Direct Testimony and Schedules
Thomas E. Kramer

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL11-_____
Exhibit___(TEK-1)

Overall Revenue Requirements
Rate Base
Income Statement

June 30, 2011

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas E. Kramer. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Principal Rate Analyst in the Revenue Requirements – North Department for Xcel Energy Services Inc. ("XES" or the "Service Company"). XES is the service company for the Xcel Energy Inc. holding company system and providing services to all of the operating utility subsidiaries of Xcel Energy Inc.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been a Principal Rate Analyst since January 2011. Prior to that date, I held the position of Senior Rate Analyst in the same Department since May 2008. My qualifications and experience are summarized in my resume provided with my testimony as Exhibit___(TEK-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy," "NSPM" or the "Company"), operating in South Dakota. The Company is a wholly-owned utility operating company subsidiary of Xcel Energy Inc.

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

A. I provide testimony supporting the Company's financial data and its request for a general rate increase in the State of South Dakota retail electric jurisdiction. My testimony supports the income statement and rate base portions of the South Dakota cost of service.

Q. WERE THE SCHEDULES PRESENTED WITH YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. IN ADDITION TO THE SCHEDULES INCLUDED WITH THIS TESTIMONY, ARE THERE ADDITIONAL SCHEDULES YOU ARE SPONSORING?

A. Yes. I am sponsoring the following Statements and supporting Schedules, which are required by South Dakota Public Utilities Commission ("Commission") Rules (Sections 20:10:13:51 *et seq*.). These Statements and Schedules are located in Volume 1 of the Application:

A. Balance sheet

B. Income statement

C. Earned surplus statements

D. Cost of plant

D-1. Detailed plant accounts

D-2. Plant addition and retirement for test period

D-3. Working papers showing plant accounts on average basis for test period

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P. Fuel cost adjustment factor

R. Purchases from affiliated companies

To the extent the Commission's rules require a discussion of the content of these required Schedules, that discussion is provided with the required Schedule. Ms. Laura McCarten provides the description of utility operations required Statement Q in her Direct Testimony. Mr. Michael Peppin provides the support for the Statement O in his Direct Testimony.

Q. HAVE YOU RELIED ON INFORMATION PROVIDED BY OTHER WITNESSES IN PREPARING YOUR TESTIMONY AND SCHEDULES?

A. Yes. I relied on and incorporated information provided by other witnesses in this proceeding. Where applicable, I indicate in my testimony where the pro forma year cost information is based on information provided by other witnesses.

Q. WILL YOUR TESTIMONY INCLUDE A DISCUSSION OF THE NUCLEAR COST RECOVERY RIDER?

A. Yes. The need for the Nuclear Cost Recovery Rider ("NCR") is discussed by Ms. Laura McCarten. The tariff and rate design for the Rider are discussed by Mr. Steven Huso. I will discuss the anticipated revenue requirement that will be addressed through the NCR and explain that the NCR has no impact on the revenue requirement established in this proceeding.

II. PRO FORMA YEAR REVENUE DEFICIENCY

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

A. The jurisdictional retail revenue requirement for South Dakota electric utility operations is $171,802,000, based on average rate base and net operating income for the 2010 pro forma year, as adjusted for known and measurable changes occurring in 2011, making the 2010 pro forma year appropriate for the final rates that will go into effect in 2012. The jurisdictional retail revenue requirement is also based on the average 2010 capital structure, long-term debt and 11.00 percent cost of equity, based on the return on equity ("ROE") recommended by Mr. Daniel Dane in his Direct Testimony.

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

A. The amount of the revenue deficiency for the pro forma year is $14,583,000. A summary of the revenue deficiency is shown in Exhibit___(TEK-1), Schedule 2 (Cost of Service Study ("COSS"), Page 5 of 6) as a comparison of the jurisdictional revenue requirement amount for the 2010 pro forma year with the revenues for the same period under present rates as approved by the Commission in Docket No. EL09-009. In order to earn an overall rate of return of 8.78 percent, South Dakota retail electric rates need to be increased by this amount, as developed in Exhibit __ (TEK-1), Schedule 2 (COSS, Page 5 of 6).

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

A. The revenue deficiency amount represents a 9.28 percent overall increase in retail revenues compared to 2010 retail revenues (adjusted for fuel recovery timing and weather) at present rates as shown in Exhibit___(TEK-1), Schedule 2 (COSS, Page 5 of 6).

Q. DID YOU PREPARE A COSS THAT SUPPORTS THE REVENUE REQUIREMENT AMOUNT AND REVENUE DEFICIENCY FOR THE PRO FORMA YEAR?

A. Yes, under my direction, a COSS was prepared. Exhibit___(TEK-1), Schedule 2 (COSS Pages 1-6) contains a copy of the jurisdictional cost of service study.

Q. IS THE COMPANY PROPOSING ANY COST RECOVERY CHANGES THAT ARE REVENUE NEUTRAL TO THE RATEPAYERS?

A. Yes. The Company is proposing two changes that affect the base rate revenue deficiency without affecting the overall revenue requirement and the overall rates paid. These two changes, totaling approximately $680,000, reflect the shift of cost recovery from rate rider recovery to base rate recovery. Therefore, $680,000 of the $14,583,000 being requested is a result of a change in the Company's method of rate recovery.

Q. PLEASE DESCRIBE THE FIRST OF THESE REVENUE NEUTRAL COST RECOVERY CHANGES INVOLVING RATE RIDERS.

A. The first requested cost recovery change is to move into base rates all projects previously approved by the Commission for recovery under the Transmission Cost Recovery ("TCR") Rider. The TCR Rider tariff was established in Docket No. EL07-007 to provide for the cost recovery of the jurisdictional portion of eligible investments in and expenses related to new or modified transmission resources. Revenue requirements for certain facilities currently collected under the TCR are being rolled into base rates and therefore removed from the riders. Under the TCR, revenue requirements for the BRIGO and Blue Lake projects are being included in the determination of the South Dakota rate case for the proforma test year. This shift from the rider to base rates is prudent as both these projects have been completed, and are included in plant in service for the entire proforma test period. The shift of these projects from the TCR into base rates is estimated to increase base rates approximately $268,000 while reducing the TCR revenue requirements by an equal amount.

Q. PLEASE DESCRIBE THE SECOND OF THESE REVENUE NEUTRAL COST RECOVERY RATE RIDER CHANGES.

A. The second proposed revenue neutral adjustment is to zero out the Environmental Cost Recovery ("ECR") Rider established in Docket No. EL07-026 and instead include recovery of the A.S. King ("King") Plant and Sherco Unit 3 mercury pollution control equipment and related expenses as part of our base rate request. This rider collects approximately $412,000 annually from customers to pay the jurisdictional portion of eligible environmental expenditures.

Q. WHERE ARE THE RATE RIDER COST RECOVERY CHANGES SHOWN IN THE DETERMINATION OF PRO FORMA YEAR REVENUE REQUIREMENTS?

A. The 2010 unadjusted test year data included recovery of the costs included in the TCR and ECR Riders. Therefore in developing the 2010 pro forma year deficiency it is necessary to remove the revenues for the two completed projects being moved into base rates and to remove the costs of those uncompleted projects that will continue to be recovered through the riders. The TCR and ECR Riders will be adjusted to exclude recovery of the 2010 project revenue requirements. The Company will adjust the TCR and ECR Riders in a compliance filing at the end of the rate case to exclude 2012 recovery for projects currently included in the TCR and ECR Riders that are moved to base rate recovery effective with implementation of final rates as a result of this docket. These adjustments were used in developing the 2010 proforma year and are included in Exhibits___(TEK-1), Schedule 6a, Column 12, and Schedule 6b, page 3, Column 34.

III. PRIMARY REASONS A RATE INCREASE IS NEEDED

Q. WHAT ARE THE PRIMARY DRIVERS FOR THE CURRENT REVENUE SHORTFALL?

A. Current rates were established based on a pro forma 2008 test year from Docket No. EL09-009. Consequently, the comparison I will provide is to the final authorized pro forma 2008 test year. Exhibit___(TEK-1), Schedule 3 (Case Drivers) contains a summary of the case drivers. The following Table 1 lists the primary drivers for an increase in the revenue requirement that have occurred since the pro forma 2008 test year.

Table 1

Case Drivers

Dollars in Millions	**Increase over 2008**
Capital Recovery	$11.5
Non-Fuel O&M Expense (includes Payroll Taxes)	$8.5
Amortization	$0.3
Subtotal	$20.3
Less Increase in Retail Margins	$(5.7)
2010 Pro Forma Deficiency	$14.6

Q. THE LARGEST INCREASE IN REVENUE REQUIREMENTS RELATES TO CAPITAL NEEDS. PLEASE PROVIDE ADDITIONAL INFORMATION CONCERNING THE INCREASED CAPITAL INVESTMENTS MADE BY THE COMPANY SINCE 2008.

A. Table 2 provides a high level breakdown of the principal capital investments and related costs since 2008, resulting in an additional revenue requirement of $11.5 million.

Table 2

Case Drivers – Capital Recovery

Dollars in Millions	**Total Revenue Requirement**
Generation Projects	
Nuclear & Wind Related	2.4
All Other Generation	1.3
Total Generation Projects	3.7
Transmission Projects	0.6
South Dakota Distribution Projects	0.2
Total Identified Projects	4.5
Other Increases / (Decreases)	0.7
Total Rate Base	5.2

Depreciation	1.2
Property Taxes	1.1
Other Return & Tax Related	4.0
Total Capital Recovery Items	$11.5

Q. PLEASE BRIEFLY DESCRIBE THE GENERATION PROJECTS.

A. In total, we have added new generating capacity (Nobles Wind) and made several critical improvements to the resources on the system (Monticello Life Cycle Management/Extended Power Uprate and Prairie Island Life Extension ("LCM/EPU")) since our last rate case in South Dakota, investing approximately $51.5 million in net generation plant in service since 2008. We believe we have done so in a cost effective manner and ensured efficient and reliable generation is available to serve customers while at the same time being environmentally responsible.

Q. PLEASE DESCRIBE THE TRANSMISSION PROJECTS.

A. The Company continues to make significant investments in transmission plants in two separate groups: (i) investments qualifying for rate rider treatment, primarily transmission investments supporting increased delivery of wind generation; and (ii) system performance and interconnection investments. However, Xcel Energy has also made significant investments in transmission projects that were not included in the TCR Rider. The Company has invested in transmission projects mainly related to system performance and interconnection investments, resulting in an increase in plant investment of approximately $9.3 million for the South Dakota jurisdiction.

Q. PLEASE DESCRIBE THE SOUTH DAKOTA DISTRIBUTION PROJECTS.

A. These project costs were specific to South Dakota and were for the purpose of adding to or improving distribution service in South Dakota and, therefore, have been directly assigned to the South Dakota jurisdiction. The Company's average investment in South Dakota distribution net plant in service has increased by approximately $4.7 million since 2008.

Q. WHAT ARE THE MAJOR INCREASES IN OPERATIONS AND MAINTENANCE ("O&M") COSTS?

A. As shown in Table 3, the major changes in O&M costs are non-fuel production expense, transmission expense, and Administration & General ("A&G").

Table 3

Non-Fuel O&M Cost Drivers

Dollars in Millions	Change in O&M	Revenue Requirement Impact
Non-Fuel Production Expense	$7.9	$4.9
Transmission	$1.8	$1.5
Distribution	$0.1	$0.1
Customer Accounts	$(0.2)	$(0.2)
Customer Information	$0.1	$0.1
A&G	$1.9	$1.9
Payroll Taxes	$0.2	$0.2
Total	$11.8	$8.5

Q. PLEASE DESCRIBE TABLE 3.

A. Table 3 compares the change in O&M as reflected in the Cost of Service between the 2008 settlement level and the 2010 pro forma year. Some O&M

costs that are not recovered in the Fuel Clause are reflected as fuel expense in the Cost of Service rather than as O&M; for example, fuel handling. Table 3 also shows the revenue requirement change associated with the change in O&M. Changes in O&M generally result in a dollar for dollar impact to revenue requirements. However, production and transmission O&M costs that are partially offset with revenue have less than a dollar for dollar impact; for example, costs shared with NPSW Company through the Interchange Agreement, or transmission costs offset with MISO revenue. See Exhibit___(TEK-1), Schedule 3 (O&M Drivers, Page 2 of 2) for detail supporting the expense and revenue re-classifications and interchange impacts.

Q. WHAT ARE THE DRIVERS FOR THE CHANGE IN O&M EXPENSE?

A. The increased non fuel production expense is associated with increased operating costs at the nuclear facilities and increased purchased demand costs. The increase in transmission expenses is associated with increased interchange charges, higher demand costs and a slight increase in maintenance activity. Pensions and benefit cost increases, employee related expenses and insurance increases account for the increased A&G between the two periods.

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

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

Q. HOW MUCH HAS DEPRECIATION EXPENSE CHANGED SINCE 2008?

A. As shown in Exhibit___(TEK-1), Schedule 4 (Income Statement 2008 Settlement Reported & 2010 Pro Forma with Increase, Page 2 of 2), depreciation expense has increased $1,242,000 since 2008. Additional plant in service of $116.6 million, as can be seen in Exhibit____(TEK-1), Schedule 12, Page 1 of 2, has been partially offset by the extended lives of the plant in service.

Q. HOW WAS DEPRECIATION EXPENSE AFFECTED BY ANY REMAINING LIFE STUDIES?

A. Included in the known and measurable pro forma adjustment section on my testimony, I address the impact on the test year of the remaining life and net salvage estimate changes for several generation related facilities

IV. DATA PROVIDED AND SELECTION OF PRO FORMA YEAR

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

A. Following the rules of the Commission, financial data is provided for the calendar year 2010 (the "unadjusted test year") and the 2010 pro forma year that includes 2011 known and measurable adjustments.

Financial data is first normalized to remove any unusual conditions in the actual year (e.g. weather normalization) that should be adjusted for rate setting purposes. Next, the actual year is adjusted for regulatory adjustments (*e.g.* foundation administration expenses, lobbying expenses, advertising, etc.). Finally, I make pro forma adjustments to reflect known and measurable changes occurring in 2011 that should be included, so that final rates, which will become effective in 2012, will reflect the Company's revenues and expenses at the time the rates go into effect.

I provide schedules for the unadjusted 2010 test year showing: the actual unadjusted average rate base consisting of the same rate base components; unadjusted operating income; overall rate of return; the calculation of required income; the income deficiency and revenue requirements. Separate rate base and income statement bridge schedules identify the adjustments described in my testimony to the unadjusted 2010 test year that create the pro forma year reflecting: the normalizing adjustments; regulatory adjustments; and the known and measureable adjustments for 2011.

In this rate case, the Company proposes to transfer recovery of certain capital projects from the TCR and ECR Riders to base rates at the time final rates go into effect in 2012. These transfers cause corresponding changes in the costs to be recovered in the rate riders.

V. JURISDICTIONAL COST OF SERVICE STUDY

A. Components of Jurisdictional COSS

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE 2010 PRO FORMA YEAR.

A. The complete jurisdictional cost of service is included in Volume 3 (Work papers) of this filing. The jurisdictional cost of service includes: a revenue requirement, rate base, income statement, income tax, and a cash working capital computation.

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

A. The pro forma year jurisdictional cost of service summary is included at Exhibit___(TEK-1), Schedule 2 (COSS, Pages 1-6). In order to facilitate a comparison to the unadjusted 2010 test year, we have also included the unadjusted 2010 test year jurisdictional cost of service summary as Exhibit ___(TEK-1), Schedule 2A (COSS, Pages 1-6).

- The cover page identifies the South Dakota retail jurisdiction requested ROE, and shows the earned ROE under current rates, the revenue deficiency, and the percent of increase that would result if rates were increased to earn the requested ROE (in this case 11.00 percent).
- The "Rate Base Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 2).
- An "Income Statement Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 3). The income statement shows the determination of total operating income at present authorized retail rates.
- The "Income Tax Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 4). The schedule shows adjustments to book income necessary to determine state and federal taxable income. The federal and state income tax calculations are carried back to the income statement on Schedule 2 (COSS, Page 3).
- The "Revenue Requirement and Return Summary" for total Company electric operations and the South Dakota jurisdiction is shown on Schedule 2 (COSS, Page 5). Specifically, the schedule shows: the

earned overall rate of return on rate base, the earned ROE, the revenue deficiency that needs to be recovered to enable the South Dakota jurisdiction electric operations to earn the requested ROE, the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.

- The computation of cash working capital, Schedule 2 (COSS, Page 6), is carried back to the rate base on Schedule 2 (COSS, Page 2).

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

A. Yes. The revenue conversion factor calculation, using a South Dakota composite tax rate of 35 percent, is included in my exhibits at Exhibit___ (TEK-1) Schedule 2 (COSS, Page 5).

B. Income Statement Schedules

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

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

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

A. I have provided two schedules related to the income statements: Exhibit___(TEK-1), Schedule 4 (2010 Pro Forma with Increase and Income

Statement 2008 Settlement); and Exhibit ___(TEK-1), Schedule 5, Page 2 of 2 (Income Statement Comparison - 2010 Pro Forma to Unadjusted Test Year).

