment can be found in Test Year
10 Workpapers, Section VIII Adjustments, Tab A22.

11
12 **5) 2012 Remaining Life Depreciation Study for Production Assets**

13 Q. PLEASE DESCRIBE THE 2012 REMAINING LIFE DEPRECIATION STUDY
14 ADJUSTMENT.

15 A. This adjustment updates the test year to include the impact of the Company's
16 2012 Average Remaining Life depreciation proposal for Production assets.
17 This adjustment is further supported by Ms. Perkett in her Direct Testimony.

18
19 The result of including this adjustment in the test year is reflected on
20 Exhibit____(AEH-1), Schedule 5, column 6 and increases test year rate base by
21 \$75,000. The adjustment is also reflected in Exhibit____(AEH-1), Schedule 6,
22 Page 2, Column 22 and decreases test year revenue requirements by \$234,000.
23 Support for this adjustment can be found in Test Year Workpapers, Section
24 VIII Adjustments, Tab A23.

25 Q. DO YOU HAVE UPDATED INFORMATION RELATED TO YOUR 2012 REMAINING
26 LIFE DEPRECIATION ADJUSTMENT?

27 A. Yes. A subsequent review of the information used to calculate the adjustment

1 revealed that it included information related to the Black Dog Steam Plant
2 Remediation Costs adjustment, described below. The Black Dog Steam Plant
3 Remediation Costs adjustment had the effect of offsetting the amount of the
4 2012 Remaining Life Depreciation adjustment, which supports an update to
5 the 2012 Remaining Life Depreciation reduction.

6
7 Q. WHAT EFFECT WOULD THIS UPDATE HAVE ON THE TEST YEAR REVENUE
8 DEFICIENCY?

9 A. The amount of the 2012 Remaining Life Depreciation reduction should be
10 larger by an amount approximately equal to the amount in the Black Dog
11 Steam Plant Remediation Costs adjustment. This update would decrease the
12 test year deficiency by approximately \$500,000.

13
14 Q. HAVE YOU INCORPORATED THIS UPDATE INTO THE TEST YEAR DEFICIENCY?

15 A. Not yet. Because the effect of the Black Dog Steam Plant Remediation Costs
16 adjustment was not identified until well after we completed the jurisdictional
17 cost of service study, we were not able to incorporate the update into our test
18 year deficiency. However, during the course of this proceeding, as with other
19 adjustments deemed necessary to establish a representative test year cost of
20 service, we will incorporate this update into our test year deficiency.

21
22 Q. DOES THIS UPDATE AFFECT THE INTERIM RATE REQUEST?

23 A. No. The 2012 Remaining Life Depreciation Study adjustment and the Black
24 Dog Steam Plant Remediation Costs adjustment are not included in the
25 calculation of the interim rate revenue deficiency. As a result, this update does
26 not affect the interim rate deficiency or the interim rate request.

27

1 **6) Black Dog Steam Plant Remediation Costs**

2 Q. PLEASE DESCRIBE THE BLACK DOG COAL PILE AND ASH PONDS REMEDIATION
3 COST ADJUSTMENT.

4 A. This adjustment reflects a net increase in depreciation due to an increase in the
5 estimated cost of removal for the coal pile and ash ponds at the Black Dog
6 steam plant. As discussed above, this adjustment is incorporated into the
7 remaining life depreciation adjustment and is further supported by Ms Perkett
8 in her Direct Testimony.

9
10 The result of including this adjustment in the test year is reflected on
11 Exhibit___(AEH-1), Schedule 5, column 7 and decrease test year rate base by
12 \$147,000. The adjustment is also reflected in Exhibit___(AEH-1), Schedule 6,
13 Page 2, Column 23 and increases test year revenue requirements by \$460,000.
14 Support for this adjustment can be found in Test Year Workpapers, Section
15 VIII Adjustments, Tab A24.

16
17 **C. Other Ratemaking Adjustments**

18 **7) Net Operating Loss and Cash Working Capital**

19 Q. PLEASE DESCRIBE THE NET OPERATING LOSS AND CASH WORKING CAPITAL
20 ADJUSTMENTS TO RATE BASE.

21 A. These two adjustments reflect the rate base effect of the other adjustments on
22 net operating losses and cash working capital. They are described in Section
23 XII of my Direct Testimony. I have also included Exhibit___(AEH-1),
24 Schedule 21 to show the NOL related deferred tax asset balance through the
25 2013 test year. This schedule also provides the supporting calculations for the
26 impact on test year revenue requirement.

27

1 **XI. INCOME STATEMENT**

2

3 **A. Revenues**

4 Q. WAS THE IMPACT OF WEATHER ON PROJECTED SALES FOR THE TEST YEAR
5 RECOGNIZED IN THE TEST YEAR REVENUE REQUIREMENT?

6 A. Yes. Test-year retail sales levels assume normal weather.

7

8 Q. Do retail operating revenues reflect the projected level of unbilled sales
9 volumes in the test year?

10 A. Yes. The level of unbilled sales volumes in the test year is incorporated into
11 the retail sales forecast, the effect of which is to project the level of revenues
12 on a calendar-month basis.

13

14 Q. HAS THE COMPANY CALCULATED UNBILLED REVENUES IN PRIOR RATE CASES
15 TO RECOGNIZE THE NET CHANGE IN UNBILLED REVENUES IN THE TEST YEAR?

16 A. Yes. This calculation of unbilled revenues is consistent with the methodology
17 in the Company's most recent North Dakota electric and natural gas rate
18 cases.

19

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

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

26

27 Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE

1 RETAIL REVENUE REQUIREMENT?

2 A. Yes. The test year includes items such as revenues from sales to other utilities,
3 transmission-related revenue, and specific tariff charges including service
4 activation fees, reconnection fees, and others. In areas where the Company
5 did not budget for the collection of these tariffed charges, a representative
6 level was determined and included in revenues in the cost of service study.
7 One other source of revenues comes from billings to NSPW under the
8 Interchange Agreement, which I discuss in more detail below.

9
10 Q. WHAT ARE WHOLESale MARGINS?

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

21
22 Q. HOW HAVE ASSET BASED MARGINS BEEN TREATED IN PRIOR RATE CASES?

23 A. Asset based margins are earned by selling energy from facilities or PPAs paid
24 for by ratepayers. As approved in Case No. PU-07-776, 85 percent of asset
25 based margins were credited to customers through the FCR.

26
27 Q. WHAT IS THE COMPANY RECOMMENDING WITH RESPECT TO ASSET BASED

1 MARGINS?

2 A. We recommend continuing to credit customers 85 percent of the asset based
3 margins through the FCR going forward.

4

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

7 A. In Case No. PU-07-776, the Company received approval to use a 50/50
8 percent margin sharing mechanism for non-asset based trading margins. The
9 sharing mechanism was selected as a reasonable balance of ratepayer and
10 Company interests. By sharing with ratepayers 50 percent of the margins, the
11 incremental cost of producing the margins was reimbursed along with a
12 reasonable contribution to joint and common costs. The customer portion
13 was approved to be credited through the FCR.

14

15 Q. WHAT IS THE COMPANY RECOMMENDING IN THIS CASE?

16 A. The Company recommends continuing the existing 50/50 percent sharing
17 mechanism as an appropriate balance of ratepayer and Company interests,
18 along with continued crediting to customers through the FCR.

19

20 **B. Operating and Maintenance Expenses**

21 Q. HOW DOES THE COMPANY DEVELOP ITS TEST-YEAR PRODUCTION EXPENSE
22 BUDGET?

23 A. The main area of expense in the production expense budget is fuel and
24 purchased power. These expenses are developed through a production budget
25 prepared to serve the combined energy and demand requirements of the NSP
26 System (*i.e.*, for both NSPM and NSPW). Our Risk Management Department
27 conducts a production simulation (called PROSYM) model run based on the

1 forecasted system sales to derive the forecasted fuel and energy costs. The
2 NSP System fuel and energy costs are then adjusted to remove the cost of
3 inter-system sales (also referred to as asset based sales) and other non-
4 recoverable fuel items, so that a base cost of fuel and purchased energy is
5 derived that only recovers the appropriate North Dakota jurisdictional share
6 of these NSP System costs. The Commercial Operations group also forecasts
7 our capacity purchases for contracts that will be in place during the test year
8 and for short-term seasonal capacity purchases for the summer season. No
9 short term capacity purchases are included in the test year. Additionally, our
10 Transmission Access department forecasts our transmission expenses forecast
11 to be paid to others (such as MISO). Mr. Foss discusses the third-party
12 transmission expenses in his Direct Testimony.

13
14 Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT WITH NSPW THAT YOU
15 REFERENCED EARLIER.

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

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

27 A. Under the Interchange Agreement, the Company and NSPW share annual

1 system generation (production) and transmission costs. Under the
2 Interchange Agreement formulas, approximately 15 percent of the costs of the
3 Company system are allocated to NSPW, and approximately 85 percent of the
4 NSPW system costs are allocated to the Company. These allocations are
5 appropriate because approximately 85 percent of the load on the integrated
6 system is the Company load and 15 percent is NSPW load. The exact
7 allocation percentages are determined by allocation factors updated and filed
8 at FERC annually. The Interchange Agreement also provides for an allocation
9 of revenues received by the Company and NSPW, such as revenues from off-
10 system wholesale sales. Interchange Agreement costs and revenues are
11 budgeted by the Company and NSPW annually. Thus, the Company's budget
12 shows Interchange Revenues – revenues that reflect the charges to NSPW for
13 its share of production and transmission assets and associated expenses.
14 Likewise, Interchange Expense reflects the Company's forecasted payments to
15 NSPW for its proportionate share of the costs of generation and transmission
16 assets and associated expenses incurred by NSPW to serve the NSP System
17 needs.

18
19 The 2013 test year Interchange Revenue and Interchange Expenses have been
20 calculated using 2013 Company and NSPW budget information. This is
21 consistent with the treatment of Interchange Revenues and Interchange
22 Expenses in our last electric rate case.

23
24 **C. Depreciation Expense**

25 Q. PLEASE IDENTIFY THE DOCKET'S ASSOCIATED WITH THE DEPRECIATION RATES
26 USED IN THIS PROCEEDING.

27 A. Depreciation Expense for the test year reflects the depreciation rates as

1 ordered in Case No. PU-10-657. Where the Company proposes a
2 depreciation rate change, that change is reflected as an adjustment on the rate
3 base bridge schedule, Exhibit ___(AEH-1), Schedule 5 and income statement
4 bridge schedule, Exhibit___(AEH-1), Schedule 6 for review in this case.

5
6 **D. Lobbying Expense**

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

9 A. No. Beginning in 1999, the Company moved all lobbying costs to below the
10 line accounting, FERC account 426.4, Expenditures for certain civic, political,
11 and related activities. Thus, no adjustment to the cost of service for lobbying
12 is required, as these below the line amounts are not used in developing the
13 cost of service.

14
15 **XII. ADJUSTMENTS TO THE INCOME STATEMENT**

16
17 Q. PLEASE IDENTIFY THE ADJUSTMENTS TO THE INCOME STATEMENT.

18 A. I have already discussed the adjustments to the Income Statement associated
19 with the changes to Rate Base. We also made Income Statement adjustments
20 for the items listed below.

21 **A. Forecast Updates**

- 22 1) Shared Asset Allocation Update
23 2) Nuclear Outage Amortization Update
24 3) Nuclear O&M Budget Update
25 4) Nuclear Management Employee Retention Program Update
26 5) Bad Debt Expense Update
27 6) Additional North Dakota Line Crew Employees

1 **B. Traditional Adjustments**

- 2 7) Advertising
3 8) Professional and Utility Association Dues
4 9) Donations
5 10) Economic Development Costs
6 11) Interest on Customer Deposits

7 **C. Rate Case Adjustments**

- 8 12) Aviation
9 13) Wholesale Billing
10 14) Asset Based Trading Margins
11 15) Non-Asset Based Trading Margins
12 16) Cell Phone Policy
13 17) Removal of Budget Rate Case Expense
14 18) Incentive Compensation

15 **D. Amortizations**

- 16 19) 2013 Rate Case Expenses Amortization
17 20) Prior Rate Case Expense Amortization
18 21) Private Fuel Storage Amortization
19 22) Emission Credit Amortization
20 23) North Dakota Demand-Side Management

21 **E. Other Ratemaking Adjustments**

- 22 24) MISO CWIP Revenue and Expense Adjustment
23 25) Net Operating Loss
24 26) Impact of Adjustments on Cash Working Capital
25 27) Change in the Cost of Capital

26
27 Each of these adjustments to the Income Statement is discussed in more detail

1 in this section of my testimony. The detailed cost items related to each
2 adjustment can be found on the Income Statement bridge schedule
3 Exhibit___(AEH-1), Schedule 6.

4
5 **A. Forecast Updates**

6 **1) Shared Asset Allocation Update**

7 Q. PLEASE DESCRIBE THE UPDATE TO THE SHARED ASSET ALLOCATION.

8 A. The Service Company makes an allocation of the revenue requirements
9 associated with assets shared by Xcel Energy operating companies across
10 those operating companies. The result is that each operating company shares
11 in the total cost of assets from which the operating company derives benefit
12 and the operating company that owns the asset is reimbursed for other
13 operating companies' use of its assets. The shared asset allocation adjustment
14 applies the shared asset allocation to the Company's updated 2013 Capital
15 Budget data.

16
17 The result of this update to the test year budget is reflected on
18 Exhibit___(AEH-1), Schedule 6, Page 1, Column 5 and decreases test year
19 revenue requirements by \$196,000. Support for this adjustment can be found
20 in Test Year Workpapers, Section VIII Adjustments, Tab A5.

21
22 **2) Nuclear Outage Amortization Update**

23 Q. PLEASE DESCRIBE THE UPDATE TO THE NUCLEAR OUTAGE AMORTIZATION.

24 A. The nuclear outage amortization budget was updated to reflect a forecasted
25 increase in the cost of the Fall 2012 Prairie Island Unit 1 refueling outage.
26 Because these additional costs were incurred in 2012, deferred to the balance
27 sheet, and are then amortized over the useful life of the outage, it was only

1 necessary to update the amortization included in the O&M budget. The
2 change in the cost of the outage was reflected in the 2013 beginning of year
3 and end of year rate base balances.

4
5 The result of this update to the test year budget is reflected on
6 Exhibit____(AEH-1), Schedule 6, Page 1, Column 6 and increases test year
7 revenue requirements by \$121,000. Support for the calculation of this
8 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
9 Tab A6.

10
11 **3) Nuclear O&M Budget Update**

12 Q. PLEASE DESCRIBE THE UPDATE TO THE NUCLEAR O&M BUDGET.

13 A. This adjustment updates the nuclear budgets for significant non-outage cost
14 changes in contract labor, material and nuclear fees identified after the original
15 O&M budgets had been completed. Mr. O'Connor provides support for
16 support for this adjustment in his Direct Testimony.

17
18 The result of this update to the test year budget is reflected on
19 Exhibit____(AEH-1), Schedule 6, Page 1, Column 7 and increases test year
20 revenue requirements by \$493,000. Support for the calculation of this
21 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
22 Tab A7.

23
24 **4) Nuclear Management Employee Retention Program Update**

25 Q. PLEASE DESCRIBE THE UPDATE FOR THE NUCLEAR EMPLOYEE RETENTION
26 PROGRAM.

27 A. This adjustment accounts for nuclear management retention agreements that

1 were issued to key nuclear operations employees after the budget cycle was
2 completed and therefore were not included in the original 2013 budget. Mr.
3 O'Connor provides support for support for this adjustment in his Direct
4 Testimony.

5
6 The result of this update to the test year budget is reflected on
7 Exhibit____(AEH-1), Schedule 6, Page 1, Column 8 and increases test year
8 revenue requirements by \$77,000. Support for the calculation of this
9 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
10 Tab A8.

11
12 **5) Bad Debt Expense Update**

13 Q. WHAT IS COMMODITY BAD DEBT EXPENSE?

14 A. Commodity bad debt expense is billed commodity revenue for electric and
15 natural gas service that is considered uncollectible from customers.

16
17 Q. WHAT IS COMMODITY REVENUE?

18 A. Commodity revenue refers to the revenue billed to our customers for the cost
19 of utility service, including fuel charges and all regulated charges to customers,
20 such as riders. This definition represents virtually all of our billed retail
21 customer revenue.

22
23
24 Q. HOW DOES THE COMPANY BUDGET AND FORECAST COMMODITY BAD DEBT
25 EXPENSE?

26 A. We recognize commodity bad debt expense through a combination of: (1)
27 estimating an amount of Accounts Reserve (or Provision) associated with

1 outstanding receivables that will be unrecoverable; and (2) writing-off
2 uncollectible accounts not previously reflected in this Reserve. From the
3 combination of these amounts, we derive a weighted average ratio of bad debt
4 to overall commodity revenue. To determine forecasted bad debt expense (as
5 is necessary for budgeting purposes and for a rate case), the Company applies
6 this bad debt ratio to forecasted commodity revenues and allocates it between
7 its electric and natural gas operations.

8
9 Q. HOW IS THE ACCOUNTS RESERVE PORTION OF BAD DEBT EXPENSE
10 CALCULATED?

11 A. The Company calculates the Reserve by applying “provisioning factors” to
12 various “aging” categories of outstanding arrearages for both active and
13 inactive customers. A provisioning factor is the percentage of the accounts
14 receivable estimated to eventually prove uncollectible. In general, as
15 arrearages age, and as they move with our customers from active to inactive
16 status, we apply a higher provisioning factor to reflect the declining likelihood
17 that we will collect the full outstanding balance. These Reserve amounts are
18 updated monthly and combined with net write-offs to become the total bad
19 debt expense for the period.

20
21 Q. HOW DOES THE COMPANY ENSURE THAT ITS PROVISIONING FACTORS ARE
22 REASONABLE?

23 A. The provisioning factors applied to outstanding arrearages are developed from
24 annual Reserve Studies in which the Company analyzes historical customer
25 payment behavior data and considers contributing factors such as the sales
26 forecast and underlying fuel forecast, any changes in credit policy, and external
27 considerations such as the economy. The Company’s most recent Reserve

1 Study was completed in June 2012.

2
3 Q. HAS THERE BEEN AN UPDATE TO THE 2013 BUDGET FOR COMMODITY BAD
4 DEBT EXPENSE?

5 A. Yes. The initial 2013 budget bad debt ratio has been revised from 0.41
6 percent to 0.39 percent based on the June 2012 study, which supported a 0.02
7 reduction in the bad debt ratio based on improved actual bad debt results of
8 the preceding year. In addition, the revised June sales forecast predicts lower
9 commodity revenues than were forecasted at the time the 2013 bad debt
10 budget was established.

11
12 Applying the revised bad debt ratio of 0.39 percent to the lower forecasted
13 commodity revenue results in the forecasted total-Company bad debt expense
14 of \$14.242 million, and \$646,000 for the North Dakota electric jurisdiction.
15 This results in the need to reduce bad debt expense forecast by \$72,000.

16
17 The result of this update to the test year budget is reflected on
18 Exhibit___(AEH-1), Schedule 6, Page 1, Column 9 and decreases test year
19 revenue requirements by \$72,000. Support for the calculation of this
20 adjustment is in Test Year Workpapers, Section VIII Adjustments, Tab A9.

1 **6) Additional North Dakota Line Crew Employees**

2 Q. PLEASE DESCRIBE THE ADJUSTMENT FOR ADDITIONAL NORTH DAKOTA LINE
3 CREW EMPLOYEES.

4 A. This adjustment updates the original O&M budgets for additional line crew
5 personnel in the North Dakota jurisdiction. An increase in linemen is
6 necessary in North Dakota to meet growth primarily in the Minot area and
7 maintain reliable service in the Fargo and Grand Forks service areas. These
8 additional staffing approvals were made subsequent to development of the
9 2013 budget, and are discussed by Mr. Foss.

10
11 The result of this update to the test year budget is reflected on
12 Exhibit___(AEH-1), Schedule 6, Page 1, Column 10 and increases test year
13 revenue requirements by \$235,000. Support for the calculation of this
14 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
15 Tab A10.

16
17 **B. Traditional Adjustments**

18 **7) Advertising**

19 Q. PLEASE DESCRIBE THE ADVERTISING EXPENSE ADJUSTMENT.

20 A. The Company has reduced Administrative and General expenses for brand
21 and image advertising costs of \$191,000, which is consistent with past North
22 Dakota electric rate case orders. The 2013 test year includes \$111,000 of
23 includable advertising costs related to mandatory notices, conservation,
24 customer programs, safety, and general advertising. Exhibit___(AEH-1),
25 Schedule 17 lists test year costs by type of includable advertising as well as the
26 advertising costs excluded from the test year.

27

1 The result of this adjustment on the test year is reflected on Exhibit___(AEH-
2 1), Schedule 6, Page 2, Column 11 and decreases test year revenue
3 requirements by \$191,000. Support for this the calculation of adjustment can
4 be found in Test Year Workpapers, Section VIII Adjustments, Tab A11.

5
6 **8) Professional and Utility Association Dues**

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

9 A. In the Company's 1992 electric rate case, Case No. PU-400-92-399, the
10 Commission determined only organizational dues related to North Dakota
11 electric operations were allowable for recovery in electric rates. This
12 adjustment removes any organizational dues not related to the electric
13 operations supporting the State of North Dakota

14
15 Q. DOES THE COMPANY REQUEST RECOVERY OF ASSOCIATION DUES PAID TO
16 CHAMBERS OF COMMERCE?

17 A. Yes. The Company has included membership dues paid to various North
18 Dakota Chambers of Commerce in the test year. Chambers of Commerce
19 provide an essential link between the Company and the communities it serves,
20 allowing for improved utility service.

21
22 Q. WHAT IS THE TOTAL PROFESSIONAL ASSOCIATION AND UTILITY DUES
23 ADJUSTMENT?

24 A. The result of including this adjustment in the test year is reflected on
25 Exhibit___(AEH-1), Schedule 6, Page 2, Column 12 and increases test year
26 revenue requirements by \$19,000. This adjustment reflects the addition of
27 \$23,000 of Chamber of Commerce membership dues, and excludes \$4,000 of

1 non-recoverable Professional and Utility Association Dues. Exhibit___(AEH-
2 1), Schedule 18 provides additional support for our inclusion of Professional
3 Association And Utility Dues in the 2013 test year. Additional support for
4 this adjustment can be found in Test Year Workpapers, Section VIII
5 Adjustments, Tab A12.

6
7 **9) Donations**

8 Q. PLEASE DESCRIBE THE CHARITABLE CONTRIBUTION ADJUSTMENT.

9 A. The Company is proposing to include 50 percent of corporate charitable
10 contributions benefiting the State of North Dakota in the test year. An
11 analysis was performed on contribution detail to insure that only amounts
12 contributed to charities and institutions that could be associated with the
13 Company's electric service territory in the North Dakota jurisdiction were
14 included in the cost of service.

15
16 The result of including this adjustment in the test year is reflected on
17 Exhibit___(AEH-1), Schedule 6, Page 2, Column 13 and increases test year
18 revenue requirements by \$157,000. Support for this adjustment can be found
19 in Test Year Workpapers, Section VIII Adjustments, Tab A13.

20
21 **10) Economic Development Costs**

22 Q. PLEASE IDENTIFY THE COMPANY ECONOMIC DEVELOPMENT PROGRAMS
23 CURRENTLY AVAILABLE.

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

1 and expanding the state and local tax base.

2
3 The Company can, through a donation, provide communities or organizations
4 involved in community and economic development with either an operating
5 grant or a one-time investment in a special project that supports the
6 community and economic development efforts of our communities.

7
8 Q. PLEASE EXPLAIN THE ADJUSTMENT RELATED TO ECONOMIC DEVELOPMENT.

9 A. Because economic development donations were recorded as below-the-line
10 expense, an adjustment is necessary to include economic development
11 contributions in the test year cost of service. This treatment is consistent with
12 prior regulatory treatment in North Dakota.

13
14 The test year includes \$171,000 in economic development costs. The result of
15 including this adjustment in the test year is reflected on Exhibit___(AEH-1),
16 Schedule 6, Page 2, Column 14. Support for this adjustment can be found in
17 Test Year Workpapers, Section VIII Adjustments, Tab A14.

18
19 **11) Interest on Customer Deposits**

20 Q. WHY HAS THE COMPANY INCLUDED AN INTEREST EXPENSE ON CUSTOMER
21 DEPOSITS?

22 A. Customer deposits are treated as customer supplied capital and thus it is
23 appropriate to pay ratepayers a return on that investment.

24
25 The result of including this adjustment in the test year is reflected on
26 Exhibit___(AEH-1), Schedule 6, Page 2, Column 15 and increases test year
27 revenue requirements by \$1,000. Support for this adjustment can be found in

2
3 **C. Rate Case Adjustments:**

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

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

8
9 **12) Aviation**

10 Q. PLEASE DESCRIBE THE AVIATION ADJUSTMENT.

11 A. The NSPM electric utility will be allocated approximately \$1.7 million in costs
12 related to the operation of two corporate aircraft used by Company personnel
13 for 2013, with \$105,000 allocated to the State of North Dakota electric
14 jurisdiction. These costs are incurred in lieu of commercial aviation
15 transportation and help to facilitate the efficient use of executive and other
16 employee time. The Company believes that use of corporate aircraft is cost
17 effective.

18
19 Q. HAS THE COMPANY COMMISSIONED A STUDY THAT CONFIRMS THE BENEFITS
20 OF USING CORPORATE AVIATION SERVICES?

21 A. Yes. The Company retained a third-party consultant to perform a cost-benefit
22 analysis for our corporate aircraft usage from 2011 through June 2012. The
23 study is included in Exhibit____(AEH), Schedule 23.

24
25 Q. PLEASE SUMMARIZE THE STUDY RESULTS.

26 A. The study sought to compare the benefits the Company obtains from using
27 corporate aviation services to commercial air travel. Specifically, the study:

1 (\$49,000).

2
3 The result of including this adjustment in the test year is reflected on
4 Exhibit___(AEH-1), Schedule 6, Page 2, Column 16 and decreases test year
5 revenue requirements by \$53,000. Support for this adjustment can be found
6 in Test Year Workpapers, Section VIII Adjustments, Tab A16

7
8 **13) Wholesale Billing**

9 Q. PLEASE DESCRIBE THE WHOLESALE BILLING ADJUSTMENT.

10 A. The Company performed a study of all costs to serve our single wholesale full
11 requirements customer served at cost-based rates. We undertook this study to
12 ensure that the wholesale jurisdiction's cost assignment fairly represents the
13 cost of providing service to this customer. I discuss the results of our study in
14 Section VII, Utility and Jurisdictional Allocations of my Direct Testimony.
15 This adjustment directly assigns \$43,000 related to customer billing, account
16 management and distribution expense to the wholesale jurisdiction and
17 decreases costs assigned to the retail jurisdictions by \$43,000 (\$3,000 for the
18 North Dakota retail jurisdiction). The Company does not plan to serve any
19 cost-based wholesale requirements customers after 2013.

20
21 The result of including this adjustment in the test year is reflected on
22 Exhibit___(AEH-1), Schedule 6, Page 2, Column 17 and decreases test year
23 revenue requirements by \$3,000. Support for this adjustment can be found in
24 Test Year Workpapers, Section VIII Adjustments, Tab A17.

1 **14) Asset Based Trading Margins**

2 Q. PLEASE DESCRIBE THE ASSET BASED TRADING MARGIN ADJUSTMENT.

3 A. The adjustment to Asset Based Trading Margins excludes the budgeted asset
4 based margins from the test year. As I previously explained, 85 percent of the
5 asset based trading margins are passed through to ratepayers using the FCR
6 adjustment and 15 percent are retained by the Company. Accordingly, I make
7 this adjustment so that no double counting occurs between base rates and the
8 FCR. This treatment is consistent with the outcomes of our last two electric
9 rate cases.

10
11 The result of including this adjustment in the test year is reflected on
12 Exhibit___(AEH-1), Schedule 6, Page 6, Column 18 and increases test year
13 revenue requirements by \$505,000. This increase is offset by 85 percent of
14 actual asset based margins credited to the fuel cost revenue requirement on a
15 going forward basis in the FCR. Support for this adjustment can be found in
16 Test Year Workpapers, Section VIII Adjustments, Tab A18.

17
18 **15) Non-Asset Based Trading Margins**

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

20 A. The adjustment to Non-Asset Based Margins excludes the non-asset based
21 trading margins from the test year. As previously explained, 50 percent of the
22 non-asset based trading margins are passed through to ratepayers using the
23 FCR adjustment and 50 percent are retained by the Company. Accordingly, I
24 make this adjustment so that no double counting occurs between base rates
25 and the FCR. This treatment is also consistent with the outcomes of our last
26 two electric rate cases.

27

1 The result of excluding these margins from the test year is reflected on
2 Exhibit___(AEH-1), Schedule 6, Page 2, Column 19 and increases test year
3 revenue requirements by \$334,000. This increase is offset by 50 percent of
4 actual non-asset based margins credited to the fuel cost revenue requirement
5 on a going forward basis in the FCR. Support for this adjustment is in Test
6 Year Workpapers, Section VIII Adjustments, Tab A19.

7
8 **16) Cell Phone Policy**

9 Q. PLEASE DESCRIBE THE CELL PHONE POLICY ADJUSTMENT.

10 A. An internal audit revealed inconsistencies among business units in spending
11 for personal communication devices, such as cell phones. The Company
12 subsequently updated its policy and clarified which employees are eligible for
13 cell phone corporate accounts or personal reimbursements. These
14 clarifications reduce the projected 2013 operating expenses.

15
16 The result of including this adjustment in the test year is reflected on
17 Exhibit___(AEH-1), Schedule 6, Page 3, Column 24 and decreases test year
18 revenue requirements by \$7,000. Support for this adjustment can be found in
19 Test Year Workpapers, Section VIII Adjustments, Tab A25.

20
21 **17) Removal of Budget Rate Case Expense**

22 Q. PLEASE DESCRIBE THE RATE CASE BUDGET EXPENSE ADJUSTMENT.

23 A. The Commission approves a level of rate case expense recovery as a part of
24 each test year. In past years, actual rate case expenses have exceeded amounts
25 approved by the Commission. As a result, the amount over that approved was
26 expensed or “written off” in the year it was incurred. The 2013 O&M budget
27 included an allowance for the write-off of prior rate case expenses. During

1 our review of the 2013 budget, we identified this amount and are excluding it
2 from the test year.

3
4 The result of including this adjustment in the test year is reflected on
5 Exhibit____(AEH-1), Schedule 6, Page 3, Column 25 and decreases test year
6 revenue requirements by \$24,000. Support for this adjustment can be found
7 in Test Year Workpapers, Section VIII Adjustments, Tab A26.

8
9 **18) Incentive Compensation**

10 Q. WHAT ADJUSTMENTS HAVE YOU MADE TO THE INCENTIVE COMPENSATION
11 EXPENSE INCLUDED IN THE UNADJUSTED TEST YEAR?

12 A. The test year adjustment reflects the exclusion of the budgeted costs for: 1)
13 the long-term portion of incentive compensation; 2) any non-corporate
14 incentive plan costs; and 3) all Annual Incentive Plan costs above 25 percent
15 of base pay. Certain long-term incentive costs associated with Restricted
16 Stock Units that relate to Nuclear Operations employees are also included in
17 the revenue requirement.

18
19 Q. WHY ARE THE COSTS OF THE NUCLEAR OPERATION'S RESTRICTED STOCK UNITS
20 INCLUDED IN THE REVENUE REQUIREMENT?

21 A. Working at nuclear plants requires specific skills, knowledge and expertise
22 Employees with nuclear backgrounds are in short supply, and rising demand
23 for employees with these skills is causing the market compensation rates to
24 rise swiftly in comparison to other professions. As a result, the compensation
25 for certain Company nuclear positions is below market levels, and there will be
26 increased pressure to match market rates. Therefore, in 2012 we implemented
27 a retention program for key nuclear employees in critical positions which

1 includes retention payments and long-term incentive payments in the form of
2 restricted stock unit awards. The Company is seeking recovery of this
3 component of the incentive program for the Nuclear Operations group.
4

5 Q. WHY HAVE YOU ADJUSTED THE ANNUAL INCENTIVE PLAN COSTS BASED ON
6 25 PERCENT OF BASE PAY?

7 A. The settlement approved in our rate case filed in 2007 included an adjustment
8 to exclude Annual Incentive Plan costs above 15 percent of base pay, and that
9 level was maintained in the settlement approved in our last rate case.
10 However, the Company believes that a cap based on 25 percent of base pay is
11 more appropriate because a 25 percent cap limits rate recovery associated with
12 executive incentive compensation without affecting rate recovery for incentive
13 compensation for other employees. That approach is similar to the
14 adjustments made to remove long term incentive compensation for executive
15 compensation. We are not requesting rate recovery of any portion of long
16 term incentive compensation costs, with the exception of eligible employees in
17 our Nuclear Business Unit for the reasons explained above and in the
18 testimony of Mr. O'Connor. A 15 percent base salary cap would go beyond
19 limiting executive incentive compensation; it would also limit recovery of
20 incentive compensation of our individual-contributors and managers.
21

22 Q. WHAT IS THE IMPACT OF THE INCENTIVE COMPENSATION ADJUSTMENT ON
23 THE TEST YEAR?

24 A. The result of including this adjustment in the test year is reflected on
25 Exhibit___(AEH-1), Schedule 6, Page 3, Column 26. The net effect is a
26 decrease in test year revenue requirements of \$530,000. Support for this
27 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,

1 Tab A27.

2
3 **D. Amortizations**

4 Q. ARE YOU PROPOSING TO AMORTIZE ANY TEST-YEAR EXPENSES IN ANY OF
5 THESE RATE CASE ADJUSTMENTS?

6 A. Yes. I am proposing to amortize certain test-year expenses over a three-year
7 period in order to normalize those expenses and prevent their over recovery.
8 I am recommending a three-year amortization period because we anticipate
9 filing another electric general rate case within three years.

10
11 **19) 2013 Rate Case Expense Amortization**

12 Q. PLEASE DESCRIBE THE 2013 RATE CASE EXPENSES AMORTIZATION.

13 A. The Company requests approval of \$618,000 of projected direct expenses
14 associated with this rate case docket and a three-year amortization period,
15 resulting in an annual amortization amount of \$206,000. Exhibit___(AEH-1),
16 Schedule 19 provides additional detail on the development of our projected
17 direct rate case expenses. A three-year amortization period is consistent with
18 our requested amortization period for other amortizations in the rate case.

19
20 The result of including this adjustment in the test year is reflected on
21 Exhibit___(AEH-1), Schedule 6, Page 3, Column 27. The net effect is an
22 increase in test year revenue requirements of \$206,000. Support for this
23 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
24 Tab A28.

1 **20) Prior Rate Case Expense Amortization**

2 Q. PLEASE DESCRIBE THE PRIOR RATE CASE EXPENSES AMORTIZATION.

3 A. The Settlement approved by the Commission in our last rate case included rate
4 case costs of \$562,000 as well as a three year amortization period. The
5 Company estimates the unamortized balance at December 31, 2012 will be
6 approximately \$212,000 and is proposing to extend the current amortization
7 period over the next three years. As a result, we have included an annual prior
8 rate case expense amortization of approximately \$71,000 in the test year.

9
10 The result of including this adjustment in the test year is reflected on
11 Exhibit____(AEH-1), Schedule 6, Page 3, Column 28. The net effect is an
12 increase in test year revenue requirements of \$71,000. Support for this
13 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
14 Tab A29.

15
16 **21) Private Fuel Storage Amortization**

17 Q. PLEASE DESCRIBE THE PRIVATE FUEL STORAGE AMORTIZATION.

18 A. The Company spent approximately \$23 million to obtain a Nuclear Regulatory
19 Commission license for Private Fuel Storage, a private independent spent fuel
20 storage installation within the Goshute Indian tribal land in Utah. Of the \$23
21 million, \$1.14 million was assigned to the State of North Dakota. In the Case
22 No. PU-07-776, the Commission approved a six-year amortization of the
23 \$1.14 million beginning in 2008. Based on a six-year amortization schedule,
24 2013 would be the final year of amortization. The unamortized balance at
25 December 31, 2012 is estimated to be approximately \$208,000. We are
26 proposing to amortize the balance as of December, 2012 over the next three
27 years. As a result, we have included an annual amortization of approximately

1 \$69,000 in the test year.

2
3 The result of including this adjustment in the test year is reflected on
4 Exhibit___(AEH-1), Schedule 6, Page 3, Column 29. The net effect is an
5 increase in test year revenue requirements of \$69,000. Support for this
6 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
7 Tab A29.

8
9 **22) Emission Credit Amortization**

10 Q. PLEASE DESCRIBE THE ADJUSTMENT FOR EMISSION CREDIT AMORTIZATION.

11 A. The Settlement approved by the Commission in our last rate case included a
12 three year amortization of the cumulative balance of deferred SO2 Allowance
13 Credits as of December 2010. The Company is proposing to continue to
14 amortize the outstanding balance as of December 31, 2012 (estimated to be
15 approximately \$99,000) over the next three years.

16
17 The result of including this adjustment in the test year is reflected on
18 Exhibit___(AEH-1), Schedule 6, Page 3, Column 30. The 2013 other revenue
19 budget included \$87,000 in SO2 allowance credits. This adjustment removes
20 the budget SO2 allowance credit of \$87,000 from other revenue and adds an
21 annual SO2 allowance amortization expense credit of approximately \$33,000
22 (one third of the \$99,000 December 31, 2012 estimated balance). The net
23 effect of this adjustment is an increase in test year revenue requirements of
24 \$54,000. Support for this adjustment can be found in Test Year Workpapers,
25 Section VIII Adjustments, Tab A29.

1 **23) 2013 DSM Amortization**

2 Q. PLEASE DESCRIBE THE 2013 DSM AMORTIZATION.

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

5 NSP is authorized to record expenditures to further promote its
6 existing Savers Switch and Peak & Energy Control Service load
7 management programs in a deferred account for amortization in
8 NSP's next general rate case. The amount deferred may not
9 exceed \$266,904 per year
10

11 The Settlement approved by the Commission in our last rate case included a
12 three year amortization of the accumulated DSM balance from the 2009 and
13 2010 calendar years of \$450,639. The estimated unamortized balance as of
14 December 31, 2012 is expected to be \$168,486. We are proposing a new
15 three-year amortization of this balance which results in an annual amortization
16 amount of approximately \$56,000.

17
18 As shown on Exhibit ___(AEH-1), Schedule 6, Page 2, Column 20 this
19 adjustment increases test-year revenue requirements by \$56,000. Support for
20 this adjustment is in Test Year Workpapers, Section VIII Adjustments, Tab
21 A20.

22
23 In addition to the amortization of the past years' balance, the Company has
24 included \$266,583 in its 2013 test-year O&M budget related to DSM. This
25 represents the anticipated ongoing annual expense for DSM.

26
27 Q. PLEASE SUMMARIZE THE TOTAL AMORTIZATIONS INCLUDED IN THE 2013 TEST
28 YEAR?

29 A. As shown on Exhibit___(AEH-1), Schedule 20, the total amortization expense

1 included in the 2013 test year is \$369,494.

2
3 **E. Other Ratemaking Adjustments**

4 **24) MISO CWIP Revenue and Expense Adjustment**

5 Q. PLEASE DESCRIBE THE MISO CWIP REVENUE AND EXPENSE ADJUSTMENT.

6 A. North Dakota does not allow a return on long term CWIP. Accordingly, this
7 adjustment removes MISO wholesale revenues that the Company receives
8 related to return on CWIP from the revenue requirement calculation for
9 North Dakota. The Company received these revenues in lieu of accumulating
10 AFUDC on these projects. Without this adjustment, the Company would be
11 providing a revenue credit for wholesale CWIP recoveries even though the
12 Commission does not allow a return on CWIP in base rates. North Dakota
13 customers will see the benefits of these revenues in the form of reduced
14 investment costs once these assets are placed in service.

15
16 The result of including this adjustment in the test year is reflected on
17 Exhibit___(AEH-1), Schedule 6, Page 3, Column 31. The net effect is an
18 increase in test year revenue requirements of \$1.65 million. Support for this
19 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
20 Tab A30.

21
22 **25) Net Operating Loss**

23 Q. PLEASE SUMMARIZE THE BACKGROUND FOR THE NET OPERATING LOSS
24 ADJUSTMENT.

25 A. The Company has experienced income tax losses as a result of the
26 combination of its extensive investments and the effect of bonus federal
27 income tax depreciation. Bonus federal income tax depreciation is the result

1 of provisions in federal tax laws that allow the Company to deduct either 50
2 percent or 100 percent of qualifying capital investments in the first year the
3 qualifying investment is placed in-service. The Tax Relief Act of 2010, which
4 became law in December 2010, provided 100 percent bonus tax depreciation
5 (“100 Percent Bonus Depreciation”) for certain projects placed into service
6 from September 9, 2010 through December 31, 2011. As a result, the entire
7 amount of the investment in qualified projects that we placed into service
8 during this period was permitted as a tax deduction in the first year the project
9 is placed in-service.

10
11 Q. WHAT IMPACT DOES THIS TAX LAW CHANGE HAVE ON THE COMPANY?

12 A. There are two significant impacts. First, the bonus tax depreciation generates
13 larger amounts of deferred income taxes. Second, the increased tax
14 depreciation expense effectively results in more deductions than the Company
15 can utilize in the current income tax periods. The result was the generation of
16 net operating losses (NOLs) for 2010 and 2011. These NOLs represent the
17 value of tax deductions that need to be carried forward to a future period
18 because they could not be used as deductions in current income tax periods or
19 applied to prior periods to obtain refunds. These excess deductions (plus
20 unused tax credits) have been deferred and are being tracked for use in future
21 periods.

22
23 Q. DO THESE NOLs AFFECT RATE BASE?

24 A. Yes. The NOLs require an adjustment that offsets the part of the ADIT rate
25 base reduction that is associated with the accelerated and bonus depreciation
26 deductions that have exceeded the Company’s taxable income and have thus
27 not resulted in deferral of income taxes. That adjustment is needed to keep

1 the Company's rate base consistent with the income tax deductions that the
2 Company has been able to use. Keeping a balance of rate base reductions
3 resulting from the ADIT and the use of accelerated and bonus depreciation
4 deductions is required under federal income tax law as part of "normalization"
5 for both accounting and ratemaking.

6
7 Q. HAVE YOU PREPARED A SCHEDULE OF THESE DEFERRED AND UNUSED EXCESS
8 DEDUCTIONS?

9 A. Yes. A schedule of these deferred and unused excess deductions for 2011
10 through 2013 has been included as Exhibit___(AEH-1), Schedule 21. This
11 schedule shows the effects on rate base and on the revenue requirement of the
12 utilization of NOLs in 2012 and 2013.

13
14 Q. PLEASE DESCRIBE THE PURPOSE OF THIS ADJUSTMENT.

15 A. The purpose of the NOL adjustment is to reflect the deferred tax asset (DTA)
16 created due to the State of North Dakota Electric being in an NOL tax
17 position prior to the test year. Because of the NOL, a DTA is included to
18 offset the beginning year rate base ADIT. The DTA offset is an increase to
19 rate base that is needed because the ADIT liability balance reflects more
20 deductions and credits than the Company has been able to use in the years
21 prior to the test year. The cumulative balance of the unused deductions and
22 credits is the basis for the DTA. During the test year, the Company is able to
23 utilize some of the accumulated deductions thereby generating an additional
24 deferred tax expense at the composite tax rate lowering the DTA as well as
25 reducing current income taxes. The annual change in these various
26 components is reflected in this adjustment. The adjustment is also included in
27 Exhibit___(AEH-1), Schedule 6, Page 2 of 3, Column 32, and results in an

1 increase to test year revenue requirements of \$265,000. Support for this
2 adjustment can be found in Test Year Workpapers, Section VIII Adjustments,
3 Tab A31.

4
5 Q. WERE ADDITIONAL REVENUES ASSOCIATED WITH A RATE INCREASE
6 CONSIDERED WHEN CALCULATING THE IMPACT OF THE NOL ON THE TEST-
7 YEAR REVENUE REQUIREMENT?

8 A. Yes. The Company included the additional revenues it is seeking in this
9 proceeding when calculating the NOL adjustment. Any change in the rate
10 increase granted by the Commission relative to the Company's request will
11 create a change to taxable income and cause a need to restate this adjustment.

12
13 Q. WHAT IS REQUIRED TO FINALIZE THE NOL ADJUSTMENT AT THE CONCLUSION
14 OF THIS CASE?

15 A. Once all items of revenue and expense have been determined in this case, a
16 recalculation of the NOL is necessary to determine the level of deductions
17 that ultimately can be utilized in the current period to reduce taxable income
18 to zero which then results in a balance of unused deductions to be carried
19 forward to a future period. As with the current determination, the
20 recalculation at the end of the case will be affected by current tax depreciation
21 deductions, annual deferred tax expense, and the ADIT balance.

22
23 **26) Impact of Adjustments on Cash Working Capital**

24 Q. HAVE YOU MADE ADJUSTMENTS TO THE INCOME STATEMENT THAT ALSO
25 AFFECT TEST YEAR RATE BASE?

26 A. Yes. The adjustments to the income statement also lead to an increase in cash
27 working capital of \$197,000. This increase in cash working capital increases

1 test year revenue requirements by \$23,000. The increase in rate base is shown
2 on Exhibit__(AEH-1), Schedule 5, Column 9. This is carried forward to
3 Exhibit__(AEH-1), Schedule 6, Page 3, Column 33 for the income statement
4 impact.

5
6 **27) Change in the Cost of Capital**

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

9 A. The revenue requirements associated with the above adjustments described in
10 sections X and XII of my testimony are calculated using the approved cost of
11 capital in our last rate case. We calculate the revenue requirement impact of
12 each adjustment at our currently authorized overall rate of return (ROR) of
13 8.30 percent (which includes the currently authorized ROE of 10.40 percent)
14 so that changes in the overall cost of capital that occur during the duration of
15 the rate case do not affect the revenue requirements for each adjustment. The
16 change in cost of capital adjustment reflects the impact of the change in the
17 approved ROR (8.30 percent) and proposed ROR (7.90% with a 10.60%
18 ROE) for all of the rate base and income statement adjustments. As shown
19 on Exhibit__(AEH-1), Schedule 6, Page 3, Column 34 this decreases test-
20 year revenue requirements by \$1.275 million.

21
22 **XIII. PROPOSED TRANSMISSION COST RECOVERY RIDER**

23
24 Q. IS THE COMPANY PROPOSING A TRANSMISSION FACILITY COST RIDER IN THIS
25 CASE?

26 A. Yes. As indicated by Ms. McCarten in her Direct Testimony, we are
27 proposing a transmission facility cost rider (TCR Rider) pursuant to N.D.C.C.

1 Section 49-05-04.3, subd. 1. The TCR Rider would provide more timely cost
2 recovery of capital investments and operating costs associated with new or
3 modified electric transmission facilities not included in base rates in this
4 proceeding, and also allow recovery of federally regulated costs charged to the
5 Company by MISO for facilities that increase regional transmission capacity or
6 reliability. The TCR Rider tariff is being proposed in this case, but the
7 Company would not begin recovery of eligible costs until January 1, 2014,
8 after a future rate adjustment filing under N.D.C.C. Section 49-05-04.3, subd.
9 2. Company witness Mr. Steven Huso supports the proposed rate design and
10 TCR Rider tariff in his Direct Testimony. I will explain our proposal for cost
11 recovery and the associated procedural mechanism related to the TCR Rider.
12

13 Q. WHAT WILL THE PROPOSED TCR RIDER APPLY TO?

14 A. The TCR Rider reflects N.D.C.C. Section 49-05-04.3, subd. 1 which:

- 15 a) Allows the public utility to recover on a timely basis its investment and
16 associated costs for new or modified electric transmission facilities not
17 reflected in the utility's general rate schedule;
- 18 b) Allows a return on the public utility's investment made for new or
19 modified electric transmission facilities at the level approved in the
20 utility's most recent general rate case;
- 21 c) Provides a current return on CWIP for new or modified electric
22 transmission facilities, provided that cost recovery from retail
23 customers of the AFUDC is not sought through any other means; and
- 24 d) Terminates cost recovery after the public utility's costs for new or
25 modified electric transmission facilities have been recovered fully or
26 have been reflected in the utility's general rate schedule.

27 N.D.C.C. Section 49-05-04.3 also states:

1 For purposes of this section, an electric transmission facility
2 includes an electric transmission line as defined in chapter 49-
3 21.1 and other transmission line equipment, including
4 substations, transformers, and other equipment constructed to
5 improve the power delivery capability or reliability of the electric
6 transmission system.
7

8 Chapter 49-21.1 in part differentiates between transmission and distribution
9 facilities, defining transmission lines as “lines designed to operate at a voltage
10 of 41.6 kilovolts or more.”
11

12 The TCR Rider would apply to facilities that meet these criteria and are not
13 included in our general rate schedules and for charges from MISO assessed
14 through Schedule 26 or Schedule 26A of the FERC-regulated MISO Open
15 Access Transmission, Energy and Operating Reserve Markets Tariff (MISO
16 Tariff). MISO bills the Company Schedule 26 and 26A charges to recover the
17 cost of transmission investments made by MISO transmission owners allowed
18 regional cost allocation and recovery pursuant to the MISO Tariff.
19

20 **A. MISO Tariff Charges**

21 Q. PLEASE EXPLAIN THE ROLE OF MISO WITH RESPECT TO THE TRANSMISSION
22 FACILITIES FOR WHICH COST RECOVERY IS SOUGHT THROUGH THE TCR RIDER.

23 A. The Company and NSPW are members and take transmission service under
24 the MISO Tariff. MISO coordinates generation and transmission of electricity
25 across the MISO region. The Company may from time to time have an
26 opportunity to invest in transmission projects that qualify for regional cost
27 allocation through the MISO Tariff. In such cases, the Company recovers all
28 or a portion of the costs of these investments through the MISO Tariff.
29 Similarly, other transmission owners may also invest in new transmission

1 projects. The amount of the costs allocated to the Company or other MISO
2 members for any particular investment is determined through the MISO Tariff
3 mechanisms, based upon the classification of the facility and a determination
4 of the benefits particular regions receive from the investments.

5
6 MISO's transmission planning process identifies and evaluates new
7 transmission expansion projects eligible for inclusion in the MISO
8 Transmission Expansion Plan (MTEP). The MTEP is a regional expansion
9 plan with three primary objectives: 1) to perform a reliability assessment of the
10 MISO integrated transmission system; 2) to review transmission owning
11 members' transmission plans and make sure that appropriate projects are
12 reviewed and recommended to the MISO Board of Directors for approval;
13 and 3) to develop transmission upgrades to improve market performance.
14 Through its MTEP process, the MISO determines whether a proposed
15 transmission project is eligible for cost-sharing pursuant to Attachment FF of
16 the MISO Tariff.

17
18 There are a variety of transmission project types under the MISO Tariff
19 eligible for cost-sharing, including the following: 1) Baseline Reliability
20 Projects (BRP) required to ensure transmission system reliability consistent
21 with North American Electric Reliability Corporation (NERC) standards;¹ 2)
22 Regionally Beneficial Projects (RBP) that provide economic benefit to the
23 MISO transmission system; 3) Generator Interconnection Project Network

¹ On October 25, 2012, MISO filed proposed changes to its Tariff that would exclude BRPs from eligibility for partial regional cost allocation. See FERC Docket No. ER13-186-000. The proposed tariff change is pending FERC action. If BRPs are no longer eligible for regional cost allocation, the project costs would be recovered in the local pricing zone only. BRPs constructed by NSPM in the NSP System pricing zone would be allocated to the NSP zone and recoverable through the TCR Rider. BRPs constructed in other pricing zones would no longer be billed through MISO Schedule 26.

1 Upgrades (GIP NU) required for the interconnection of generation to the
2 MISO transmission system; or 4) Multi Value Projects (MVP) that address
3 regional public policy, reliability, and economic value to the MISO footprint.
4 The MISO's annual MTEP review process identifies those transmission
5 projects that will be included in "Appendix A" to the MTEP, and the
6 respective cost-sharing is identified for each project as applicable.

7
8 If the MTEP eligibility screening process shows that a specific transmission
9 project does not meet the criteria for partial (e.g., RBP) or full (e.g., MVP)
10 regional cost allocation, but is determined to provide local benefits, the costs
11 for that transmission project are assigned to the pricing zone of the
12 transmission owner of the facility. For example, for a proposed transmission
13 facility that primarily benefits a local load center, MISO would not administer
14 cost-sharing provisions under Attachment FF and the local transmission
15 owner(s) would bear those costs.

16
17 The regional cost allocation criteria and recovery mechanisms are specified in
18 detail in Attachment FF (specifying the Transmission Expansion Planning
19 Protocols), Attachment GG (specifying the calculation of the Network
20 Upgrade Charge), Attachment MM (specifying the calculation of the Multi
21 Value Project Charge), Schedule 26 (specifying the Network Upgrade Charge
22 for Transmission Expansion Plan), and Schedule 26A (specifying the Multi
23 Value Project Charge for Transmission Expansion Plan) of the MISO Tariff.

24
25 Q. HOW DOES THE COMPANY PROPOSE TO RECOVER MISO SCHEDULE 26 AND
26 26A CHARGES?

27 A. The Company proposes flowing the North Dakota jurisdictional portion of its

1 Schedule 26 and Schedule 26A charges and revenues through the TCR Rider.
2 The Schedule 26 and 26A revenues recovered by the Company for its
3 investments in regionally allocated projects would be reflected as an offset to
4 the Schedule 26 and 26A charges.

5 Q. How DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF PROJECTS
6 DETERMINED TO PROVIDE ONLY LOCAL BENEFITS?

7 A. The Company proposes that the TCR Rider would, in the future, allow
8 recovery of the capital and operating costs for transmission projects
9 determined to provide local benefits (i.e., projects not eligible for MISO
10 regional cost allocation) if the project costs are not yet included in base rates.

11
12 **B. TCR Revenue Requirement Method**

13 Q. WHAT METHOD DOES THE COMPANY PROPOSE FOR CALCULATING THE LEVEL
14 OF INVESTMENT AND COSTS TO INCLUDE IN THE TCR RIDER RATE?

15 A. There are two alternative methods of calculating the TCR Rider rates, referred
16 to as the “Split Method” and the “All-In Method.” The Company proposes to
17 use the All-In Method.

18
19 Q. PLEASE DESCRIBE THE TWO METHODS.

20 A. With the All-In Method, the retail rate base amount and the revenue credit are
21 based on the Company’s entire investment in the projects eligible for regional
22 allocation. With the Split Method, the retail rate base amount and the revenue
23 credit are proportional to the amount of costs allocated to the Company
24 through the MISO Tariff.

25
26 The All-In Method treats the Company’s investments as being all in the retail
27 rate base. Under this method, a traditional retail revenue requirement is

1 calculated on the entire investment, both the amount associated with the
2 provision of retail service and the amount regionally allocated to other utilities.
3 The Company's retail rate of return is applied to 100 percent of the investment
4 (treating it all as retail rate base) and 100 percent of the operating costs related
5 to the investments are treated as retail costs. In addition, 100 percent of the
6 revenues the Company receives from MISO under Schedules 26 or 26A are
7 treated as a retail revenue credit to reduce the retail revenue requirement. The
8 All-In Method treats all of the Company's investments as retail rate base
9 investments even though a portion of the investment is used for providing
10 wholesale service under the MISO Tariff.

11
12 The Split Method is mechanically similar to the All-In Method, but limits the
13 portion of the transmission investments treated as retail rate base to an
14 amount proportional to the costs allocated to the Company's retail load
15 serving obligations through the MISO Tariff. The amount of the investments
16 not used to serve the Company's retail customers is treated as a separate
17 FERC-jurisdictional investment. This method recognizes that the Company's
18 investment in these transmission projects is larger than the share of costs
19 being allocated to the Company through the MISO Tariff. The Split Method
20 treats the retail investment as retail rate base and the FERC investment as
21 FERC rate base.

22
23 Q. DOES THE ALL-IN METHOD RESULT IN LOWER RATES FOR CUSTOMERS?

24 A. Whether the All-In Method results in higher or lower rates for the Company's
25 North Dakota retail customers depends on whether the MISO revenues
26 received are more or less than the retail revenue requirement. If the MISO
27 revenues are higher than the retail revenue requirement, retail rates will be

1 lower; if the MISO revenues are lower than the retail revenue requirement,
2 retail rates will be higher. In either case, however, the MISO revenues will
3 reduce the total costs borne by our retail electric customers because a portion
4 of the cost is recovered through wholesale uses under the MISO Tariff.

5
6 Q. DOES THE COMMISSION PREFER ONE METHOD OVER THE OTHER?

7 A. The Commission has previously approved both methods. The Commission
8 approved MDU's request to use the All-In Method in its May 16, 2012 Order
9 in Case Nos. PU-11-672 and PU-11-681. Earlier, the Commission approved
10 Otter Tail Power's request to use the Split Method in its April 25, 2012 Order
11 in Case Nos. PU-11-153 and PU-11-682. As I understand, Commission Staff
12 has indicated a preference for the All-In Method.

13
14 Q. WHY DOES THE COMPANY PREFER THE ALL-IN METHOD?

15 A. There are two reasons. The first is that the Split Method would be
16 administratively burdensome for the Company to implement under our
17 current accounting systems. The Company uses the All-In Method in
18 Minnesota. The Split Method would require that we develop a separate cost
19 of service for North Dakota excluding the portion of the investment and
20 related O&M costs allocated to the FERC transmission jurisdiction. While the
21 Company tracks investments by project during construction, once the projects
22 go into service we record the investment to Plant in Service and the
23 investment by project is no longer tracked. To implement the Split Method,
24 we would need to separately track the investment subject to FERC
25 jurisdiction, depreciate it separately, and determine the appropriate portion of
26 O&M to allocate to these separate investments.

27 In addition, if there are later additions to a transmission facility that is subject

1 to the Split Method, the Company would need to determine the appropriate
2 split of the new investments and the associated O&M costs. While the Split
3 Method may more precisely reflect jurisdictional responsibility, it would be
4 burdensome to implement fairly both initially and in each TCR rate
5 adjustment filing and each future rate case when transmission related O&M
6 costs would need to be allocated.

7
8 Q. DOES THE ALL-IN METHOD EFFECTIVELY RECOGNIZE FERC'S JURISDICTION
9 OVER THE PORTION OF TRANSMISSION NOT USED TO SERVE THE COMPANY'S
10 RETAIL CUSTOMERS?

11 A. Yes. We currently use the All-In Method, which recognizes all costs incurred
12 by the Company and revenues received by the Company under MISO
13 Schedules 26 and 26A. In this manner, the full costs and revenues associated
14 with our use of other utilities' transmission facilities, and the use of our
15 transmission facilities by other utilities, are fully addressed.

16
17 **C. TCR Rider Implementation**

18 Q. WHEN WOULD THE TCR RIDER TAKE EFFECT?

19 A. The TCR Rider tariff sheet would be effective with final rates in this
20 proceeding, with the initial rate set at zero. We propose to file our forecasted
21 revenue requirement and summary of previous year's collections in a TCR
22 Rider rate adjustment filing submitted no later than November 1 of each year
23 along with a true-up adjustment. These filings would establish the TCR Rider
24 rate to be applied to customer bills beginning in January of the next year.
25 Based on this proposal, we would make our first TCR Rider rate adjustment
26 filing after the conclusion of this rate proceeding, but no later than November
27 1, 2013, with TCR Rider rates proposed to be effective on January 1, 2014.

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Q. WHAT COSTS WOULD BE INCLUDED IN THE FIRST TCR RIDER RATE FILING

A. Our first filing would include the projected annual North Dakota jurisdictional revenue requirements not otherwise included in general rates for new or modified transmission facilities 41.6 kV or larger that can be shown to improve the power delivery capability or reliability of the electric transmission system. We would use a standardized revenue requirements financial model to calculate the capital and operating costs eligible for TCR Rider recovery, including a return on CWIP. In addition, we would request recovery of the difference between the MISO Schedule 26 and 26A revenues and expenses included in base rates and the forecast amount for the projected year. The total costs would be divided by the forecast North Dakota retail sales for the projected year.

Q. DO YOU PROPOSE TO USE A FERC ACCOUNT AS A TCR TRACKER ACCOUNT?

A. Yes. We propose to use FERC account 182.3 Other Regulatory Assets to track the TCR Rider costs and revenues. Using a tracker account ensures that no over-or under-recoveries of costs would occur through the TCR Rider.