Q. WHAT DOES EXHIBIT ___(TEK-1), SCHEDULE 4 INCLUDE?

A. Schedule 4 (2010 Pro Forma with Increase and Income Statement 2008 Settlement) consists of two comparative income statements for the pro forma year. Page 1 of Schedule 4 is a comparative income statement for the 2010 pro forma year showing the income effect of present authorized rates and proposed rates. This comparative income statement was prepared from the results of the jurisdictional cost of service study and includes the revenue deficiency in the South Dakota jurisdiction electric utility operations. Page 2 of Schedule 4 shows a comparative income statement of the 2010 pro forma year after the proposed rate increase, and the 2008 settlement test year as reported.

C. Compliance with Commission Orders

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

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

- Post Retirement Medical Benefits ("OPEBs") – Pay as you go. In Docket No. EL09-009 the Commission reaffirmed its position to not use accrual accounting and instead to use pay as you go as the appropriate mechanism for recovering the cost of OPEBs. We have adjusted the 2010 actual year to reflect the use of pay as you go accounting.

- Non-Asset Based Margins. The Commission's Order in Docket No. EL09-009 approved a non-asset based sharing mechanism under which the Company provided 25 percent of the non-asset based margins to the ratepayers through the fuel adjustment clause. To test the reasonableness of that sharing mechanism, the Company was directed to conduct and present incremental and fully allocated cost studies in this proceeding. I will discuss those studies and our recommendation to retain the existing sharing mechanism later in my Direct Testimony
- Moving Completed TCR and ECR Projects to Base Rates. In Docket EL09-009 the Company was directed to move the costs of completed TCR and ECR projects into the base rate revenue requirement. On that basis, as I discussed earlier, we have proposed moving the costs of TCR and ECR projects completed in 2010 into base rates
- Depreciation of Prairie Island Nuclear Generating Plants. In Docket EL09-009, the Commission ordered a 20 year life extension for Prairie Island. The 2010 unadjusted test year data reflects this requirement and, therefore, no pro forma adjustment is required.
- Amortization. In Docket No EL09-009 the Commission approved a six year amortization period for the Private Spent Fuel Storage Facility; and a five year amortization period for Rate Case Expense and SO2 emissions. Because we are filing a rate case within two years, those costs have not been fully amortized. Therefore, it is reasonable to retain the existing amortization period for those costs and no adjustment to the 2010 actual year costs was needed.

- Renewable Development Fund Cost Recovery. In Docket No. EL09-009, the Commission disallowed any cost recovery for Renewable Development Fund costs. Those costs were therefore removed from the 2010 actual year costs and no adjustment was needed.

D. Jurisdictional Allocations.

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

A. The pro forma year includes both costs incurred directly by the Company's electric operating business and costs directly assigned or allocated by the Service Company for corporate functions (*e.g.,* accounting, human resources, law, etc.). The Service Company cost allocation and billing process is subject to Federal Energy Regulatory Commission ("FERC") jurisdiction and authorization under a Utility Services Agreement between Xcel Energy and the Service Company. O&M cost assignments and allocations were the same as used by the Company in the recent Minnesota electric rate case filed with the Minnesota Commission (MPUC Docket No. E002/GR-10-971) and the rate case recently filed with the North Dakota Public Service Commission (PU-10-657). Non-O&M costs include such items as book depreciation expense, deferred income taxes and property taxes. All of the common investments and their related costs, be they software or other common investments, are evaluated by asset location as to whether they should be direct assigned to Electric or Gas, or allocated based on Customers, Customer Bills, Transportation Studies, or the Three Factor Allocator (revenues, utility plant in service, and total employees). Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost

Assignment and Allocation Manual ("CAAM") included in Volume 4 of this Application.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE COSTS FOR ELECTRIC UTILITY OPERATIONS IN SOUTH DAKOTA.

A. Expenses are generally determined on a functional basis (*i.e.* Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to the South Dakota jurisdiction electric utility operations or allocated to the electric operations based on cost causation. A summary and description of the allocation factors used to allocate expenses and capital items to the South Dakota jurisdictional electric operations income statement and rate base are contained in the CAAM included in Volume 4.

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

A. A summary and description of the allocation factors used to allocate expenses and capital items to the South Dakota jurisdictional electric operations income statement and rate base is contained in Exhibit___(TEK-1) Schedule 8 (Allocation Factors). Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Detailed records are maintained on a functional basis (*i.e.* Production, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly, or allocated based on the use of such assets in providing electric service in a particular jurisdiction and the underlying elements of cost causation.

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

A. The Company's production and transmission system is designed, built, and operated to provide an integrated source of electricity shared by the Company's electric customers first between NSPM and Northern States Power Company – Wisconsin ("NSPW") operating companies through the Interchange Agreement approved by the FERC and discussed later in my testimony. With respect to allocations involving transmission and generation, it is first necessary to allocate expenses and investments between NSPW and NSPM. Those allocations are performed in accordance with the Interchange Agreement. Pursuant to that Interchange Agreement, approximately 16 percent of the costs are allocated to NSPW with a remaining 84 percent allocated to NSPM. The NSPM costs are then allocated between South Dakota, Minnesota and North Dakota and a small group of wholesale customers taking service under rates regulated by FERC. The result is that those investments and expenses that are subject to the Interchange Agreement are allocated approximately 4.7 percent to South Dakota. Those investments and expenses that are not subject to the Interchange Agreement are allocated approximately 5.6 percent to South Dakota.

Q. PLEASE DESCRIBE THE METHODS OF ALLOCATING COSTS BETWEEN THE FOUR JURISDICTIONS SERVED BY NSPM.

A. To allocate NSPM investment in production and bulk transmission facilities to jurisdictional areas, I used the average of the 12-monthly coincident peak demands ("12 CP Method") for the actual year ended December 31, 2010. The Commission accepted this method of allocation in previous rate proceedings

(Docket Nos. EL09-009, EL92-016, F-3764 and F-3780). It is reasonable to use coincident peak demands as an allocation basis, because these facilities are designed to meet peak requirements and operate as an integrated system across all jurisdictions. Similarly, fixed operating costs, which are not sensitive to changes in the amount of energy produced, also have been allocated on a demand basis. Expenses and investment related to units of output, such as nuclear fuel, were allocated on the basis of energy requirements. Items of plant that serve only the jurisdiction in which they are located are directly assigned to that jurisdiction.

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

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

Q. PLEASE DESCRIBE ANY ADJUSTMENTS MADE TO THE ALLOCATION FACTORS FOR USE IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2010.

A. To allocate investment in production and bulk transmission facilities for the 2010 year, I used the 2010 12-month coincident peak demands and energy allocators unadjusted for weather. In order to remove the effect of weather on the demand and energy allocators, an adjustment was applied to the unadjusted test year data. This adjustment is discussed in greater detail under the section Known and Measurable Pro Forma Adjustments. The same customer allocation factor is used for the unadjusted and pro forma years ending December 31, 2010. The allocation factors used in the development of data in the unadjusted and pro forma year-end December 31, 2010 may be found on

Exhibit___(TEK-1) Schedule 8 (Allocation Factors). The revenues and expenses allocated to South Dakota can be found on Exhibit___(TEK-1), Schedule 2 (Cost of Service Study ("COSS"), Page 3 of 6) for the pro forma year and Exhibit___(TEK-1), Schedule 2A (Unadjusted Cost of Service Study ("COSS"), Page 3 of 6) for the unadjusted test year.

E. Pro Forma Adjustments.

Q. PLEASE IDENTIFY ALL THE PRO FORMA ADJUSTMENTS MADE TO THE UNADJUSTED TEST YEAR TO DEVELOP THE PRO FORMA YEAR ENDED DECEMBER 31, 2010.

A. The following is a comprehensive list of all the adjustments included in the rate case to arrive at the 2010 pro forma test year. It was necessary to make three categories of changes to the 2010 actual year to make the resulting pro forma 2010 test year appropriate for setting rates that will be finalized and applied to service provided in 2012 and after. The first category of change is to normalize the 2010 data. The second category of change is to reflect prior regulatory decisions for what may be appropriately included in a pro forma year. The third category of changes is for known and measurable changes occurring in 2011 that need to be reflected in order for rates to be appropriate when charged in 2012:

Normalization of 2010 Unadjusted Base Data:

1) Weather Normalization;
2) Fuel Lag Adjustment;
3) Fuel Recovery Timing;
4) Incentive Compensation;
5) Vegetation Management;
6) Storm Damage;

7) Claims & Injury Compensation;

8) One-Time Fuel Write-Off;

Adjustments Reflecting Regulatory Practice:

9) Advertising Expenses;

10) Economic Development Costs;

11) Interest on Customer Deposits;

12) Professional and Utility Association Dues;

13) Charitable Contributions/Donations;

14) SFAS 106 Post Retirement Medical;

15) 2011 Rate Case Expense;

Known and Measurable Adjustments:

16) Nobles Wind Project;

17) Monticello Extended Power Uprate Project;

18) Prairie Island Life Extension Project;

19) King Plant Mercury Sorbent;

20) Merricourt Removal;

21) Steam Remaining Life Adjustment;

22) Other Production Remaining Life Adjustment;

23) Bonus Tax Depreciation;

24) Net Operating Loss;

25) Union Wage Adjustment;

26) Non-Union Wage Adjustment;

27) Margin Sharing on Trading Activity;

28) Wholesale Billing Adjustment;

29) Foundation Administrative Expenses;

30) Employee Expense Reductions;

31) Pension and Insurance Adjustment;

32) Weather Normalized Allocator; and

33) Removal of TCR & ECR Costs

A list of these pro forma year adjustments is shown on Exhibit___(TEK-1), Schedule 9 (Rate Case adjustments). I will also discuss each adjustment later in my testimony. In addition, I have provided a bridge schedule (Exhibit___(TEK-1), Schedule 6a (Rate Base) and Exhibit___(TEK-1), Schedule 6b (Income Statement) that shows all normalized, regulatory and known and measurable changes adjustments included in Exhibit___(TEK-1), Schedule 9.

1. Pro Forma Year Normalizing Adjustments.

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2010 ACTUAL DATA FOR THE PURPOSE OF NORMALIZING THE EXPENSES. PLEASE EXPLAIN.

A. The purpose of the pro forma year is to set rates based on a representative set of revenues and expenses. Consequently, it is necessary to normalize certain 2010 actual data.

Q. WHAT IS THE WEATHER NORMALIZATION ADJUSTMENT?

A. Our 2010 actual year reflects actual sales. Sales are affected by weather. Therefore, it was necessary to weather normalize the retail sales margin. For 2010, the estimated weather impact on sales was a positive 14,307 MWh's, meaning that weather had a favorable effect on sales relative to the budgeted sales. Therefore an adjustment is needed to reflect revenues in the test year based upon normal weather. This adjustment decreases retail revenue by $1,280,000.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 2. As shown on Schedule 6b, page 1, column 2, row 29, this adjustment increases test-year revenue requirements by $1,280,000.

Q. DO RETAIL OPERATING REVENUES REFLECT CALENDAR MONTH SALES VOLUMES IN THE PRO FORMA YEAR?

A. Yes. Non-fuel unadjusted test year revenues are on a calendar-month basis. However, the unadjusted test year reflects fuel revenues and fuel expenses that include a recovery lag of approximately 2.5 months. A pro forma adjustment was made to adjust the timing of both fuel revenue and expenses to an actual 2010 calendar-month basis. This adjustment has no impact on the revenue deficiency as the adjustment to revenue is offset by an equal adjustment to fuel expense. The adjustment reduces both retail revenues and fuel expense by $407,000, resulting in no change to revenue requirements.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 3. As shown on Schedule 6b, page 1, column 3, row 29, this adjustment had no impact on test-year revenue requirements.

Q. IS THE COMPANY MAKING ANY OTHER SALES ADJUSTMENTS FOR THE PRO FORMA YEAR 2011?

A. No. The budgeted 2011 South Dakota sales are currently estimated to be 1.46 percent higher than the actual 2010 sales, (on a weather normalized basis the increase is 2.19 percent). Actual weather normalized sales growth 2010 over 2009 was only 1.04 percent and 2009 over 2008 was 0.33 percent. Given the recent actual results when compared to the budgeted 2011 sales estimate, I am not recommending any pro forma adjustments related to sales.

Q WHAT IS THE FUEL RECOVERY ADJUSTMENT?

A During the fiscal year 2010, the Company reassessed the methodology it was using to recognize the unbilled deferred fuel costs at month end that should be recovered through the fuel clause recovery mechanism. The Company had been recording this estimated deferred fuel cost on the balance sheet as a regulatory asset. Beginning in September of 2010 the unbilled deferred fuel cost is now being booked into revenue at month end and then reversed at the start of the next month. Since this method of recording the unbilled deferred fuel cost began in September 2010 the test year does not include a full year's worth of accruals and accrual reversals. This is a one-time adjustment to reverse the December, 2010 deferred fuel costs entry that was reversed in January 2011. On a going forward basis all future test years should include a full 12 months of entries.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 4. As shown on Schedule 6b, page 1, column 4, row 29, this adjustment decreases test-year revenue requirements by $2,635,000.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING THE 2010 INCENTIVE COMPENSATION PAYMENTS?

A. Incentive compensation payouts can vary from year to year based upon the actual results for the year compared to the plan objectives. For example, in the 2008 plan year, no Annual Incentive Plan ("AIP") payment was awarded. As a result, the Commission approved setting the incentive level in the last case (Docket No. EL09-009) based upon a four-year average payout percentage. During the four-year period of 2007-2010 the AIP payments made were, on average, 83 percent of the target payout of 100 percent. Therefore, I applied the same methodology, applying 83 percent to the 2010 AIP expense booked. We also removed from the unadjusted test year 2010 the long-term portion of officer's incentive compensation, and any non-corporate incentive plan costs. See the incentive pay work papers at Volume 3 for this calculation.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 5. As shown on Schedule 6b, page 1, column 5, row 29, this adjustment decreases test-year revenue requirements by $727,000.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING VEGETATION MANAGEMENT/TREE TRIMMING?

A. In accordance with the Settlement Agreement in Docket No. EL09-009, the Commission approved normalizing tree trimming based upon the five-year average of the actual experience. Therefore, I applied the same methodology, and replaced the 2010 actual year vegetation and tree trimmings costs with the average tree trimming costs for the five-year period 2006 through 2010.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 6. As shown on Schedule 6b, page 1, column 6, row 29, this adjustment decreases test-year revenue requirements by $9,000.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING STORM DAMAGE EXPENSE?

A. In accordance with the Settlement Agreement in Docket No. EL09-009, the Commission approved normalizing annual storm damage based upon the five-year average of the actual experience. Consequently, I normalized the annual storm damage by replacing the actual storm damage costs in the 2010 with the average storm damage costs for the five year period 2006 through 2010.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 7. As shown on Schedule 6b, page 1, column 7, row 29, this adjustment decreases test-year revenue requirements by $129,000.

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING CLAIMS AND INJURIES COMPENSATION EXPENSE?

A. In accordance with the Settlement Agreement in Docket No. EL09-009, the Commission approved normalizing annual claims and injuries compensation expense based upon the five-year average of the actual experience. Therefore, I applied the same methodology, and included an adjustment equal to the difference between the actual claims and injuries compensation costs included in the 2010 actual year and the average claims and injuries compensation costs for the five year period 2006 through 2010.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 8. As shown on Schedule 6b, page 1, column 8, row 29, this adjustment decreases test-year revenue requirements by $70,000.

Q. PLEASE EXPLAIN THE FUEL WRITE-OFF ADJUSTMENT?

A. Included in the 2010 actual expenses was a one-time write off of fuel costs that had been deferred on the balance sheet. This deferred fuel balance had been estimated to reflect the level of fuel costs that would be recovered through the South Dakota fuel recovery clause. The balance had been building up over time. In 2010, an assessment of the deferred balance determined that the cumulative balance was in excess of the actual level that should be deferred and the Company recorded an entry to expense in the current period in the amount of the excess deferred balance. This adjustment removes this one-time write off from the test year.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 9. As shown on Schedule 6b, page 1, column 9, row 29, this adjustment decreases test-year revenue requirements by $9,607,000.

2. Pro Forma Year Adjustments Reflecting Regulatory Practices

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2010 ACTUAL DATA FOR CERTAIN REGULATORY ADJUSTMENTS.

A. In this section I discuss the following adjustments made to the 2010 actual data to be consistent with prior regulatory adjustments made by the Commission.

- Advertising Expenses;
- Economic Development Costs;
- Interest on Customer Deposits;
- Professional and Utility Association Dues;
- Charitable Contributions/Donations;

- SFAS 106 Post Retirement Medical;
- 2011 Rate Case Expense;

Q. WHAT ADVERTISING ADJUSTMENT DID YOU MAKE?

A. The Company is required to reduce general and administrative expense for brand and image advertising costs that are not allowed to be recovered from South Dakota customers. The allowed advertising expense is primarily related to providing information on safety and customer information. Representative advertisements for which we are asking recovery and the relative dollar values are included in Volume 1, Schedule H-3. Because we recorded the cost of brand and image advertising below the line, most of those costs were not included in the 2010 unadjusted expenses. However, I removed $220,000 for advertisements that had the purpose of promoting the Company's brand or image along with other advertising expenses not recoverable from South Dakota customers that were included in the unadjusted 2010 year expenses.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 10. As shown on Schedule 6b, page 1, column 10 row 29, this adjustment decreases test-year revenue requirements by $220,000.