Q. DOES THE COMPANY PROPOSE TO INCLUDE A CARRYING CHARGE ON THE BALANCE IN THE TCR RIDER TRACKER ACCOUNT?

A. No. We are not proposing to calculate carrying charges on the monthly balance in the TCR Rider tracker account because we are proposing to use a projected year to set the TCR Rider adjustment factor.

Q. HAVE YOU PREPARED A SAMPLE TCR RIDER REVENUE REQUIREMENT MODEL, TRACKER SCHEDULE, AND RATE CALCULATION?

1 A. Yes. Exhibit___(AEH-1), Schedule 22 is a sample TCR Rider model, tracker
2 schedule, and rate calculation. The proposed revenue requirement calculation
3 reflects the All-In Method described above.

4

5

XIV. CONCLUSION

6

7 Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

8 A. I recommend that the Commission determine an overall retail revenue
9 requirement of \$199.624 million and 2013 revenue deficiency of \$16.900
10 million for the Company's North Dakota jurisdictional electric operation,
11 determined by the cost of service for the 2013 test year. I also recommend the
12 Commission grant an interim rate increase of \$14.704 million for the
13 Company's North Dakota jurisdictional operation.

14

15 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

16 A. Yes, it does.

1 STATE OF NORTH DAKOTA
2 BEFORE THE
3 PUBLIC SERVICE COMMISSION
4
5

6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota Corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-12-____
9 in North Dakota)

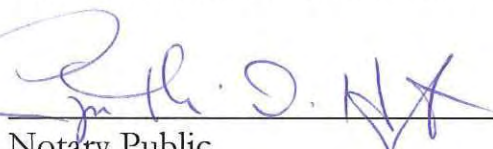
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13 AFFIDAVIT OF
14 Anne E. Heuer
15
16

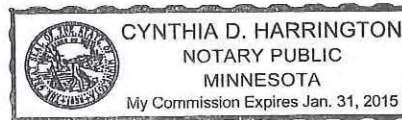
17 I, the undersigned, being duly sworn, depose and say that the foregoing is
18 the Direct Testimony of the undersigned, and that such Direct Testimony and the
19 exhibits or schedules sponsored by me to the best of my knowledge, information
20 and belief, are true, correct, accurate and complete, and I hereby adopt said
21 testimony as if given by me in formal hearing, under oath.
22

23
24 

25 Anne E. Heuer
26
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28

29
30 Subscribed and sworn to before me, this 11th day of December, 2012.
31

32
33 
34 Notary Public
35
36



Northern States Power Company
Electric Utility – State of North Dakota
Resume of Anne E. Heuer

Case No. PU-12-____
Exhibit____(AEH-1), Schedule 1
Page 1 of 1

Manager
Revenue Analysis

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

Current Responsibilities

Since January 2007, I have been the manager of Revenue Analysis. In this position, I am responsible for the general administration of the 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 Northern States Power Company 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

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,
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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Rate Case Expense Amortization	Schedule 19
Period Case Amortizations	Schedule 20
Net Operating Loss (NOL)	Schedule 21
Transmission Cost Recovery Rider Statute	Schedule 22
Aviation Analysis	Schedule 23

ROE = 9.13%
Deficiency = \$3,530
% Increase = 2.00%
Required ROE = 10.40%

Case No. PU-12-____
Exhibit____(AEH-1) Schedule 3
Page 1 of 6

Northern States Power Company (ND)
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2011 Actual

Summary Reports

December 2012

Northern States Power Company (ND)
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2011 Actual

(Dollars in Thousands)

Rate Base Summary

	Total Company Electric			ND Retail Electric			All Other		
	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1 Plant Investment	13,216,717	14,116,949	13,666,833	717,685	767,404	742,545	12,499,032	13,349,545	12,924,288
2 Depreciation Reserve	<u>(6,397,374)</u>	<u>(6,682,453)</u>	<u>(6,539,914)</u>	<u>(356,583)</u>	<u>(372,741)</u>	<u>(364,662)</u>	<u>(6,040,791)</u>	<u>(6,309,712)</u>	<u>(6,175,252)</u>
3 Net Utility Plant	6,819,343	7,434,496	7,126,919	361,102	394,663	377,883	6,458,241	7,039,833	6,749,036
4 C.W.I.P.	10,725	9,299	10,012	695	619	657	10,030	8,680	9,355
5 Accumulated Deferred Taxes	(1,206,080)	(1,570,986)	(1,388,533)	(57,798)	(77,332)	(67,565)	(1,148,282)	(1,493,654)	(1,320,968)
Other Rate Base:									
6 Cash Working Capital	(4,234)	(4,234)	(4,234)	1,098	1,098	1,098	(5,333)	(5,333)	(5,333)
7 Materials & Supplies	124,370	124,370	124,370	7,213	7,213	7,213	117,157	117,157	117,157
8 Fuel Inventory	87,684	87,684	87,684	5,454	5,454	5,454	82,230	82,230	82,230
9 Non-Plant Assets & Liab	(103,873)	(27,412)	(65,643)	(6,196)	(1,609)	(3,903)	(97,677)	(25,803)	(61,740)
10 Prepays & Other	52,033	63,661	57,847	3,587	4,049	3,818	48,446	59,612	54,029
11 Total Rate Base	5,779,968	6,116,878	5,948,422	315,155	334,155	324,655	5,464,812	5,782,722	5,623,766

(Dollars in Thousands)

Income Statement Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Operating Revenues</u>				
1	Retail	3,111,896	176,290	2,935,606
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	548	0	548
4	Other Operating	633,598	37,594	596,004
5	Gross Earnings Tax	0	0	0
6	Total Operating Revenues	3,746,042	213,884	3,532,158
<u>Expenses</u>				
Operating Expenses:				
7	Fuel & Purchased Energy	1,228,707	76,040	1,152,667
8	Power Production	740,713	43,220	697,493
9	Transmission	195,079	11,219	183,860
10	Distribution	112,987	6,737	106,250
11	Customer Accounting	59,289	4,411	54,878
12	Customer Service & Information	115,749	489	115,260
13	Sales, Econ Dvlp & Other	254	135	119
14	Administrative & General	189,841	11,770	178,071
15	Total Operating Expenses	2,642,619	154,021	2,488,598
16	Depreciation	322,366	17,334	305,032
17	Amortization	24,003	551	23,452
Taxes:				
18	Property	123,651	5,881	117,770
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	172,843	9,312	163,531
21	State & Federal Income (see Page 3)	(9,613)	(0)	(9,613)
22	Payroll & Other	30,956	1,820	29,136
23	Total Taxes	317,837	17,013	300,824
24	Total Expenses	3,306,825	188,919	3,117,906
25	AFUDC	0	0	0
26	Total Operating Income	439,217	24,965	414,252

(Dollars in Thousands)

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Income Before Taxes</u>				
1	Total Operating Revenues	3,746,042	213,884	3,532,158
2	less: Total Operating Expenses	(2,642,619)	(154,021)	(2,488,598)
3	Book Depreciation & Amortization	(346,369)	(17,885)	(328,484)
4	Taxes (Other Than Current Income)	(327,450)	(17,013)	(310,437)
5	Total Before Tax Book Income	429,604	24,965	404,639
<u>Tax Additions</u>				
6	Book Depreciation	322,366	17,334	305,032
7	Deferred Income Taxes & ITC	172,843	9,312	163,531
8	Nuclear Fuel Burn (ex D&D)	112,373	6,463	105,910
9	Nuclear Outage Accounting	56,367	3,584	52,783
10	Avoided Tax Interest	32,264	1,797	30,467
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	Total Tax Additions	696,213	38,490	657,723
<u>Tax Deductions</u>				
18	Debt Interest Expense	171,315	9,350	161,964
19	Tax Depreciation & Removal	858,548	49,688	808,860
20	Manufacture Production Deduction	0	0	0
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	73,637	4,417	69,220
25	Net Preferred Stock Deduction	0	0	0
26	Total Tax Deductions	1,103,500	63,455	1,040,044
27	State Taxable Income	22,317	(0)	22,318
28	State Income Tax Rate	8.89%	5.15%	N/A
29	State Taxes before Credits	1,984	(0)	1,984
30	State Credits	0	0	0
31	Total State Income Taxes	1,984	(0)	1,984
32	Federal Taxable Income	20,333	(0)	20,333
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	7,117	(0)	7,117
35	Federal Tax Credits	18,714	0	18,714
36	Total Federal Income Taxes	(11,597)	(0)	(11,597)
37	Total Federal & State Income Taxes	(9,613)	(0)	(9,613)

Revenue Requirement & Return Summary

(Dollars in Thousands)

<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1 Long Term Debt	6.1187%	46.9000%	2.8700%	State of North Dakota Tax rate	5.15%
2 Short Term Debt	3.0636%	0.4300%	0.0100%	Federal Statutory Tax rate	35.00%
3 Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate*Fed Rate)	33.20%
4 Common Equity	10.4000%	52.6700%	5.4800%	Total North Dakota Composite Tax Rate	38.35%
5 Required Rate of Return			8.3600%	Total Corporate Composite Tax Rate	40.78%

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
Rate of Return (ROR)			
6 Total Operating Income	439,217	24,965	414,252
7 Total Average Rate Base	<u>5,948,422</u>	<u>324,655</u>	<u>5,623,766</u>
8 ROR (Operating Income / Rate Base)	7.38%	7.69%	7.37%

Return on Equity (ROE)			
9 Total Operating Income	439,217	24,965	414,252
10 Debt Interest (Rate Base * Weighted Debt Cost)	(171,315)	(9,350)	(161,964)
11 Preferred Stock (Rate Base * Weighted Preferred Cost)	<u>0</u>	<u>0</u>	<u>0</u>
12 Earnings Available for Common	267,903	15,615	252,288
13 Equity Rate Base (Rate Base * Equity Ratio)	<u>3,133,034</u>	<u>170,996</u>	<u>2,962,038</u>
14 ROE (Earnings for Common / Equity Rate Base)	8.55%	9.13%	8.52%

Revenue Deficiency			
15 Require Operating Income (Rate Base * Required Return)	497,288	27,141	470,147
16 Operating Income	<u>439,217</u>	<u>24,965</u>	<u>414,252</u>
17 Operating Income Deficiency	58,071	2,176	55,895
18 Revenue Conversion Factor (1/(1-Composite Tax Rate))	<u>1.68858</u>	<u>1.62201</u>	<u>N/A</u>
19 Revenue Deficiency (Income Deficiency * Conversion Factor)	98,057	3,530	94,527

Total Retail Revenue Requirements			
20 Retail Related Revenues	3,112,444	176,290	2,936,154
21 Revenue Deficiency	<u>98,057</u>	<u>3,530</u>	<u>94,527</u>
22 Total Retail Revenue Requirements	3,210,501	179,820	3,030,681

23 Percentage Increase (Decrease)	3.15%	2.00%	3.22%
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(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Expenses	Lead Days	Total Company Electric		ND Retail Electric		All Other	
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
Fuel Expenses							
1 Coal & Rail Transport	21.08	344,376	7,259,446	21,420	451,534	322,956	6,807,912
2 Gas for Generation	38.45	103,070	3,963,042	6,411	246,503	96,659	3,716,539
3 Oil	22.51	2,413	54,317	150	3,377	2,263	50,940
4 Nuclear & EOL	0.00	100,902	0	6,330	0	94,572	0
5 Nuclear Disposal	76.00	11,471	871,796	660	50,160	10,811	821,636
6		562,232	12,148,600	34,971	751,573	527,261	11,397,027
Purchased Power							
7 Purchases	28.12	875,869	24,629,436	52,855	1,486,283	823,014	23,143,154
8 Interchange	38.21	124,334	4,750,802	7,242	276,717	117,092	4,474,085
		1,000,203	29,380,238	60,097	1,762,999	940,106	27,617,239
Labor & Related Costs							
9 Regular Payroll	12.31	377,411	4,645,929	23,546	289,851	353,865	4,356,078
10 Incentive Compensation	255.05	19,953	5,089,013	1,199	305,805	18,754	4,783,208
11 Pension & Benefits	19.20	70,563	1,354,810	4,201	80,659	66,362	1,274,150
12 Subtotal Labor & Related		467,927	11,089,752	28,946	676,315	438,981	10,413,436
13							
14 All Other Operating Expenses	35.01	612,257	21,435,118	30,007	1,050,545	582,250	20,384,573
15 Property Tax	356.72	123,651	44,108,785	5,881	2,097,870	117,770	42,010,914
16 Employer's Payroll Taxes	26.56	30,956	822,191	1,820	48,339	29,136	773,852
17 Gross Earnings Tax	51.98	0	0	0	0	0	0
18 Federal Income Tax	37.75	(11,597)	(437,792)	(0)	(1)	(11,597)	(437,791)
19 State Income Tax	37.75	1,984	74,897	(0)	(0)	1,984	74,897
20 State Sales Tax Customer Billings	35.73	0	0	0	0	0	0
21 Total Expenses	42.55	2,787,613	118,621,789	161,722	6,387,641	2,625,891	112,234,147
22 Net Annual Expense Amount			324,991		17,500		307,491
Revenues							
	Lag Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
23 Computer Billing	100.00%	42.85	3,111,896	176,290	7,554,379	2,935,606	125,796,588
24 Hand Billed	0.00%	43.07	0	0	0	0	0
25 Retail Revenue Adjustments	0.00	0	0	0	0	0	0
26 Interdepartmental	0.00	548	0	0	0	548	0
27 Late Payment	0.00	4,932	0	294	0	4,638	0
28 Connect and Trouble Charges	42.85	2,176	93,246	278	11,913	1,898	81,333
29 CIP Incentive	0.00	0	0	0	0	0	0
30 Rentals	114.17	4,187	478,030	262	29,913	3,925	448,117
31 Interchange Revenues	38.21	439,429	16,790,582	26,220	1,001,866	413,209	15,788,716
32 Sales for Resale	37.10	75,069	2,785,060	4,571	169,584	70,498	2,615,476
33 Production Associated Revenues	37.10	5,875	217,963	365	13,542	5,510	204,421
34 MISO	14.00	9,445	132,230	543	7,602	8,902	124,628
35 Point to Point Firm	37.10	56,409	2,092,774	3,244	120,352	53,165	1,972,422
36 Services & Facilities	37.10	8,743	324,365	498	18,476	8,245	305,890
37 Ancillary	37.10	23,479	871,071	1,350	50,085	22,129	820,986
38 Distribution Associated Revenues	42.85	159	6,813	0	0	159	6,813
39 Other	42.85	8,508	364,585	268	11,484	8,240	353,100
40 JOA - Rev fr/to PSC	37.10	(4,813)	(178,562)	(299)	(11,093)	(4,514)	(167,469)
41 (blank)	0.00	0	0	0	0	0	0
42 (blank)	0.00	0	0	0	0	0	0
43 (blank)	0.00	0	0	0	0	0	0
44 Total Revenues	42.00	3,746,042	157,329,124	213,884	8,978,103	3,532,158	148,351,021
45 Net Annual Amount			431,039		24,598		406,441
46 Expense / Revenue Factor			0.7441		0.76		
47 Allocated Revenue Amount			320,757		18,598		
48 Net Cash Working Capital			(4,234)		1,098		(5,332)

Adjustment Type	Adjustment	Adjustment Description
Forecast Updates	Bemidji CAPX2020	Corrects in service dates that were incorrectly budgeted
Forecast Updates	Brookings CAPX2020	Corrects in service dates that were incorrectly budgeted
Forecast Updates	Nuclear Fuel Updates	Updated nuclear fuel forecast
Forecast Updates	Shared Asset Allocation Updates	Revised network shared asset allocation based on new NSPM 2013 Capital Budget
Forecast Updates	Nuclear Amortization Updates	Nuclear Amortization budget update for forecasted increase in the PI Unit 1 Outage.
Forecast Updates	Nuclear O&M Budget Updates	Incorporates cost changes identified after the original Nuclear business area O&M budget had been completed.
Forecast Updates	Nuclear Management Employee Retention Updates	Incorporate nuclear retention agreements issued to key nuclear operations employees after the budget cycle was completed
Forecast Updates	Bad Debt	To update the revenues to reflect latest revenues in test year
Forecast Updates	ND Line Crew Employees	Update the original operating and maintenance budgets for additional linemen to meet growing need and maintain reliable service.
Traditional Adjustments	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
Traditional Adjustments	Association Dues	Traditional adjustment made for Association Dues to adjust to allowed level of recovery
Traditional Adjustments	Donations	Traditional adjustment made to include for recovery 50% of charitable donations
Traditional Adjustments	Economic Development	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Traditional Adjustments	Interest on Customer Deposits	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Precedential Adjustments - non-plant related	Aviation	Remove 50% of aviation costs
Precedential Adjustments - non-plant related	Wholesale Billing	To allocate an appropriate level of costs to wholesale
Precedential Adjustments - non-plant related	Asset Margin Sharing	Adjusts for 100% margin sharing of asset based sales
Precedential Adjustments - non-plant related	Non-Asset Margin Sharing	Adjusts for 25% of non-asset based sales
Precedential Adjustments - non-plant related	ND DSM	Adjustment is to record the annual amortization of the certain ND DSM related costs.
Rate Case Adjustments - plant related	2012 Depreciation Study	This adjustment updates the test year base data to include the impact of the Average Service Life adjustment.
Rate Case Adjustments - plant related	Remaining Life	Impact of a decrease from MN Valley full reserve and an increase from all other steam production plants.
Rate Case Adjustments - plant related	Black Dog Removal/Remediation Costs	Incorporate increased cost of removal estimate for Black Dog. Includes a reallocation of 2010 removal study between steam and other production units.
Rate Case Adjustments - non plant related	Cell phone policy adjustment	Removes expenses related to employee cell phone use
Rate Case Adjustments - non plant related	Rate case budget exclusion	Removes additional expense budgeted for rate case expenses
Rate Case Adjustments - non plant related	Incentive Compensation	Excludes items not eligible for recovery
Rate Case Adjustments - non plant related	MISO Revenue and Expense Adjustment	Adjustment removes the MISO revenues and expenses associated with transmission projects currently in Construction Work in Progress (CWIP).
Rate Case Adjustments - amortizations	2013 Rate Case	The proposed 3 year amortization for 2013 rate case expenses
Rate Case Adjustments - amortizations	Prior North Dakota Rate Case	The proposed 3 year amortization for the prior ND approved rate case expenses.
Rate Case Adjustments - amortizations	Private Fuel Storage Amortization	The proposed 3 year amortization for unamortized balance as of December 2012.
Rate Case Adjustments - amortizations	Emission Credit Amortization	The proposed 3 year amortization for unamortized balance as of December 2012.
Other Ratemaking Adjustments	Net Operating Loss	Adjust Tax Depreciation, Deferred Taxes and ADIT to include deductions previously deferred to result in zero taxable income.
Other Ratemaking Adjustments	Income Statement Cash Working Capital	Cash Working Capital impacts of the various bridge schedule adjustments.
Other Ratemaking Adjustments	Cost of Capital Change	Impact on revenue requirements associated with the difference between the proposed capital structure and the last authorized.

Northern States Power Company
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2013 Unadjusted Test Year versus Final Adjusted Test Year
(\$000's)

Line No.	Description Work Paper Reference	Unadjusted (1)	Forecast Updates			Rate Case Adjustments				Proposed 2013 Test Year (10)
			Bemidji CAPX2020 WP A-1 (2)	Brookings CAPX2020 WP A-2 (3)	Nuclear Fuel Updates WP A-4 (4)	2012 Depreciation Study WP A-22 (5)	Production Remaining Life WP A-23 (6)	Black Dog Removal / Remediation WP A-24 (7)	Net Operating Loss WP A-31 (8)	
1	Electric Plant as Booked									
2	Production	\$536,836			\$243					\$537,079
3	Transmission	\$134,112	\$1,906	\$194						\$136,211
4	Distribution	\$138,686								\$138,686
5	General	\$29,097								\$29,097
6	Common	\$29,899								\$29,899
6	TOTAL Utility Plant in Service	\$868,630	\$1,906	\$194	\$243	\$0	\$0	\$0	\$0	\$870,972
7	Reserve for Depreciation									
8	Production	\$289,353			\$25		(\$127)	\$248		\$289,499
9	Transmission	\$38,928	\$40	(\$3)		(\$178)				\$38,787
10	Distribution	\$62,205				\$742				\$62,947
11	General	\$11,125				(\$72)				\$11,053
12	Common	\$17,274				\$29				\$17,303
12	TOTAL Reserve for Depreciation	\$418,885	\$40	(\$3)	\$25	\$521	(\$127)	\$248	\$0	\$419,589
13	Net Utility Plant in Service									
14	Production	\$247,483			\$218		\$127	(\$248)		\$247,580
15	Transmission	\$95,184	\$1,866	\$196		\$178				\$97,424
16	Distribution	\$76,481				(\$742)				\$75,739
17	General	\$17,972				\$72				\$18,044
18	Common	\$12,625				(\$29)				\$12,596
18	Net Utility Plant in Service	\$449,745	\$1,866	\$196	\$218	(\$521)	\$127	(\$248)	\$0	\$451,383
19	Utility Plant Held for Future Use	\$0								\$0
20	Construction Work in Progress	\$2,037								\$2,037
21	Less: Accumulated Deferred Income Taxes	\$90,835	\$706	\$26	(\$12)	(\$213)	\$52	(\$102)	\$1,491	\$92,784
22	Cash Working Capital	(\$1,123)								(\$926)
23	Other Rate Base Items:									
24	Materials and Supplies	\$7,613								\$7,613
25	Fuel Inventory	\$5,899								\$5,899
26	Non-Plant Assets & Liabilities	(\$1,809)								(\$1,809)
27	Prepayments	\$1,050								\$1,050
28	Deferred Revenues - Nuc Outage	\$0								\$0
29	Nuclear Outage Amortization	\$5,018								\$5,018
30	Customer Advances	(\$18)								(\$18)
31	Customer Deposits	(\$213)								(\$213)
31	Other Working Capital	\$398								\$398
32	Total Other Rate Base Items	\$17,938	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$17,938
33	Total Average Rate Base	\$377,762	\$1,160	\$171	\$229	(\$308)	\$75	(\$147)	(\$1,491)	\$377,648

Forecast Updates											
Line No.	Description Work Paper Reference	Unadjusted (1)	Bemidji CAPX2020 WP A1 (2)	Brookings CAPX2020 WP A2 (3)	Nuclear Fuel Updates WP A4 (4)	Shared Asset Allocation WP A5 (5)	Nuclear Amortization WP A6 (6)	Nuc Fees & Cont Labor WP A7 (7)	Nuclear Retention WP A8 (8)	Bad Debt WP A9 (9)	ND Line Employees WP A10 (10)
Operating Revenues											
1	Retail	\$182,724	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2	CIP Revenue Adjustment	0	0	0	0	0	0	0	0	0	0
3	Interdepartmental	0	0	0	0	0	0	0	0	0	0
4	Other Operating	48,616	0	0	0	0	0	0	0	0	0
5	Total Operating Revenues	\$231,340	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Expenses											
Operating Expenses:											
6	Fuel & Purchased Energy	\$82,971	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
7	Power Production	45,530	0	0	0	0	121	493	77	0	0
8	Transmission	14,568	0	0	0	0	0	0	0	0	0
9	Distribution	6,528	0	0	0	0	0	0	0	0	235
10	Customer Accounting	4,358	0	0	0	0	0	0	0	(72)	0
11	Customer Service & Information	505	0	0	0	0	0	0	0	0	0
12	Sales, Econ Dvlp & Other	2	0	0	0	0	0	0	0	0	0
13	Administrative & General	15,600	0	0	0	(196)	0	0	0	0	0
14	Total Operating Expenses	\$170,062	\$0	\$0	\$0	(\$196)	\$121	\$493	\$77	(\$72)	\$235
15	Depreciation	\$21,238	\$39	\$1	\$0	\$0	\$0	\$0	\$0	\$0	\$0
16	Amortization	\$4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Taxes:											
17	Property	\$7,915	\$25	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
18	Deferred Income Tax & ITC	10,212	35	42	13	0	0	0	0	0	0
19	Federal & State Income Tax	(6,481)	0	0	0	0	0	0	0	0	0
20	Payroll & Other	1,932	0	0	0	0	0	0	0	0	0
21	Total Taxes	\$13,578	\$60	\$42	\$13	\$0	\$0	\$0	\$0	\$0	\$0
22	Total Expenses	\$204,882	\$99	\$43	\$13	(\$196)	\$121	\$493	\$77	(\$72)	\$235
23	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
24	Total Operating Income	\$26,458	(\$99)	(\$43)	(\$13)	\$196	(\$121)	(\$493)	(\$77)	\$72	(\$235)
Calculation of Revenue Requirements											
25	Rate Base	\$377,763	\$1,160	\$171	\$229	\$0	\$0	\$0	\$0	\$0	\$0
26	Required Operating Income	31,354	96	14	19	0	0	0	0	0	0
27	Operating Income	23,115	(23)	1	35	121	(75)	(304)	(47)	44	(145)
28	Operating Income Deficiency	8,239	119	14	(16)	(121)	75	304	47	(44)	145
29	Revenue Deficiency	\$13,364	\$193	\$22	(\$26)	(\$196)	\$121	\$493	\$77	(\$72)	\$235
Calculation of Income Taxes											
30	Operating Revenue	\$231,340	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
31	- Operating Exp	170,062	0	0	0	(196)	121	493	77	(72)	235
32	- Amortizations	4	0	0	0	0	0	0	0	0	0
33	- Taxes oth than Inc	9,847	25	0	0	0	0	0	0	0	0
34	Operating Income before Adjs	\$51,427	(\$25)	\$0	\$0	\$196	(\$121)	(\$493)	(\$77)	\$72	(\$235)
35	Additions to Income	\$15,185	(\$98)	(\$123)	\$0	\$0	\$0	\$0	\$0	\$0	\$0
36	Deduct from Income	\$60,535	\$43	(\$14)	\$118	\$0	\$0	\$0	\$0	\$0	\$0
37	Debt Synchronization	\$10,691	\$33	\$5	\$6	\$0	\$0	\$0	\$0	\$0	\$0
38	State Taxable Income	(\$4,614)	(\$199)	(\$114)	(\$124)	\$196	(\$121)	(\$493)	(\$77)	\$72	(\$235)
39	State Income Tax before Credits	(\$238)	(\$10)	(\$6)	(\$6)	\$10	(\$6)	(\$25)	(\$4)	\$4	(\$12)
40	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
41	Federal Taxable Income	(\$4,376)	(\$189)	(\$108)	(\$118)	\$186	(\$115)	(\$468)	(\$73)	\$68	(\$223)
42	Fed Income Tax before Credits	(\$1,532)	(\$66)	(\$38)	(\$41)	\$65	(\$40)	(\$164)	(\$26)	\$24	(\$78)
43	Federal Tax Credits	\$1,369	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
44	Income Tax	(\$3,138)	(\$76)	(\$44)	(\$48)	\$75	(\$46)	(\$189)	(\$30)	\$28	(\$90)

Line No.	Description Work Paper Reference	Traditional Adjustments					Rate Case Adjustments							
		Advertising WP A11 (11)	Assn Dues WP A12 (12)	Donations WP A13 (13)	Economic Develop WP A14 (14)	Interest on Customer Deposits WP A15 (15)	Aviation WP A16 (16)	Wholesale Billing WP A17 (17)	Asset Margin Sharing WP A18 (18)	NonAsset Margin Sharing WP A19 (19)	ND DSM WP A20 (20)	2012 Depreciation Study WP A22 (21)	Remaining Life WP A23 (22)	Black Dog Cost of Removal WP A24 (23)
Operating Revenues														
1	Retail	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
2	CIP Revenue Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	
3	Interdepartmental	0	0	0	0	0	0	0	0	0	0	0	0	
4	Other Operating	0	0	0	0	0	0	(505)	(334)	0	0	0	0	
5	Total Operating Revenues	\$0	\$0	\$0	\$0	\$0	\$0	(\$505)	(\$334)	\$0	\$0	\$0	\$0	
Expenses														
Operating Expenses:														
6	Fuel & Purchased Energy	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
7	Power Production	0	0	0	0	0	0	0	0	0	0	0	0	
8	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	
9	Distribution	0	0	0	0	0	0	0	0	0	0	0	0	
10	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0	0	
11	Customer Service & Information	(48)	0	0	0	0	0	0	0	0	0	0	0	
12	Sales, Econ Dvlp & Other	0	0	0	171	0	0	0	0	0	0	0	0	
13	Administrative & General	(143)	19	157	0	1	(52)	(3)	0	0	0	0	0	
14	Total Operating Expenses	(\$191)	\$19	\$157	\$171	\$1	(\$52)	(\$3)	\$0	\$0	\$0	\$0	\$0	
15	Depreciation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$1,042	(\$254)	\$497	
16	Amortization	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$56	\$0	\$0	\$0	
Taxes:														
17	Property	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
18	Deferred Income Tax & ITC	0	0	0	0	0	0	0	0	0	(425)	104	(203)	
19	Federal & State Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	
20	Payroll & Other	0	0	0	0	0	(1)	0	0	0	0	0	0	
21	Total Taxes	\$0	\$0	\$0	\$0	\$0	(\$1)	\$0	\$0	\$0	(\$425)	\$104	(\$203)	
22	Total Expenses	(\$191)	\$19	\$157	\$171	\$1	(\$53)	(\$3)	\$0	\$0	\$56	\$617	(\$150)	\$294
23	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
24	Total Operating Income	\$191	(\$19)	(\$157)	(\$171)	(\$1)	\$53	\$3	(\$505)	(\$334)	(\$56)	(\$617)	\$150	(\$294)
Calculation of Revenue Requirements														
25	Rate Base	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$309)	\$75	(\$147)	
26	Required Operating Income	0	0	0	0	0	0	0	0	0	(26)	6	(12)	
27	Operating Income	118	(12)	(97)	(105)	(1)	33	2	(311)	(206)	(35)	(620)	151	(296)
28	Operating Income Deficiency	(118)	12	97	105	1	(33)	(2)	311	206	35	595	(145)	283
29	Revenue Deficiency	(\$191)	\$19	\$157	\$171	\$1	(\$53)	(\$3)	\$505	\$334	\$56	\$965	(\$234)	\$460
Calculation of Income Taxes														
30	Operating Revenue	\$0	\$0	\$0	\$0	\$0	\$0	(\$505)	(\$334)	\$0	\$0	\$0	\$0	
31	- Operating Exp	(191)	19	157	171	1	(52)	(3)	0	0	0	0	0	
32	- Amortizations	0	0	0	0	0	0	0	0	56	0	0	0	
33	- Taxes oth than Inc	0	0	0	0	0	(1)	0	0	0	0	0	0	
34	Operating Income before Adjs	\$191	(\$19)	(\$157)	(\$171)	(\$1)	\$53	\$3	(\$505)	(\$334)	(\$56)	\$0	\$0	
35	Additions to Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
36	Deduct from Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
37	Debt Synchronization	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$9)	\$2	(\$4)	
38	State Taxable Income	\$191	(\$19)	(\$157)	(\$171)	(\$1)	\$53	\$3	(\$505)	(\$334)	(\$56)	\$9	(\$2)	
39	State Income Tax before Credits	\$10	(\$1)	(\$8)	(\$9)	(\$0)	\$3	\$0	(\$26)	(\$17)	(\$3)	\$0	(\$0)	
40	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
41	Federal Taxable Income	\$181	(\$18)	(\$149)	(\$162)	(\$1)	\$50	\$3	(\$479)	(\$317)	(\$53)	\$9	(\$2)	
42	Fed Income Tax before Credits	\$63	(\$6)	(\$52)	(\$57)	(\$0)	\$18	\$1	(\$168)	(\$111)	(\$19)	\$3	(\$1)	
43	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
44	Income Tax	\$73	(\$7)	(\$60)	(\$66)	(\$0)	\$20	\$1	(\$194)	(\$128)	(\$21)	\$3	(\$1)	

Rate Case Adjustments (cont.)

Line No.	Description Work Paper Reference	Cell Phone Policy WP A25 (24)	Rate Case Budget Exclusion WP A26 (25)	Incentive Pay WP A27 (26)	Rate Case Expense Amortization WP A28 (27)	Prior ND Rate Case WP A29 (28)	PFS WP A29 (29)	Emission Cr Amortization WP A29 (30)	MISO CWIP Rev & Exp WP A30 (31)	NOL Adjustment WP A31 (32)	Income Statement CWC (33)	Cost of Capital Change (34)	Proposed 2013 Test Year
Operating Revenues													
1	Retail	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$182,724
2	CIP Revenue Adjustment	0	0	0	0	0	0	0	0	0	0	0	\$0
3	Interdepartmental	0	0	0	0	0	0	0	0	0	0	0	\$0
4	Other Operating	0	0	0	0	0	0	(87)	(2,188)	0	0	0	\$45,502
5	Total Operating Revenues	\$0	\$0	\$0	\$0	\$0	\$0	(\$87)	(\$2,188)	\$0	\$0	\$0	\$228,226
Expenses													
Operating Expenses:													
6	Fuel & Purchased Energy	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$82,971
7	Power Production	0	0	0	0	0	0	0	0	0	0	0	\$46,221
8	Transmission	0	0	0	0	0	0	0	(537)	0	0	0	\$14,031
9	Distribution	0	0	0	0	0	0	0	0	0	0	0	\$6,763
10	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0	\$4,286
11	Customer Service & Information	0	0	0	0	0	0	0	0	0	0	0	\$457
12	Sales, Econ Dvlp & Other	0	0	0	0	0	0	0	0	0	0	0	\$173
13	Administrative & General	(7)	(24)	(530)	0	0	0	0	0	0	0	0	\$14,822
14	Total Operating Expenses	(\$7)	(\$24)	(\$530)	\$0	\$0	\$0	\$0	(\$537)	\$0	\$0	\$0	\$169,724
15	Depreciation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$22,563
16	Amortization	\$0	\$0	\$0	\$206	\$71	\$69	(\$33)	\$0	\$0	\$0	\$0	\$373
Taxes:													
17	Property	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$7,940
18	Deferred Income Tax & ITC	0	0	0	0	0	0	0	0	2,982	0	0	\$12,760
19	Federal & State Income Tax	0	0	0	0	0	0	0	0	0	0	0	(\$6,481)
20	Payroll & Other	0	0	0	0	0	0	0	0	0	0	0	\$1,931
21	Total Taxes	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$2,982	\$0	\$0	\$16,150
22	Total Expenses	(\$7)	(\$24)	(\$530)	\$206	\$71	\$69	(\$33)	(\$537)	\$2,982	\$0	\$0	\$208,811
23	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
24	Total Operating Income	\$7	\$24	\$530	(\$206)	(\$71)	(\$69)	(\$54)	(\$1,651)	(\$2,982)	\$0	\$0	\$19,415
Calculation of Revenue Requirements													
25	Rate Base	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,491)	\$197	\$0	\$377,648
26	Required Operating Income	0	0	0	0	0	0	0	0	(124)	\$16	(1,511)	\$29,834
27	Operating Income	4	15	327	(127)	(44)	(43)	(33)	(1,018)	(287)	\$2	(724)	\$19,415
28	Operating Income Deficiency	(4)	(15)	(327)	127	44	43	33	1,018	163	\$14	(786)	\$10,419
29	Revenue Deficiency	(\$7)	(\$24)	(\$530)	\$206	\$71	\$69	\$54	\$1,651	\$265	\$23	(\$1,275)	\$16,900
Calculation of Income Taxes													
30	Operating Revenue	\$0	\$0	\$0	\$0	\$0	\$0	(\$87)	(\$2,188)	\$0	\$0	\$0	\$228,226
31	- Operating Exp	(7)	(24)	(530)	0	0	0	0	(537)	0	\$0	0	\$169,724
32	- Amortizations	0	0	0	206	71	69	(33)	0	0	\$0	0	\$373
33	- Taxes oth than Inc	0	0	0	0	0	0	0	0	0	\$0	0	\$9,871
34	Operating Income before Adjs	\$7	\$24	\$530	(\$206)	(\$71)	(\$69)	(\$54)	(\$1,651)	\$0	\$0	\$0	\$48,258
35	Additions to Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$14,964
36	Deduct from Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$10,641	\$0	\$0	\$71,323
37	Debt Synchronization	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$42)	\$6	(\$1,888)	\$8,799
38	State Taxable Income	\$7	\$24	\$530	(\$206)	(\$71)	(\$69)	(\$54)	(\$1,651)	(\$10,599)	(\$6)	\$1,888	(\$16,900)
39	State Income Tax before Credits	\$0	\$1	\$27	(\$11)	(\$4)	(\$4)	(\$3)	(\$85)	(\$546)	(\$0)	\$97	(\$870)
40	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
41	Federal Taxable Income	\$7	\$23	\$503	(\$195)	(\$67)	(\$65)	(\$51)	(\$1,566)	(\$10,053)	(\$5)	\$1,791	(\$16,029)
42	Fed Income Tax before Credits	\$2	\$8	\$176	(\$68)	(\$24)	(\$23)	(\$18)	(\$548)	(\$3,519)	(\$2)	\$627	(\$5,610)
43	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$1,369)	\$0	\$0	\$0
44	Income Tax	\$3	\$9	\$203	(\$79)	(\$27)	(\$26)	(\$21)	(\$633)	(\$2,695)	(\$2)	\$724	(\$6,481)

Northern States Power Company
Electric Utility - State of North Dakota
SUMMARY OF REVENUE REQUIREMENTS
Test Year Ending December 31, 2013
(\$000's)

Case No. PU-12-____
Exhibit____(AEH-1) Schedule 7
Page 1 of 1

<u>Line</u>	<u>Description</u>	Adjusted Proposed Test Year <u>2013</u>
1	Average Rate Base	\$377,648
2	Operating Income (Before AFUDC)	\$19,415
3	Allowance for Funds Used During Construction	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$19,415
5	Overall Rate of Return (Line 4 / Line 1)	5.14%
6	Required Rate of Return	7.90%
7	Operating Income Requirement (Line 1 x Line 6)	\$29,834
8	Income Deficiency (Line 7 - Line 4)	\$10,419
9	Gross Revenue Conversion Factor	1.62201
10	Revenue Deficiency (Line 8 x Line 9)	\$16,900
11	Retail Related Revenue Under Present Rates	\$182,724
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	9.25%

ROE = 5.35%
Deficiency = \$16,900
% Increase = 9.25%
Required ROE = 10.60%

Case No. PU-12-____
Exhibit____(AEH-1) Schedule 8
Page 1 of 6

Northern States Power Company
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Proposed 2013 Test Year

Summary Reports

December 2012

Northern States Power Company
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Proposed 2013 Test Year

(Dollars in Thousands)

Case No. PU-12-_____
 Exhibit____(AEH-1) Schedule 8
 Page 2 of 6

Rate Base Summary

	Total Company Electric			ND Retail Electric			All Other		
	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>
1 Plant Investment	14,512,422	15,975,443	15,243,933	827,530	914,414	870,972	13,684,892	15,061,029	14,372,961
2 Depreciation Reserve	<u>(7,025,573)</u>	<u>(7,401,268)</u>	<u>(7,213,421)</u>	<u>(407,853)</u>	<u>(431,326)</u>	<u>(419,589)</u>	<u>(6,617,720)</u>	<u>(6,969,942)</u>	<u>(6,793,832)</u>
3 Net Utility Plant	7,486,849	8,574,175	8,030,512	419,677	483,088	451,383	7,067,172	8,091,087	7,579,129
4 C.W.I.P.	35,107	31,610	33,359	2,163	1,912	2,037	32,944	29,698	31,322
5 Accumulated Deferred Taxes	(1,589,312)	(1,816,096)	(1,702,704)	(86,356)	(99,212)	(92,784)	(1,502,956)	(1,716,883)	(1,609,920)
Other Rate Base:									
6 Cash Working Capital	(46,175)	(46,175)	(46,175)	(926)	(926)	(926)	(45,248)	(45,248)	(45,248)
7 Materials & Supplies	125,754	125,754	125,754	7,613	7,613	7,613	118,141	118,141	118,141
8 Fuel Inventory	90,495	90,495	90,495	5,899	5,899	5,899	84,596	84,596	84,596
9 Non-Plant Assets & Liab	(46,907)	(12,429)	(29,668)	(2,860)	(758)	(1,809)	(44,047)	(11,671)	(27,859)
10 Prepays & Other	91,497	108,869	100,183	5,704	6,766	6,235	85,793	102,103	93,948
11 Total Rate Base	6,147,308	7,056,204	6,601,756	350,913	404,381	377,648	5,796,395	6,651,822	6,224,109

Northern States Power Company
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
Proposed 2013 Test Year

Case No. PU-12-____
Exhibit____(AEH-1) Schedule 8
Page 3 of 6

(Dollars in Thousands)

Income Statement Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Operating Revenues</u>				
1	Retail	3,049,972	182,724	2,867,248
2	CIP Adjustment to Program Costs	0	0	0
3	Interdepartmental	540	0	540
4	Other Operating	736,136	45,502	690,634
5	Gross Earnings Tax	0	0	0
6	Total Operating Revenues	3,786,648	228,226	3,558,422
<u>Expenses</u>				
Operating Expenses:				
7	Fuel & Purchased Energy	1,278,735	82,971	1,195,764
8	Power Production	755,534	46,221	709,313
9	Transmission	232,973	14,031	218,942
10	Distribution	110,834	6,763	104,071
11	Customer Accounting	57,725	4,286	53,439
12	Customer Service & Information	36,890	457	36,433
13	Sales, Econ Dvlp & Other	309	173	136
14	Administrative & General	233,106	14,822	218,284
15	Total Operating Expenses	2,706,106	169,724	2,536,382
16	Depreciation	371,234	22,563	348,671
17	Amortization	23,100	373	22,727
Taxes:				
18	Property	167,591	7,940	159,651
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	224,372	12,760	211,612
21	State & Federal Income (see Page 3)	(105,791)	(6,481)	(99,310)
22	Payroll & Other	31,388	1,931	29,457
23	Total Taxes	317,560	16,151	301,410
24	Total Expenses	3,418,000	208,811	3,209,189
25	AFUDC	0	0	0
26	Total Operating Income	368,648	19,415	349,233

(Dollars in Thousands)

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Income Before Taxes</u>				
1	Total Operating Revenues	3,786,648	228,226	3,558,422
2	less: Total Operating Expenses	(2,706,106)	(169,724)	(2,536,382)
3	Book Depreciation & Amortization	(394,334)	(22,936)	(371,398)
4	Taxes (Other Than Current Income)	(423,351)	(22,631)	(400,720)
5	Total Before Tax Book Income	262,857	12,934	249,922
<u>Tax Additions</u>				
6	Book Depreciation	371,234	22,563	348,671
7	Deferred Income Taxes & ITC	224,372	12,760	211,612
8	Nuclear Fuel Burn (ex D&D)	120,368	7,249	113,119
9	Nuclear Outage Accounting	74,486	4,664	69,822
10	Avoided Tax Interest	52,435	3,051	49,384
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	Total Tax Additions	842,895	50,288	792,608
<u>Tax Deductions</u>				
18	Debt Interest Expense	153,821	8,799	145,022
19	Tax Depreciation & Removal	1,122,833	69,100	1,053,733
20	Manufacture Production Deduction	0	0	0
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	36,449	2,223	34,226
25	Net Preferred Stock Deduction	0	0	0
26	Total Tax Deductions	1,313,102	80,122	1,232,981
27	State Taxable Income	(207,350)	(16,900)	(190,451)
28	State Income Tax Rate	9.07%	5.15%	N/A
29	State Taxes before Credits	(18,797)	(870)	(17,927)
30	State Credits	0	0	0
31	Total State Income Taxes	(18,797)	(870)	(17,927)
32	Federal Taxable Income	(188,553)	(16,029)	(172,524)
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	(65,994)	(5,610)	(60,383)
35	Federal Tax Credits	21,000	0	21,000
36	Total Federal Income Taxes	(86,994)	(5,610)	(81,383)
37	Total Federal & State Income Taxes	(105,791)	(6,481)	(99,310)

Revenue Requirement & Return Summary

(Dollars in Thousands)

<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1 Long Term Debt	5.1400%	44.9600%	2.3100%	State of North Dakota Tax rate	5.15%
2 Short Term Debt	0.7500%	2.4800%	0.0200%	Federal Statutory Tax rate	35.00%
3 Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate*Fed Rate)	33.20%
4 Common Equity	10.6000%	52.5600%	5.5700%	Total North Dakota Composite Tax Rate	38.35%
5 Required Rate of Return			7.9000%	Total Corporate Composite Tax Rate	40.89%

<u>Rate of Return (ROR)</u>	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
6 Total Operating Income	368,648	19,415	349,233
7 Total Average Rate Base	<u>6,601,756</u>	<u>377,648</u>	<u>6,224,109</u>
8 ROR (Operating Income / Rate Base)	5.58%	5.14%	5.61%

<u>Return on Equity (ROE)</u>	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
9 Total Operating Income	368,648	19,415	349,233
10 Debt Interest (Rate Base * Weighted Debt Cost)	(153,821)	(8,799)	(145,022)
11 Preferred Stock (Rate Base * Weighted Preferred Cost)	<u>0</u>	<u>0</u>	<u>0</u>
12 Earnings Available for Common	214,827	10,616	204,211
13 Equity Rate Base (Rate Base * Equity Ratio)	<u>3,469,883</u>	<u>198,492</u>	<u>3,271,391</u>
14 ROE (Earnings for Common / Equity Rate Base)	6.19%	5.35%	6.24%

<u>Revenue Deficiency</u>	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
15 Require Operating Income (Rate Base * Required Return)	521,539	29,834	491,705
16 Operating Income	<u>368,648</u>	<u>19,415</u>	<u>349,233</u>
17 Operating Income Deficiency	152,891	10,419	142,472
18 Revenue Conversion Factor (1/(1-Composite Tax Rate))	<u>1.69184</u>	<u>1.62201</u>	<u>N/A</u>
19 Revenue Deficiency (Income Deficiency * Conversion Factor)	258,667	16,900	241,767

<u>Total Retail Revenue Requirements</u>	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
20 Retail Related Revenues	3,050,512	182,724	2,867,788
21 Revenue Deficiency	<u>258,667</u>	<u>16,900</u>	<u>241,767</u>
22 Total Retail Revenue Requirements	3,309,179	199,624	3,109,555

23 Percentage Increase (Decrease)	8.48%	9.25%	8.43%
--	--------------	--------------	--------------

Rate Base Detail - Cash Working Capital

Expenses	Lead Days	Total Company Electric		ND Retail Electric		All Other				
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days			
Fuel Expenses										
1	Coal & Rail Transport	18.09	326,178	5,900,560	21,263	384,648	304,915	5,515,912		
2	Gas for Generation	37.01	122,911	4,548,936	8,012	296,524	114,899	4,252,412		
3	Oil	19.40	41	795	3	58	38	737		
4	Nuclear & EOL	0.00	108,580	0	7,137	0	101,443	0		
5	Nuclear Disposal	76.13	11,787	897,344	710	54,052	11,077	843,292		
6			569,497	11,347,636	37,125	735,282	532,372	10,612,354		
Purchased Power										
7	Purchases	33.09	796,126	26,343,809	50,896	1,684,149	745,230	24,659,661		
8	Interchange	38.21	133,505	5,101,226	8,143	311,144	125,362	4,790,082		
			929,631	31,445,035	59,039	1,995,293	870,592	29,449,743		
Labor & Related Costs										
9	Regular Payroll	11.89	385,032	4,578,030	23,893	284,088	361,139	4,293,943		
10	Incentive Compensation	252.18	26,337	6,641,665	1,612	406,514	24,725	6,235,151		
11	Pension & Benefits	16.80	93,851	1,576,697	5,843	98,162	88,008	1,478,534		
12	Subtotal Labor & Related		505,220	12,796,392	31,348	788,764	473,872	12,007,628		
13										
14	All Other Operating Expenses	29.21	701,758	20,498,351	42,212	1,233,013	659,546	19,265,339		
15	Property Tax	355.99	167,591	59,660,720	7,940	2,826,561	159,651	56,834,159		
16	Employer's Payroll Taxes	28.44	31,388	892,675	1,931	54,918	29,457	837,757		
17	Gross Earnings Tax	53.06	0	0	0	0	0	0		
18	Federal Income Tax	36.75	(86,994)	(3,197,014)	(5,610)	(206,176)	(81,383)	(2,990,838)		
19	State Income Tax	36.75	(18,797)	(690,806)	(870)	(31,990)	(17,927)	(658,816)		
20	State Sales Tax Customer Billings	28.99	148,826	4,314,466	0	0	148,826	4,314,466		
21	Total Expenses	46.49	2,948,120	137,067,455	42.72	173,114	7,395,665	46.73	2,775,006	129,671,791
22	Net Annual Expense Amount			375,527			20,262			355,265
Revenues										
	Lag Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days			
23	Computer Billing 100.00%	41.28	3,049,972	125,902,844	182,724	7,542,847	2,867,248	118,359,997		
24	Hand Billed 0.00%	41.28	0	0	0	0	0	0		
25	Retail Revenue Adjustments	0.00	0	0	0	0	0	0		
26	Interdepartmental	0.00	540	0	0	0	540	0		
27	Late Payment	0.00	4,684	0	278	0	4,406	0		
28	Connect and Trouble Charges	41.28	2,235	92,261	274	11,311	1,961	80,950		
29	CIP Incentive	0.00	210	0	0	0	210	0		
30	Rentals	-11.29	4,205	(47,474)	268	(3,026)	3,937	(44,449)		
31	Interchange Revenues	38.21	441,961	16,887,330	27,615	1,055,169	414,346	15,832,161		
32	Sales for Resale	41.06	141,870	5,825,182	9,115	374,262	132,755	5,450,920		
33	Production Associated Revenues	41.06	6,459	265,207	421	17,286	6,038	247,920		
34	MISO	14.00	1,659	23,226	100	1,400	1,559	21,826		
35	Point to Point Firm	41.06	38,519	1,581,590	2,320	95,259	36,199	1,486,331		
36	Services & Facilities	41.06	8,783	360,630	523	21,474	8,260	339,156		
37	Ancillary	41.06	80,738	3,315,102	4,863	199,675	75,875	3,115,428		
38	Distribution Associated Revenues	41.28	0	0	0	0	0	0		
39	Other	41.28	10,489	432,986	95	3,922	10,394	429,064		
40	JOA - Rev fr/to PSC	41.06	(5,676)	(233,057)	(370)	(15,192)	(5,306)	(217,864)		
41	(blank)	0.00	0	0	0	0	0	0		
42	(blank)	0.00	0	0	0	0	0	0		
43	(blank)	0.00	0	0	0	0	0	0		
44	Total Revenues	40.78	3,786,648	154,405,827	40.77	228,226	9,304,387	40.78	3,558,422	145,101,440
45	Net Annual Amount			423,030			25,491			397,538
46	Expense / Revenue Factor			0.7786			0.7585			
47	Allocated Revenue Amount			329,353			19,336			
48	Net Cash Working Capital			(46,175)			(926)			(45,248)

<u>Line</u>	<u>of the Revenue Deficiency</u>	<u>Revenue Deficiency (millions)</u>
1	Capital Recovery: for additional rate base investment (includes return requirement, change in capital structure, cost of capital and depreciation)	<u>\$10.1</u>
	Operating Expenses (including reclasses shown on page 2):	
2	Power Production	\$3.0
3	Transmission	\$0.7
4	Distribution	\$0.3
5	Customer Accounts	\$0.2
6	Customer Info Services, Sales & Economic Development	\$0.1
7	Administrative and General Expense	<u>\$2.1</u>
8	Total Operating Expenses	<u>\$6.3</u>
9	Taxes Other than Income Taxes - Payroll, Real Estate, Personal Property:	\$2.2
10	Amortizations	\$0.0
11	Subtotal	\$18.7
12	Less, Net Sales and Growth in Margin (including reclasses)	(\$1.8)
13	Net Revenue Deficiency	<u><u>\$16.9</u></u>

Northern States Power Company
 Electric Utility - State of North Dakota
 SUMMARY OF TEST YEAR O&M EXPENSE CHANGES
 Test Year Ending December 31, 2011
 (\$000's)

Case No. PU-12-____
 Exhibit____(AEH-1) Schedule 9
 Page 2 of 2

Summary of Test Year O & M Expense Changes
 Since Case No. PU-10-657
 Shown by Functional Grouping, Gross Dollar Change Over
 Two Year Interval Since the 2011 Test Year
 (dollars in thousands)

<u>Line</u>	<u>Functional Class</u>	<u>Increase (Decrease)</u>	<u>Annual Avg % Chg</u>
	Power Production	\$3,145	
	Reclass Fixed Interchange to Margin	<u>(\$145)</u>	
1	Net Power Production	\$3,000	3.7%
	Transmission Operating and Maintenance	\$2,684	
	Reclass Transmission Revenues from Margin	<u>(\$1,188)</u>	
	Reclass Transmission Interchange to Margin	<u>(\$805)</u>	
2	Net Transmission Operating and Maintenance	\$691	16.4%
3	Distribution and Maintenance Expense	\$271	2.1%
4	Customer Accounting	\$218	2.7%
5	Customer Services and Sales Expenses	\$60	5.3%
6	Administrative and General Expenses	\$2,072	8.1%
7	Total Change In Operating Expenses	<u><u>\$6,312</u></u>	4.8%

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

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

Formula for Gross Revenue Conversion Factor

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

Gross Revenue Conversion Factor:

$$GR = \frac{1}{1 - 0.38348}$$

$$GR = 1.62201$$

Northern States Power Company
Electric Utility - State of North Dakota
**OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES**
Test Year Ending December 31, 2013
(Dollars in Thousands)

Line No.	Description	Test Year Ending 12/31/13	Final	Test Year Ending 12/31/13
		Present Rates (A)	Increase (B)	Final Rates (C) = (B) + (A)
<u>Operating Revenues</u>				
1	Retail	\$182,724	\$16,900	\$199,624
2	CIP Revenue Adjustment	0		0
3	Interdepartmental	0		0
4	Other Operating	45,502		45,502
5	Gross Earnings Tax	0		0
6	Total Operating Revenues	<u>\$228,226</u>	<u>\$16,900</u>	<u>\$245,127</u>
<u>Expenses</u>				
Operating Expenses:				
7	Fuel & Purchased Energy	\$82,971		\$82,971
8	Power Production	46,221		46,221
9	Transmission	14,031		14,031
10	Distribution	6,763		6,763
11	Customer Accounting	4,286		4,286
12	Customer Service & Information	457		457
13	Sales, Econ Dvlp & Other	173		173
14	Administrative & General	14,822		14,822
15	Total Operating Expenses	<u>\$169,724</u>	<u>\$0</u>	<u>\$169,724</u>
16	Depreciation	\$22,563		\$22,563
17	Amortizations	373		373
Taxes:				
18	Property	\$7,940		\$7,940
19	Gross Earnings	0		0
20	Deferred Income Tax & ITC	12,760		12,760
21	Federal & State Income Tax	(6,481)	6,481	(0)
22	Payroll & Other	1,931		1,931
23	Total Taxes	<u>\$16,151</u>	<u>\$6,481</u>	<u>\$22,631</u>
24	Total Expenses	<u>\$208,811</u>	<u>\$6,481</u>	<u>\$215,293</u>
25	AFUDC	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>
26	Total Operating Income	<u>\$19,415</u>	<u>\$10,419</u>	<u>\$29,834</u>

Note: Revenues reflect calendar month sales.

**Northern States Power Company
Electric Utility - State of North Dakota
Statement of Operating Income
(000's)**

**Case No. PU-12-____
Exhibit ____ (AEH-1)
Schedule 11, Page 2 of 2**

Line No.	Description	Proposed Test Year 2013			2013 Test Year Adjusted (J) (Col F + G)
		Total Utility Unadjusted (G)	2013 Test Year Unadjusted (H)	Adjustments (I)	
Operating Revenues					
1	Retail	\$3,131,396	\$182,724	\$0	\$182,724
2	CIP Adjustment to Program Costs	0	0	0	0
3	Interdepartmental	540	0	0	0
4	Other Operating	726,922	48,616	(3,114)	45,502
5	Gross Earnings Tax	0	0	0	0
6	Total Operating Revenues	\$3,858,858	\$231,340	(\$3,114)	\$228,226
Expenses					
Operating Expenses:					
7	Fuel & Purchased Energy	\$1,278,735	\$82,971	\$0	\$82,971
8	Power Production	746,064	45,530	691	46,221
9	Transmission	241,890	14,568	(537)	14,031
10	Distribution	110,589	6,528	235	6,763
11	Customer Accounting	58,989	4,358	(72)	4,286
12	Customer Service & Information	119,066	505	(48)	457
13	Sales, Econ Dvlp & Other	55	2	171	173
14	Administrative & General	246,244	15,600	(778)	14,822
15	Total Operating Expenses	\$2,801,632	\$170,062	(\$338)	\$169,724
16	Depreciation	\$372,409	\$21,238	\$1,325	\$22,563
17	Amortizations	14,552	4	\$369	373
Taxes:					
18	Property	\$167,170	\$7,915	\$25	\$7,940
19	Gross Earnings	0	0	0	0
20	Deferred Income Tax & ITC	174,353	10,212	2,548	12,760
21	Federal & State Income Tax	(61,510)	(2,414)	(4,067)	(6,481)
22	Payroll & Other	31,398	1,932	(1)	1,931
23	Total Taxes	\$311,411	\$17,645	(\$1,495)	\$16,151
24	Total Expenses	\$3,500,004	\$208,950	(\$139)	\$208,811
25	Allowance for Funds Used During Constructi	\$0	\$0	\$0	\$0
26	Total Operating Income	\$358,854	\$22,390	(\$2,975)	\$19,415

Northern States Power Company
Cost Assignment and Allocation Manual

December 2012

Northern States Power Company Cost Assignment and Allocation Manual

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I. INTRODUCTION

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

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

NSPM is engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. NSPM also purchases, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota.

NSPM owns the following direct subsidiaries: United Power and Land Co., which holds real estate; and Private Fuel Storage LLC, which is involved in developing a private temporary spent nuclear fuel facility. NSPM is a wholly owned subsidiary of Xcel Energy.

As a member of a holding company system, NSPM receives administrative, management, environmental and other support services from Xcel Energy Services Inc. (“XES” or the “Service Company”), a centralized service company. The Service Company provides services to the Xcel Energy Inc. subsidiaries, at cost, pursuant to service agreements. The service agreement between NSPM and XES was submitted to, and approved by, the Minnesota Public Utilities Commission (“Minnesota Commission”). The cost allocation methodologies under which XES costs are assigned and allocated are set forth in that Minnesota Commission approved service agreement, and while those allocation methodologies are not the subject of this NSPM CAAM, they are referenced in several sections of the CAAM. Those same cost allocation methodologies were incorporated in the most recent ND electric rate case, Case Nos. PU-10-657 and PU-11-55.

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

- The Service Company is listed as an affiliate company in the Affiliate Transaction section for the services it provides to NSPM.
- The Service Company and all other companies in the Xcel Energy Inc. holding company system of companies are included in the Corporate Organization to provide a listing of all affiliates of NSPM.

- The Service Company is also referenced in the Cost Assignment and Allocation Process section because this section covers processes that may cross multiple legal entities.

The NSPM CAAM contains the following sections:

- Introduction (Section I)
- Corporate Organization (Section II)
- Description of Services (Section III)
- Transactions with Affiliates (Section IV)
- Cost Assignment and Allocation Process (Section V)
- Allocating Workorders (Section VI)
- Utility Allocations (Section VII)
- Nonregulated Business Activity Allocations (Sections VIII)
- Jurisdictional Allocations (Section IX)
- Definitions, Abbreviations and Acronyms (Section X)

II. CORPORATE ORGANIZATION

OVERVIEW OF COMPANY SYSTEM

Xcel Energy Inc. is a registered holding company. The Parent directly owns four operating public utility subsidiaries that serve electric, natural gas, thermal and propane customers in eight states. These four utility subsidiaries are NSPM; Northern States Power Company, a Wisconsin corporation (“NSPW”); Public Service Company of Colorado, a Colorado corporation (“PSCo”); and Southwestern Public Service Company, a New Mexico corporation (“SPS”). Their collective service territories include portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. The Parent’s regulated businesses also include WestGas InterState, Inc., an interstate natural gas pipeline company regulated by the FERC.

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

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

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2011)

Xcel Energy Inc.