Q. HOW HAVE YOU TREATED ECONOMIC DEVELOPMENT COSTS?

A. In its last rate case, Docket No. EL09-009, the Company was authorized to recover 50 percent of its then current economic development expense up to $100,000 incurred for the benefit of South Dakota communities. Consequently, $50,000 of economic development costs has been included in the pro forma year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 11 As shown on Schedule 6b, page 1, column 11 row 29, this adjustment increases test-year revenue requirements by $50,000.

Q. WHY DID YOU MAKE AN ADJUSTMENT FOR INTEREST ON CUSTOMER DEPOSITS?

A. Customer deposits are treated as customer supplied capital and thus it is appropriate to pay ratepayers a return on their investment. The average balance of customer deposits is deducted from rate base while at the same time a pro forma year operating expense is increased to permit the recovery of the interest paid on these deposits.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 12. As shown on Schedule 6b, page 1, column 12, row 29, this adjustment increases test-year revenue requirements by $1,000.

Q. WHY DID YOU MAKE AN ADJUSTMENT TO ASSOCIATION DUES?

A. We are requesting recovery of our association dues, except for the portion of the dues that pays for social organizations or lobbying activities. Lobbying expenses are recorded below the line and consequently we do not have a separate lobbying adjustment. However, certain association dues include a component for social or lobbying activities of the organization. An analysis was prepared to eliminate that portion of the dues from the test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 13 As shown on Schedule 6b, page 1, column 13, row 29, this adjustment decreases test-year revenue requirements by $1,000.

Q. HOW HAVE YOU REFLECTED CHARITABLE CONTRIBUTIONS?

A. We are aware that the Commission has historically not approved charitable contributions. This was reinforced once again in the Settlement Agreement in Docket No. EL09-009. As a result, no charitable contributions were included in the 2010 actual year expenses. Although the Company believes requesting recovery of 50 percent of our charitable contributions made to South Dakota charities and institutions would be appropriate, we made no adjustment to include any charitable contributions in the test year.

The detailed jurisdictional operating income impacts of making no adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 14 As shown on Schedule 6b, page 1, column 14, row 29, there is no impact on test-year revenue requirements.

Q. WHY HAVE YOU INCLUDED AN ADJUSTMENT FOR STATEMENT OF FINANCIAL STANDARD ("SFAS") 106 POST RETIREMENT MEDICAL EXPENSES?

A. Prior to the issuance of SFAS 106, businesses recorded post-retirement benefit expenses other than pensions (primarily health care provided to retirees) on a pay-as-you-go basis. SFAS 106, which became effective in 1993, established an accrual accounting process under which the future projected cost of other post employment benefits or OPEBs was recognized at the time the benefits were earned. It also established a transition period of up to 30 years to recover the amounts that had not been previously recovered under the pay-as-you-go method but which would have been recognized under the SFAS 106 accrual method.

Fundamentally, using an actuarial estimate, the annual recorded amount is the current period expense for future postretirement benefits, such that the expense is fully recovered over the working life of the future retiree. The actuarially estimated amount is debited as expense and credited to the accumulated provision for OPEBs, creating a liability. When actual post-retirement health care costs are incurred, the liability is debited and cash is credited to pay the bill.

Q. HAS THE COMMISSION ADOPTED SFAS 106 FOR RATEMAKING PURPOSES?

A. No. In a January 26, 1993 Order in Docket No. EL92-016, the Commission declined to adopt SFAS 106 for ratemaking purposes. In Docket No. EL09-009, the Commission accepted the Company's adjustment that converted the test year SFAS 106 method of accounting used for financial reporting purposes to the Pay-Go method.

Q. WHAT ADJUSTMENT IS THE COMPANY REQUESTING IN THIS RATE REQUEST?

A. The Company is required to comply with SFAS 106 for financial reporting purposes. In addition, the Company is required to use SFAS 106 in the other jurisdictions in which it provides service. Consequently, it was necessary to convert from recognition of SFAS 106 to Pay-Go in the 2010 pro forma year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 2. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 1, column 15. As shown on Schedule 6b, page 1, column 15, row 29, this adjustment increases test-year revenue requirements by $483,000.

Q. PLEASE EXPLAIN THE AMORTIZATION OF RATE CASE EXPENSES IN THIS PROCEEDING.

A. The Company is projecting direct expenses associated with this rate case docket of $388,100. We propose to amortize these expenses over a two year period because we reasonably expect to file our next electric rate case within two years. Amortizing these expenses over a two-year period results in an annual amortization of $194,050. The development of our projected rate case costs is shown on Exhibit __ (TEK-1), Schedule 11 (Rate Case Expenses).

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 16. As shown on Schedule 6b, page 2, column 16, row 29, this adjustment increases test-year revenue requirements by $194,000.

3. Known and Measurable Pro Forma Adjustments

Q. DID YOU FURTHER ADJUST THE BASE 2010 DATA TO DEVELOP THE PRO FORMA YEAR?

A. Yes. I made additional pro forma known and measurable adjustments to the unadjusted 2010 test year data. These adjustments are necessary to have final rates reflect the cost of service at the time the final rates become effective. These adjustments are:

- Nobles Wind Project;

- Monticello Extended Power Uprate Project;
- Prairie Island Life Extension Project;
- King Plant;
- Merricourt;
- Steam Remaining Life Adjustment;
- Other Production Remaining Life Adjustment;
- Bonus Tax Depreciation;
- Net Operating Loss;
- Union Wage Adjustment;
- Non-Union Wage Adjustment;
- Margin Sharing on Trading Activity;
- Wholesale Billing Adjustment;
- Foundation Administrative Expenses;
- Employee Expense Reductions;
- Pension and Insurance;
- Weather Normalization Allocator; and
- Removal of TCR & ECR Costs

Q. WHAT STANDARD DO YOU APPLY WHEN ASSESSING WHETHER TO MAKE AN ADJUSTMENT FOR A KNOWN AND MEASURABLE CHANGE?

A. In order to be considered for a known and measurable change, there needs to be compelling evidence that the adjustment yields a more accurate ongoing level of cost. Factors such as the following would be considered:

- A signed contract in place (e.g. union wage increases);
- Action already taken by the Company (e.g. employee expense reductions);

- Major capital projects with actual or projected 2010 or 2011 in-service dates.

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO GENERATION THAT BECAME OPERATIONAL IN 2010 AND 2011?

A. I made adjustments for the Nobles Wind Project, The Monticello LCM/EPU Project; and the Prairie Island License Extension Project

Q. PLEASE DESCRIBE THE NOBLES WIND PROJECT AND THE ASSOCIATED ADJUSTMENT.

A. The Nobles Wind Project is a 201 MW wind energy generation facility consisting of 134 General Electric 1.5 MW wind turbines located within a project site encompassing approximately 25,000 acres in Nobles County, Minnesota. The project went into service in December 2010. The adjustment was determined by comparing the 2011 capital related revenue requirement to the 2010 capital related revenue requirement included in the unadjusted 2010 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 3. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 17. As shown on Schedule 6b, page 2, column 17, row 29, this adjustment increases test-year revenue requirements by $2,085,000.

Q. PLEASE DESCRIBE THE MONTICELLO LCM/EPU PROJECT AND THE ASSOCIATED ADJUSTMENT?

A. The Monticello LCM/EPU project will increase the power output at Monticello by 71 MW and also make investments needed to keep the plant operating safely and reliably into its extended license life. The Monticello project received a Certificate of Need for license extension in 2007 and a Certificate of Need for the Extended Power Uprate in 2009.

The Monticello LCM/EPU adjustment updates the test year for the projected 2011 in service costs associated with the project. The current planned in-service data for the project is during two separate outages, May and November of 2011. The adjustment was determined by comparing the 2011 capital related revenue requirement to the 2010 capital related revenue requirement included in the unadjusted 2010 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 4. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 18. As shown on Schedule 6b, page 2, column 18, row 29, this adjustment increases test-year revenue requirements by $1,833,000.

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND LIFE EXTENSION PROJECT AND THE ASSOCIATED ADJUSTMENT?

A. The Prairie Island Life Extension Project includes a series of individual capital projects at the plant necessary for continued operation during the 20 year license extension for which the Company has requested NRC approval. This extended life has already been assumed as appropriate in the previous South Dakota general rate case for the purpose of setting depreciation rates used in the determination of the depreciation expense included in cost of service. The Prairie Island life extension adjustment updates the test year for these projects, all of which have projected 2011 in service dates.

The adjustment was determined by comparing the 2011 capital related revenue requirement to the 2010 capital related revenue requirement included in the unadjusted 2010 test year.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 5. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 19. As shown on Schedule 6b, page 2, column 19, row 29, this adjustment increases test-year revenue requirements by $766,000.

Q. WHAT OTHER GENERATION RELATED ADJUSTMENT HAVE YOU MADE TO THE TEST YEAR?

A. Four additional adjustments have been made to the test year related to production facilities. The first adjustment is associated with the King Plant and results from moving the cost previously recovered through the ECR into base rates. The second removes costs associated with the Merricourt Wind project, which was cancelled in early 2011. The third adjustment is a steam production related remaining life adjustment. The fourth adjustment is a remaining life adjustment for other production facilities.

Q. WHAT IS THE KING PLANT MERCURY ADJUSTMENT?

A. The King Plant adjustment is needed to keep the Company whole as a result of moving recovery of the King Plant mercury control costs from the ECR into base rates. Under the ECR, the Company would have recovered a full year's worth of revenue requirements in the rider. Transferring recovery to base rates creates a situation where a portion of the 2010 revenue requirements would not be recovered based upon the 13 month average calculation for plant related rate base and given the fact the ECR allows recovery of CWIP. Due to the fact that normalization adjustments are permitted in South Dakota, the Company would be kept whole by moving the King Plant costs into base rates.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 6. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 20. As shown on Schedule 6b, page 2, column 20, row 29, this adjustment increases test-year revenue requirements by $12,000.

Q. WHAT IS THE MERRICOURT REMOVAL ADJUSTMENT?

A. The Merricourt removal adjustment updates the test year for the effect of cancelling the project. The project was included in construction work in process ("CWIP") at the time it was cancelled. Since South Dakota rules do not allow CWIP as a component of rate base in the development of revenue requirements the adjustment is limited to the impact on accumulated deferred income taxes.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 7. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit

___(TEK-1), Schedule 6b, page 2, column 21. As shown on Schedule 6b, page 2, column 21, row 29, this adjustment had no impact on the test-year revenue requirements.

Q. WHAT IS THE STEAM REMAINING LIFE ADJUSTMENT?

A. The Steam remaining life adjustment reflects the proposed changes in the remaining lives for the following plants:

Black Dog Units 3 and 4 steam production plant;
Red Wing refuse-derived fuel steam production plant,
Wilmarth refuse-derived fuel steam production plant, and
Sherburne County ("Sherco") Unit 3 steam production plant.

In addition, this adjustment recognizes the new net salvage values for all steam production plants.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 8. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 22. As shown on Schedule 6b, page 2, column 22, row 29, this adjustment decreases test-year revenue requirements by $482,000.

Q. WHAT IS THE OTHER PRODUCTION FACILITY REMAINING LIFE ADJUSTMENT?

A. The other production remaining life adjustment reflects the proposed remaining lives for the following plants:

Inver Hills other production plant, and
Riverside other production plant.

In addition, this adjustment sets new net salvage rates for all other production plants.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 9. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 23. As shown on Schedule 6b, page 2, column 23, row 29, this adjustment increases test-year revenue requirements by $98,000.

Q. PLEASE EXPLAIN THE BONUS DEPRECIATION ADJUSTMENT.

A. In December 2010, the Federal Government passed tax legislation that increased or extended the determination of bonus tax depreciation of certain qualifying facilities.

Q. WHAT EXACTLY IS BONUS TAX DEPRECIATION?

A. Bonus Tax Depreciation is the result of provisions in federal tax laws that allow the Company to deduct either 50 percent or 100 percent of qualifying capital investments in the first year the qualifying investment is placed in-service. In the case of the 50 percent bonus depreciation, the remaining 50 percent is depreciated for tax purposes using the existing accelerated depreciation schedules. Since the onset of the recession in 2008, Congress has enacted three separate laws that provided 50 percent Bonus Tax Depreciation in an effort to stimulate the economy. The Tax Relief Act of 2010 ("2010 TRA"), which became law in December 2010, provided 100 percent bonus tax depreciation ("100 Percent Bonus Depreciation") for certain projects placed into service from September 9, 2010 through December 31, 2011. In the case of 100

Percent Bonus Depreciation, the entire amount of the investment in a qualified project is permitted as a tax deduction in the first year the project is placed in-service. Both the Bonus Tax Depreciation deductions and the existing accelerated depreciation deductions are normalized for accounting and ratemaking.

The estimated impact of these various tax laws on the level of tax depreciation deductions was incorporated into the base data used to develop the jurisdictional COSS. Subsequent to the processing of this information, the IRS issued new guidelines defining investments that qualify for the 100% Percent Bonus Depreciation under the 2010 TRA. These new guidelines required the Company to propose an adjustment.

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

A. There are two significant impacts. First, the bonus tax depreciation generates a larger balance of deferred income taxes and second, the increased tax depreciation expense effectively results in more deductions than the Company can utilize in the current period. The result is the generation of a Net Operating Loss ("NOL") for 2010.

Q. PLEASE EXPLAIN THE BONUS DEPRECIATION AND NET OPERATING LOSS TEST YEAR ADJUSTMENT?

A. The test year has been adjusted to reduce the accumulated deferred income taxes and deferred income tax expense, and also reduced Bonus Tax Depreciation resulting from the latest interpretation of qualifying investments based on IRS guidance received after the closing of the 2010 books. This resulted in fewer investments qualifying for the 100 Percent Bonus Depreciation.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 10. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 24. As shown on Schedule 6b, page 2, column 24, row 29, this adjustment decreases test-year revenue requirements by $611,000.

As I explained, as a result of the bonus tax depreciation, the Company has more tax deductions than it can utilize in 2010, creating a NOL. This represents the value of tax deductions that need to be carried forward to a future period. The Company has determined the value of the NOL and made appropriate adjustments to the test-year to adjust both current and deferred tax items.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(TEK-1), Schedule 6a, page 1, column 11. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___(TEK-1), Schedule 6b, page 2, column 25. As shown on Schedule 6b, page 2, column 25, row 29, this adjustment decreases test-year revenue requirements by $1,343,000.

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

A. No. The Company did not include the additional revenues it is seeking in this proceeding when calculating the NOL adjustment. Any rate increase granted by the Commission will create additional taxable income and consume a portion of the approximate $20.4 million of tax deductions that cannot be utilized in the current period.

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

A. Once all items of revenue and expense have been determined in this case, a recalculation of the NOL is necessary to determine the level of deductions that must be carried forward to a future period. As with the current determination, the recalculation at the end of the case will be affected by current tax depreciation deductions, annual deferred tax expense and the accumulated deferred tax balance.

Q. PLEASE EXPLAIN THE UNION WAGE INCREASES.

A. We have completed negotiations with our union employees and, therefore, the wage increases for 2011 is known and measurable. The increase for 2011 is 2.5 percent.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 2, column 26. As shown on Schedule 6b, page 2, column 26, row 29, this adjustment increases test-year revenue requirements by $161,000.

Q. WHAT NON-UNION WAGE INCREASE ARE YOU INCLUDING?

A. There are two annualizing adjustments made to non-union wages. First we annualized the 2010 annual wage increase, which became effective March 2010. Second, effective March 1, 2011, non-union employees received an average 2.75 percent merit wage increase.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 2, column 27. As shown on Schedule 6b, page 2, column 27, row 29, this adjustment increases test-year revenue requirements by $277,000.

Q. WHAT ARE WHOLESALE MARGINS?

A. There are two categories of short-term wholesale margins (revenues less costs): asset based transactions and non-asset based transactions. Asset based transactions are comprised of sales of excess energy from Company owned generation assets. Non-asset based transactions are undertaken to obtain margins from purchases and sales of energy unrelated to meeting the energy needs of our retail customers. The only transactions that qualify as a non-asset based transaction are third-party supplied electricity that are not purchased to meet the needs of our retail customers and that are resold.

Q HOW WERE ASSET BASED MARGINS TREATED IN OUR LAST RATE CASE?

A. Because asset based margins are earned by selling energy from facilities paid for by the ratepayers, all asset based margins were credited to the ratepayers. In our last rate case (EL09-009), the margins were credited to the ratepayers through the fuel clause adjustment ("FCA").

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

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

Q WHY IS IT APPROPRIATE TO CONTINUE THE CURRENT PASS THROUGH MECHANISM?

A. There are a number of important benefits with using the FCA pass through mechanism.

First, asset based margins are volatile, making it impossible to establish a representative fixed credit. The FCA pass through mechanism allows 100 percent of the asset based margins, no more and no less to be credited. Asset based margins are volatile for the following reasons:

1) They vary with the weather. For example, during hot summers there is less excess energy available to sell than during cool summers.
2) They vary with plant outages. Plant outages are planned for off peak periods when we would normally have excess energy to sell. Outages take plants off line eliminating the ability to obtain margins during the period of the outage. Outages are not uniform in number or duration.
3) The price varies with supply and demand. During the current recession, demand has been lower, lowing the price of energy and thus margins.
4) Wind generation adds to volatility. As wind generation is added, there will be additional excess energy when the wind blows. At the same time, the regional growth of wind generated energy will lower the price of energy.