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

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2011) (continued)

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

Groveland Terrace Townhomes LP

LIST OF REGULATED & NONREGULATED AFFILIATES (as of December 31, 2011) (continued)

Hearthstone Village LP
J&D 14-93 LP
Jefferson Heights of Zumbrota LP
Lakeville Court LP
Lauring Green LP
Links Lane LP
Lyndale Avenue Townhomes LP
Mahtomeci Woodland LP
Majestic View LP
Mankato Townhomes LLP
Marsh Run of Brainerd LP
Marvin Garden LP
MDI LP #44
Moorhead Townhomes LP
Oakdale Leased Housing Associates LP
Park Rapids Townhomes LP
Plover LLC
Rochester Townhome LP
Rushford Housing LP
RWIC Credit Fund LP-1993
Safe Haven Homes, LLC
Shade Tree Apartments LP
Shakopee Boulder Ridge LP
Shenandoah Woods LP
Sioux Falls Housing Equity Fund II LP
Sioux Falls Partners LP
Sioux River LP
St. Cloud Housing LP
Stradford Flats LP
Tower Terrace LP
Wyoming LP
Wyoming LP II
Xcel Energy Wholesale Group Inc. *
 Quixx Corporation *
 Quixx Carolina, Inc. *
 Quixx Linden, LP *
 Quixxlin Corp. *
 Quixx Linden LP *
Xcel Energy WYCO Inc.
 WYCO Development, LLC

* Company is being classified in discontinued operations

III. DESCRIPTION OF SERVICES

OVERVIEW

The following pages provide a description of NSPM's regulated services and nonregulated business activities. Each description identifies the types of costs associated with each service or business activity, and identifies the business area or department which offers the service.

REGULATED SERVICES

ELECTRIC UTILITY

Electric – Residential

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

Electric – Commercial and Industrial

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

Electric – Street Lighting

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

Electric – Other Sales to Public Authorities

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

Electric - Resale

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

Electric - Interdepartmental

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

Off-System Electric Sales

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

OTHER ELECTRIC OPERATING REVENUE

Rent from Electric Property

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

Interchange Agreement

The Interchange Agreement is a FERC-approved rate schedule that provides for the intercompany sharing of production and transmission costs of NSPM and NSPW. NSPM and NSPW operate an integrated production and transmission system, and the Interchange Agreement provides for the costs of that integrated system to be shared between NSPM and NSPW based upon demand and energy ratios reflecting usage by the respective companies. The costs associated with this agreement reside in FERC account 557, Other Power Supply Expenses; and FERC 566, Miscellaneous Transmission Expenses. The revenues reside in FERC account 456, Other Electric Revenues.

Joint Operating Agreement

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

Miscellaneous Electric Revenue

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

GAS UTILITY

Gas - Residential

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

Gas – Commercial and Industrial

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

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

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

Gas – Interruptible

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

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

Gas – Large Firm Transportation

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

Gas – Interruptible Transportation

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

Gas – Negotiated Transportation

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

Gas – Interdepartmental

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

Gas – Limited Firm

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

Gas – Daily Balancing Service

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

OTHER GAS REVENUE

Miscellaneous Gas Revenue

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

COMMON ELECTRIC AND GAS REVENUE

Late Payments Fees/Miscellaneous Service Revenues

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

CIP Incentives

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

ConnectSmart

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

Hazardous Waste Disposal

NSPM has a Hazardous Waste Consolidation facility at Chestnut Service Center in Minneapolis, Minnesota. The facility gathers hazardous waste material from power plants and service centers in both NSPM and NSPW service territories, consolidates and compacts the material, and packages it for shipment to a permanent hazardous waste disposal site. In addition, NSPM provides these services to various third-party customers.

NONREGULATED BUSINESS ACTIVITIES

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

HomeSmart

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

Customer Owned Street Lighting Maintenance

NSPM supplies maintenance services for communities that own their own street light systems. Services range from lamp replacement and cleaning to a full service maintenance package, which includes pole, fixture and underground fault repair. Costs related to this activity include labor and materials associated with the service provided. In addition, payroll taxes, lost time and pension and benefit costs are allocated based on labor dollars, and a labor related overhead and a corporate residual overhead are applied to nonregulated business activities. The revenues and costs associated with this service are identified by unique JDE accounts and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E-002/M-92-614 for the Minnesota Commission order to treat this service as nonregulated.

Sherco Steam Sales to Liberty Paper Inc

NSPM supplies steam from the Sherburne County Generating Station to Liberty Paper, Inc. ("LPI") in order to meet LPI's thermal energy needs. The revenues and costs associated with this service are identified by unique JDE accounts, and are recorded in FERC 417, Revenues from Nonutility Operations; and FERC 417.1, Expenses from Nonutility Operations. See Docket E002/M-93-1253 for the Minnesota Commission order to treat this service as nonregulated.

IV. TRANSACTIONS WITH AFFILIATES

OVERVIEW

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

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

As noted in the Introduction, NSPM receives administrative, management, accounting, legal, engineering, environmental and other support services from the Service Company. The Service Company provides the services to the Xcel Energy Inc. subsidiaries, at cost, pursuant to service agreements and allocation methods that were approved by the SEC under PUHCA 1935 prior to implementation. While federal supervision over utility holding companies was transferred from the SEC to FERC in 2005, there have been no changes or updates in the XES allocation methods since 2004 and only minor changes in the service agreement to reflect transfer of oversight to the FERC. The updated service agreement between NSPM and the Service Company has been approved by the Minnesota Commission. The cost allocation methodologies under which the Service Company costs are assigned and allocated are set forth in the service agreement, and while they are not the subject of this NSPM CAAM, they are included in this section to provide as complete a picture as possible of all affiliate transactions. NSPM's affiliate transactions currently consist primarily of transactions with the Service Company for these services.

Terms of Transactions

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

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

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

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

SERVICES PROVIDED BY NSPM TO AFFILIATES

<u>Nature of Transactions</u>	<u>Terms</u>
<u>NSPW</u>	
<i>Operations and Maintenance</i> – Production, decommissioning and transmission costs associated with the Interchange Agreement (FERC Docket No. ER02-808-000).	Fully distributed cost
<i>SCADA and Gas Dispatch</i> – Sharing of SCADA costs in accordance with Docket G-002/AI-94-831.	Fully distributed cost
<i>Materials and Supplies</i> – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost
<i>Miscellaneous</i> – Miscellaneous other charges, including labor, lease costs, lawn care, sewer, trash removal, and cash advances through PSC-Wisconsin approved borrowing agreement (Certificate of Authority and Order) and an Intercompany Note.	Fully distributed cost

PSCo

<i>Materials and Supplies</i> – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost
<i>Joint Operating Agreement</i> – Margin sharing associated with proprietary energy trading activities.	Fully distributed cost

SPS

<i>Materials and Supplies</i> – Materials and supplies, and any associated freight, purchase loadings and warehouse loadings.	Fully distributed cost
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Joint Operating Agreement – Margin sharing associated with proprietary energy trading activities. Fully distributed cost

Miscellaneous – Miscellaneous other charges, including labor and associated loadings and lease costs. Fully distributed cost

Eloigne Company

Miscellaneous – Miscellaneous other charges, including lease costs. Fully distributed cost

United Power and Land Company

Electric – Commercial and Wholesale – Regulated electric services. Tariff Rate

Xcel Energy Inc.

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

SERVICES PROVIDED BY AFFILIATES TO NSPM

Xcel Energy Services Inc.

The nature, frequency and terms of the services provided by the Service Company to NSPM are as follows:

Nature of Transactions

*Executive Management Services** – Represents charges for Xcel Energy Inc. executive management and services, including, but not limited to, officers of Xcel Energy Inc.

Terms

Fully distributed cost

*Investor Relations** – Provides communications to investors and the financial community. Coordinates the transfer agent and shareholder record keeping functions and plans the annual shareholder meeting. Fully distributed cost

*Internal Audit** – Reviews internal controls and procedures to ensure assets are safeguarded and transactions are properly authorized and recorded. Evaluates contract risks. Fully distributed cost

*Legal** – Provides legal services related to labor and employment law, litigation, contracts, rates and regulation, environmental matters, real estate and other Fully distributed cost

legal matters.

*Claims Services** – Provides claims services related to casualty, public and company claims. Fully distributed cost

*Corporate Communications** – Provides corporate communications, speech writing and coordinates media services. Provides advertising and branding development for the companies within the Xcel Energy Inc. system. Manages and tracks all contributions made on behalf of the Xcel Energy Inc. system. Fully distributed cost

*Employee Communications** – Develops and distributes communications to employees. Fully distributed cost

*Corporate Strategy & Business Development** – Facilitates development of corporate strategy and prepares strategic plans, monitors corporate performance and evaluates business opportunities. Develops and facilitates process improvements. Fully distributed cost

*Government Affairs** – Monitors, reviews and researches government legislation. Fully distributed cost

*Facilities & Real Estate** – Operates and maintains office buildings and service centers. Procures real estate and administers real estate leases. Administers contracts to provide security, housekeeping and maintenance services for such facilities. Procures office furniture and equipment. Fully distributed cost

*Facilities Administrative Services** – Includes, but is not limited to, the functions of Mail Delivery, Duplicating and Records Management. Fully distributed cost

*Supply Chain** – Includes contract negotiations, development and management of supplier relationships and acquisition of goods and services. Also includes inventory planning and forecasting, ordering, accounting and database management. Warehousing services include receiving, storing, issuing, shipping, returns and distribution of material and parts. Fully distributed cost

*Supply Chain Special Programs** – Develops and implements special programs utilized across the company such as procurement cards, travel services and compliance with corporate minority women business expenditures program goals. Fully distributed cost

*Human Resources ("HR")** – Establishes and administers policies related to employment, compensation and benefits. Maintains HR computer system, the tuition reimbursement plan and diversity program. Coordinates the bargaining strategy and labor agreements with union employees. Provides technical and professional development training and general HR support services.

Fully distributed cost

*Finance & Treasury** – Coordinates activities related to securities issuance, including maintaining relationships with financial institutions, cash management, investing activities and monitoring the capital markets. Performs financial and economic analysis.

Fully distributed cost

*Accounting, Financial Reporting & Taxes** – Maintains the books and records. Prepares financial and statistical reports, tax filings and ensures compliance with the applicable laws and regulations. Maintains the accounting systems. Coordinates the budgeting process.

Fully distributed cost

*Business Unit Accounting and Budgeting** – Provides financial analysis, budgeting and administrative support for the business units. (In addition, certain Business Unit Presidents are here rather than in the Executives service function.)

Fully distributed cost

*Payment & Reporting** – Processes payments to vendors and prepares statistical reports.

Fully distributed cost

*Receipts Processing** – Processes payments received from customers of the operating companies and affiliates.

Fully distributed cost

*Payroll** – Processes payroll including, but not limited to, time reporting, calculation of salaries and wages, payroll tax reporting and compliance reports.

Fully distributed cost

*Rates & Regulation** – Determines the operating companies' regulatory strategy, revenue requirements and rates for electric and gas customers. Coordinates the regulatory compliance requirements and maintains relationships with the regulatory bodies.

Fully distributed cost

*Energy Supply Engineering and Environmental** – Provides engineering services to the generation business. Establishes policies and procedures for compliance with environmental laws and regulations. Researches emerging environmental issues and monitors

Fully distributed cost

compliance with environmental requirements.
Oversees environmental clean up projects.

*Energy Supply Business Resources** – Provides performance, specialists and analytical services to the operating companies' generation facilities. Fully distributed cost

*Energy Markets Regulated Trading & Marketing** – Provides electric trading services to the operating companies' electric generation systems, including load management, system optimization and resource acquisition. Fully distributed cost

*Energy Markets-Fuel Procurement** – Purchases fuel for operating companies' electric generation systems (excluding nuclear). Fully distributed cost

*Energy Delivery Marketing** – Develops new business opportunities and markets the products and services for the Delivery Business Unit. Fully distributed cost

*Energy Delivery Construction, Operations & Maintenance** – Constructs, maintains and operates electric and gas delivery systems. Fully distributed cost

*Energy Delivery Engineering/Design** – Provides engineering and design services in support of capacity planning, construction, operations and material standards. Fully distributed cost

*Marketing & Sales** – Provides marketing and sales services for the operating companies and affiliates for their electric and natural gas customers, including strategic planning, segment identification, business analysis, sales planning and customer service. Fully distributed cost

*Customer Service** – Provides service activities to retail and wholesale customers. These services include meter reading, customer billing, call center and credit and collections. Fully distributed cost

*Aviation Services** – Provides aviation and travel services to employees. Fully distributed cost

*Fleet** – Oversees the operating companies' Fleet Services. Fully distributed cost

*Business Systems** – Provides basic information technology services such as: application management, Fully distributed cost

voice and data network operations and management, customer support services, problem management services, security administration and systems management. In addition, Business Systems acts as a single point of contact for delivery of all technical services to Xcel Energy Inc. They partner with IBM to ensure the delivery of benchmarking, continuous improvement, and leadership around strategic initiatives and key developments in the marketplace. They work collaboratively with partners and vendors to identify and co-fund opportunities that significantly benefit Xcel Energy Inc.'s business.

* Corporate Governance activities within this Service Function will be allocated using the average of the Assets Ratio including Xcel Energy Inc.'s per book assets, Revenue Ratio with intercompany dividends assigned to Xcel Energy Inc., and allocated labor hours, including overtime.

NSPW

Operations and Maintenance – Production, decommissioning and transmission costs associated with the Interchange Agreement (FERC Docket No. ER02-808-000).

Fully distributed cost

Miscellaneous – Miscellaneous other charges, including labor and associated loadings, contract labor, employee expenses, and cash advances through PSC-Wisconsin approved borrowing agreement (Certificate of Authority and Order) and an Intercompany Note.

Fully distributed cost

Materials and Supplies – Materials and supplies, including any associated freight, purchase loadings and warehouse loadings.

Fully distributed cost

PSCo

Miscellaneous – Miscellaneous other charges, including labor and associated loadings, lease costs, and employee expenses.

Fully distributed cost

SPS

Miscellaneous – Miscellaneous other charges, including labor and associated loadings and lease costs.

Fully distributed cost

Xcel Energy Inc.

Miscellaneous – Miscellaneous other charges including contributions of capital, restricted stock units, and performance share plan.

Fully distributed
cost

V. COST ASSIGNMENT AND ALLOCATION PROCESS

OVERVIEW

This section of the CAAM provides an overview of the cost assignment and allocation principles of NSPM and the accounting processes within the monthly accounting close and within the JD Edwards (“JDE”) general ledger system, including both system generated processes and manual processes, used to assign and allocate costs between the regulated services and the nonregulated business activities of NSPM. Each major step of the accounting process is identified in the following paragraphs and will be explained in conjunction with the process flowchart on page V-18. Each major step results in costs being either directly assigned or allocated to regulated services and nonregulated business activities. The result of applying these principles is that each company, utility, jurisdiction and nonregulated business activity pays the full cost for any service provided to support their respective operations.

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

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

COST ASSIGNMENT AND ALLOCATION PRINCIPLES

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

The hierarchical cost assignment and allocation principles are:

1. Tariffed rate shall be used to value tariffed services provided.
2. Costs shall be directly assigned to either regulated or nonregulated business activities whenever possible.
3. Costs that cannot be directly assigned are common costs, which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causation.

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

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

ACCOUNTING PROCESSES

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

FEEDER SYSTEMS (Addendum A, Flowchart Item 1)

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

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

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

PowerPlant System

PowerPlant tracks all capital projects and work order expenditures for Xcel Energy Inc. utility operating companies on a life-to-date basis. Once expenditures are recorded on the books of the appropriate legal entity, PowerPlant generates the overhead allocations and if appropriate the Allowance for Funds Used During Construction ("AFUDC"), and applies the overheads to the individual work orders. In addition, PowerPlant calculates monthly depreciation by legal entity and handles the transfer of work orders from FERC account 107, Construction Work in Progress, to FERC account 106, Completed Construction-Not Unitized, to FERC account 101, Utility Plant in Service. The transfer of non-utility costs is within FERC account 121, Non-Utility Property using sub accounts; from FERC account 12140, Non-Utility Construction Work in Progress, to FERC account 12112, Non-Utility Completed Construction-Not Unitized, to FERC account 12111, Non-Utility Plant in Service-Unitized.

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

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

Maximo System

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

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

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

- Labor Distribution
- Labor Overheads
- Aviation Distribution
- Stores/Warehouse Overhead
- Purchasing Overhead
- Transportation Distribution
- Accounts Payable
- Information Technology
- Shared Assets Distribution
- Facilities Distribution
- Money Pool
- Customer Billing

JDE GENERAL LEDGER PROCESSING (Addendum A, Flowchart Item 2)

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

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

SERVICE BILLING (Addendum A, Flowchart Item 3)

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

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

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

CLEARING ACCOUNTS (Addendum A, Flowchart Item 4)

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

ALLOCATING WORK ORDERS (Addendum A, Flowchart Item 5)

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

UTILITY ALLOCATIONS (Addendum A, Flowchart Item 6)

NSPM's costs are directly assigned or allocated to electric, gas or nonregulated business activities whenever possible or charged as common and then allocated to the electric and gas utilities using Utility Allocations. Common utility costs are grouped into two categories: (1) O&M utility allocations and (2) rate base and non-O&M utility allocations. The O&M utility allocations are done monthly within the JDE system and are explained below. A study is performed annually, as well as for rate case filing purposes, to identify all rate base and non-O&M costs that are common among the utility operations of NSPM. These costs are then allocated among the utilities according to the allocations described in Section VII.

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

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

JURISDICTIONAL ALLOCATIONS (Addendum A, Item 8)

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

Service:

LABOR DISTRIBUTION

Description:

Wages and salaries of employees engaged in work on behalf of regulated services and nonregulated activities are assigned or allocated based on positive time reporting through the TIME labor distribution system. Positive time reporting requires each employee to report the hours worked for each day using one-sixth of an hour or greater increments, while providing for aggregation of time when appropriate. Under this method, employees' time is reported on the basis of accounting codes related to specific operating utility companies or affiliates and/or functional services.

Provider of Service:

Service Company
Operating companies or affiliates

User of Service:

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

Method of Allocation: All bi-weekly and semi-monthly employees' labor expenses are recorded by company personnel on time sheets and entered into various time reporting systems, all of which feed into the TIME labor distribution system. The employee submitting the time sheet is responsible for coding the JDE account numbers to charge the appropriate operating companies or affiliates, business function (e.g., capital, operations, maintenance, clearing, purchasing and/or warehousing, etc.) and regulated or nonregulated operations.

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

The TIME labor distribution system used for bi-weekly employees includes the distribution of actual paid and accrued labor dollars/hours to the JDE account number charged based on the hours worked. Accrual of payroll is to facilitate the recording of labor costs on a calendar month basis. This includes any reversal of the prior month's accrual. The charge of labor dollars for semi-monthly employees to JDE account numbers is based on a distribution of the monthly salary of the employee.

Service: **LABOR OVERHEADS**

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

Benefit employees:

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

Non-Benefit employees:

- Payroll taxes (FICA, FUTA, SUTA)

Provider of Service: Service Company
Operating companies or affiliates

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

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

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

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

Labor overhead rates are updated each month to ensure the actual costs are charged out. Additionally, a year-end true up is recorded to bring the overhead clearing accounts to zero for the calendar year.

Service: **AVIATION DISTRIBUTION**

Description: The Aviation Services department in the Service Company is responsible for managing and operating the two corporate leased aircraft used by the Xcel Energy system of companies. Costs include: pilot salaries and labor overheads, operation and maintenance costs, lease costs, hangar costs and administrative and general costs associated with managing the Aviation Services department.

Provider of Service: Service Company

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: Aviation costs are billed out using the corporate governance three-factor formula based on revenues, assets and number of employees.

Any spousal use of the aircraft must be approved and is billed to the holding company.

Service: **STORES/WAREHOUSE OVERHEAD**

Description: Inventory warehousing costs, including labor, supervision, materials and supplies are allocated through pools specific to business area as an overhead on materials and supplies as materials and supplies are issued/returned from a storeroom or warehouse.

In the Energy Supply business area, the inventory warehousing costs related to the Sherco and Hayden plants are direct charged to station operating and maintenance (O&M) and capital projects (when dedicated capital project support is performed).

Provider of Service: Service Company
Operating companies

User of Service: Operating companies or affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation: Overhead costs for inventory items, including rent, labor, supervision and adjustments, are accumulated within the Supply Chain or Energy Supply business area. These accumulated overhead costs are allocated to material issuances from the storeroom using the same account coding where the materials were originally charged. Certain allocated overhead expenses are capped at \$3,500 per purchase order.

Each business area has a separate pool for each operating company and sets an overhead application rate for budgeting for the year based on projected overhead and materials activity.

During the year as actuals are recorded, the balances in the undistributed stores/warehouse clearing accounts are compared to the materials activity and historical trending and a new rate is determined.

Service: **PURCHASING OVERHEAD**

Description: The Supply Chain organization in the Service Company has the responsibility for distributing the corporate purchasing and contract services costs to the functional area(s) of the operating companies or affiliates along with the cost of the materials and supplies ordered. Purchasing costs are made up of activities such as developing requisitions, contracts and purchase orders to procure materials and services and manage supplier relationships, negotiating complex procurement agreements/contracts for strategic supplier partnerships and service contracts, monitoring supplier performance, and managing purchase records, supplier qualification records and the supplier diversity program.

The purchasing function is done in two different areas of the company. Supply Chain uses PassPort for companywide purchases and the Energy Supply business area uses Maximo for production related purchases.

Provider of Service: Service Company
Operating companies

User of Service: Service Company, operating companies and affiliates, including utility operations, jurisdictions, and nonregulated business activities within an operating company.

Method of Allocation: Costs are collected in clearing accounts on the Service Company and the operating companies and cleared via an overhead loading. The loading follows the accounting for certain purchases with the offset going to a contra clearing account.

For PassPort and Maximo, certain purchases are loaded with the purchasing overhead loading up to a \$3,500 cap. The \$3,500 cap is calculated based on the value of the purchase order for purchase order payments, the total value of the contract payment authorization or the total value of the invoice for the request for payment. For PassPort, the loading is calculated and a new record is posted to the general ledger as a detail item. For Maximo, the loading is calculated once a month and shows up as a separate summary transaction on the general ledger.

Service: **TRANSPORTATION DISTRIBUTION**

Description: The Fleet Services department in the Service Company is responsible for managing the fleet assets owned by the operating companies. Fleet assets are vehicle units that are organized into class categories, which group together vehicles similar in nature. These classes are also grouped on vehicle features and costs of the units. For example, automobiles are classified by compact,

mid-sized or intermediate and full size. Each of these classes will have its own unique individual fixed rate to bill users.

The Transportation Distribution system bills internal functional areas of operating companies and affiliates for the cost of using vehicles or associated equipment. It distributes the operating costs related to vehicle units using usage rates based on the type of unit.

Costs included in the calculation of the monthly billing rate are: depreciation, lease costs, property taxes, material and labor costs for maintenance, fuel, labor loadings, and an overhead that includes labor, facilities, insurance, utilities, computer, phone, and office supplies.

Provider of Service: Service Company
Operating companies

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions and nonregulated business activities within an operating company.

Method of Allocation: The Transportation Distribution system bills each user for units assigned based on the monthly rates calculated by class category. Each month a validation report is reviewed to ensure all costs are billed and any invalid accounts are reviewed and corrected.

Service: **INFORMATION TECHNOLOGY**

Description: The Business Systems organization in the Service Company is responsible for managing the corporate Information Technology ("IT") assets and services of Xcel Energy. Business Systems bills out O&M and capital costs related to Xcel Energy's corporate IT equipment and services incurred internally, as well as costs incurred through external sources, primarily IBM and Dell. Costs include system O&M, desktop services, phone service, servers, infrastructure costs, software, software licensing, system design and implementation, labor and labor overheads, etc.

Provider of Service: Service Company

User of Service: Service Company, operating companies or affiliates, including utility operations, jurisdictions and nonregulated activities within an operating company.

Method of Allocation: IT costs are charged through several different methods.

Costs are charged directly to the operating companies, affiliates, jurisdictions or nonregulated activities on the invoice, timesheet, expense report or other source document to the company(ies) benefiting from the service whenever possible.

If costs can not be charged directly to an operating company, affiliate, jurisdiction or nonregulated activity, the costs are charged to a Service Company indirect allocation workorder that will assign the costs using a cost causative method to the companies benefiting from the system application or service.

For costs that can be identified as benefiting a particular service function, those services would be charged to a Service Company indirect allocation workorder using the approved allocation factor for that business area.

Service:

ACCOUNTS PAYABLE

Description:

The Payment and Reporting Department (Accounts Payable), in the Service Company, processes several types of documents for payment on behalf of the operating companies and affiliates. Accounts Payable uses PassPort and Concur to process invoice payments associated with purchase orders, contracts, requests for payment (non-purchase orders, non-contract invoices) and employee payments, including per diem charges, suggestion system award payments and employee expense reimbursements.

The charges for goods, materials and services, which post directly to the general ledger of each operating company and affiliate, differ for each type of document.

Provider of Service:

Service Company

User of Service:

Service Company, operating companies and affiliates, including utility operations, jurisdictions, and nonregulated activities within an operating company.

Method of Allocation:

Within each operating company and affiliate, charges are directly assigned whenever possible. Charges may be distributed to multiple business functions or business areas based on the accounting code(s) on each document. If necessary, costs may be allocated using any surrogate measure that has a logical or observable correlation to the charges in the quantities sold, the services that caused the cost to be incurred or that benefited from the cost. The following are examples of some of the logical or observable correlations used to allocate costs contained on Accounts Payable documents:

- Quantity (units, count, etc.)
- Measurement or size (length, space, columnar inch, etc.)
- Volume (barrels, gallons, liters, etc.)
- Weight (ounce, pound, ton, etc.)
- Hours (hours of professional or contract services)
- Labor dollars (charge is in the same proportion as the labor hours of the department)
- Number of customers, meters, employees, etc.
- Revenue dollars
- Plant in service
- Square footage

Service: **SHARED ASSETS DISTRIBUTION**

Description: Shared assets are defined as capitalized assets that are owned by one legal entity but are used for the benefit of multiple entities. This would include structures and improvements, office furniture and equipment, computer and communication equipment, and some software systems that are used by employees in the performance of their jobs.

Provider of Service: Operating companies or affiliates

User of Service: Service Company, operating companies and affiliates

Method of Allocation: All shared asset costs are billed through the Service Company and either charged to a Service Company indirect workorder that will assign the costs using a cost causative method to the companies benefiting from the system application or service, or charged to the facilities clearing pool that will assign the costs following the labor of the employees housed in the particular facility.

Service: **FACILITIES DISTRIBUTION**

Description: Facilities costs, which include owned and leased buildings, operation and maintenance costs for the leased and owned buildings (unless covered by the rent or lease agreement), as well as internal administrative and general labor and non-labor costs are allocated to the functional area(s) of operating companies and other affiliates who benefit from the use of these facilities. The Property Services department is responsible for the owned and leased facility records.

Utility owned facilities have depreciation costs with an allowed rate of return for the assets owned, the costs of which are charged directly to depreciation expense.

Provider of Service: Service Company or operating companies

User of Service: Service Company, operating companies and affiliates

Method of Allocation: Costs are accumulated in the clearing account of the company benefitting from the use of the building, and are then allocated to functional FERC rent accounts based on the most recent quarter's labor charges.

Service: **MONEY POOL**

Description: Through the Utility Money Pool, temporary surplus funds of Xcel Energy Inc. and the operating companies are available for short-term loans to other operating companies with cash needs.

Provider of Service: Service Company

User of Service: Operating companies

Method of Allocation: An operating company can borrow from, and make loans to, the Utility Money Pool, which is administered at cost by the Service Company. In addition, the holding company can deposit surplus funds into the utility money pool. The holding company can be repaid for funds deposited, but cannot borrow from the utility money pool. Interest income or expense is charged or credited, as appropriate, to the Utility Money Pool participants.

All charges are directly billed to the appropriate operating company.

NSPM petitioned for and received approval on the use of a utility money pool in Docket No. AI-04-100.

Service: **CUSTOMER BILLING**

Description: NSPM bills customers for electric, gas, propane and miscellaneous nonregulated activities through the customer billing system.

Provider of Service: Operating companies

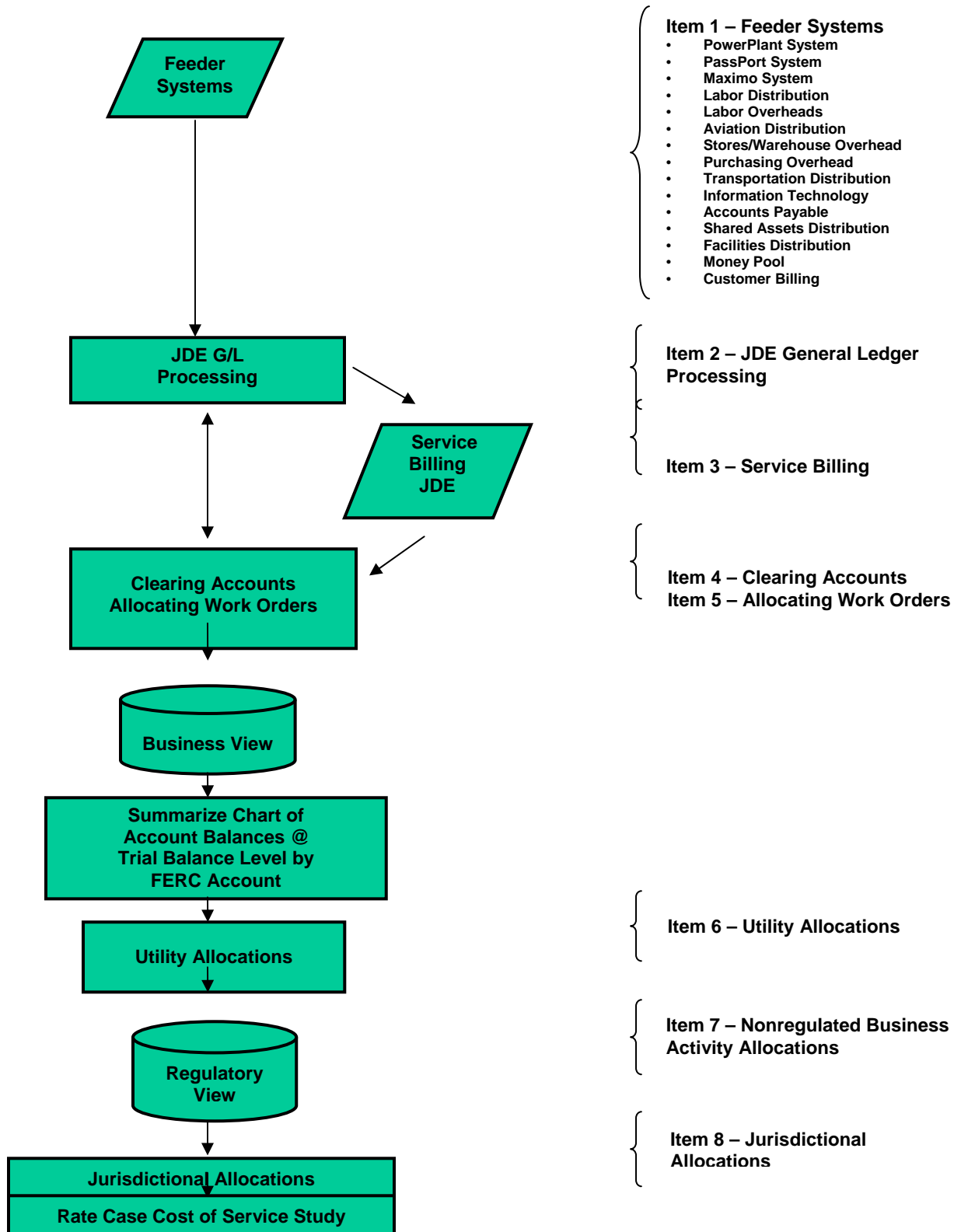
User of Service: Operating companies, including utility operations, jurisdictions, and nonregulated activities.