A second benefit of passing the asset based margins through the FCA is that it has a stabilizing impact on customer bills. As the cost of energy increases, the amount of margins available to offset those costs will be greater. Similarly, as the cost of energy decreased, the amount of margins available will be lower. Consequently passing both the fuel costs and the asset based margins through the FCA will have a levelizing effect.

Third, margins may increase in the future, and a pass through mechanism would allow the ratepayers to gain the full benefit of an increase. There are two factors that could result in future increases in asset based margins: (1) as the economy recovers, demand will increase, increasing the cost of energy which would increase margins; and (2) as new wind generation is added by Xcel Energy and in the region, additional energy should become available for sale, increasing margins.

Q. IS NON-ASSET BASED ACTIVITY REGULATED?

A. Yes. This activity is regulated by the FERC. Although the sale prices are not subjected to significant regulation, the allocation between the operating companies of margins is regulated. The Joint Operating Agreement ("JOA"), a FERC-approved tariff between NSP and the other Xcel Energy utility operating companies, anticipated such trading, defined in that agreement as "Non System Marketing."

Q. PLEASE DESCRIBE THE JOA AND ITS PURPOSE.

A. The JOA was established in 2000 with the completion of the Xcel Energy Inc. merger. Its purpose is to coordinate the trading and resource acquisition activities of the Xcel Energy utility operating companies, including the

Company. The JOA ensures that we coordinate these activities, including Non-System Marketing, to the joint benefit of all of the operating companies.

Q. WHAT GUIDANCE DOES THE JOA PROVIDE REGARDING REGULATORY TREATMENT OF MARGINS GENERATED FROM THESE ACTIVITIES?

A. The JOA requires that all margins from such activity -- regardless of which utility operating company executed a specific transaction -- be pooled and allocated among the operating companies based on each company's prior year's peak demand. Once this allocation is made, the margins are subject to the applicable regulatory treatment of the relevant state jurisdiction.

Q. HOW WAS THE COST OF NON-ASSET BASED MARGINS ADDRESSED IN THE PRIOR RATE CASE, DOCKET NO. E09-009?

A. Non-asset based margins are relatively new. In the last electric rate case, the Company received approval to use a 25/75 percent margin sharing mechanism (customer to Company, respectively) of non-asset based trading margins. The sharing mechanism was selected as a reasonable balance of ratepayer and Company interests. By paying the ratepayers 25 percent of the margins, the incremental cost of producing the margins was reimbursed along with a reasonable contribution to joint and common costs. At the time of the last rate case, an incremental cost study had not been conducted, and therefore the specific amount of contribution provided under the mechanism was not known. Consequently, the Company agreed to perform an incremental and a fully distributed cost study of non-asset based trading activities as part of its next general electric rate case application.

Q. HAS THE COMPANY CONDUCTED THE INCREMENTAL AND EMBEDDED COST STUDIES, AND IF SO, WHAT WERE THE RESULTS?

A. Yes, it has. Exhibit __ (TEK-1), Schedule 10 is a report of those studies, explaining the methodologies used and the results ("Cost Study"). In summary, the incremental cost represents the costs that would cease to be incurred if the non-asset based business were to be terminated. The fully allocated cost methodology includes the incremental costs and a full allocation of common costs. The following table shows the results of those two studies and compares them to the existing 25 percent sharing mechanism. The 3 year average period of 2007 to 2009 was used for this analysis.

	Incremental Cost Method	Fully Allocated Cost Method
25% Margin Sharing	$55,196	$55,196
Cost Estimate	$31,889	$67,896
Sharing compared to cost	$12,307	($12,700)

Q. WHAT IS THE COMPANY RECOMMENDING IN THIS CASE?

A. The Company recommends continuing the existing sharing mechanism as an appropriate balance of ratepayer and Company interests.

Q. PLEASE EXPLAIN WHY THE CURRENT SHARING MECHANISM PROVIDES A REASONABLE BALANCE OF INTEREST.

A. Incremental costs represent the costs that would cease to exist if the Company eliminated its non-asset based energy trading. The fully allocated costs include all incremental costs and includes an assignment of overhead costs – or costs that would not go away if the Company ceased non-asset based trading. Therefore, the fully allocated cost study includes costs of conducting the utility business not of conducting the non-asset based trading activity.

The 25 percent sharing mechanism provides a reasonable balance. It covers all of the incremental costs; preventing any cross subsidy. It also provides a significant amount of contribution to common costs. Thus, the current sharing mechanism has benefitted and would continue to benefit the ratepayers.

We request that the fully allocated costs not be assigned to this activity. Doing so would undo the existing balance of interests, under which the Company is encouraged to continue this business to the benefit of the ratepayers. Because the margins from this activity are relatively small and the Company absorbs 100 percent of the risk related to these transactions, imposing additional costs on this activity would upset the balanced approach to this activity that is reflected in the existing margin sharing mechanism.

Q. WHAT SPECIFICALLY IS THE PURPOSE OF THE ASSET/NON-ASSET ADJUSTMENT?

A. For fiscal year 2010, the Company had positive non-asset margins that are included in the other revenue section of the income statement. Based upon the sharing agreement for non-asset margins, (South Dakota customers keep 25 percent of their jurisdictional share and shareholders keep the remaining 75 percent). The adjustment to the test year removes the 75 percent shareholder portion of the margin. Failure to remove the shareholder portion from other revenue would understate revenue requirements for the test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 2, column 28. As shown on Schedule 6b, page 2, column 28, row 29, this adjustment increases test-year revenue requirements by $135,000.

Q. PLEASE DESCRIBE THE WHOLESALE BILLING ADJUSTMENT.

A. In a review of cost assignments to our wholesale jurisdiction, we determined that the costs assigned to the wholesale jurisdiction in 2010 did not fairly represents the cost of providing billing and account management services to these customers. This adjustment directly assigns additional costs related to customer billing and account management expenses to the wholesale jurisdiction and likewise decreases costs assigned to the retail jurisdictions.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 2, column 29. As shown on Schedule 6b, page 2, column 29, row 29, this adjustment decreases test-year revenue requirements by $10,000.

Q. HOW HAVE YOU TREATED THE XCEL ENERGY FOUNDATION ADMINISTRATION COSTS?

A. In its last rate case, Docket No. EL09-009, the Company was denied recovery of the Xcel Energy Foundation administration expenses. Therefore, an adjustment was made to remove these costs from the test year.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 2, column 30. As shown on Schedule 6b, page 2, column 30, row 29, this adjustment decreases test-year revenue requirements by $22,000.

Q. WHY HAVE YOU INCLUDED AN ADJUSTMENT REDUCING EMPLOYEE EXPENSES?

A. Based upon a review of the 2009 actual employee expense transactions, we have determined there were instances where some social expenses (e.g. athletic tickets) should have been recorded below the line but were not. This adjustment is the Company's estimate of South Dakota portion of those employee's expenses.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 3, column 31. As shown on Schedule 6b, page 3, column 31, row 28, this adjustment decreases test-year revenue requirements by $25,000.

Q WHY ARE YOU REQUESTING A KNOWN AND MEASUREABLE INCREASE IN PENSION EXPENSE?

A. The cost of pension expense increased in 2011 by $5.2 million on a total Company basis compared to the 2010 actual test year. This is a known increase for 2011. The South Dakota jurisdictional portion of this change equals $269,000.

The primary cause of the increase in pension expense since 2008 is the recognition of 2008 market losses in pension assets, which have affected both the pension plan for Company employees and the pension plan for XES employees. Under standard actuarial practices, these market losses are phased into the calculation of current pension expenses at the rate of 20 percent of losses per year, beginning in 2009 and continuing until 2013. The 2011 pension expenses are also affected by: (i) a decrease in the long-run return on pension assets from 8.75 percent in 2008 to 8.50 percent in 2009 and the current 2011 level of 8.00 percent; (ii) a decrease in the discount rate for the pension plan for

Company employees (which matches the return on assets) from 8.75 percent in 2008 to 8.50 percent in 2009 and the 2011 level of 8.00 percent; and (iii) a change in the discount rate for the pension plan for XES employees from 6.25 percent in 2008 to 6.75 percent in 2009 and subsequent decreases to the 2011 level of 5.50 percent. These changes to the return on assets and the discount rates reflect changing market conditions and were based on information provided by our actuaries and external advisors, and were reviewed for reasonableness by both our actuaries and our external auditors.

Q. PLEASE DESCRIBE WHAT ADDITIONAL ADJUSTMENTS ARE BEING PROPOSED BY THE COMPANY RELATED TO EMPLOYEE BENEFITS.

A. Although the Company is projecting an increase in active healthcare costs in 2011, the amount of this increase is not yet known and therefore does not meet the known and measurable criteria for making an adjustment. The projected increase on a total Company basis is approximately $1.5 million.

The Company has determined the 2011 levels associated with retiree medical, long-term disability and workers compensation will decline. Given this decrease an adjustment to the test year was deemed proper. The net impact of these three known changes represents a decrease to the South Dakota jurisdictional cost of $65,000.

The detailed jurisdictional operating income impacts of the adjustment for pension and health insurance are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 3, column 32. As shown on Schedule 6b, page 3, column 32, row 28, this adjustment increases test-year revenue requirements by $204,000.

Q. WHY HAVE YOU INCLUDED A WEATHER ADJUSTED ALLOCATOR ADJUSTMENT?

A. The Company's demand and energy allocation factors are developed based upon sales. At the time the baseline inputs for the cost of service study for the case were developed, the weather normalized factors had not yet been finalized. This adjustment estimates the impact of the weather-normalized demand and energy allocators on expenses allocated the South Dakota jurisdiction using actual demand and energy allocators.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit ___ (TEK-1), Schedule 6b, page 3, column 33. As shown on Schedule 6b, page 3, column 33, row 29, this adjustment increases test-year revenue requirements by $298,000.

Q. PLEASE EXPLAIN THE COST OF CAPITAL, CASH WORKING CAPITAL AND ROUNDING ADJUSTMENTS INCLUDED IN SCHEDULE 6B, PAGE 32, COLUMNS 35, 36, AND 37.

A. The cost of capital adjustment quantifies the effect of the proposed change in the capital structure from that authorized in Docket EL09-009.

The adjustments made in developing the pro forma year affect the cash working capital requirements. As a result, it is necessary to recalculate the change in the cash working capital. This recalculation will need to be repeated once the final Commission approved adjustments are known.

Similarly, the numerous components of the adjustments can result in a slight deviation between the actual total revenue requirement and the sum of all of the parts. The rounding adjustment is to bring the final 2010 pro forma income statement back into proper balance. Like the cash working capital adjustment, it will need to be recalculated once the final Commission approved adjustments are know.

Q. WITH THESE PRO FORMA CHANGES, IS THE PRO FORMA YEAR AN ACCURATE AND RELIABLE BASIS UPON WHICH TO SET RATES?

A. Yes. With the adjustments I previously described, the pro forma year is a reasonable projection of Company costs and revenues on which to base this request for rate relief.

VI. RATE BASE

Q. IS THE 2010 PRO FORMA RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma year rate base was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases. As a result of the above-described pro forma adjustments, the pro forma rate base appropriately represents the costs and investments in place at the time rates take affect in 2012.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

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

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PRO FORMA YEAR RATE BASE.

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

- Net Utility Plant;
- Accumulated Deferred Income Taxes; and
- Other Rate Base.

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

A. Exhibit ___(TEK-1), Schedule 13 (Rate Base unadjusted test year to pro forma year for both total Company and South Dakota jurisdiction) and Exhibit ___(TEK-1), Schedule 12, page 1 (2008 Settlement with 2010 pro forma) and page 2 (rate base comparisons for 2010 actual, 2010 test year unadjusted, and 2010 pro forma).

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

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

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

A. The net utility plant is included in rate base at depreciated original cost reflecting the 13-month average of projected net plant balances. This presentation is consistent with the net utility plant calculation in Docket No. EL09-009.

Q. WHAT HISTORICAL BASE DID XCEL ENERGY RELY ON AS A STARTING POINT TO DEVELOP THE NET PLANT BALANCES FOR THE PRO FORMA YEAR?

A. The historical base used was Xcel Energy's actual net investment (Plant in Service less Accumulated Depreciation) on the books and records of the Company for the period ending December 1, 2009 through December 31, 2010.

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

A. The average net utility plant included in the pro forma year rate base is $384,563,000, as shown on Exhibit___(TEK-1), Schedule 13, Page 1. This is comprised of an average plant balance of $747,609,000 as detailed on Exhibit___(TEK-1), Schedule 13, Page 1, minus an average depreciation reserve of $363,046,000 also shown by component on Exhibit___(TEK-1), Schedule 13, Page 1.

B. Construction Work In Progress

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

A. No. CWIP is not included in rate base, and there is no corresponding offset of Allowance for Funds Used During Construction ("AFUDC") added to operating income.

C. Accumulated Deferred Income Taxes

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

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

Q. WHY ARE ACCUMULATED DEFERRED INCOME TAXES DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

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

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED IN THE PROJECTED PRO FORMA YEAR RATE BASE?

A. As shown on Exhibit___(TEK-1), Schedule 13, Page 1, $76,523,000 was deducted. This amount reflects a 13-month average of pro forma year ADIT balances.

D. Other Rate Base

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

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

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

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

Q. HOW WERE PRO FORMA YEAR MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies and Fuel Inventory amounts shown on Exhibit___(TEK-1), Schedule 2, Page 2, are based on the 13-month average balances for December 2009 through December 2010, respectively. The Materials and Supplies average balance included in the pro forma year rate base equals $6,260,000. The pro forma year average rate base amount for Fuel Inventory is $4,816,000.

Q. HOW WERE PRO FORMA YEAR NON-PLANT ASSETS AND LIABILITIES DETERMINED?

A. These balances as shown on Exhibit___(TEK-1), Schedule 2, Page 2, represent the December 2009 to December 2010 actual 13-month average balances. Any book/tax timing differences associated with these items has been reflected in the determination of current and deferred income tax provision and accumulated deferred tax balances previously discussed. This group is primarily comprised of liabilities that reduce pro forma year rate base by $2,603,000.

Q. HOW WERE PRO FORMA YEAR PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Items of Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances during the period ended December 2010. The net impact of these various items increase pro forma year rate base by $9,855,000 as shown on Exhibit___(TEK-1), Schedule 2, Page 2.

Q. HOW WERE PRO FORMA YEAR CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

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

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

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

Q. HAS XCEL ENERGY UPDATED ANY COMPONENT OF THE LEAD/LAG STUDY SINCE THE LAST SOUTH DAKOTA ELECTRIC RATE CASE (DOCKET NO. EL09-009)?

A. Yes. An update to the South Dakota computer billed revenue lag component of the study was prepared using data through December 2010. All the other lead/lag calculations are based upon data through December 2008, which is the same inputs used in Docket No. EL09-009. In addition, the Company incorporated revisions to the lead/lag information based upon the Settlement Agreement for the computer billing revenue lag days and revised the revenue lag and expense lead days for interchange revenue and expenses. The Company felt these South Dakota adjustments were reasonable and were consistent with the cash working capital calculations used by the Company. The results of the updated lead/lag study for electric operations were incorporated into the South Dakota jurisdiction cash working capital calculations as shown on Exhibit___(TEK-1), Schedule 2 (COSS, Page 6 of 6). The lead/lag study can be found in Volume 4 of our Application.

Q. WHAT IS THE PRO FORMA YEAR CASH WORKING CAPITAL AMOUNT?

A. The amount included in the average rate base is a negative $2,976,000, as shown on Exhibit___(TEK-1), Schedule 2, (COSS Page 2 of 6). This calculation will need to be revised after the Commission determines the final revenue requirement and rate of return, as these decisions will impact the test-year level of cash working capital.

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

A. The negative cash working capital indicates overall revenue collections lead the date when the associated costs of service are paid. This means that, on average, cash working capital is being provided by the ratepayers. Accordingly, the negative cash working capital is included as a decrease to rate base and will lower the annual revenue requirement.

VII. INCOME STATEMENT

A. Revenues

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

A. Yes. The pro forma year includes items such as revenues from transmission-related revenue and specific tariff charges including service activation fees, reconnection fees and others. One other source of revenues comes from billings to NSPW under the Interchange Agreement, which I discuss in more detail below.

B. Operating and Maintenance Expenses

Q. HOW DOES XCEL ENERGY DEVELOP ITS PRO FORMA YEAR PRODUCTION EXPENSE?

A. The major cost in production expense is fuel and purchased energy. The pro forma year expenses are based on unadjusted test year fuel and purchased energy, adjusted for normal weather and fuel recovery timing so that a base cost of fuel and purchased energy is derived that only includes the appropriate South Dakota jurisdictional share of these NSP System costs on a calendar month basis.

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

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

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

A. Under the Interchange Agreement, the Company and NSPW share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 16 percent of the costs of the Company system are allocated to NSPW, and approximately 84 percent of the NSPW system costs are allocated to the Company, because approximately 84 percent of the load on the integrated system is the Company load and 16 percent is NSPW load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually. The Interchange Agreement also provides for an allocation of revenues received by the Company and NSPW, such as revenues from off-system wholesale sales.

The 2010 unadjusted test year Interchange Revenue and Interchange Expenses have been calculated using 2010 Company and NSPW actual information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in the Company's 2008 unadjusted test year in Docket No. EL09-009.