Method of Allocation: Costs related to customer billing are direct charged to specific operating companies whenever possible.

When costs cannot be directly assigned to a specific operating company, they are allocated based on the number of customers.

Nonregulated activities that use the customer billing system are billed for services provided based on the number of customers being billed and/or the number of phone calls which come into the call center and are then transferred to the nonregulated activity.

ADDENDUM A – PROCESS FLOWCHART



VI. ALLOCATING WORKORDERS

OVERVIEW

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

ALLOCATIONS

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

Compass/Maximo

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

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

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

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

Electric Management System (EMS, also known as Electric SCADA)

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

Workorder Number	Allocation Method	Basis for Allocation Selection
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12004	Number of RTUs	Number of RTUs is a reasonable methodology because the RTUs transmit the data used by the SCADA system.
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The operation and maintenance costs of the EMS are allocated to the following FERC accounts:

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

Gas SCADA

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

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

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

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

Network Services

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

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

These circuit costs are allocated to the following FERC accounts:

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

VII. UTILITY ALLOCATIONS

OVERVIEW

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

O&M UTILITY ALLOCATIONS

Introduction

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

Methodology

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

Customer Allocator

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

Revenue Allocator

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

Three-Factor Allocator

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

Labor Allocator

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

RATE BASE AND NON-O&M UTILITY ALLOCATIONS

Introduction

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

Methodology

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

Three-Factor Allocator

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

Computer Software Study

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

Transportation Study

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

Table A – O&M Utility Allocations

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

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

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

Common	31/Common General Plant	Big Oaks Rec Area	Three-Factor Allocation
Common	31/Common General Plant	Black Dog	Direct Assignment to Electric
Common	31/Common General Plant	High Bridge	Direct Assignment to Electric
Common	31/Common General Plant	Riverside	Direct Assignment to Electric
Common	31/Common General Plant	Sherco	Direct Assignment to Electric
Common	31/Common General Plant	Gas Prod – Wescott – MN	Direct Assignment to Gas
Common	31/Common General Plant	General Tools and Other Equipment	Three-Factor Allocation
Common	31/Common General Plant	General Plant – MN	Three-Factor Allocation
Common	31/Common General Plant	General Plant – SD	Three-Factor Allocation
Common	31/Common General Plant	General Plant – ND	Three-Factor Allocation

VIII. NONREGULATED ACTIVITY ALLOCATIONS

INTRODUCTION

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

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

The Minnesota Commission established the following hierarchical cost assignment and allocation principles in Docket 1008:

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

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

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

Evaluation Process

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

Business Profile

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

Direct Charging (Addresses Principle #2)

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

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

Cost Causation Allocations (Addresses Principle #3)

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

Overhead Costs (Addresses Principle #4)

The overhead allocation factors capture indirect costs associated with providing services to nonregulated activities.

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

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

Working Capital Fee (Addresses Principle #3)

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

IX. JURISDICTIONAL ALLOCATIONS

INTRODUCTION

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

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

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

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

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

Direct Assignment Based on FERC Account and Location

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

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

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

Allocation Based on Cost Causal Relationship

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

Electric

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

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

Gas

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

Electric & Gas

Cost and investment in support of NSPM's Distribution, Customer Accounting, and Customer Information & Sales are more easily identified by state based on the location or where the work is being performed, or they can be allocated to jurisdiction using customers as a basis. NSPM has service territory that borders on North Dakota and South Dakota.

In cases where services are provided and serve all regional customers, a regional allocator is developed which reflects the number of customers served in Minnesota and North Dakota or Minnesota and South Dakota, depending on the region. This represents a causal relationship between costs incurred in those regions and the assignment of costs to jurisdiction. Locating services performed in the Fargo area is an example of these types of costs. Locating services are performed for customers on both sides of the border and are, therefore allocated to jurisdiction based on the number of year-end average customers in the North Dakota Region, which includes Fargo, Moorhead, Grand Forks, East Grand Forks and Minot.

Allocation Based on a Default Allocator

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

Common and General Plant Investment

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

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

Administrative and General Expenses

When assigning or allocating A&G expenses to jurisdiction, the business area associated with the JDE general ledger account is an additional piece of information used in determining the jurisdiction(s) benefiting from the expenditure. A&G costs for business areas that support the electric production portion of the business, Energy Supply and Nuclear Generation, are allocated to jurisdiction using the twelve-month coincident peak demand allocator. Any Distribution business area A&G costs that cannot be directly assigned to jurisdictions based on the location code are allocated to jurisdiction using the twelve-month end-of-year average customer allocator.

Electric A&G costs for the remaining business areas that support a corporate function are allocated to jurisdiction using a equally weighted two-factor allocator based on electric plant in service and electric O&M expense (excluding A&G). The two factor allocator is developed by first calculating a three part historical ratio of plant investment directly serving production, transmission or distribution and a three part historical ratio of O&M expenses assigned to FERC accounts that are either production, transmission or directly serve customers (distribution, customer accounting, customer information or sales). These two ratios are then averaged to develop an equally weighted production, transmission and distribution ratio. This resulting three part ratio is then multiplied times the jurisdictional O&M default allocation ratios. The electric production portion is allocated to jurisdiction

using a twelve-month coincident peak demand allocator; the transmission portion using the transmission demand allocator; and the customer portion is allocated using twelve-month end-of-year customers. The final step is to add the three sets of jurisdictional ratios together to form the two factor jurisdictional allocator used to allocate electric A&G costs supporting corporate functions.

Gas A&G expenses are allocated to jurisdiction using the appropriate customer allocation as a default allocator, based on the JDE account location code.

A more detailed description of each allocation type and method of allocation, including examples of why the allocation was chosen to assign costs to jurisdiction is included below.

Table C in this section lists the methodology applied to specific pools of costs.

ALLOCATION METHODS

GAS & ELECTRIC

Allocation: Direct Assigned

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

Allocation: Direct Assigned: State of Minnesota

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the State of Minnesota jurisdiction. The types of costs direct assigned include: direct and indirect assessments related to one of Minnesota's regulatory bodies, Legal Department expense budgeted in support of Minnesota, economic development activities in the Twin Cities metro area, facilities expenses in support of the Distribution business unit in Twin Cities metro area, delivery system operation and maintenance costs in the Metro Area, Northwest and Southeast Regions and Automated Energy System (AES) expenses.

Allocation: Direct Assigned: State of North Dakota

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

Allocation: Direct Assigned: State of South Dakota

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

Allocation: Direct Assigned: Wholesale

This allocation type is used for all expenses that are determined to be for the direct benefit or in direct support of the wholesale full requirements jurisdiction. The types of costs direct assigned include: customer billing expenses budgeted in support of wholesale customers and labor and related expenses in support of wholesale customer metering,

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

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

Allocation: Customers Year-End Average

Minnesota Co. MN/ND/SD

This allocation type is used to assign costs to all of Minnesota Company's jurisdictions (Minnesota, North Dakota, South Dakota, and Wholesale) when the work performed benefits all of the company's customers equally. This is the default allocator that is used for the Electric and Gas Distribution, Customer Accounting, Customer Information, Sales and Administrative & General FERC accounts where the general ledger account JDE Business Unit Category Code 6 (Location code) designates support of NSPM Company.

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

Allocation: Customers Year End Average

Minnesota/North Dakota

This allocation type is used to assign costs to both the North Dakota and Minnesota jurisdictions based on customers in the entire North Dakota Region. This includes customers in Fargo, Moorhead, Grand Forks, East Grand Forks and Minot service areas. This method is the default allocator for O&M expenses associated with general ledger accounts where the JDE business unit category Code 6 (Location code) designates support for Minnesota/North Dakota.

Allocation: Customers Year End Average

Minnesota/South Dakota

This allocation type is used to assign costs to both the South Dakota and Minnesota jurisdictions based on customers in the entire South Dakota Region. This method is the default allocator for O&M expenses associated with general ledger accounts where the JDE Business Unit Category Code 6 (Location code) designates support for Minnesota/South Dakota.

Allocation: Study Jurisdictional Budget Transmission

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

Allocation: Study for Distribution Plant Serving Wholesale

This study is used for distribution substations that are also serving wholesale customers to insure an appropriate amount goes to that jurisdiction.

Allocation: Study Jurisdictional Budget Distribution

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

ELECTRIC UTILITY ONLY

Allocation: Energy

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

Allocation: DemandProd (Coincident Peak)

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

Allocation: DemandTran (Coincident Peak)

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

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

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

GAS UTILITY ONLY

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

Retail revenues include components for the recovery of costs associated with product and delivery of product to the service area. Such costs include capacity or entitlement costs, pipeline transportation costs, commodity costs and costs of alternative gas (propane-air or liquefied natural gas) supplied during times of firm peak demand. Regulations provide for the automatic adjustment of billing rates for price changes and the annual true up of the cost of gas incurred. Demand, Commodity and Purchased Gas Adjustment are components of the Retail Revenues Cost of Gas Recovery study. The portion of total Minnesota Company Cost of Gas included in Retail Revenues that the Minnesota jurisdiction represents is also applied to total Minnesota Company Cost of Gas expense accounts to achieve revenue neutrality for revenue requirements consideration.

Allocation: Design Demand Day

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

Allocation: Load Dispatch

Expressed as a percentage, Load Dispatch is a combination of the Minnesota jurisdiction Design Demand Day and the Minnesota jurisdiction total Retail sales and Transportation throughput each weighted equally.

Allocation: Limited Firm and Standby Services Study

Expressed as a percentage, Limited Firm and Standby services, in revenues, is the ratio of Minnesota jurisdiction availability charges and volumetric charges to the total Minnesota Company; in costs, it is the ratio of Minnesota jurisdiction volumetric product costs to the total Minnesota Company program product costs.

Table C

Allocation to Jurisdiction							
Selection Criteria *							
Sub-Business Unit (CC2)	Plant Function	Functional Class ID / Description	Location (CC6)	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Production	Production	1 / Electric Steam Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	2 / Electric Nuclear Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	3 / Electric Hydro Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	4 / Electric Other Production Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	22 / Nuclear Fuel			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	FERC MN		Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Production	Production	23 / Decommissioning	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Production	Production	23 / Decommissioning	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Production	Production	23 / Decommissioning	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Production	23 / Decommissioning	Wisconsin		Electric	WI	Direct Assigned - Wisconsin
Electric Transmission	Transmission	5 / Electric Transmission Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Transmission	5 / Transmission Direct Assignment	Minnesota	DRCT	Electric	MN	Direct Assigned – State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Transmission	5 / Transmission Serving Distribution	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Production	Transmission	5 / Transmission Generation Step-up		BSLD, PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)

Selection Criteria *							
Sub-Business Unit (CC2)	Plant Function	Functional Class ID / Description	Location (CC6)	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Electric Transmission	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Transmission	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Distribution	6 / Electric Distribution Plant	Minnesota		Electric	MN	Direct Assigned - State of Minnesota
Electric Distribution	Distribution	6 / Electric Distribution Plant	North Dakota		Electric	ND	Direct Assigned - State of North Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	South Dakota		Electric	SD	Direct Assigned - State of South Dakota
Electric Distribution	Distribution	6 / Electric Distribution Plant	Wholesale		Electric	WHSL	Direct Assigned - Wholesale Full Requirements
Production	Distribution	6 / Distribution Generation Step-up		PEAK	Electric	MN/ND/SD/WHSL	Electric - Demand Prod (Coincident Peak)
Electric Transmission	Distribution	6 / Distribution Serving Transmission		TBULK	Electric	MN/ND/SD/WHSL	Electric - Demand Tran (Coincident Peak)
Electric Distribution	Common & General	24 / Electric Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	26 / Common Intangible Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	29 / Electric General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Electric Distribution	Common & General	31 / Common General Plant			Electric	MN/ND/SD/WHSL	Customer Year End Average - Electric Minnesota Company MN/ND/SD/WHSL
Gas	Production	7 / Gas Manufactured Production Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Storage	9 / Gas Underground Storage Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Transmission	10 / Gas Transmission Plant			Gas	MN	Direct Assigned – State Of Minnesota
Gas	Transmission	10 / Gas Transmission Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Distribution	11 / Gas Distribution Plant			Gas	MN	Direct Assigned – State of Minnesota
Gas	Distribution	11 / Gas Distribution Plant			Gas	ND	Direct Assigned – State of North Dakota
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Gas - Design Demand Day

Selection Criteria *							
Sub-Business Unit (CC2)	Plant Function	Functional Class ID / Description	Location (CC6)	Functional Use	Utility	Jurisdiction	Allocation Methodology
Budget							
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Gas - Design Demand Day
Gas	Common & General	25 / Gas Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	26 / Common Intangible Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	30 / Gas General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	31 / Common General Plant			Gas	MN/ND	Customer Year End Average - Gas Minnesota Company MN/ND
Gas	Common & General	34 / Gas Other Storage Plant			Gas	MN/ND	Gas - Design Demand Day

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

X. DEFINITIONS

Abbreviations or Acronyms

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

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

Terms

The following terms are used within the CAAM document:

Accounts Payable	The Payment and Reporting Department of Xcel Energy Services Inc.
Administrative and General	Includes activity in FERC accounts 920-935, Administrative and General Expenses.
Affiliate Transaction	A transfer of a good, service or asset from the utility to a non-regulated division, subsidiary or affiliate, or from a non-regulated division, subsidiary or affiliate to the utility.
Allocated	To distribute a joint or common cost to more than one affiliate, utility operation, jurisdiction or non-regulated business activity. For example, labor of an employee who works for more than one affiliate, shall be allocated based on positive time reporting or other allocation method as identified in the CAAM. Similarly, non-labor joint or common costs such as vehicles, advertising, space, etc. are subject to the cost allocation principles.
Convenience Payments	Payments made by an operating company or the Service Company on behalf of another operating company or affiliate. Convenience payments are recorded in the intercompany accounts of the company. Convenience payments are not the result of the

	Operating Company or the Service Company providing a service (a good, product or service) to an operating company or affiliate.
Cost Allocation	The method(s) used to allocate a joint or common cost.
Cost Assignment	The method or process of directly assigning a cost.
Customer Accounting Costs	Includes activity in FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910, Customer Service and Informational Expenses; and FERC accounts 911-917, Sales Expenses.
Fully Distributed Cost	Transactions billed include all direct and indirect costs, including overheads.
Operations and Maintenance	Includes activity in FERC accounts 500-935 with the exception of FERC account 501, Fuel; FERC accounts 901-903, Customer Accounts Expenses; FERC accounts 906-910; Customer Service and Informational Expenses; FERC accounts 911-917, Sales Expenses and FERC accounts 920-935, Administrative and General Expenses.
Supply Chain	The Supply Chain Department of the Service Company.
Service Function	A specific function of an Organizational Area. Examples include but not limited to: Executive Management, Internal Audit, Payroll and Marketing and Sales.
Subledger	A JDE Business Unit code or Work Order that designates who the charge is being billed to. A subledger is assigned to only one company or legal entity.
Tariff Rate	The price charged to customers under applicable tariffs on file with federal or state regulatory commissions. Tariff rates are used for transactions with affiliates involving the provision of regulated services.
Work Order	Accumulates costs, either for Capital, Expense or to be further allocated.

Line	Description	Allocation Basis
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The allocation factors on this page were used to determine North Dakota jurisdictional amounts for all of the years presented in these schedules.

1	Production	Demand/Energy
2	Transmission	Demand
3	Distribution	Customers/Direct Assigned
4	Customer Accounting	Customers/Direct Assigned
5	Customer Service & Information	Customers/Direct Assigned
6	Sales, Econ Dvlp & Other	Customers/Direct Assigned
7	Administrative & General	Customers/Two Factor/Demand/Direct Assigned

**Northern States Power Company
 Electric Utility - State of North Dakota
 Operating Income Jurisdictional Allocation Factors
 OPERATING INCOME JURISDICTIONAL ALLOCATION FACTORS**

**Case No. PU-12-____
 Exhibit__(AEH-1)
 Schedule 13, Page 2 of 3**

Test Year 2013				
Line No.	Allocation Factor	Total Utility	North Dakota Jurisdiction	Allocation Factor
1	Demand	68,552,209	4,128,692	6.0227%
2	Energy	35,830,400	2,335,747	6.5189%
3	Customers	1,411,397	90,037	6.3793%
4	Two-Factor			6.1305%

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

**Allocators for Common and General Plant
 for 2013 Budget
 Based on 2011 Actual Data**

O&M Allocator	2011 Actuals	Ratio
O&M excluding A&G		
Production	537,736,599	61.86%
Transmission	42,980,343	4.94%
Distribution/Customer	<u>288,611,880</u>	<u>33.20%</u>
	\$ 869,328,822	100.00%

**Plant in Service used to allocate Electric General Plant
 Source - 2011 FERC Form 1
 Pages 204-207**

	2011 Year End Balance	Ratio
Production	\$ 6,490,298,740	55.77%
Transmission	\$ 1,979,213,495	17.00%
Distribution	\$ <u>3,168,661,143</u>	<u>27.23%</u>
	\$ 11,638,173,378	100.00%

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

Production	58.8100%
Transmission	10.9700%
Distribution	<u>30.2200%</u>
	100.0000%

13 Budget Allocators

EProd Demand Alloc

MN	87.9164%
ND	6.0227%
SD	6.0017%
WHL	0.0592%
	<u>100.0000%</u>

ETrans Demand Alloc

MN	87.9164%
ND	6.0227%
SD	6.0017%
WHL	0.0592%
	<u>100.0000%</u>

ECustomerMN/SD/ND

MN	87.5336%
ND	6.3793%
SD	6.0870%
WHL	0.0001%
	<u>100.0000%</u>

2013 Budget A&G Jurisdictional Allocators

ELECTRIC A&G Alloc

2 Factor Allocator	O&M and Plant	MN	ND	SD	WHL	Check
Production	58.8100%	51.7036%	3.5419%	3.5296%	0.0348%	58.8100%
Transmission	10.9700%	9.6444%	0.6607%	0.6584%	0.0065%	10.9700%
Distribution/Customers	30.2200%	26.4527%	1.9278%	1.8395%	0.0000%	30.2200%
Resulting Allocator	100.00%	87.8007%	6.1305%	6.0275%	0.0413%	100.0000%

**Northern States Power Company
 Electric Utility - State of North Dakota
 Rate Base Jurisdictional Allocation Factors**

**Case No. PU-12-____
 Exhibit ____ (AEH-1)
 Schedule 14, Page 1 of 2**

Line No.	Description	Allocation Basis
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The allocation factors on this page were used to determine North Dakota jurisdictional rate base amounts for all of the years presented in these schedules.

The following allocation factors are used to compute North Dakota jurisdictional amounts for Plant-in-Service, Accumulated Depreciation, Accumulated Deferred Income Tax and Construction Work in Progress:

1	Production	Demand/Energy
2	Transmission	Demand
3	General Production Transmission Other	Demand/Customers/Direct Assigned
4	Common Production Transmission Other	Demand/Customers/Direct Assigned

In addition, the following allocation factors are used to compute North Dakota jurisdictional amounts:

5	Other Rate Base: Materials & Supplies	Demand/Customers/Direct Assigned
	Non-Plant Assets & Liabilities	Demand/Customers/Direct Assigned
	Prepayments	Demand/Customers/Direct Assigned
	Fuel Inventory	Energy

**Northern States Power Company
Electric Utility - State of North Dakota
Rate Base Jurisdictional Allocation Factors**

**Case No. PU-12-____
Exhibit ____ (AEH-1)
Schedule 14, Page 2 of 2**

Test Year 2013

<u>Line No.</u>	<u>Allocation Factor</u>	<u>Total Utility</u>	<u>North Dakota Jurisdiction</u>	<u>Allocation Factor</u>
1	Demand	68,552,209	4,128,692	6.0227%
2	Energy	35,830,400	2,335,747	6.5189%
3	Customers	1,411,397	90,037	6.3793%

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

Northern States Power Company
Electric Utility - State of North Dakota
Average Rate Base
(\$000's)

Case No. PU-12-____
Exhibit ____ (AEH-1)
Schedule 15, Page 1 of 3

Line		Proposed
No.	Description	2013
		Test Year
		Average Rate Base
		(A)
	Electric Plant as Booked	
1	Production	\$537,079
2	Transmission	136,211
3	Distribution	138,686
4	General	29,097
5	Common	29,899
6	TOTAL Utility Plant in Service	<u>\$870,972</u>
	Reserve for Depreciation	
7	Production	\$289,499
8	Transmission	38,787
9	Distribution	62,947
10	General	11,053
11	Common	17,303
12	TOTAL Reserve for Depreciation	<u>\$419,589</u>
	Net Utility Plant in Service	
13	Production	\$247,580
14	Transmission	97,424
15	Distribution	75,739
16	General	18,044
17	Common	12,596
18	Net Utility Plant in Service	<u>\$451,383</u>
19	Utility Plant Held for Future Use	\$0
20	Construction Work in Progress	\$2,037
21	Less: Accumulated Deferred Income Taxes	\$92,784
22	Cash Working Capital	(\$926)
	Other Rate Base Items:	
23	Materials and Supplies	\$7,613
24	Fuel Inventory	5,899
25	Non-Plant Assets & Liabilities	(1,809)
26	Prepayments	1,050
27	Nuclear Outage Amortization	5,018
28	Customer Advances	(18)
29	Customer Deposits	(213)
30	Other Working Capital	398
31	Total Other Rate Base Items	\$17,938
32	Total Average Rate Base	<u><u>\$377,648</u></u>

**Northern States Power Company
Electric Utility - State of North Dakota
Comparison of Detail Rate Base
(\$000's)**

**Case No. PU-12-____
Exhibit ____ (AEH-1)
Schedule 15, Page 2 of 3**

		Proposed Test Year 2013					
Line No.	Description	Total Utility			North Dakota Jurisdiction		
		Unadjusted (A)	Adjustments (B)	2013 Proposed (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	2013 Proposed (F) (D) + (E)
	Electric Plant as Booked						
1	Production	\$8,744,174	\$4,026	\$8,748,200	\$536,836	\$243	\$537,079
2	Transmission	2,215,333	33,799	2,249,132	134,112	2,099	136,211
3	Distribution	3,289,816	0	3,289,816	138,686	0	138,686
4	General	473,780	0	473,780	29,097	0	29,097
5	Common	483,005	0	483,005	29,899	0	29,899
6	TOTAL Utility Plant in Service	\$15,206,108	\$37,825	\$15,243,933	\$868,630	\$2,342	\$870,972
	Reserve for Depreciation						
7	Production	\$4,779,091	\$2,435	\$4,781,525	\$289,353	\$146	\$289,499
8	Transmission	646,035	(2,348)	643,687	38,928	(141)	\$38,787
9	Distribution	1,329,021	742	1,329,763	62,205	742	62,947
10	General	181,059	(1,188)	179,872	11,125	(72)	11,053
11	Common	278,103	472	278,575	17,274	29	17,303
12	TOTAL Reserve for Depreciation	\$7,213,308	\$114	\$7,213,421	\$418,885	\$704	\$419,589
	Net Utility Plant in Service						
13	Production	\$3,965,083	\$1,593	\$3,966,675	\$247,483	\$97	\$247,580
14	Transmission	1,569,299	36,147	1,605,445	95,184	2,240	\$97,424
15	Distribution	1,960,796	(742)	1,960,054	76,481	(742)	75,739
16	General	292,721	1,188	293,909	17,972	72	18,044
17	Common	204,902	(472)	204,430	12,625	(29)	12,596
18	Net Utility Plant in Service	\$7,992,800	\$37,713	\$8,030,512	\$449,745	\$1,638	\$451,383
19	Utility Plant Held for Future Use	\$0	\$0	\$0	\$0	\$0	\$0
20	Construction Work in Progress	\$33,359	\$0	\$33,359	\$2,037	\$0	\$2,037
21	Less: Accumulated Deferred Income	\$1,666,435	\$36,269	\$1,702,704	\$90,835	\$1,949	\$92,784
22	Cash Working Capital	(\$44,592)	(\$1,583)	(\$46,175)	(\$1,123)	\$197	(\$926)
	Other Rate Base Items:						
23	Materials and Supplies	\$125,754	\$0	\$125,754	\$7,613	\$0	\$7,613
24	Fuel Inventory	90,495	0	90,495	5,899	0	5,899
25	Non-Plant Assets & Liabilities	(29,668)	0	(29,668)	(1,809)	0	(1,809)
26	Prepayments	17,260	0	17,260	1,050	0	1,050
27	Nuclear Outage Amortization	80,242	0	80,242	5,018	0	5,018
28	Customer Advances	(2,349)	0	(2,349)	(18)	0	(18)
29	Customer Deposits	(3,343)	0	(3,343)	(213)	0	(213)
30	Other Working Capital	8,373	0	8,373	398	0	398
31	Total Other Rate Base Items	\$286,764	\$0	\$286,764	\$17,938	\$0	\$17,938
32	Total Average Rate Base	\$6,601,896	(\$140)	\$6,601,756	\$377,762	(\$114)	\$377,648

Northern States Power Company
Electric Utility - State of Minnesota
COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2013
(\$000's)

Case No. PU-12-____
Exhibit____(AEH-1) Schedule 15
Page 3 of 3

Proposed Test Year 2013							
Line No.	Description	Total Utility			North Dakota Jurisdiction		
		Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Construction Work in Progress						
1	Production	\$18,648	\$0	\$18,648	\$1,162	\$0	\$1,162
2	Transmission	11,404	0	11,404	724	0	724
3	Distribution	1,106	0	1,106	13	0	13
4	General	1,482	0	1,482	93	0	93
5	Common	718	0	718	46	0	46
6	TOTAL Construction Work In Progress	\$33,359	\$0	\$33,359	\$2,037	\$0	\$2,037

Proposed Test Year 2013							
Line No.	Description	Total Utility			North Dakota Jurisdiction		
		Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Accumulated Deferred Income Taxes						
7	Production	\$1,015,900	(\$1,012)	\$1,014,889	\$63,230	(\$61)	\$63,169
8	Transmission	367,879	13,463	381,342	22,307	804	23,110
9	Distribution	518,256	(303)	517,953	21,559	(302)	21,257
10	General	61,734	484	62,218	3,818	30	3,848
11	Common	36,783	(193)	36,591	2,275	(12)	2,263
12	Net Operating Loss (NOL)	(316,801)	23,829	(292,973)	(21,275)	1,491	(19,784)
13	Non-Plant Related	(17,315)	0	(17,315)	(1,079)	0	(1,079)
14	TOTAL Accum Deferred Income Taxes	\$1,666,435	\$36,269	\$1,702,704	\$90,835	\$1,950	\$92,784

**Northern States Power Company
Electric Utility - State of North Dakota
Charitable Donations
YEAR ENDED 12-31-13**

**Case No. PU-12-____
Exhibit____(AEH-1)
Schedule 16**

ELECTRIC	North Dakota Jurisdiction	
Corporate Contributions		
Electric Corporate Contributions	\$	2,315
Focus Area Grants		
Electric Focus Area Grants	\$	130,822
Matching Gifts Program		
Electric Matching Grants	\$	17,227
United Way		
Electric United Way	\$	63,675
Management Reductions	\$	(9,262)
Business Area Donations	\$	108,340
Total Electric	\$	313,117
Recover 50% of Total	\$	156,559

<u>INCLUDABLE:</u>	FERC	North Dakota Jurisdiction
General Advertising	930.1	\$ 12,070
Diversity Recruiting Ads		
Supplier Diversity Ads		
Job Posings		
Energy Update		
Online Information		
Mandatory Notices	928.0	\$ 9,761
Conservation (General)	909.1	\$ 6,900
Customer Programs	909.1	\$ 24,341
Bill Inserts / Direct mailings		
InfoSmart		
Billwise		
Paysmart		
BudgetSmart		
Energy Solutions		
Energy Update		
Online Information		
Safety Advertising	909.1	\$ 58,170
Billboards/Inserts		
TV, Radio Advertising		
Newspapers		
Online Information		
TOTAL INCLUSION		<u><u>\$ 111,242</u></u>

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of North Dakota
Advertising Expense
YEAR ENDED 12-31-13

Case No. PU-12-____
Exhibit__(AEH-1)
Schedule 17, Page 2 of 2

<u>EXCLUDABLE</u>	<u>FERC</u>	<u>North Dakota Jurisdiction</u>
Brand/Image and Sponsorship	930.1	\$ (137,102)
Branding	921	\$ (5,541)
Customer Program	909.1	\$ (47,865)
Non-Recoverable DSM	908	\$ (511)
TOTAL EXCLUSION		<u>\$ (191,019)</u>

**Northern States Power Company
Electric Utility - State of North Dakota
Organizational Dues
YEAR ENDED 12-31-13**

**Case No. PU-12-____
Exhibit__(AEH-1)
Schedule 18**

	<u>North Dakota Jurisdiction</u>
<u>INCLUDABLE:</u>	
Association Dues	
Professional Association and Utility Dues	77,606
Chamber of Commerce Dues	22,760
TOTAL INCLUSION	<u><u>\$ 100,366</u></u>

	<u>North Dakota Jurisdiction</u>
<u>EXCLUDABLE</u>	
Association Dues	
Professional Association and Utility Dues	(3,600)
TOTAL EXCLUSION	<u><u>\$ (3,600)</u></u>