Q. TO WHAT FERC ACCOUNTS ARE INTERCHANGE REVENUE AND INTERCHANGE EXPENSES RECORDED?

A. Interchange Agreement revenues related to fixed and variable production as well as transmission system costs are recorded to FERC Account 456 – Other Electric Revenues. Interchange Agreement expense (billings from NSPW to the Company) are recorded to the following FERC Accounts:

Interchange Agreement Cost	FERC Account and Description
Fixed Production	557 – Other Power Supply Expenses-Other
Variable Production	557 – Other Power Supply Expenses-Other
Transmission	566 – Miscellaneous Transmission Expenses

Work papers supporting the calculation for Interchange Agreement revenues (billings from the Company to NSPW) can be found in Volume 3, Section R1, Tab - Interchange Agreement. Work papers supporting the calculation of Interchange Agreement expenses (billings from NSPW to the Company) can be found in Volume 3, Section O1, Tab - Interchange Agreement.

C. Depreciation/Amortization Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THIS PROCEEDING?

A. Depreciation expense for the pro forma year reflects the depreciation rates last certified by the Minnesota Commission, and is consistent with the ongoing practice followed by the Company, with the Commission's approval, in South Dakota rate case proceedings.

Q. What Amortizations have been included in the Test Year?

A. The Company has included the ongoing amortizations for the three items authorized in the Settlement Agreement for Docket No. EL09-009. These three amortizations relate to the Private Fuel Storage, Rate Case Expense for 2008, and Sale of Emission Allowances.

Q. Has the Company changed the amortization periods for any of these items?

A. No, the annual amortization amounts reflected in the test year are in accordance with the amortization time frame ordered in the Settlement Agreement. The private fuel storage cost is being amortized over six years, and the emission credit and 2008 rate case costs over five years.

Q. Is the remaining amortization period still appropriate for these three items?

A. Yes, the Company feels that the amortization periods remaining for these items is reasonable given that the Company anticipates seeking future rate recovery prior to the amortization periods expiring.

VIII. NUCLEAR COST RECOVERY RIDER

Q. WHY IS THE COMPANY PROPOSING A NUCLEAR COST RECOVERY ("NCR") RIDER ?

A. As described in the Direct Testimony of Ms. Laura McCarten, The Company is in a period of making substantial capital investments at the Monticello and Prairie Island nuclear plants in order to both extend the lives of each plant by 20 years and to increase the available power at Monticello. Specifically, for the Monticello plant, the Company has included as known and measurable adjustments to the Test Year, the 2011 revenue requirements associated with the 2011 Monticello LCM/EPU project. The details of this project are covered in the Pro Forma Adjustments section of my testimony. This consists of plant additions being made in May and November of 2011 totaling roughly $365 million on a total Company basis. Due to the size of this project and the timing associated with completion, the Company is recommending that a rate rider be established to true-up 2011 revenue requirements to actual cost and recover actual revenue requirements associated with these two additions during 2012 and until we file our next rate case. In addition, the NCR Rider would recover, with Commission approval, other future nuclear capital project costs.

Q. WILL THE PROPOSED RIDER RECOVERY ASSOCIATED WITH THIS PROJECT BE BASED ON ACTUAL COSTS?

A. Yes. The Company is proposing to file with the Commission, 60 days after the completion of this project, a Rate Rider recovery plan based on actual project costs. The recovery plan will propose a rider recovery mechanism that reports actual project revenue requirements as compared to those included in base rate recovery and calculates a true-up amount based on that comparison, estimates the 2012 revenue requirements, and proposes an NCR Rate Rider adjustment factor at a level that will recover the 2012 revenue requirements (net of the 2011 true-up amount). The proposal will also include the accounting required for an NCR tracker account.

Q. HAVE YOU DEVELOPED AN ESTIMATE OF THE ADDITIONAL REVENUE REQUIREMENTS ASSOCIATED WITH A FULL-YEAR RECOVERY OF THE MONTICELLO LCM/EPU PROJECT?

A. Yes, I have. Based on the information used to develop the partial 2011 year adjustment to the 2010 test year, I have computed the additional revenue requirement associated with a full year of operation in 2012. Based on the comparison of the 2011 and 2012 revenue requirements, the increased annual revenue requirement would total approximately $956,000 using the data available today.

Q. HAVE YOU DEVELOPED A SCHEDULE SUPPORTING THIS ESTIMATE?

A. Yes, I have. Exhibit___(TEK-1), Schedule 7, provides the supporting information for this estimate. This schedule shows the 2011 revenue requirement, the 2012 revenue requirement and the net revenue requirement increase using 13 month average balances and annual costs for these two periods.

IX. CONCLUSION

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend that the Commission determine an overall retail revenue requirement of $171,802,000 and revenue deficiency of $14,583,000 for the Company's South Dakota jurisdictional electric operation, determined by the cost of service for the 2010 unadjusted test year adjusted to reflect those pro forma adjustments needed to make the pro forma year representative of the conditions facing the Company when it implements final rates in 2012.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

Northern States Power Company, a Minnesota corporation
Electric Utility – South Dakota
Resume of Thomas E. Kramer

Principal Rate Analyst
Revenue Requirement North

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

Current Responsibilities

Since January 2011, I have been a Principal Rate Analyst in the Revenue Requirements – North Department. In this position, I am responsible 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, a Minnesota corporation, 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 History

Xcel Energy – Minneapolis, MN
- Senior Rate Analyst, May 2008 to December 2010

Nuclear Management Company, LLC – Hudson, WI.
- Controller, May 2002 to May 2008
- General Ledger Manager, February 2000 to May 2002

Xcel Energy – Minneapolis, MN.
- Manager of Gas Finance, July 1994 to January 2000
- Administrator Business Unit Accounting, Departmental Budgets, and Security Issuance and Reporting, February 1984 to June 1994

Deloitte & Touche
- Auditor/Senior Auditor, July 1979 to February 1984

Education and Certifications

- Bachelor of Accounting Degree – University of Minnesota Duluth, May 1979
- Certified Public Accountant certification, August 1981 (non-active status)

ROE = 5.41%
Deficiency = $14,583
% Increase = 9.28%
Required ROE = 11.00%

Northern States Power Company (MN)
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2010 Pro Forma

Summary Reports

June 30, 2011

Northern States Power Company (MN)
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2010 Pro Forma
(Dollars in Thousands)

Rate Base Summary

		Total Company Electric			South Dakota 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	13,081,604	13,081,604	13,081,604	747,609	747,609	747,609	12,333,995	12,333,995	12,333,995
2	Depreciation Reserve	(6,382,836)	(6,382,836)	(6,382,836)	(363,046)	(363,046)	(363,046)	(6,019,790)	(6,019,790)	(6,019,790)
3	Net Utility Plant	6,698,768	6,698,768	6,698,768	384,563	384,563	384,563	6,314,205	6,314,205	6,314,205
4	C.W.I.P.	0	0	0	0	0	0	0	0	0
5	Accumulated Deferred Taxes	(1,324,475)	(1,324,475)	(1,324,475)	(76,523)	(76,523)	(76,523)	(1,247,952)	(1,247,952)	(1,247,952)
	Other Rate Base:									
6	Cash Working Capital	(66,840)	(66,840)	(66,840)	(2,976)	(2,976)	(2,976)	(63,864)	(63,864)	(63,864)
7	Materials & Supplies	111,130	111,130	111,130	6,260	6,260	6,260	104,870	104,870	104,870
8	Fuel Inventory	86,048	86,048	86,048	4,816	4,816	4,816	81,232	81,232	81,232
9	Non-Plant Assets & Liab	(45,059)	(45,059)	(45,059)	(2,603)	(2,603)	(2,603)	(42,456)	(42,456)	(42,456)
10	Prepaids & Other	80,864	80,864	80,864	9,855	9,855	9,855	71,009	71,009	71,009
11	**Total Rate Base**	**5,540,436**	**5,540,436**	**5,540,436**	**323,392**	**323,392**	**323,392**	**5,217,044**	**5,217,044**	**5,217,044**

(Dollars in Thousands)

Income Statement Summary

		Total Company Electric	South Dakota Retail Electric	All Other
	Operating Revenues			
1	Retail	2,962,850	157,219	2,805,631
2	Interdepartmental	417	-	417
3	Other Operating	724,787	39,017	685,770
4	**Total Operating Revenues**	**3,688,054**	**196,236**	**3,491,818**
	Expenses			
	Operating Expenses:			
5	Fuel & Purchased Energy	1,318,220	70,096	1,248,124
6	Power Production	717,380	40,429	676,951
7	Transmission	174,348	9,754	164,594
8	Distribution	109,763	6,397	103,366
9	Customer Accounting	58,762	3,996	54,766
10	Customer Service & Information	79,140	424	78,716
11	Sales, Econ Dvlp & Other	332	53	279
12	Administrative & General	202,435	12,334	190,101
13	Total Operating Expenses	2,660,380	143,483	2,516,897
14	Depreciation	337,640	19,769	317,871
15	Amortization	744	402	342
	Taxes:			
16	Property	123,472	5,969	117,503
17	Deferred Income Tax & ITC	138,445	5,942	132,503
18	State & Federal Income (see Page 3)	8,111	86	8,024
19	Payroll & Other	29,044	1,670	27,374
20	Total Taxes	299,072	13,667	285,404
21	**Total Expenses**	**3,297,836**	**177,321**	**3,120,514**
22	AFUDC	0	-	0
23	**Total Operating Income**	**390,218**	**18,915**	**371,304**

(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	SD Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,688,054	196,236	3,491,818
2	less: Total Operating Expenses	(2,660,380)	(143,483)	(2,516,897)
3	Book Depreciation & Amortization	(338,384)	(20,171)	(318,213)
4	Taxes (Other Than Current Income)	(290,961)	(13,581)	(277,380)
5	**Total Before Tax Book Income**	**398,329**	**19,001**	**379,328**
	Tax Additions			
6	Book Depreciation	337,640	19,769	317,871
7	Deferred Income Taxes & ITC	138,445	5,942	132,503
8	Nuclear Fuel Burn (ex D&D)	118,069	6,607	111,462
9	Nuclear Outage Accounting	57,586	3,223	54,363
10	Avoided Tax Interest	24,648	1,308	23,340
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**	**676,388**	**36,849**	**639,539**
	Tax Deductions			
18	Debt Interest Expense	166,767	9,734	157,033
19	Tax Depreciation & Removal	892,836	46,282	846,554
20	Manufacture Production Deduction	0	0	0
21	Open Line	0	0	0
22	Open Line	0	0	0
23	Open Line	0	0	0
24	Other Tax/Book Timing Differences	(4,729)	(413)	(4,316)
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**1,054,874**	**55,603**	**999,271**
27	**State Taxable Income**	**19,843**	**247**	**19,596**
28	State Income Tax Rate	9.03%	0.00%	N/A
29	State Taxes before Credits	1,791	0	1,791
30	State Credits	944	0	944
31	**Total State Income Taxes**	**847**	**0**	**847**
32	**Federal Taxable Income**	**18,996**	**247**	**18,749**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	6,649	86	6,562
35	Federal Tax Credits	(615)	0	(615)
36	**Total Federal Income Taxes**	**7,264**	**86**	**7,177**
37	**Total Federal & State Income Taxes**	8,111	86	8,024

Northern States Power Company (MN)
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2010 Pro Forma

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.3300%	47.5200%	3.0100%
2	Short Term Debt	0.0000%	0.0000%	0.0000%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.0000%	52.4800%	5.7700%
5	**Required Rate of Return**			**8.7800%**

Composite Income Tax Rates		
State of South Dakota Tax rate		0.00%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		35.00%
Total South Dakota Composite Tax Rate		**35.00%**
Total Corporate Composite Tax Rate		**40.87%**

		Total Company Electric	SD Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	390,218	18,915	371,304
7	Total Average Rate Base	5,540,436	323,392	5,217,044
8	**ROR** (Operating Income / Rate Base)	**7.04%**	**5.85%**	**7.12%**
	Return on Equity (ROE)			
9	Total Operating Income	390,218	18,915	371,304
10	Debt Interest (Rate Base * Weighted Debt Cost)	(166,767)	(9,734)	(157,033)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	223,451	9,180	214,271
13	Equity Rate Base (Rate Base * Equity Ratio)	2,907,621	169,716	2,737,905
14	**ROE** (Earnings for Common / Equity Rate Base)	**7.69%**	**5.41%**	**7.83%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	486,450	28,394	458,056
16	Operating Income	390,218	18,915	371,304
17	Operating Income Deficiency	96,232	9,479	86,753
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69110	1.53846	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**162,738**	**14,583**	**148,155**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,963,267	157,219	2,806,048
21	Revenue Deficiency	162,738	14,583	148,155
22	**Total Retail Revenue Requirements**	**3,126,005**	**171,802**	**2,954,203**
23	**Percentage Increase (Decrease)**	**5.49%**	**9.28%**	**5.28%**

(Dollars in Thousands)

Rate Base Detail - Cash Working Capital

			Total Company Electric			South Dakota Retail Electric			All Other	
	Expenses									
	Includable Expenses	**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Fuel Expenses									
1	Coal & Rail Transport	21.08	311,859	6,573,988		17,455	367,951		294,404	6,206,036
2	Gas for Generation	38.45	125,679	4,832,358		7,034	270,457		118,645	4,561,900
3	Oil	22.51	2,859	64,356		160	3,602		2,699	60,754
4	Nuclear & EOL	0.00	118,069	0		6,608	0		111,461	0
5	Nuclear Disposal	76.00	12,700	965,200		711	54,036		11,989	911,164
6			571,166	12,435,901		31,968	696,046		539,198	11,739,855
	Purchased Power									
7	Purchases	28.12	774,568	21,780,852		34,533	971,068		740,035	20,809,784
8	Interchange	31.79	116,312	3,697,558		6,509	206,921		109,803	3,490,637
			890,880	25,478,411		41,042	1,177,989		849,838	24,300,422
	Labor & Related Costs									
9	Regular Payroll	12.31	365,958	4,504,943		21,525	264,973		344,433	4,239,970
10	Incentive Compensation	255.05	16,861	4,300,398		952	242,808		15,909	4,057,590
11	Pension & Benefits	19.20	74,060	1,421,952		4,492	86,246		69,568	1,335,706
12	Subtotal Labor & Related		456,879	10,227,293		26,969	594,027		429,910	9,633,266
13										
14	All Other Operating Expenses	35.01	741,455	25,958,340		43,504	1,523,075		697,951	24,435,265
15	Property Tax	356.72	123,472	44,044,932		5,969	2,129,262		117,503	41,915,670
16	Employer's Payroll Taxes	26.56	29,044	771,409		1,670	44,355		27,374	727,053
17	Gross Earnings Tax	51.98	0	0		0	0		0	0
18	Federal Income Tax	37.75	7,264	274,199		86	3,262		7,177	270,937
19	State Income Tax	37.75	847	31,975		0	0		847	31,975
20	State Sales Tax Customer Billings	35.73	138,813	4,959,788		5,736	204,947		133,077	4,754,841
21	Total Expenses	41.96	2,959,820	124,182,248	40.61	156,944	6,372,963	42.03	2,802,875	117,809,284
22	**Net Annual Expense Amount**			340,225			17,460			322,765
	Revenues	**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
23	Computer Billing 100.00%	33.67	2,962,850	99,759,160		157,219	5,293,564		2,805,631	94,465,596
24	Hand Billed 0.00%	33.67	0	0		0	0		0	0
25	Retail Revenue Adjustments	0.00	0	0		0	0		0	0
26	Interdepartmental	0.00	417	0		0	0		417	0
27	Late Payment	0.00	0	0		0	0		0	0
28	Connect and Trouble Charges	42.85	2,232	95,646		256	10,970		1,976	84,676
29	CIP Incentive	0.00	0	0		0	0		0	0
30	Rentals	114.17	4,088	466,727		243	27,743		3,845	438,984
31	Interchange Revenues	31.13	414,842	12,914,031		23,217	722,745		391,625	12,191,286
32	Sales for Resale	37.10	214,520	7,958,692		10,891	404,056		203,629	7,554,636
33	Production Associated Revenues	37.10	5,650	209,615		316	11,724		5,334	197,891
34	MISO	14.00	10,457	146,398		585	8,190		9,872	138,208
35	Point to Point Firm	37.10	44,744	1,660,002		2,504	92,898		42,240	1,567,104
36	Services & Facilities	37.10	8,654	321,063		480	17,808		8,174	303,255
37	Ancillary	37.10	17,289	641,422		967	35,876		16,322	605,546
38	Distribution Associated Revenues	42.85	126	5,399		0	0		126	5,399
39	Other	42.85	13,500	578,502		191	8,185		13,309	570,317
40	JOA - Rev fr/to PSC	37.10	(11,315)	(419,787)		(633)	(23,484)		(10,682)	(396,302)
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	33.71	3,688,054	124,336,871	33.69	196,236	6,610,275	33.71	3,491,818	117,726,597
45	Net Annual Amount			340,649			18,110			322,539
46	Expense / Revenue Factor			0.802542			0.7998			
47	**Allocated Revenue Amount**			273,385			14,485			
48	**Net Cash Working Capital**	**Page 1 - Line 6**		(66,840)			(2,976)			(63,865)