Northern States Power Company
Electric Utility - State of North Dakota
Test Year Ending December 31, 2013

Case No. PU-12-____
Exhibit____(AEH-1)
Schedule 19

<u>2012 ND Electric Rate Case Expenses</u>		<u>North Dakota Jurisdiction</u>
Consulting Fees		\$153,000
Itron & Christensen Assoc	10,000	
Robinson	35,000	
Concentric	100,000	
Towers Watson	8,000	
Outside Legal Fees		300,000
State Agency Fees and Administrative Law Judge		125,000
Administrative Costs (transcripts, admin)		40,000
TOTAL		<u><u>\$618,000</u></u>
 <u>Recommended Amortization Period 3 Years</u>		
Annual Amortization Expense		<u><u>206,000</u></u>

Northern States Power Company
 Electric Utility - State of North Dakota
 Test Year Ending December 31, 2013
 2013 ND Test Year Amortizations

Case No. PU-12-____
 Exhibit____(AEH-1)
 Schedule 20

<u>New Amortization Requested in this Docket</u>	<u>Estimated Expense</u>	<u>Recommended Amortization Timeline</u>	<u>North Dakota Annual Amount</u>
Rate Case Costs per (AEH-1) Schedule 19	\$618,000	3 Years	\$206,000
<u>Approved Amortization Items From PU10-657</u>	<u>Unamortized Balance 12/31/12</u>		
SO2 Emission Credits	(\$98,522)	3 Years	(\$32,841)
Private Fuel Storage	\$208,095	3 Years	\$69,365
Rate Case Costs PU-10-657	\$212,423	3 Years	\$70,808
2008 - 2010 Deferred DSM	\$168,486	3 Years	\$56,162
Total Test Year Amortizations			<u><u>\$369,494</u></u>

Impact of Unused/(Utilized) Tax Deductions on Rate Base	2011 EOY Balances	2012 Bridge Annual Utilization Amounts	2012 Bridge EOY Balances	2013 Test Year Annual Utilization Amounts	2013 Test Year EOY Balances
1. Unused/(Utilized) Deductions	53,022	(8,007)	45,015	(10,641)	34,374
2. Deferred Tax Effect of Unused/(Utilized) Deductions	21,621	(3,274)	18,347	(4,351)	13,996
3. Unused/(Utilized) Credits	<u>1,663</u>	<u>1,265</u>	<u>2,928</u>	<u>1,369</u>	<u>4,297</u>
4. Accumulated Deferred Income Taxes (ADIT)	23,284	(2,009)	21,275	(2,982)	18,293

Impact of Unused/(Utilized) Tax Deductions on Revenue Requirements	2012 Bridge Year Utilization Adjustment	2013 Test Year Utilization Adjustment	Comment
5. Deferred Tax Asset BOY	0	0	Zero since adjustment reflects current year utilization
6. Deferred Tax Asset EOY	<u>(2,009)</u>	<u>(2,982)</u>	From Utilization columns on Line 4
7. Average Rate Base	(1,005)	(1,491)	(BOY + EOY)/2
8. Return Requirement	(83)	(124)	Rate Base * Req Rate of Return
9. RR Tax on Equity Return	<u>(34)</u>	<u>(51)</u>	(T/(1-T))*RB*Equity Return
10. Rate Base Revenue Requirement	(118)	(175)	Line 8 + Line 9
11. Deferred Tax	2,009	2,982	From Utilization columns on Line 4
12. Current Tax Rev Req ¹	<u>(1,679)</u>	<u>(2,543)</u>	From Line 17
13. Total Revenue Requirements	<u>213</u>	<u>265</u>	Line 10+11+12
<i>¹ Current Income Tax Rev Req Calculation</i>			
14. Utilized Deductions	8,007	10,641	Unused Annual Deductions
15. Deferred Taxes	2,009	2,982	Line 11
16. Unused Tax Credits	<u>1,265</u>	<u>1,369</u>	From Utilization columns on Line 3
17. Current Income Tax Revenue Requirement	<u>(1,679)</u>	<u>(2,543)</u>	(T/(1-T))*(-Line 14+15+16)+Line 16

Adjustment Cap Structure	Cost	Ratio	Weighted Cost
Long Term Debt	6.07%	46.30%	2.81%
Short Term Debt	2.06%	1.14%	0.02%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	10.40%	52.56%	<u>5.47%</u>
Req Rate of Return			8.30%
Corp Composite Tax Rate	40.89%		
ND Composite Tax Rate	38.35%		

Example Project A	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Total												
Rate Base												
CWIP	144,146,388	162,612,103	182,953,091	194,884,857	203,445,908	215,503,853	219,522,582	234,050,683	251,434,174	271,405,861	289,091,590	193,029,380
Plant In-Service	14,890,644	15,659,359	16,512,900	17,488,348	19,439,226	20,796,695	31,413,657	32,497,816	33,922,687	34,552,629	35,176,429	143,991,243
Less Accumulated Book Depreciation Reserve	1,394	2,754	4,271	5,901	8,502	12,493	23,773	41,866	60,580	79,933	99,285	202,425
Less Accumulated Deferred Taxes	(1,602,190)	(1,664,047)	(1,736,839)	(1,821,101)	(1,786,879)	(1,574,614)	(932,859)	71,827	1,138,754	2,264,796	3,358,892	15,294,850
End Of Month Rate Base	160,637,828	179,932,755	201,198,559	214,188,405	224,663,512	237,862,668	251,845,326	266,434,806	284,157,527	303,613,761	320,809,841	321,523,348
Return on Rate Base												
Debt Return	361,145	407,266	455,770	496,734	524,794	553,104	585,609	619,777	658,417	702,876	746,707	768,123
Equity Return	685,799	773,379	865,486	943,275	996,560	1,050,320	1,112,045	1,176,928	1,250,303	1,334,731	1,417,962	1,458,632
Total Return on Rate Base	1,046,944	1,180,645	1,321,255	1,440,008	1,521,353	1,603,424	1,697,654	1,796,704	1,908,720	2,037,607	2,164,668	2,226,755
Income Statement Items												
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	-	-	-	-	-	-	-	-	-	-	-	-
Property Taxes	17,046	17,046	17,046	17,046	17,046	17,046	17,046	17,046	17,046	17,046	17,046	17,046
Book Depreciation	748	1,360	1,516	1,630	2,601	3,992	11,280	18,093	18,713	19,353	19,352	103,140
Deferred Taxes	(117,441)	(61,857)	(72,792)	(84,263)	34,222	212,265	641,755	1,004,686	1,066,928	1,126,041	1,094,097	11,935,958
Gross Up for Income Tax	603,690	608,799	684,944	751,533	668,291	524,642	130,159	(194,214)	(205,918)	(206,633)	(115,324)	(11,144,080)
Less OATT Credit	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Statement Expense	504,043	565,349	630,715	685,946	722,160	757,945	800,240	845,611	896,770	955,808	1,015,172	912,064
Revenue Requirement												
Total	1,550,988	1,745,993	1,951,970	2,125,954	2,243,513	2,361,369	2,497,895	2,642,316	2,805,490	2,993,415	3,179,840	3,138,819
Jurisdictional Allocator	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%	5.1121%
Are costs eligible for recovery in the Rider?	1	1	1	1	1	1	1	1	1	1	1	1
Rider Eligible Revenue Requirement	79,288	89,257	99,787	108,681	114,691	120,716	127,695	135,078	143,419	153,026	162,557	160,460
Rider Eligible Revenue Requirement: Annual Totals	-	-	-	-	-	-	-	-	-	-	-	1,494,653

2013 Tracker													
Carryover	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Annual Total
Example Project A	79,288	89,257	99,787	108,681	114,691	120,716	127,695	135,078	143,419	153,026	162,557	160,460	1,494,653
Example Project B	-	-	-	-	-	-	-	-	-	-	-	-	-
Example Project C	-	-	-	-	-	-	-	-	-	-	-	-	-
Example Project D	-	-	-	-	-	-	-	-	-	-	-	-	-
Example Project E	-	-	-	-	-	-	-	-	-	-	-	-	-
Example Project F	-	-	-	-	-	-	-	-	-	-	-	-	-
Example Project G	-	-	-	-	-	-	-	-	-	-	-	-	-
Example Project H	-	-	-	-	-	-	-	-	-	-	-	-	-
Example Project I	-	-	-	-	-	-	-	-	-	-	-	-	-
RECB - 26 & 26(a)	(42,911)	(76,161)	(89,190)	(92,604)	(54,398)	(78,917)	(115,041)	(111,274)	(90,721)	(88,767)	(84,415)	(79,234)	(1,003,632)
Transmission Projects	-	36,377	13,096	10,597	16,077	60,293	41,799	12,654	23,803	52,699	64,259	78,141	491,021
TCR True-up Carryover	(10,000)	(833)	(833)	(833)	(833)	(833)	(833)	(833)	(833)	(833)	(833)	(833)	(10,000)
Revenue Requirement	35,544	12,263	9,764	15,243	59,460	40,965	11,821	22,970	51,865	63,426	77,308	80,392	481,021
Revenue Collections	44,974	41,933	43,302	35,939	35,787	35,935	40,560	39,823	36,821	38,204	40,004	47,740	481,021
Balance	-	(9,430)	(39,100)	(72,638)	(93,334)	(69,661)	(64,630)	(93,370)	(110,222)	(95,178)	(69,957)	(32,653)	(0)

	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Monthly Revenue Requirement	35,544	12,263	9,764	15,243	59,460	40,965	11,821	22,970	51,865	63,426	77,308	80,392
Rate Period Calculations												
Revenue Requirement for Rate Period	481,021	481,021	481,021	481,021	481,021	481,021	481,021	481,021	481,021	481,021	481,021	481,021
Revenue Collections for Rate Period	0	0	0	0	0	0	0	0	0	0	0	0
Revenue Needs During Remaining Rate Period	0	0	0	0	0	0	0	0	0	0	0	481,021
Sales Customer Group												
Customer Group (Billed by total Usage)												
Total Retail	212,304,457	197,948,994	204,412,867	169,652,640	168,936,002	169,634,162	191,469,077	187,988,337	173,819,778	180,348,586	188,844,227	225,361,957
<hr/>												
Total kWh Sales in Month	212,304,457	197,948,994	204,412,867	169,652,640	168,936,002	169,634,162	191,469,077	187,988,337	173,819,778	180,348,586	188,844,227	225,361,957
Total kWh Sales in Rate Period	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084	2,270,721,084
RR/kWh Sales	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212	\$ 0.000212
Revenues												
Total Retail	44,974	41,933	43,302	35,939	35,787	35,935	40,560	39,823	36,821	38,204	40,004	47,740
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Forecast Totals	44,974	41,933	43,302	35,939	35,787	35,935	40,560	39,823	36,821	38,204	40,004	47,740
Actual Revenues												
Combined Actual & Forecast	44,974	41,933	43,302	35,939	35,787	35,935	40,560	39,823	36,821	38,204	40,004	47,740
Annual Total	0	0	0	0	0	0	0	0	0	0	0	481,021

Aviation Services Analysis

2011 and June 2012 Year-to-Date Cost/Benefit Analysis

September 28, 2012

Outline

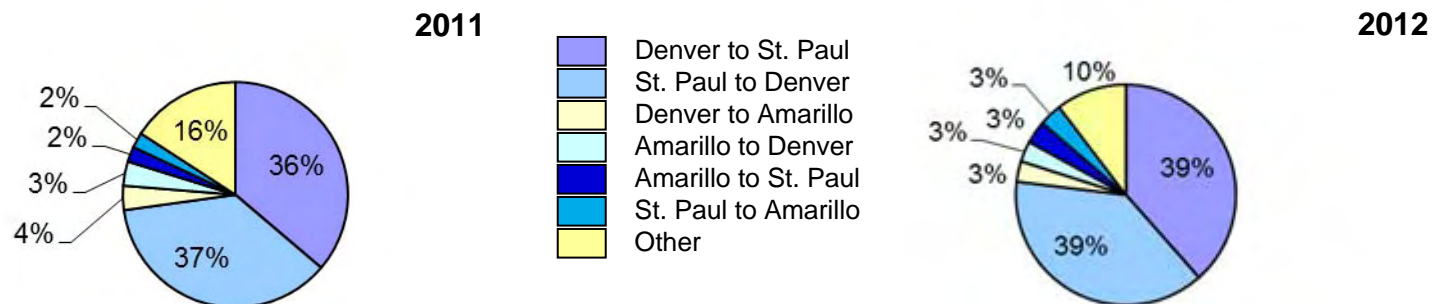
- ◆ Overview of Xcel Energy Aviation Services
- ◆ Summary of Industry Cost/Benefit Studies
- ◆ The Value of Employees' Time
- ◆ Value per Man-Hour (VMH)
- ◆ In-Flight Productivity
- ◆ Productivity During Transportation and Wait Time
- ◆ Analytical Approach
 - Assumptions
 - Average One-Way Commercial Airfares
 - Travel Times by City Pair
 - Overview of Total Cost Calculation
- ◆ Summary of Results
- ◆ Appendices
 - Example Analysis: Denver, CO to Minneapolis, MN
 - Sources

Overview of Xcel Energy Aviation Services

- ◆ The Mission of the Xcel Energy Aviation Department is to provide convenient, efficient, and safe aviation travel and related services that enhance Xcel Energy profitability and performance through time savings and increased employee productivity
- ◆ Xcel Energy operates two Learjet 45 business aircraft, with hangar facilities in St. Paul, MN, Englewood, CO, and Amarillo, TX
- ◆ A summary of recent operating statistics is shown below:

	2011	June 2012 YTD
No. of Flights (Legs)	776	299
No. of Passengers	4,256	1,740
Nautical Miles (NM)	445,261	176,060
Flight Hours	1,227	480
Total Aviation Expenditures	\$5,693,362	\$2,428,177

- ◆ While the Xcel Energy fleet flies between St. Paul, Denver (Englewood), Amarillo, and other cities, more than 80% of the flights in 2011 and 2012 were between three city pairs:



Summary of Industry Cost/Benefit Studies

- ◆ A number of studies conducted over the past 10 years have quantified the benefits of corporate aircraft (please see the Sources in the Appendices)
- ◆ Most of these studies define benefits broadly and attempt to correlate the use of corporate aircraft with an increase in shareholder value
 - Various shareholder value dimensions have been considered:
 - Revenue/market share growth
 - Profit margin growth
 - Asset efficiency
 - Customer and employee satisfaction
 - Many of these metrics are not applicable to a franchised utility
- ◆ However, other factors are included in these analyses, and it is these that we have focused on in this analysis:
 - Travel expense savings
 - Employee time savings
 - Increased productivity in flight
 - Productivity during transportation and wait time
- ◆ A number of other tangible and intangible benefits are often cited, some which directly impact travel times and productivity, either in flight, or before or after a trip. These include:
 - Reduced travel expenses (due to elimination of overnight stays)
 - Scheduling convenience
 - Elimination of interruptions, noise, and distractions
 - Reduced stress and post-trip fatigue
 - Personal security
- ◆ We did not attempt to quantify the potential value of these benefits in this analysis

The Value of Employees' Time

- ◆ A study completed by Arthur Andersen in 2001¹ describes the “time savings of flying business aircraft non-stop on passenger-directed schedules between close-in general aviation airports using small, quick-access passenger facilities rather than flying scheduled airlines (and commonly making connections) on airline schedules between (distant) commercially served airports with vast passenger terminals.”
- ◆ The study goes on to state, “the value of a unit of employee time saved resulting from the use of business aircraft... must exceed its cost, as common business sense requires employees to generate more in revenue or profit improvement than they are paid—if they don’t, the company will not survive. The value of employee time concept is perhaps most tangibly illustrated by the hourly billing rates found for personnel in service industries. These billing rates are designed to reflect the cost of compensation for that individual, but also cover overhead, support, profit, and other costs or financial considerations for the employer.”
- ◆ The PRC Aviation study² is premised on the concept that “the direct benefits and advantages of business aircraft are either measured in terms of time saved for key employees or converted to an equivalent increment of time saved (gained). The financial value of these benefits can only be established by determining a proper dollar value of a unit of such employees’ time to the employer.”
- ◆ Further, “the field of human resource accounting has established the principle that the value of specific groups, or types of employees, to the employer can be expressed by applying a multiplying factor to the employee’s base salary.”
- ◆ This multiplying factor has been called “value per man-hour” (VMH) in other analyses. A number of VMH factors have been utilized in various studies:
 - The 2004 Daniel Sweet study³ suggests a VMH factor of 2.5 times (for a professional-level employee)
 - The PRC Aviation study concludes that a “multiplier of 5.7 is appropriate for a senior corporate executive, and 3.8 is appropriate as the multiplier for middle management and professional personnel” (see page 6)
 - The NBAA TravelSense model⁴ also uses the same factors of 5.7 for “senior executives” and 3.8 for “middle management and professionals” (and cites the PRC study)
 - The Andersen study includes an example with “position leverage multipliers of 5 to 20 times annual compensation”

¹ *Business aviation in today's economy, A guide to the analysis of business aircraft use, benefits and effects on shareholder value*, Summer 2001, Arthur Andersen LLC

² *Business Aircraft Operations Financial Benefits and Intangible Advantages*, 1991 (Revised 1995), PRC Aviation

³ *Business Travel Value Analysis*, April 2004, Daniel L. Sweet

⁴ *TravelSense – Business Travel Productivity Tracking Software User's Guide*, Release 3, 1999, National Business Aviation Association, Inc.

The Value of Employees' Time (Cont'd)

- ◆ The Defense Contract Audit Agency Contract Audit Manual states:
 - “The ASBCA (Armed Services Board of Contract Appeals) ruled (in the General Dynamics case no. 31359, 92-2, BCA 24922) that ‘time savings, productivity gains, or more effective use of personnel’ can be used to demonstrate and justify the higher cost of private aircraft.”
 - “The ASBCA also ruled that it is appropriate for the contractor to consider the value of executive time in the cost-benefit analysis. The ASBCA accepted the concept that the calculation of the value of the executive's time could include an estimate of the executive's value to the corporation in addition to the executive salary and fringe benefits. The ASBCA referred to the estimate of the executive's value to the corporation as a ‘multiplier’.”
- ◆ The Minnesota Department of Transportation (MN/DOT) states on its web site that:¹
 - “Elected officials and state employees are encouraged to utilize MN/DOT's aircraft whenever it is most cost effective in conducting official business outside the metropolitan area and time is essential. Flying increases employee productivity and is often the most cost efficient means of travel when comparing driving time, lodging and meal expenses.”
 - “The value of employee time often exceeds its cost to the company by substantial margins, further increasing the importance of employee time saving. A study conducted by PRC Aviation produced values of 5.7 times the rate of a senior executive and 3.8 times the rate of a middle management/professionals salary to determine the exact hourly value that employee has to the organization. Subsequently, MN/DOT, in a study of their own, determined that a multiplying factor for (a Transportation Worker) specialist should be included at the rate of 2.4 times their hourly and benefits rate.”
 - “There would be those who would argue that no one person's worth is 5.7 times their salary. However, using a base salary multiplier of 2 could easily be defended as merely a loss of productive time while driving plus the time to accomplish the normal working tasks above that as a doubling of time.”
- ◆ “A Harvard study and industry analysts have found that on average, each employee generates revenue and/or adds value at a rate of three times their salary.”²
- ◆ “(R)esearch... has indicated that the individual's value is between one and three times their salary (a Harvard University study found that it was three times a person's salary, which many analysts have found to be an accurate estimate).³

¹ <http://dotapp7.dot.state.mn.us/flyordrive/about.vm>

² *Topic Brief - Calculating the Cost of Vacancy*, 2009, Volt Information Sciences, Inc.

³ *Calculating the Cost of Vacancies*, October 16, 2007, Dr. John Sullivan, Human Resources Leader

Value per Man-Hour (VMH)

- ◆ The PRC Aviation study identified a number of methods which are “widely applied professionally and in business practices” to determine the value of executives and other employees to corporations
 - Eight methods were determined to be appropriate for application to corporate personnel. (Three were excluded as the resulting multipliers were thought to be too extreme [high])
 - Of the remaining five methods used as a basis for determination of senior executive value, four of the five were also used for the determination of the value of middle management and professional personnel
- ◆ These methods, and the results computed by PRC Aviation, are shown in the table below:

Method	Senior Executive	Middle Mgmt.	Description
Service Industries	5.0 to 7.0	2.5 to 5.0	Billing rates versus salary levels for service service firms for different types of employee (senior partners 5 to 7X, partners and senior associates 3 to 5X, and professional employees at engineering firms 2.5 to 3X)
Five Times Salary	N/A	N/A	5X salary rule of thumb for key man insurance (rationale is that a replacement can be found and trained within a five-year period)
10 Percent Rule Whole Life	4.9	N/A	Amount of life insurance that can be purchased with 10% of salary
Benefit Term Insurance	5.0 to 7.0	3.0	Group term insurance benefits offered to employees (often 3X salary) and senior executives, 2 to 4X salary above the basic group policy)
Replacement Cost Insurance Present Value of Term of Replacement	5.0 to 5.3	3.5	Present value of the replacement cost over the life of the employee (15 to 20 years)
Replacement Cost Insurance Present Value of Term of Replacement Plus Inefficiencies	6.4 to 6.7	4.8	Present value of the replacement cost over the life of the employee (15 to 20 years), including learning curve inefficiencies over 3 to 5 years
PRC Averages	5.7	3.8	

In-Flight Productivity

- ◆ In 1997, Louis Harris and Associates, Inc., conducted a survey on behalf of the National Business Aircraft Association¹. They concluded that passengers of business aircraft are more productive aboard company aircraft than in the office or aboard commercial aircraft

Passengers report spending nearly half (48 percent) of their time aboard company aircraft in work-related meetings, conferences, or discussions with other company employees or customers, compared with only six percent of time in these activities while aboard commercial aircraft.

Further, compared to a typical office productivity level of 5.0, passengers rank their productivity while aboard the company jet at 6.2, while productivity aboard commercial airline aircraft is only 3.2.

- ◆ In 2009, a similar survey was conducted by Harris Interactive² which stated that employees use their time onboard company aircraft more effectively and productively than when they are in the office or on commercial flights

Passengers dedicate the majority of their time aboard business aircraft to work-related tasks: an average of 36% of their time is spent in meetings with colleagues, almost one third (30%) of their in-flight time is dedicated to doing individual work tasks (another 6% was spent in work-related meetings with customers).

The allocation of time changes significantly when these passengers fly on commercial planes. Over one third (36%) of the time is spent doing non-work related activities such as reading or entertainment, 28% of the time is allocated to individual work tasks, and most of the remaining time (25%) is spent sleeping or resting (8% is spent on other non-work-related activities).

In total, passengers spend over twice the amount of time on work-related tasks when they are on business aircraft as opposed to commercial (72% vs. 31%).

Passengers were also asked to rate their productivity aboard the aircraft in a typical hour using a scale from 1 to 10, where 5 was the office baseline. Compared to a typical hour in the office (five, the baseline on the scale), passengers rate their productivity aboard a company jet at 6, which is a 20% increase in productivity as compared to the office. Airline aircraft productivity ranks significantly below office productivity at an average of 3. This is a 40% drop in productivity from time in the office.

- ◆ The 2004 Daniel Sweet study also applied different productivity credits—in this case 75% for travel by corporate aircraft, and 15% for travel by commercial airline

¹ Survey of Companies Using Turbine-Powered General Aviation Aircraft for Business Transportation, Study No. 718235, June 24, 1997, Louis Harris and Associates, Inc.

² The Real World of Business Aviation: A Survey of Companies Using General Aviation Aircraft, October 15, 2009, Harris Interactive, Inc.

Productivity During Transportation and Wait Time

- ◆ In 2011, the University of Applied Science Heilbronn partnered with the Association of Corporate Travel Executives (ACTE), SAP, and DuntonTinnus Consulting to conduct a study¹ on the productivity effect of smart phones for business travelers
- ◆ The research methodology involved undertaking a series of personal interviews with experts in the travel industry, followed by a detailed online survey answered by 210 ACTE members, 90% of whom already owned a smart phone
- ◆ Based on this survey, the perceived productivity improvement through the usage of smart phones was substantial
 - “75% of the respondents agreed or strongly agreed to the statement that a mobile device enormously increases their productivity.”*
 - “The usage of mobile technology increases the productivity of business travelers between 30-50%.”*
- ◆ The main influencing factors for more productive trips were time saving aspects and a more flexible choice of working hours and environments
 - “Checking and responding to emails, using the organizer (calendar, reminder, etc.) are the most common features used by respondents of the survey. Using the web browsing capabilities is still just the third most common tool.”*
- ◆ In November 2011, Citrix Systems, Inc. announced findings from a global survey² that examined the adoption of consumer-focused communications devices in the workplace and their impact on corporate security and privacy. The survey revealed that several companies were benefiting from an increase of as much as 30% in productivity due to use of personal smart phones, tablets, and other devices for business use
 - “Businesses are seeing productivity gains of up to 36 percent from employees using both personal and business devices. (In the U.S.) 53 percent of businesses have recorded productivity improvements of more than 10 percent, with 16 percent confirming gains of more than 30 percent.”*

¹ *Mobile Technology and Business Travel: How does mobile technology influence the productivity of business travelers?*, 2011, University of Applied Science Heilbronn with partners ACTE Global, SAP and DuntonTinnus Consulting

² *Businesses Unprepared to Support New Mobile Ways of Working*, November 21, 2011, Citrix Systems, Inc.

Analytical Approach

- ◆ For the purposes of this analysis, comparisons of the door-to-door travel time for Xcel Energy Aviation Services passengers versus commercial airline alternatives were developed
 - Commute time between Xcel Energy offices and airports/hangars was based on Google Maps estimated drive times
 - Average flight times between city pairs were based on Xcel Energy actuals and published flight times for commercial airlines on Travelocity and other web sites
 - Allowances for average commercial air travel delays were based on Bureau of Transportation Statistics results
- ◆ Passenger mix was analyzed for all flights flown in 2011 and 2012. The average compensation per passenger (average salary for each level times a benefits loader, plus incentives) was computed
- ◆ The “lost” productivity during travel time was computed for each option by applying a VMH multiplier
 - A productivity differential for work-related activities during flight time was applied, based on the results of the 2009 Harris study
 - 72% for corporate aircraft (a “loss” of productivity of 28%); 31% for commercial airlines (a “loss” of 69%)
 - Based on the 2011 ACTE and University Heilbronn study, a productivity factor of 40% was applied for work-related activities during transportation, security, check-in and wait time (***this is a change in methodology from the 2011 analysis***)
- ◆ Cost per flight for Xcel Energy corporate aircraft was based on average cost per nautical mile and distance per leg
- ◆ Commercial airfares reflect the average of the lowest round-trip prices by departure date over 2011 and June year-to-date 2012, based on published customer searches on Priceline (prices were based on 7 to 21-day advance purchases prior to departure with a trip length of 2 to 10 days (see page 11 for more details))
- ◆ The total cost of each travel option for each leg, based on the average number of passengers flying between each city pair, was then computed
 - An example of this analysis is shown in the Appendices
- ◆ The total cost and total travel time for each option for all six city pair legs were summarized

Assumptions

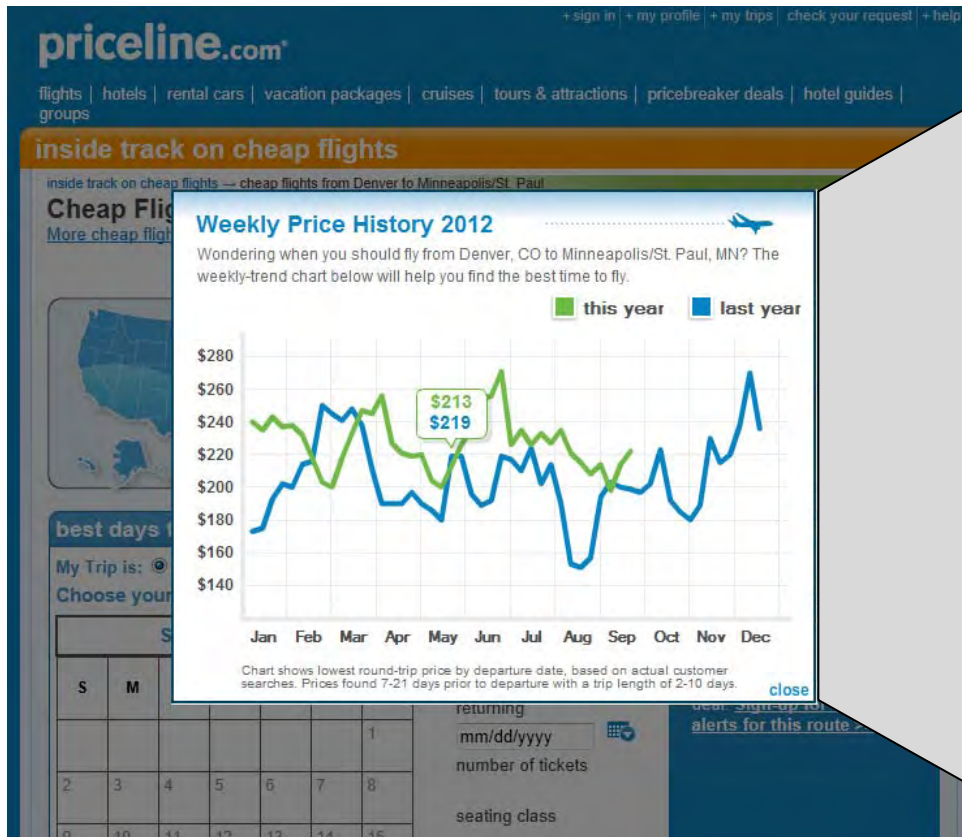
◆ Commercial One-Way Airfares

- Since the commercial airfares used in the analysis are historical, they may differ from current fares due to the addition or deletion of flights between city pairs by the airlines, changes in fuel costs, etc.
- The commercial airfare analysis also involves assumptions regarding what might be considered “reasonable” flight options for business travel. Hence, the commercial flight time analysis excludes flights leaving in the middle of the day and flights with unusually long flight times
- The MSP-AMA commercial flight path is relatively long with no direct flights connecting the two airports and is likely to involve an overnight hotel stay. Hotel charges related to commercial travel have not been included in this analysis