ROE = 1.33%
Deficiency = $22,429
% Increase = 14.29%
Required ROE = 11.00%

Northern States Power Company (SD)
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2010 Actual/Baseline

Summary Reports

June 30, 2011

(Dollars in Thousands)

Rate Base Summary

		Total Company Electric			South Dakota 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	12,476,649	12,476,649	12,476,649	714,371	714,371	714,371	11,762,278	11,762,278	11,762,278
2	Depreciation Reserve	(6,381,238)	(6,381,238)	(6,381,238)	(362,969)	(362,969)	(362,969)	(6,018,269)	(6,018,269)	(6,018,269)
3	Net Utility Plant	6,095,411	6,095,411	6,095,411	351,402	351,402	351,402	5,744,009	5,744,009	5,744,009
4	C.W.I.P.	0	0	0	0	0	0	0	0	0
5	Accumulated Deferred Taxes	(1,287,871)	(1,287,871)	(1,287,871)	(75,503)	(75,503)	(75,503)	(1,212,368)	(1,212,368)	(1,212,368)
	Other Rate Base:									
6	Cash Working Capital	(68,088)	(68,088)	(68,088)	(2,794)	(2,794)	(2,794)	(65,294)	(65,294)	(65,294)
7	Materials & Supplies	111,130	111,130	111,130	6,260	6,260	6,260	104,870	104,870	104,870
8	Fuel Inventory	86,048	86,048	86,048	4,816	4,816	4,816	81,232	81,232	81,232
9	Non-Plant Assets & Liab	(113,676)	(113,676)	(113,676)	(6,495)	(6,495)	(6,495)	(107,181)	(107,181)	(107,181)
10	Prepaids & Other	80,864	80,864	80,864	9,855	9,855	9,855	71,009	71,009	71,009
11	**Total Rate Base**	**4,903,818**	**4,903,818**	**4,903,818**	**287,541**	**287,541**	**287,541**	**4,616,277**	**4,616,277**	**4,616,277**

(Dollars in Thousands)

Income Statement Summary

		Total Company Electric	South Dakota Retail Electric	All Other
	Operating Revenues			
1	Retail	2,983,429	156,951	2,826,478
2	Interdepartmental	417	-	417
3	Other Operating	753,270	39,152	714,118
4	**Total Operating Revenues**	**3,737,116**	**196,103**	**3,541,013**
	Expenses			
	Operating Expenses:			
5	Fuel & Purchased Energy	1,332,731	80,110	1,252,621
6	Power Production	717,081	40,130	676,951
7	Transmission	174,351	9,757	164,594
8	Distribution	109,899	6,533	103,366
9	Customer Accounting	58,722	3,996	54,726
10	Customer Service & Information	80,376	492	79,884
11	Sales, Econ Dvlp & Other	93	3	90
12	Administrative & General	212,762	12,482	200,280
13	Total Operating Expenses	2,686,015	153,503	2,532,512
14	Depreciation	316,793	18,618	298,175
15	Amortization	828	828	0
	Taxes:			
16	Property	116,166	5,560	110,606
17	Deferred Income Tax & ITC	341,876	19,226	322,650
18	State & Federal Income (see Page 3)	(162,803)	(13,970)	(148,833)
19	Payroll & Other	29,059	1,671	27,388
20	Total Taxes	324,298	12,487	311,811
21	**Total Expenses**	**3,327,934**	**185,436**	**3,142,498**
22	AFUDC	-	-	-
23	**Total Operating Income**	**409,182**	**10,667**	**398,515**

Northern States Power Company (MN) | Docket No. EL-11____
Electric Utility - South Dakota Retail Jurisdiction | Exhibit___(TEK-1) Schedule 2A
Cost of Service Study | Page 4 of 6
2010 Actual/Baseline
(Dollars in Thousands)

Income Tax Summary

		Total Company Electric	SD Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,737,116	196,103	3,541,013
2	less: Total Operating Expenses	(2,686,015)	(153,503)	(2,532,512)
3	Book Depreciation & Amortization	(317,621)	(19,446)	(298,175)
4	Taxes (Other Than Current Income)	(487,101)	(26,457)	(460,644)
5	**Total Before Tax Book Income**	**246,379**	**(3,303)**	**249,682**
	Tax Additions			
6	Book Depreciation	316,793	18,618	298,175
7	Deferred Income Taxes & ITC	341,876	19,226	322,650
8	Nuclear Fuel Burn (ex D&D)	118,069	6,607	111,462
9	Nuclear Outage Accounting	57,586	3,223	54,363
10	Avoided Tax Interest	38,713	2,150	36,563
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**	**873,037**	**49,824**	**823,213**
	Tax Deductions			
18	Debt Interest Expense	147,605	8,655	138,950
19	Tax Depreciation & Removal	1,349,330	76,601	1,272,729
20	Manufacture Production Deduction	0	0	0
21	Open Line	0	0	0
22	Open Line	0	0	0
23	Open Line	0	0	0
24	Other Tax/Book Timing Differences	(6,719)	(526)	(6,193)
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**1,490,216**	**84,730**	**1,405,486**
27	**State Taxable Income**	**(370,800)**	**(38,209)**	**(332,591)**
28	State Income Tax Rate	9.03%	0.00%	N/A
29	State Taxes before Credits	(33,468)	0	(33,468)
30	State Credits	944	0	944
31	**Total State Income Taxes**	**(34,412)**	**0**	**(34,412)**
32	**Federal Taxable Income**	**(336,388)**	**(38,209)**	**(298,179)**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	(117,736)	(13,373)	(104,362)
35	Federal Tax Credits	10,655	597	10,058
36	**Total Federal Income Taxes**	**(128,391)**	**(13,970)**	**(114,420)**
37	**Total Federal & State Income Taxes**	(162,803)	(13,970)	(148,833)

Revenue Requirement & Return Summary

(Dollars in Thousands)

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.3300%	47.5200%	3.0100%
2	Short Term Debt	0.0000%	0.0000%	0.0000%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.0000%	52.4800%	5.7700%
5	**Required Rate of Return**			**8.7800%**

Composite Income Tax Rates		
State of South Dakota Tax rate		0.00%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate * Fed Rate)		35.00%
Total South Dakota Composite Tax Rate		**35.00%**
Total Corporate Composite Tax Rate		**40.87%**

		Total Company Electric	SD Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	409,182	10,667	398,515
7	Total Average Rate Base	4,903,818	287,541	4,616,277
8	**ROR (Operating Income / Rate Base)**	**8.34%**	**3.71%**	**8.63%**
	Return on Equity (ROE)			
9	Total Operating Income	409,182	10,667	398,515
10	Debt Interest (Rate Base * Weighted Debt Cost)	(147,605)	(8,655)	(138,950)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	261,577	2,012	259,565
13	Equity Rate Base (Rate Base * Equity Ratio)	2,573,524	150,901	2,422,622
14	**ROE (Earnings for Common / Equity Rate Base)**	**10.16%**	**1.33%**	**10.71%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	430,555	25,246	405,309
16	Operating Income	409,182	10,667	398,515
17	Operating Income Deficiency	21,373	14,579	6,794
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69110	1.53846	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**36,144**	**22,429**	**13,715**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	2,983,846	156,951	2,826,895
21	Revenue Deficiency	36,144	22,429	13,715
22	**Total Retail Revenue Requirements**	**3,019,990**	**179,380**	**2,840,610**
23	**Percentage Increase (Decrease)**	**1.21%**	**14.29%**	**0.49%**

Northern States Power Company (MN)
Electric Utility - South Dakota Retail Jurisdiction
Cost of Service Study
2010 Actual/Baseline
(Dollars in Thousands)

Docket No. EL-11____
Exhibit___(TEK-1) Schedule 2A

Rate Base Detail - Cash Working Capital

Line	Expenses	Lead Days	Total Company Electric Dollars	Total Company Electric Dollar x Days		South Dakota Retail Electric Dollars	South Dakota Retail Electric Dollar x Days		All Other Dollars	All Other Dollar x Days
	Includable Expenses									
	Fuel Expenses									
1	Coal & Rail Transport	21.08	311,859	6,573,988		17,455	367,951		294,404	6,206,036
2	Gas for Generation	38.45	125,679	4,832,358		7,034	270,457		118,645	4,561,900
3	Oil	22.51	2,859	64,356		160	3,602		2,699	60,754
4	Nuclear & EOL	0.00	118,069	0		6,608	0		111,461	0
5	Nuclear Disposal	76.00	12,700	965,200		711	54,036		11,989	911,164
6			571,166	12,435,901		31,968	696,046		539,198	11,739,855
	Purchased Power									
7	Purchases	28.12	788,672	22,177,457		44,140	1,241,217		744,532	20,936,240
8	Interchange	31.79	116,312	3,697,558		6,509	206,921		109,803	3,490,637
			904,984	25,875,015		50,649	1,448,138		854,335	24,426,877
	Labor & Related Costs									
9	Regular Payroll	12.31	365,885	4,504,044		21,118	259,963		344,767	4,244,082
10	Incentive Compensation	255.05	29,689	7,572,179		1,679	428,229		28,010	7,143,951
11	Pension & Benefits	19.20	70,317	1,350,086		4,073	78,202		66,244	1,271,885
12	Subtotal Labor & Related		465,891	13,426,310		26,870	766,393		439,021	12,659,917
13										
14	All Other Operating Expenses	35.01	743,974	26,046,530		44,016	1,541,000		699,958	24,505,530
15	Property Tax	356.72	116,166	41,438,736		5,560	1,983,363		110,606	39,455,372
16	Employer's Payroll Taxes	26.56	29,059	771,807		1,671	44,382		27,388	727,425
17	Gross Earnings Tax	51.98	0	0		0	0		0	0
18	Federal Income Tax	37.75	(128,391)	(4,846,746)		(13,970)	(527,373)		(114,420)	(4,319,373)
19	State Income Tax	37.75	(34,412)	(1,299,068)		0	0		(34,412)	(1,299,068)
20	State Sales Tax Customer Billings	35.73	138,813	4,959,788		5,736	204,947		133,077	4,754,841
21	Total Expenses	42.32	2,807,250	118,808,273	40.37	152,500	6,156,897	42.43	2,654,750	112,651,376
22	**Net Annual Expense Amount**			325,502			16,868			308,634
	Revenues	**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
23	Computer Billing 100.00%	33.67	2,983,429	100,452,054		156,951	5,284,540		2,826,478	95,167,514
24	Hand Billed 0.00%	33.67	0	0		0	0		0	0
25	Retail Revenue Adjustments	0.00	0	0		0	0		0	0
26	Interdepartmental	0.00	417	0		0	0		417	0
27	Late Payment	0.00	0	0		0	0		0	0
28	Connect and Trouble Charges	42.85	2,232	95,646		256	10,970		1,976	84,676
29	CIP Incentive	0.00	27,153	0		0	0		27,153	0
30	Rentals	114.17	4,088	466,727		243	27,743		3,845	438,984
31	Interchange Revenues	31.13	414,842	12,914,031		23,217	722,745		391,625	12,191,286
32	Sales for Resale	37.10	216,150	8,019,165		11,026	409,065		205,124	7,610,100
33	Production Associated Revenues	37.10	5,650	209,615		316	11,724		5,334	197,891
34	MISO	14.00	10,457	146,398		585	8,190		9,872	138,208
35	Point to Point Firm	37.10	44,744	1,660,002		2,504	92,898		42,240	1,567,104
36	Services & Facilities	37.10	8,582	318,392		480	17,808		8,102	300,584
37	Ancillary	37.10	17,289	641,422		967	35,876		16,322	605,546
38	Distribution Associated Revenues	42.85	0	0		0	0		0	0
39	Other	42.85	13,398	574,131		191	8,185		13,207	565,946
40	JOA - Rev fr/to PSC	37.10	(11,315)	(419,787)		(633)	(23,484)		(10,682)	(396,302)
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	33.47	3,737,116	125,077,798	33.69	196,103	6,606,260	33.46	3,541,013	118,471,538
45	Net Annual Amount			342,679			18,099			324,580
46	Expense / Revenue Factor			0.751181			0.7777			
47	**Allocated Revenue Amount**			257,414			14,076			
48	**Net Cash Working Capital**	Page 1 - Line 6		(68,088)			(2,792)			(65,296)

($000's)

Line	of the Revenue Deficiency	Revenue Deficiency (millions)
1	Capital Recovery: for additional rate base investment (includes return requirement, change in capital structure, cost of capital, property taxes and depreciation)	$11.5
	Operating Expenses (including reclasses shown on page 2):	
2	Power Production	$4.9
3	Transmission	$1.5
4	Distribution	$0.1
5	Customer Accounts	($0.2)
6	Customer Info Services, Sales & Ecnomic Developm	$0.1
7	Administrative and General Expense	$1.9
8	Total Operating Expenses	$8.3
9	Payroll Taxes	$0.2
10	Amortizations	$0.3
11	Subtotal	$20.3
12	Less, Net Sales and Growth in Margin (including reclasses)	($5.7)
13	Net Change in Revenue Deficiency	$14.6
14	2008 Revenue Deficiency/(Sufficiency)	$0.0
15	Pro Forma Deficiency/(Sufficiency)	$14.6

Summary of Test Year O & M Expense Changes
Since Docket No. E09-009
Shown by Functional Grouping, Gross Dollar Change Over
Two Year Interval Since the 2008 Test Year
(dollars in thousands)

Line	Functional Class	Increase (Decrease)
1	Capital Recovery: for additional rate base investment (includes return requirement, change in capital structure, cost of capital, property taxes and depreciation)	$10,037
2	Reclass of Decommissioning settlement in EL09-009 from Amortizations	$1,474
3	Net Capital Recovery	$11,511
4	Power Production	$7,861
5	Reclass Def Elec Energy Cost to Margin	($2,087)
6	Reclass of WI IA Variable Costs to Margin	$38
7	Net Power Production	$5,812
8	Interchange Impact	($901)
9	Net Power Production after Interchange	$4,911
10	Transmission Operating and Maintenance	$1,755
11	Interchange Impact	($274)
12	Net Transmission after Interchange	$1,481
13	Distribution and Maintenance Expense	$147
14	Customer Accounting	($232)
15	Customer Services and Sales Expenses	$92
16	Administrative and General Expenses	$1,932
17	Total Change In Operating Expenses	$8,331
18	Payroll Taxes	$218
19	Total Change In Operating Expenses & Payroll Taxes	$8,549
20	Amortizations	$1,723
21	Reclass of Decommissioning settlement from EL09-009 to Capital Recovery	($1,474)
22	Net Amortizations	$249
23	Sales and Growth in Margin	$8,949
24	Reclass Def Elec Energy Cost from Power Production	($2,087)
25	Reclass of WI IA Variable Costs from Power Production	$38
26	Net Interchange Impact	($1,175)
27	Net Sales and Growth in Margin	$5,725

OPERATING REVENUES, OPERATING EXPENSE,
TOTAL AVAILABLE FOR RETURN WITH PRESENT AND FINAL RATES
2010 Pro Forma
(Dollars in Thousands)

Line No.	Description	2010 Pro Forma Present Rates (A)	Final Increase (B)	2010 Pro Forma Final Rates (C) = (B) + (A)
	Operating Revenues			
1	Retail	$157,219	$14,583	$171,802
2	Interdepartmental	0		0
3	Other Operating	39,017		39,017
4	**Total Operating Revenues**	$196,236	$14,583	$210,819
	Expenses			
	Operating Expenses:			
5	Fuel & Purchased Energy	$70,096		$70,096
6	Power Production	40,429		40,429
7	Transmission	9,754		9,754
8	Distribution	6,397		6,397
9	Customer Accounting	3,996		3,996
10	Customer Service & Information	424		424
11	Sales, Econ Dvlp & Other	53		53
12	Administrative & General	12,334		12,334
13	Total Operating Expenses	$143,483	$0	$143,483
14	Depreciation	$19,769		$19,769
15	Amortizations	402		402
	Taxes:			
16	Property	$5,969		$5,969
17	Deferred Income Tax & ITC	5,942		5,942
18	Federal & State Income Tax	86	5,104	5,190
19	Payroll & Other	1,670		1,670
20	Total Taxes	$13,667	$5,104	$18,771
21	**Total Expenses**	$177,321	$5,104	$182,425
22	AFUDC	$0		$0
23	**Total Operating Income**	$18,915	$9,479	$28,394

Note: Revenues reflect calendar month sales.

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
STATEMENT OF OPERATING INCOME
2008 Settlement versus 2010 Pro Forma
($000's)

Line No.	Description	2008 Settlement As Reported (A)	2010 Pro Forma Final Rates (B)	Change (C) = (B) - (A)
	Operating Revenues			
1	Retail	$103,124	$171,802	$68,678
2	Interdepartmental	0	0	0
3	Other Operating	34,632	39,017	4,385
4	**Total Operating Revenues**	$137,756	$210,819	$73,063
	Expenses			
	Operating Expenses:			
5	Fuel & Purchased Energy	$20,565	$70,096	$49,531
6	Power Production	32,568	40,429	7,861
7	Transmission	8,000	9,754	1,754
8	Distribution	6,250	6,397	147
9	Customer Accounting	4,228	3,996	(232)
10	Customer Service & Information	332	424	92
11	Sales, Econ Dvlp & Other	53	53	0
12	Administrative & General	10,402	12,334	1,932
13	Total Operating Expenses	$82,398	$143,483	$61,085
14	Depreciation (1)	$18,527	$19,769	$1,242
15	Amortizations (1)	153	402	249
	Taxes:			
16	Property	$4,919	$5,969	$1,050
17	Deferred Income Tax & ITC	3,382	5,942	2,560
18	Federal & State Income Tax	3,925	5,190	1,265
19	Payroll & Other	1,452	1,670	218
20	Total Taxes	$13,678	$18,771	$5,093
21	**Total Expenses**	$114,756	$182,425	$67,669
22	AFUDC	$0	$0	$0
23	**Total Operating Income**	$23,000	$28,394	$5,394

Note: Revenues reflect calendar month sales.