◆ Productivity Analysis

- The transportation and wait time analysis assumes no productivity for one leg of office-airport transportation. The underlying assumption is that a passenger will drive for one leg of airport transportation and take a taxi or shuttle for the other leg. Zero productivity was assumed for driving time and time to get to the car if the passenger was driving
- Zero productivity was assumed for taxiing and deplaning time
- The definition of Arrival Delay on Therefore Average Delay time for commercial airlines has been split 50/50 between productive and non-productive time. The underlying assumption is that a passenger can be productive during boarding delays due to smart phone usage, etc. However, commercial airlines’ rules prohibit the use of smart phones during take-off and landing, making tarmac/landing delays unproductive

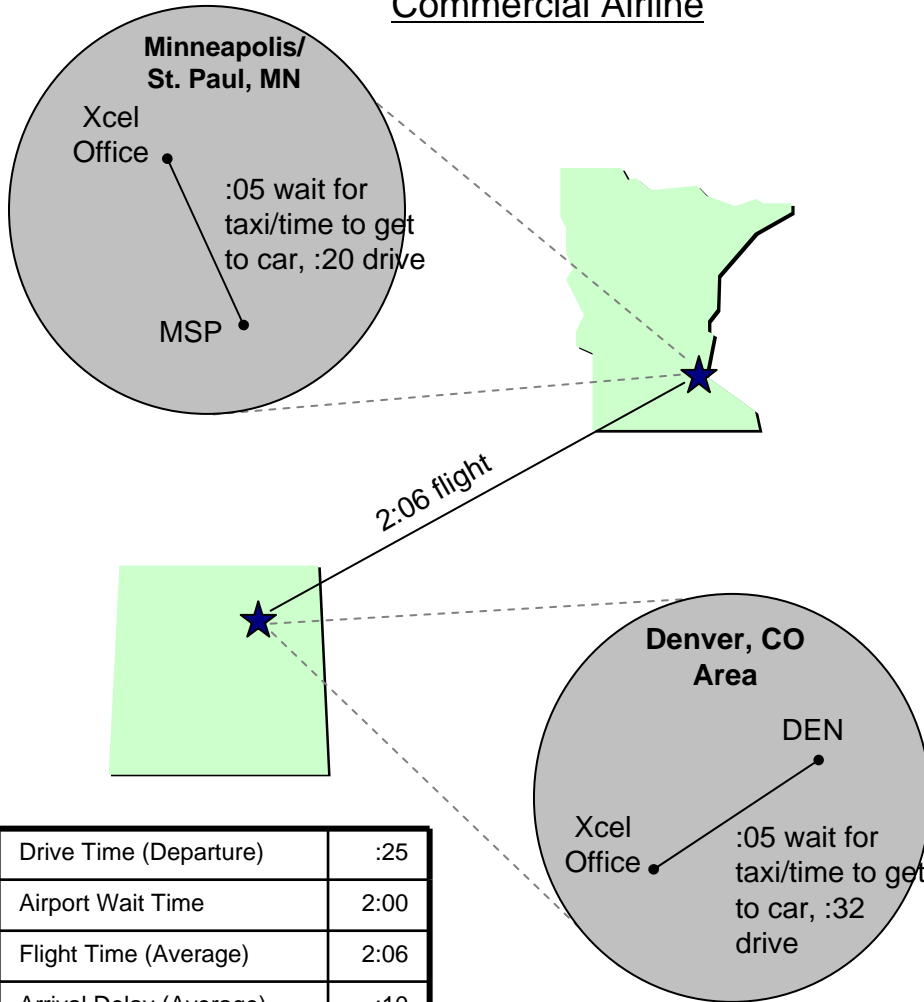
Average One-Way Commercial Airfares



- ◆ Commercial one-way airfares reflect 50% of the average of the lowest round-trip prices available by departure date between 2011 and YTD June 2012, based on published actual customer searches on Priceline
- ◆ Per Priceline, prices were found 7-21 days prior to departure with a trip length of 2-10 days

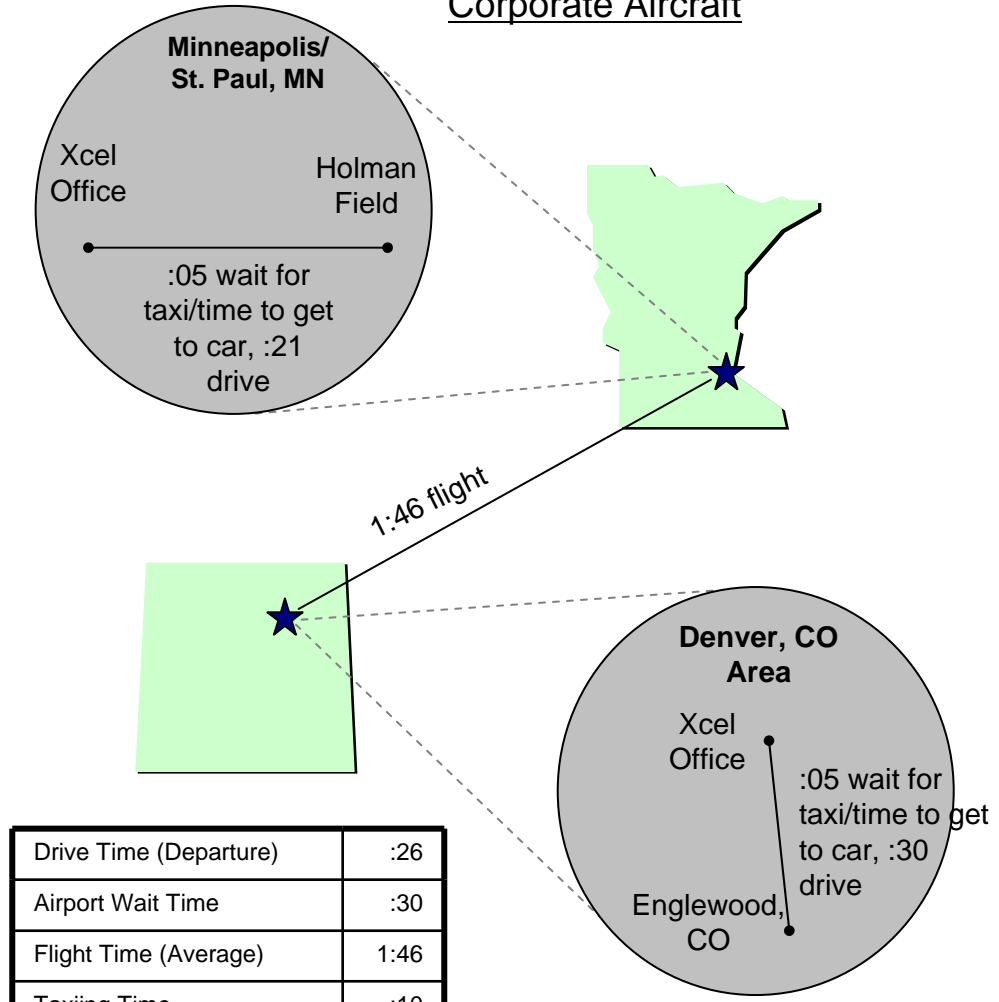
Travel Times: St. Paul, MN to Denver, CO

Commercial Airline



Drive Time (Departure)	:25
Airport Wait Time	2:00
Flight Time (Average)	2:06
Arrival Delay (Average)	:10
Deplaning Time	:15
Drive Time (Arrival)	:37
TOTAL	5:33

Corporate Aircraft

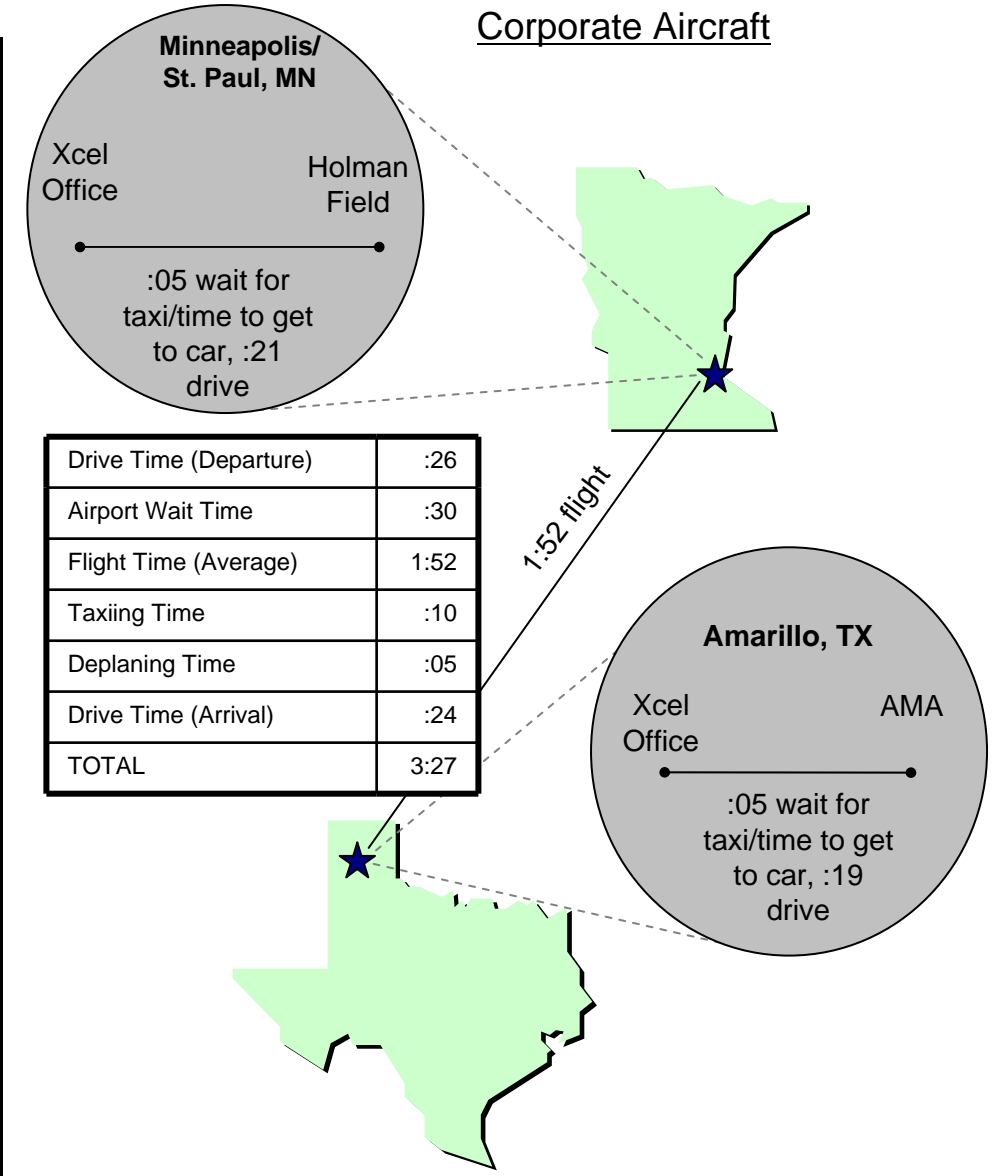
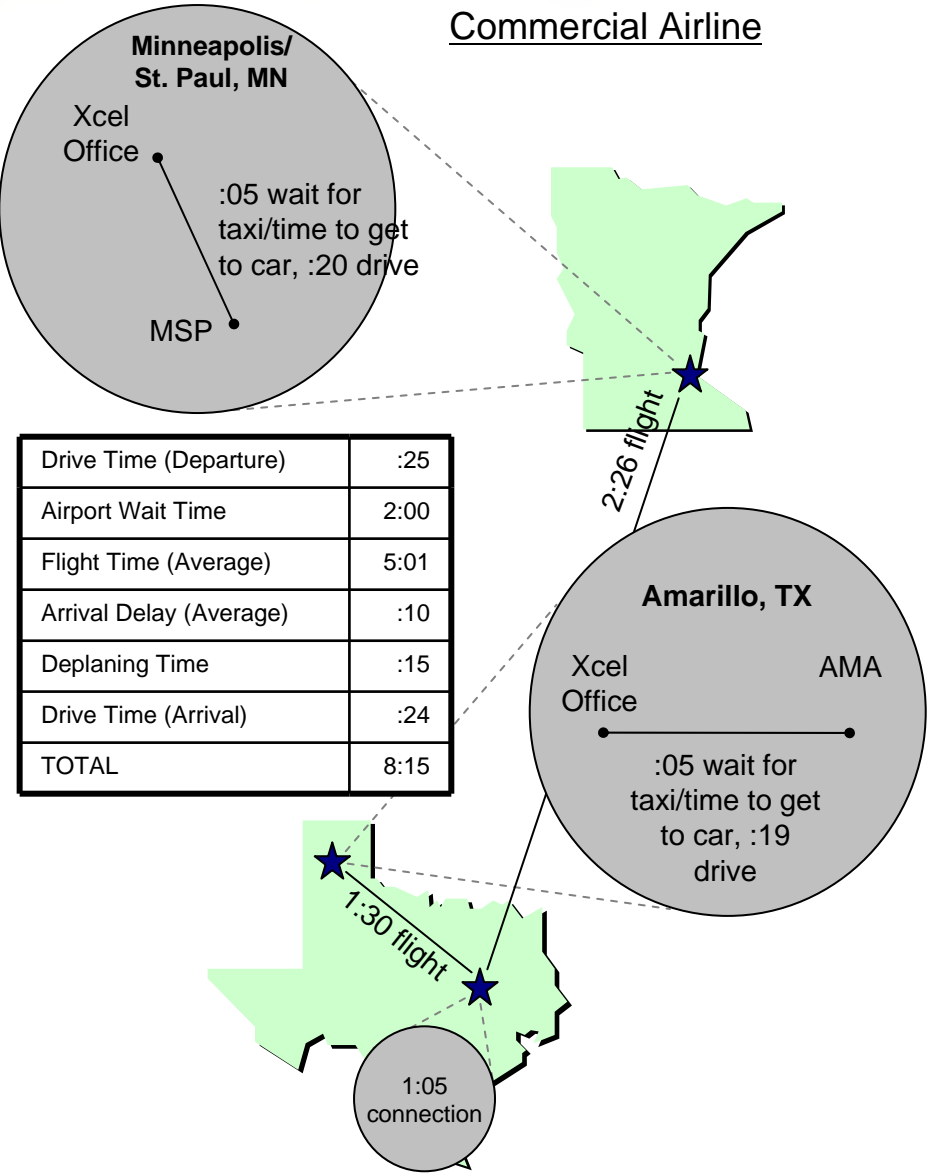


Drive Time (Departure)	:26
Airport Wait Time	:30
Flight Time (Average)	1:46
Taxiing Time	:10
Deplaning Time	:05
Drive Time (Arrival)	:35
TOTAL	3:32

Travel Times: St. Paul, MN to Amarillo, TX

Commercial Airline

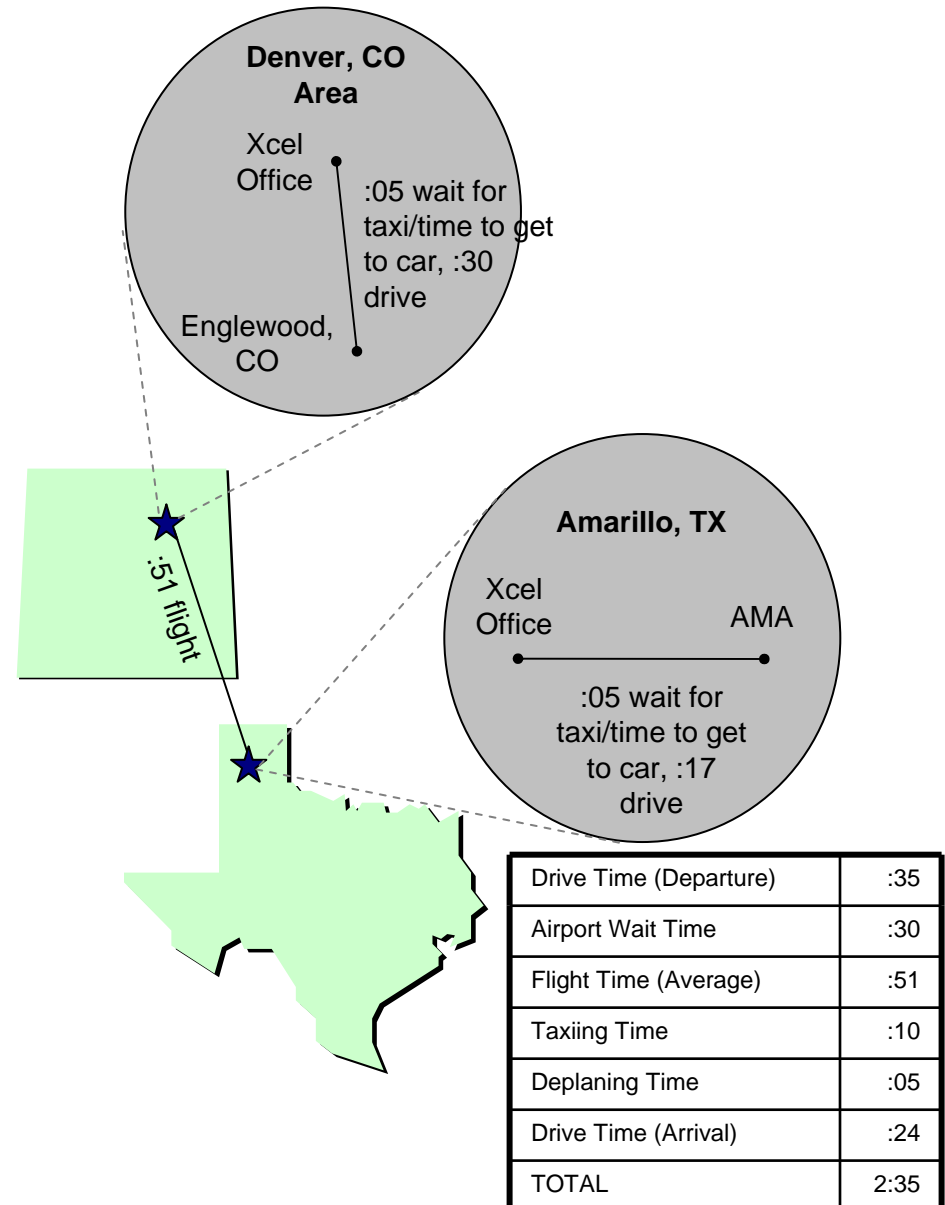
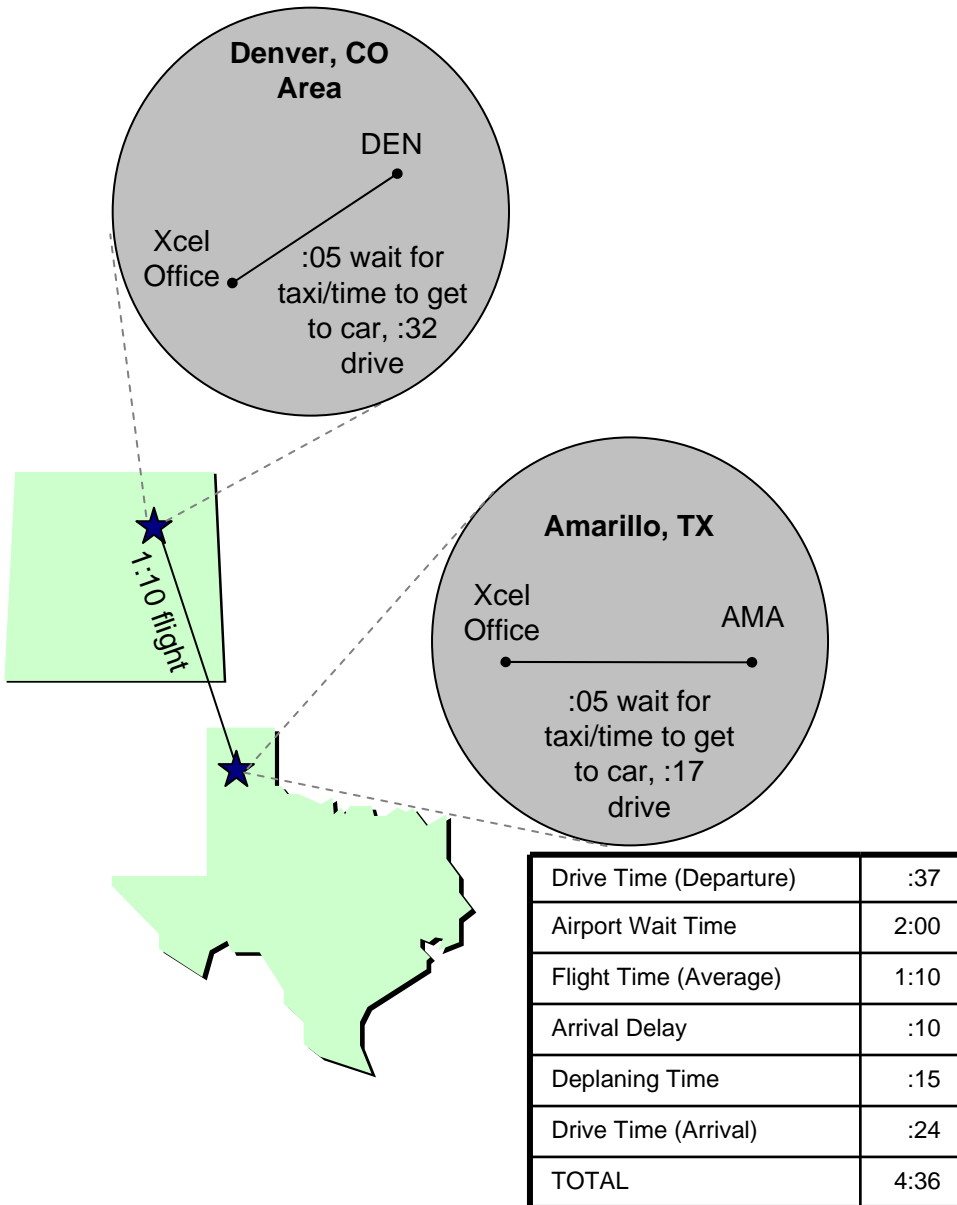
Corporate Aircraft



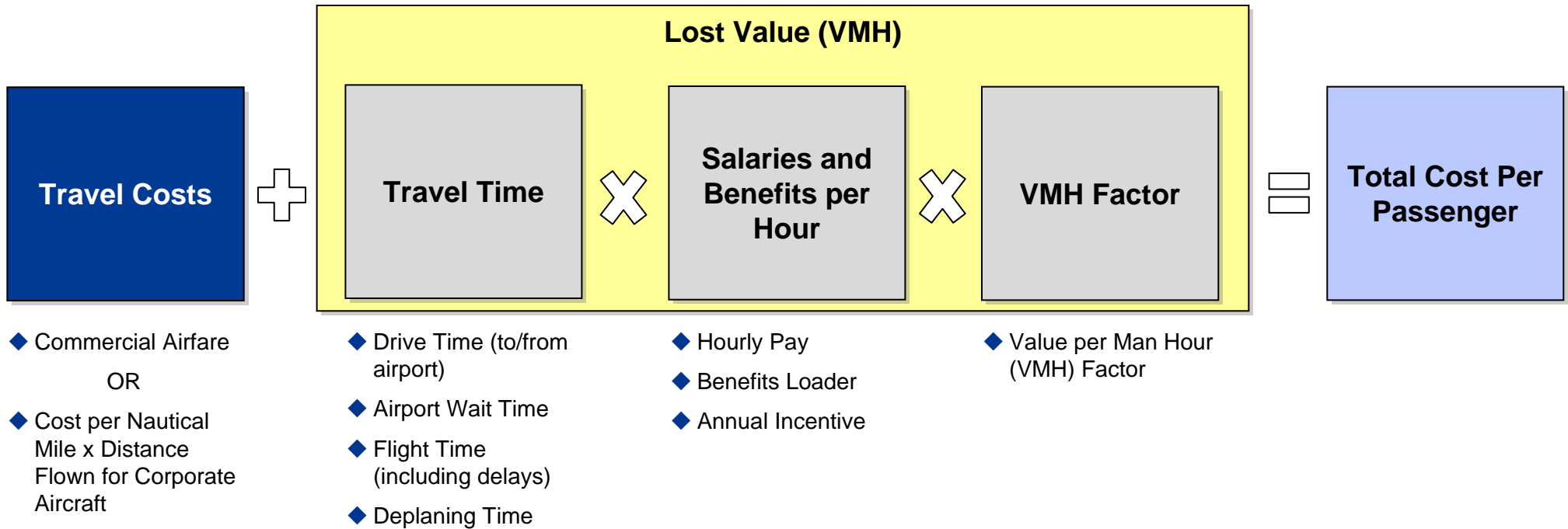
Travel Times: Denver, CO to Amarillo, TX

Commercial Airline

Corporate Aircraft



Overview of Total Cost Calculation



Overview of Total Cost Calculation (Cont'd)

Example: Denver, CO to Minneapolis, MN

Commercial Airline

Travel Costs
\$115.00



Lost Value (VMH)
\$1,170.81



Average Number of Passengers
6.1



Total Cost Per Flight
\$7,893.77

Assumes 2x VMH multiplier

Corporate Aircraft

Travel Costs
\$1,379.37



Lost Value (VMH)
\$572.35



Average Number of Passengers
6.1



Total Cost Per Flight
\$11,981.90

Additional Costs Utilizing Corporate Aircraft
\$4,088.13

Summary of Results

- ◆ Based on 2011 and annualized 2012 cost and travel statistics, Xcel Energy's corporate aircraft fleet cost between \$1.9M and \$2.3M more than comparable commercial airline travel alternatives for the six city pairs analyzed

Incremental Cost of Corporate Aircraft Use (More)/Less Than Commercial Airline Use

	2011	2012 Annualized
2.0 VMH	(\$2,261,252)	(\$1,889,158)

Example Analysis: Minneapolis, MN to Denver, CO

Cost-Benefit Analysis of Corporate Aircraft and Commercial Airline Travel (Example)

Year **2012** Change Cell B3 on "Summary" worksheet to 2012 to apply 2012 data

Minneapolis to Denver		Corporate Aircraft	Commercial Airline
Distance (NM)		614	614
Average Pax per Leg		6.1	6.1
Number of Legs		1	1

Time Spent for One Way Trip		Corporate Aircraft	Commercial Airline
Wait Time for Taxi or Shuttle/Time to get to Car if Driving Office to Airport		0.08	0.08
Allowance for Security, Check-in and Wait Time		0.35	0.33
		0.50	2.00
Flight Time		1.75	2.09
Taxiing Time		0.17	0.00
Average Delay		0.00	0.16
Deplaning Time		0.08	0.25
Wait Time for Taxi or Shuttle/Time to get to Car if Driving Airport to Office		0.08	0.08
		0.50	0.53
Total (one way trip)		3.52	5.53

Total travel times

Commute time based on Google Maps search results

Cost for One Way Trip per Person		Corporate Aircraft	Commercial Airline
Travel-En Route		\$1,383.29	\$107.50
Lost VMH per One Way Trip Per Person		\$576.73	\$1,196.51
Rental Car/Taxi/Shuttle		\$0.00	\$0.00
Hotel		\$0.00	\$0.00
Meals		\$0.00	\$0.00
Other		\$0.00	\$0.00
Total Cost		\$1,960.02	\$1,304.01

Cost For All Passengers		Corporate Aircraft	Commercial Airline
Average Pax per Leg		6.1	6.1
Total Cost		\$11,998.71	\$7,982.81

Comparative costs of corporate vs. commercial air travel for all passengers on this flight

Average flight times; Corporate per Xcel Energy, Commercial is average per published flight times

Value per Man Hour (VMH) Calculations						
	% Flights Flown	Hourly Salary	Benefits Loader	Total Hourly Compensation	Value Multiplier	VMH
Board Members	0%	\$ -	0%	\$ -	-	\$ -
CEO	1%	\$ 1,060	22%	\$ 1,293	2.0	\$ 2,586
COO	0%	\$ 748	26%	\$ 942	2.0	\$ 1,883
Senior Executive	12%	\$ 270	29%	\$ 349	2.0	\$ 698
Vice President	18%	\$ 151	33%	\$ 200	2.0	\$ 401
Director/Manager	42%	\$ 78	37%	\$ 107	2.0	\$ 213
Other Employees	24%	\$ 55	40%	\$ 77	2.0	\$ 154
Non-Employees	2%	\$ -	0%	\$ -	-	\$ -
				Wt. Average		\$ 311

Go to "Assumptions" to change the values in these cells

VMH

Total Lost VMH		Corporate Aircraft	Commercial Airline
Potential Lost VMH During Transportation, Security, Check-in and Wait Time*		\$ 313.72	\$ 807.47
% of Transportation and Wait Time Spent on Work-Related Activities	40%		40%
Potential Lost VMH During Flight		\$ 544.87	\$ 650.76
% of Flight Time Spent on Work-Related Activities	72%		72%
VMH on Work-Related Activities		\$ 517.79	\$ 524.72
Lost VMH During Driving and Wait Time*		\$ 235.93	\$ 263.00
Total Lost VMH		\$ 576.73	\$ 1,196.51

Productivity during transportation and wait time

Productivity differential between Corporate and Commercial air travel during flight

Cost of Corporate Aircraft Service	
Nautical Miles Flown	176,060
Aviation Expenditures	\$ 2,428,177
Cost per Nautical Mile	\$ 13.79

Sources

- ◆ *Business Aircraft Operations Financial Benefits and Intangible Advantages*, 1991 (Revised 1995), PRC Aviation
- ◆ *Survey of Companies Using Turbine-Powered General Aviation Aircraft for Business Transportation*, Study No, 718235, June 24, 1997, Louis Harris and Associates, Inc.
- ◆ *TravelSense – Business Travel Productivity Tracking Software User’s Guide*, Release 3, 1999, National Business Aviation Association, Inc.
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- ◆ *Business Travel Value Analysis*, April 2004, Daniel L. Sweet
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- ◆ *The Real World of Business Aviation: A Survey of Companies Using General Aviation Aircraft*, October 15, 2009, Harris Interactive, Inc.
- ◆ *DCAA Contract Audit Manual (DCAA Manual 7640.1)*, December 2009, Defense Contract Audit Agency
- ◆ *Fly or Drive Calculator*, Minnesota Department of Transportation
- ◆ *Mobile Technology and Business Travel: How does mobile technology influence the productivity of business travelers?*, 2011, University of Applied Science Heilbronn with partners ACTE Global, SAP, and DuntonTinnus Consulting
- ◆ *Businesses Unprepared to Support New Mobile Ways of Working*, November 21, 2011, Citrix Systems, Inc.