(1) Include reclass of $1,474 from Amortization to Depreciation per TEK-1 Schedule 3 Page 2 of 2, line 21

($000's)

Line No.	Description	2010 Unadjusted Test Year	Pro Forma Adjustments (1)	2010 Pro Forma
	Electric Plant as Booked			
1	Production	$394,510	$33,896	$428,406
2	Transmission	$97,917	($658)	$97,259
3	Distribution	$180,529	$0	$180,529
4	General	$17,445	$0	$17,445
5	Common	$23,970	$0	$23,970
6	TOTAL Utility Plant in Service	$714,371	$33,238	$747,609
	Reserve for Depreciation			
7	Production	$236,566	$90	$236,656
8	Transmission	$32,575	($13)	$32,562
9	Distribution	$72,024	$0	$72,024
10	General	$6,866	$0	$6,866
11	Common	$14,938	$0	$14,938
12	TOTAL Reserve for Depreciation	$362,969	$77	$363,046
	Net Utility Plant in Service			
13	Production	$157,944	$33,806	$191,750
14	Transmission	$65,342	($645)	$64,697
15	Distribution	$108,505	$0	$108,505
16	General	$10,579	$0	$10,579
17	Common	$9,032	$0	$9,032
18	Net Utility Plant in Service	$351,402	$33,161	$384,563
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$0	$0	$0
21	Less: Accumulated Deferred Income Taxes	$75,503	$1,020	$76,523
22	Cash Working Capital	($2,794)	($182)	($2,976)
	Other Rate Base Items:			
23	Materials and Supplies	$6,260	$0	$6,260
24	Fuel Inventory	$4,816	$0	$4,816
25	Non-Plant Assets & Liabilities	($6,495)	$3,892	($2,603)
26	Prepayments	$1,122	$0	$1,122
27	Customer Advances	($157)	$0	($157)
28	Interest on Customer Deposits	($156)	$0	($156)
29	Nuclear Outage Amortization	$3,090	$0	$3,090
30	SD Private Fuel Amortization	$933	$0	$933
31	SD Rate Case Expense Amortization	$244	$0	$244
32	SD SO2 Emission Allowance Sales Amortiz	($202)	$0	($202)
33	SD AFUDC Amortization	$4,715	$0	$4,715
34	Other Working Capital	$266	$0	$266
35	Total Other Rate Base Items	$14,436	$3,892	$18,328
36	Total Average Rate Base	$287,541	$35,851	$323,392

2010 PRO FORMA to 2010 UNADJUSTED TEST YEAR
2010 Pro Forma
(Dollars in Thousands)

Line No.	Description	2010 Unadjusted Test Year (A)	Final Increase (B) = (C) - (A)	2010 Pro Forma Final Rates (C)
	Operating Revenues			
1	Retail	$156,951	$268	$157,219
3	Interdepartmental	0	0	0
4	Other Operating	39,152	(135)	39,017
6	**Total Operating Revenues**	$196,103	$133	$196,236
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$80,110	($10,014)	$70,096
8	Power Production	40,130	299	40,429
9	Transmission	9,757	(3)	9,754
10	Distribution	6,533	(136)	6,397
11	Customer Accounting	3,996	0	3,996
12	Customer Service & Information	492	(68)	424
13	Sales, Econ Dvlp & Other	3	50	53
14	Administrative & General	12,482	(148)	12,334
15	Total Operating Expenses	$153,503	($10,020)	$143,483
16	Depreciation	$18,618	$1,151	$19,769
17	Amortizations	828	(426)	402
	Taxes:			
18	Property	$5,560	$409	$5,969
20	Deferred Income Tax & ITC	19,226	(13,284)	5,942
21	Federal & State Income Tax	(13,970)	14,056	86
22	Payroll & Other	1,671	(1)	1,670
23	Total Taxes	$12,487	$1,180	$13,667
24	**Total Expenses**	$185,436	($8,115)	$177,321
25	AFUDC	$0	$0	$0
26	**Total Operating Income**	$10,667	$8,248	$18,915

Note: Revenues reflect calendar month sales.

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENT SCHEDULES
2010 Unadjusted Test Year versus 2010 Pro Forma Test Year
($000's)

Line No.	Description	Unadjusted (1)	SFAS 106 Pay Go (2)	Noble Wind (3)	Monti EPU (4)	PI Life Extension (5)	King Mercury (6)	Merricourt (7)	Steam Remaining Life (8)	Other Prod Remaining Life (9)	Bonus Tax Depreciation (10)	Net Operating Loss (11)	Remove Riders (12)	Income Statement (13)	2010 Pro Forma (14)
	Electric Plant as Booked														
1	Production	$394,510		$22,248	$6,636	$4,870	$142						($658)		$427,748
2	Transmission	$97,917													$97,917
3	Distribution	$180,529													$180,529
4	General	$17,445													$17,445
5	Common	$23,970													$23,970
6	TOTAL Utility Plant in Service	$714,371	$0	$22,248	$6,636	$4,870	$142	$0	$0	$0	$0	$0	($658)		$747,609
	Reserve for Depreciation														
7	Production	$236,566		$569	($377)	$104	$3		($263)	$54			($13)		$236,643
8	Transmission	$32,575													$32,575
9	Distribution	$72,024													$72,024
10	General	$6,866													$6,866
11	Common	$14,938													$14,938
12	TOTAL Reserve for Depreciation	$362,969	$0	$569	($377)	$104	$3	$0	($263)	$54	$0	$0	($13)		$363,046
	Net Utility Plant in Service														
13	Production	$157,944		$21,679	$7,013	$4,766	$139	$0	$263	($54)			($645)		$191,105
14	Transmission	$65,342													$65,342
15	Distribution	$108,505													$108,505
16	General	$10,579													$10,579
17	Common	$9,032													$9,032
18	Net Utility Plant in Service	$351,402	$0	$21,679	$7,013	$4,766	$139	$0	$263	($54)	$0	$0	($645)		$384,563
19	Utility Plant Held for Future Use	$0													$0
20	Construction Work in Progress	$0													$0
21	Less: Accumulated Deferred Income Taxe	$75,503	$1,577	$3,358	$1,792	$539	$19	$14	$100	($21)	($1,853)	($4,470)	($35)		$76,523
22	Cash Working Capital	($2,794)												($182)	($2,976)
	Other Rate Base Items:														
23	Materials and Supplies	$6,260													$6,260
24	Fuel Inventory	$4,816													$4,816
25	Non-Plant Assets & Liabilities	($6,495)	$3,892												($2,603)
26	Prepayments	$1,122													$1,122
27	Customer Advances	($157)													($157)
28	Interest on Customer Deposits	($156)													($156)
29	Nuclear Outage Amortization	$3,090													$3,090
30	SD Private Fuel Amortization	$933													$933
31	SD Rate Case Expense Amortization	$244													$244
32	SD SO2 Emission Allowance Sales Amo	($202)													($202)
33	SD AFUDC Amortization	$4,715													$4,715
34	Other Working Capital	$266													$266
35	Total Other Rate Base Items	$14,436	$3,892	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,328
36	Total Average Rate Base	$287,541	$2,315	$18,321	$5,221	$4,227	$120	($14)	$163	($33)	$1,853	$4,470	($610)	($182)	$323,392

($000's)

Line No.	Description	As Filed (1)	Weather Normalization (2)	Fuel Lag (3)	Fuel Recovery Timing (4)	Incentive Comp (5)	Vegitation Mgmt (6)	Storm Damage (7)	Claims & Injury Comp (8)	Fuel Exp Write-Off (9)	Advertising (10)	Economic Development (11)	Interest on Customer Deposits (12)	Association Dues (13)	Donations (14)	SFAS 106 Pay Go (15)
	Operating Revenues															
1	Retail	$156,951	($1,280)	($407)	$2,635											
2	Interdepartmental	0														
3	Other Operating	39,152														
4	**Total Operating Revenues**	$196,103	($1,280)	($407)	$2,635	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Expenses															
	Operating Expenses:															
5	Fuel & Purchased Energy	$80,110		($407)						($9,607)						
6	Power Production	$40,130														
7	Transmission	$9,757					($2)									
8	Distribution	$6,533					($7)	($129)								
9	Customer Accounting	$3,996														
10	Customer Service & Information	$492									($68)					
11	Sales, Econ Dvlp & Other	$3										$50				
12	Administrative & General	$12,482				($727)			($70)		($152)		$1	($1)		$215
13	Total Operating Expenses	$153,503	$0	($407)	$0	($727)	($9)	($129)	($70)	($9,607)	($220)	$50	$1	($1)	$0	$215
14	Depreciation	$18,618														
15	Amortization	$828														
	Taxes:															
16	Property	$5,560														
17	Deferred Income Tax & ITC	$19,226														$46
18	Federal & State Income Tax	($13,970)	($448)	$0	$922	$254	$3	$45	$25	$3,362	$77	($18)	($0)	$0	$0	($139)
19	Payroll & Other	$1,671														
20	Total Taxes	$12,487	($448)	$0	$922	$254	$3	$45	$25	$3,362	$77	($18)	($0)	$0	$0	($93)
21	**Total Expenses**	$185,436	($448)	($407)	$922	($473)	($6)	($84)	($46)	($6,245)	($143)	$33	$1	($1)	$0	$122
22	Allowance for Funds Used During Construction	$0														
23	**Total Operating Income**	$10,667	($832)	$0	$1,713	$473	$6	$84	$46	$6,245	$143	($33)	($1)	$1	$0	($122)
	Calculation of Revenue Requirements															
24	Rate Base	$287,541	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,315
25	Required Operating Income	$25,246	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$193
26	Operating Income	$10,667	($832)	$0	$1,713	$473	$6	$84	$46	$6,245	$143	($33)	($1)	$1	$0	($122)
27	Operating Income Deficiency	$14,579	$832	$0	($1,713)	($473)	($6)	($84)	($46)	($6,245)	($143)	$33	$1	($1)	$0	$314
28	Revenue Deficiency	**$22,429**	**$1,280**	**$0**	**($2,635)**	**($727)**	**($9)**	**($129)**	**($70)**	**($9,607)**	**($220)**	**$50**	**$1**	**($1)**	**$0**	**$483**
29	Revenue Requirements	$179,380	$1,280	$0	($2,635)	($727)	($9)	($129)	($70)	($9,607)	($220)	$50	$1	($1)	$0	$483
	Calculation of Income Taxes															
30	Operating Revenue	$196,103	($1,280)	($407)	$2,635	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	- Operating Exp	$153,503	$0	($407)	$0	($727)	($9)	($129)	($70)	($9,607)	($220)	$50	$1	($1)	$0	$215
32	- Amortizations	$828	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	- Taxes oth than Inc	$7,231	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34	Operating Income before Adjs	$34,541	($1,280)	$0	$2,635	$727	$9	$129	$70	$9,607	$220	($50)	($1)	$1	$0	($215)
35	Additions to Income	$11,980	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Deduct from Income	$76,075	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$113
37	Debt Synchronization	$8,655	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$70
38	State Taxable Income	($38,209)	($1,280)	$0	$2,635	$727	$9	$129	$70	$9,607	$220	($50)	($1)	$1	$0	($398)
39	State Income Tax before Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
40	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
41	Federal Taxable Income	($38,209)	($1,280)	$0	$2,635	$727	$9	$129	$70	$9,607	$220	($50)	($1)	$1	$0	($398)
42	Fed Income Tax before Credits	($13,373)	($448)	$0	$922	$254	$3	$45	$25	$3,362	$77	($18)	($0)	$0	$0	($139)
43	Federal Tax Credits	$597	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	Income Tax	($13,970)	($448)	$0	$922	$254	$3	$45	$25	$3,362	$77	($18)	($0)	$0	$0	($139)

Northern States Power Company, a Minnesota corporation
Electric Utility - South Dakota
2010 Unadjusted Test Year to 2010 Pro Forma Bridge Sched
($000's)

Line No.	Description	2011 Rate Case Exp (16)	Noble Wind (17)	Monti EPU (18)	PI Life Exstension (19)	King Mercury (20)	Merricourt (21)	Steam Remaining Life (22)	Other Prod Remaining Life (23)	Bonus Tax Depreciation (24)	Net Operating Loss (25)	Union Wage Adjustment (26)	Non-Union Wage Adjustment (27)	Margin Sharing (28)	Wholesale Billing (29)	Foundation Administration Costs (30)
	Operating Revenues															
1	Retail															
2	Interdepartmental															
3	Other Operating													(135)		
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($135)	$0	$0
	Expenses															
	Operating Expenses:															
5	Fuel & Purchased Energy															
6	Power Production															
7	Transmission															
8	Distribution															
9	Customer Accounting															
10	Customer Service & Information															
11	Sales, Econ Dvlp & Other															
12	Administrative & General											$161	$277		($10)	($21)
13	Total Operating Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$161	$277	$0	($10)	($21)
14	Depreciation		$1,015	$349	$214	$6		($525)	$108							
15	Amortization	$194														
	Taxes:															
16	Property		$274	$76	$59	$2										
17	Deferred Income Tax & ITC		($4,673)	$3,697	$283	($37)	$10	$200	($42)	($3,705)	($8,940)					
18	Federal & State Income Tax	($68)	$3,215	($3,365)	($410)	$27	($9)	($2)	$0	$3,153	$7,695	($56)	($97)	($47)	$4	$8
19	Payroll & Other															($1)
20	Total Taxes	($68)	($1,184)	$408	($68)	($8)	$1	$198	($42)	($552)	($1,245)	($56)	($97)	($47)	$4	$7
21	**Total Expenses**	$126	($169)	$757	$146	($2)	$1	($327)	$66	($552)	($1,245)	$105	$180	($47)	($7)	($14)
22	Allowance for Funds Used During Construction															
23	**Total Operating Income**	($126)	$169	($757)	($146)	$2	($1)	$327	($66)	$552	$1,245	($105)	($180)	($88)	$7	$14
	Calculation of Revenue Requirements															
24	Rate Base	$0	$18,321	$5,221	$4,227	$120	($14)	$163	($33)	$1,853	$4,470	$0	$0	$0	$0	$0
25	Required Operating Income	$0	$1,524	$434	$352	$10	($1)	$14	($3)	$154	$372	$0	$0	$0	$0	$0
26	Operating Income	($126)	$169	($757)	($146)	$2	($1)	$327	($66)	$552	$1,245	($105)	($180)	($88)	$7	$14
27	Operating Income Deficiency	$126	$1,355	$1,191	$498	$8	$0	($313)	$64	($397)	($873)	$105	$180	$88	($7)	($14)
28	Revenue Deficiency	**$194**	**$2,085**	**$1,833**	**$766**	**$12**	**$0**	**($482)**	**$98**	**($611)**	**($1,343)**	**$161**	**$277**	**$135**	**($10)**	**($22)**
29	Revenue Requirements	$194	$2,085	$1,833	$766	$12	$0	($482)	$98	($611)	($1,343)	$161	$277	$135	($10)	($22)
	Calculation of Income Taxes															
30	Operating Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($135)	$0	$0
31	- Operating Exp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$161	$277	$0	($10)	($21)
32	- Amortizations	$194	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	- Taxes oth than Inc	$0	$274	$76	$59	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)
34	Operating Income before Adjs	($194)	($274)	($76)	($59)	($2)	$0	$0	$0	$0	$0	($161)	($277)	($135)	$10	$22
35	Additions to Income	$0	($691)	$62	($126)	($3)	($25)	$0	$0	$0	$0	$0	$0	$0	$0	$0
36	Deduct from Income	$0	($10,708)	$9,442	$857	($85)	$0	$0	$0	($9,066)	($20,416)	$0	$0	$0	$0	$0
37	Debt Synchronization	$0	$557	$159	$129	$4	($0)	$5	($1)	$56	$136	$0	$0	$0	$0	$0
38	State Taxable Income	($194)	$9,186	($9,615)	($1,171)	$76	($25)	($5)	$1	$9,010	$20,280	($161)	($277)	($135)	$10	$22
39	State Income Tax before Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
40	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
41	Federal Taxable Income	($194)	$9,186	($9,615)	($1,171)	$76	($25)	($5)	$1	$9,010	$20,280	($161)	($277)	($135)	$10	$22
42	Fed Income Tax before Credits	($68)	$3,215	($3,365)	($410)	$27	($9)	($2)	$0	$3,153	$7,098	($56)	($97)	($47)	$4	$8
43	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	($597)	$0	$0	$0	$0	$0
44	Income Tax	($68)	$3,215	($3,365)	($410)	$27	($9)	($2)	$0	$3,153	$7,695	($56)	($97)	($47)	$4	$8

($000's)

Line No.	Description	Employee Expense Reduction (31)	Pension and Insurance (32)	Weather Normalized Allocator (33)	Rider Removal (34)	Cost of Capital (35)	CWC (36)	Rounding (37)	2010 Pro Forma (38)
	Operating Revenues								
1	Retail				($680)			$0	$157,219
2	Interdepartmental							0	$0
3	Other Operating							0	$39,017
4	**Total Operating Revenues**	$0	$0	$0	($680)		$0	$0	$196,236
	Expenses								
	Operating Expenses:								
5	Fuel & Purchased Energy			$299				$0	$70,395
6	Power Production			($1)				$0	$40,129
7	Transmission							$0	$9,755
8	Distribution							$0	$6,397
9	Customer Accounting							$0	$3,996
10	Customer Service & Information							$0	$424
11	Sales, Econ Dvlp & Other							$0	$53
12	Administrative & General	($25)	$204					$0	$12,334
13	Total Operating Expenses	($25)	$204	$298	$0		$0	$0	$143,483
14	Depreciation				($16)			$0	$19,769
15	Amortization				($620)			$0	$402
	Taxes:								
16	Property				($2)			$0	$5,969
17	Deferred Income Tax & ITC				($123)			$0	$5,942
18	Federal & State Income Tax	$9	($71)	($104)	$86	$4	$2	$0	$86
19	Payroll & Other							$0	$1,670
20	Total Taxes	$9	($71)	($104)	($39)	$4	$2	$0	$13,667
21	**Total Expenses**	($16)	$133	$194	($675)	$4	$2	$0	$177,321
22	Allowance for Funds Used During Construction							$0	$0
23	**Total Operating Income**	$16	($133)	($194)	($5)	($4)	($2)	$0	$18,915
	Calculation of Revenue Requirements								
24	Rate Base	$0	$0	$0	($610)	$0	($182)	$0	$323,392
25	Required Operating Income	$0	$0	$0	($51)	$165	($15)	$0	$28,394
26	Operating Income	$16	($133)	($194)	($5)	($4)	($2)	$0	$18,915
27	Operating Income Deficiency	($16)	$133	$194	($46)	$169	($13)	$0	$9,479
28	Revenue Deficiency	**($25)**	**$204**	**$298**	**($71)**	**$260**	**($20)**	**$0**	**$14,583**
29	Revenue Requirements	($25)	$204	$298	($71)	$260	($20)	$0	$171,802
	Calculation of Income Taxes								
30	Operating Revenue	$0	$0	$0	($680)	$0	$0	$0	$196,236
31	- Operating Exp	($25)	$204	$298	$0	$0	$0	$0	$143,483
32	- Amortizations	$0	$0	$0	($620)	$0	$0	$0	$402
33	- Taxes oth than Inc	$0	$0	$0	($2)	$0	$0	$0	$7,639
34	Operating Income before Adjs	$25	($204)	($298)	($58)	$0	$0	$0	$44,712
35	Additions to Income	$0	$0	$0	($59)	$0	$0	$0	$11,138
36	Deduct from Income	$0	$0	$0	($343)	$0	$0	$0	$45,869
37	Debt Synchronization	$0	$0	$0	($19)	($11)	($6)	$0	$9,734
38	State Taxable Income	$25	($204)	($298)	$245	$11	$6	$0	$247
39	State Income Tax before Credits	$0	$0	$0	$0	$0	$0	$0	$0
40	State Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0
41	Federal Taxable Income	$25	($204)	($298)	$245	$11	$6	$0	$247
42	Fed Income Tax before Credits	$9	($71)	($104)	$86	$4	$2	$0	$86
43	Federal Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0
44	Income Tax	$9	($71)	($104)	$86	$4	$2	$0	$86

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
10245258 MNGP Extended Power Uprate Revenue Requirements
South Dakota Electric Rate Case 2012, 2011 and Difference
(000's)

Rate Case COSS Cap Str

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.3300%	47.5200%	3.0100%
Short Term Debt	0.0000%	0.0000%	0.0000%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	11.0000%	52.4800%	5.7700%
Required Rate of Return			8.7800%
Tax Rate (SD)	35.0000%		

	2012		2011		Difference	
Annual Revenue Requirement	Total Company	SD Jurisdiction	Total Company	SD Jurisdiction	Total Company	SD Jurisdiction
Plant Investment	367,834	17,217	141,766	6,636	226,068	10,582
Depreciation Reserve	(7,311)	(342)	(9,177)	(430)	1,866	88
CWIP	-	-	-	-	-	-
Accumulated Deferred Taxes	101,132	4,734	55,991	2,621	45,141	2,112
	274,013	12,825	94,952	4,445	179,061	8,382
Average Rate Base	274,013	12,825	94,952	4,445	179,061	8,382
Debt Return	8,248	386	2,858	134	5,390	252
Equity Return	15,811	740	5,479	256	10,332	484
Current Income Tax Requirement	169	8	(54,178)	(2,536)	54,347	2,544
Book Depreciation	20,479	959	7,455	349	13,024	610
Annual Deferred Tax	12,505	585	77,776	3,640	(65,271)	(3,055)
ITC Flow Thru	-	-	-	-	-	-
Tax Depreciation & Removal Expense	50,174	2,348	201,731	9,442	(151,557)	(7,094)
AFUDC Expenditure	-	-	-	-	-	-
Avoided Tax Interest	1,694	79	10,405	487	(8,711)	(408)
Property Taxes	4,193	196	1,616	76	2,577	121
Total Revenue Requirements	61,405	2,874	41,006	1,919	20,399	**956**

Line No.	Description	Allocation Basis
	The allocation factors on this page were used to determine South Dakota jurisdictional operating income amounts for all of the years presented in these schedules. Accounts not on this page have been directly asigned to jurisdiction.	
1	Fuel & Purchased Energy	Energy
2	Power Production Expense	Demand - Production
3	Transmission Expense	Demand - Transmission
4	Distribution Expense	Customers
5	Customer Accounting Expense	Customers
6	Customer Service & Info Expense	Customers
7	Sales Expense	Customers
8	Administrative & General	Customers Demand - Production Demand - Transmission TwoFactor

		Unadjusted Test Year 2010		
Line No.	Allocation Factor	Total Utility	South Dakota Jurisdiction	Allocation Factor
1	Demand - Prod(1)	70,107,355	3,923,283	5.5961%
2	Demand - Tran (2)	70,107,355	3,923,283	5.5961%
3	Energy (3)	37,281,034	2,086,639	5.5971%
4	Customers(4)	1,392,498	83,182	5.9736%
5	TwoFactor	100.0000%	5.7096%	

Line No.	Allocation Factor	Total Utility	MN Utility	WI Utility
6	36 mth Demand	100.0000%	83.6422%	16.3578%
7	Energy	100.0000%	83.7930%	16.2070%

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers
(5) TwoFactor
(6) 36 Mth Demand
(7) Energy

Line No.	Allocation Factor	Unadjusted Test Year 2010 Total Utility	South Dakota Jurisdiction	Allocation Factor
1	Demand - Production	70,107,355	3,923,283	5.5961%
2	Demand - Transmission	70,107,355	3,923,283	5.5961%
3	Energy	37,281,034	2,086,639	5.5971%
4	Customers	1,392,498	83,182	5.9736%
5	TwoFactor	see page 4		

Line No.	Allocation Factor	Total Utility	MN Jurisdiction	WI Jurisdiction
6	36 Mth Demand	100.0000%	83.6422%	16.3578%
7	Energy	100.0000%	83.7930%	16.2070%

(1) Demand w/o Contract Services
(2) Demand
(3) Energy
(4) Average number of Customers
(5) TwoFactor
(6) 36 Mth Demand
(7) Energy

Alloctors for Common and General Plant
for 2010 Actual
Based on 2009 Actual Data

O&M Allocator

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

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

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

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

Production	57.1831%
Transmission	11.7901%
Distribution	31.0268%
	100.0000%

11 Budget Allocators

EProd Demand Alloc	
MN	88.4924%
ND	5.8107%
SD	5.5779%
WHLSL	0.1190%
	100.0000%

ETrans Demand Alloc	
MN	88.4924%
ND	5.8107%
SD	5.5779%
WHLSL	0.1190%
	100.0000%

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

2010 Actual A&G Jurisdicational Allocators

ELECTRIC A&G Alloc

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

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of South Dakota
SUMMARY OF TEST PERIOD ADJUSTMENTS
Test Year Ending December 31, 2010
($000's)

Docket No. EL11-____
Exhibit___(TEK-1) Schedule 9

Adjustment Type	Adjustment	Adjustment Description
Pro Forma Normalization	Weather	Adjust for normal weather
Pro Forma Normalization	Fuel Lag	Required to record fuel expense and revenue on a calendar versus billing basis
Pro Forma Normalization	Deferred Fuel Recovery	Required as a result of changing the accounting for deferred fuel beginning in Sept 2010
Pro Forma Normalization	Incentive Compensation	Excludes items not eligible for recovery
Pro Forma Normalization	Vegetation Management	Normalize vegetation management expenses over 5 years
Pro Forma Normalization	Storm Damnage	Normalize storm expenses over 5 years
Pro Forma Normalization	Claims & Injury Compensation	Normalize claims expenses over 5 years
Pro Forma Normalization	One time Fuel Write Off	One one time deferred fuel write-off
Traditional Adjustments	Advertising	Traditional adjustment made for advertising costs to adjust to allowed level of recovery
Traditional Adjustments	Economic Development	Traditional adjustment made for economic development costs to adjust to allowed level of recovery
Traditional Adjustments	Interest on Customer Deposits A&G	Traditional adjustment made for interest on customer deposits to adjust to allowed level of recovery
Traditional Adjustments	Association Dues	Traditional adjustment made for Association Dues to adjust to allowed level of recovery
Traditional Adjustments	Donations	Traditional adjustment made for donations to adjust to allowed level of recovery
Traditional Adjustments	FAS 106 PayGo	To adjust FAS106 to Pay as you go accounting
Traditional Adjustments	CY Rate Case Costs	Amortization of rate case expenses incurred in preperation of current case
Known and Measurable Adjustments	Nobles Wind	Annualize 2010 plant additions
Known and Measurable Adjustments	Monticello EPU	Incorporate 2011 plant additions
Known and Measurable Adjustments	PI Projects Life Extension Projects	Annualize 2010 plant addition as well as incorporate 2011 plant additions
Known and Measurable Adjustments	King Mercury Sorbent	Annualize 2010 additions since project is being shifted from ECR rider recovery
Known and Measurable Adjustments	Merricourt Removal	Project was cancelled
Known and Measurable Adjustments	Steam Prod Depr Lives & Net Salvage	Update remaining lives and net salvage
Known and Measurable Adjustments	Other Prod Depr Lives & Net Salvage	Update remaining lives and net salvage
Known and Measurable Adjustments	Bonus Tax Depreciation	Adjust bonus tax depreciation for latest interpretation of tax law
Known and Measurable Adjustments	Net Operating Loss (NOL)	Adjust for tax loss position in 2010
Known and Measurable Adjustments	Union Wages	Known union wage increases
Known and Measurable Adjustments	NonUnion Wages	Known non-union wage increases
Known and Measurable Adjustments	Margin Sharing on Trading Activity	Remove shareholder portion of margins related to asset and non-asset trading
Known and Measurable Adjustments	Wholesale Billing	To allocate an appropriate level of costs to wholesale
Known and Measurable Adjustments	Foundation Administrative Costs	Remove foundation administration
Known and Measurable Adjustments	Employee Expense Reduction	To ensure no inappropriate costs are included in test year based on a study of 2009 costs
Known and Measurable Adjustments	Pension & Insurance	Known increases for pension and medical expenses
Known and Measurable Adjustments	Weather Normalized Allocators	Update allocators to reflect normal weather
Known and Measurable Adjustments	Remove TCR	Remove TCR Revenues and costs remaining in the rider
Known and Measurable Adjustments	Remove ECR	Remove ECR Revenues and costs remaining in the rider

NSP Non-Asset Based Margin Study

Introduction

In its most recent general electric rate case (Docket No. EL09-009), Northern States Power Company, a Minnesota corporation (the "Company" or "NSPM") committed to perform an incremental and a fully distributed cost study of non-asset based trading activities as part of its next general electric rate case application.

This report summarizes the cost study undertaken by the Company to determine the incremental costs along with the fully allocated cost of obtaining non-asset based trading margins.

Background

There are two categories of short-term wholesale trading; asset based transactions and non-asset based transactions. Asset based transactions involve the sales of excess energy from Company owned generation assets. Non-asset based transactions are undertaken to make revenues and are unrelated to meeting the needs of the Native Load. The only transactions that qualify as a non-asset based transaction are third-party supplied electricity that are not purchased to meet the needs of the serving native load and which are resold. The costs that are being examined in this study are exclusively for non-asset based transactions.

Definitions

Incremental Costs

In developing these studies, the Company has defined incremental costs as those costs that would cease to be incurred if the Company stopped performing non-asset based trading transactions for the Company. Thus if the business ceased, so too would the cost. There would be no continuing need to compensate the ratepayers.

Fully Allocated Costs

The definition that the Company is using to determine fully distributed costs includes the incremental costs along with a reasonable contribution of common overhead costs.

<u>Incremental Costs</u>

The first step taken to identify the incremental costs was to identify all expenses that are booked to the non-asset based trading account. Each cost has been reviewed to determine if it is directly incurred as a result of non-asset based trading activities. The most obvious of these direct costs are productive labor as well as associated payroll taxes. There are a number of other costs that are allocated to the non-asset based trading account, for example systems costs such as billing and payment tracking, described later. However there is no direct cost causation nexus that suggests that such costs would not be incurred in the absence of NSPM non-asset based trading and therefore have not been counted as being incremental.

Labor overhead costs are not as clearly definable as "direct" compared to production labor. If an employee charges time to non-asset based trading activities, the costs are allocated to the three operating companies in the same manner that margins are shared under the Joint Operating Agreement ("JOA"). Should NSPM discontinue non-asset based trading activities, no productive labor costs would be allocated to the jurisdiction. Labor overhead charges reflect the allocation of the non-productive labor costs (for example pension and insurance). Only if there is a one-to-one correlation between productive labor and employee reductions should all the non-productive labor costs be considered incremental. At the same time, it would not be reasonable to assume that there would be no non-productive labor savings.

We have developed allocation factors, by business groups, to identify a reasonable amount of non-productive labor costs that should be included as incremental. The three business groups that are directly involved with non-asset based trading are trading, risk management and accounting. These groups represent the functions that are required for non-asset based trading activities. As part of this study, we consulted with management in each department to determine a reasonable work force reduction that would result from the elimination of non-asset based trading in NSPM. We then determined the total number of employees within the group to develop an allocation factor to be applied to that group's non-productive labor costs.

For example, within the trading group we would expect the elimination of between one and two full-time employees out of a total of 14 employees if NSPM non-asset based trading were to be eliminated. We then divided 1.5 into 14 and allocated 10.714 percent of associated trading labor overheads and defined that share as incremental. We developed a different allocator for each trading, risk and accounting group to assign non productive labor to incremental costs:

Department	**Allocator**
Trading	10.714%
Risk Management	1.818%
Accounting	1.22%

No capital costs were included as being incremental – such costs are sunk and therefore would not be eliminated if NSPM non-asset based trading stopped.

For the three-year period 2007 through 2009, the average annual incremental costs incurred to facilitate non-asset based trading margins allocated to the South Dakota jurisdiction were $31,889. Please see Attachment A for the actual annual amounts for 2007 to 2009 and the forecasted amounts for 2011 and 2012.

In comparison, for the three-year period 2007 through 2009, using a 25 percent sharing mechanism, as approved in Docket No. EL09-009, the Company would have, on average, paid $55,196 to South Dakota ratepayers.

Fully Allocated Costs

There are two components of the fully allocated costs – expenses and a share of capital costs. All expenses that are booked to non-asset based trading are counted as fully distributed. To use the same example described above, systems costs that were specifically excluded from incremental costs due to a direct cost-causation link are included in the fully distributed costs. Labor, indirect labor overhead (which includes rents) and IT system costs were the operating and maintenance ("O&M") expenses included in the study.

The labor itself is directly recorded as being non-asset trading, however, the Company has included labor overhead allocations to the directly assigned labor in the fully allocated section of the study.

A labor overhead rate of 11.57 percent, the same rate applied to total labor and labor loadings for charges to the non-regulated businesses within NSPM and for third party billings, was used.

Please see Attachment B for the actual annual labor and labor overhead for 2007 to 2009 and the forecasted amounts for 2011 and 2012.

In addition to the labor and labor overhead expenses, the Company identified systems used to facilitate non-asset based trading. The table below summarizes the systems identified which support non-asset based trading activities.

System	**Description**
ACES	Manages trade data (e.g. counterparty, volume, price), used to verify information with counterparties and as a source for accounting records.
JDE	General ledger system used to account for trade activity for financial reporting.
Altra Reports	Database for retrieval, storing and reporting of transaction data from ACES.
Bookrunner	Repository system used in calculating Value-at-Risk (VAR) and forward MTM transactions.
PCI	Bid-to-bill transaction management tool used for MISO activity.
Passport	Records payments made by Accounts Payable.
XRT	Records payments made by Cash Management.
Documentum	Storage of contract documentation.

An analysis was conducted to determine the amount of O&M for each system allocated to NSPM. A portion of the total system O&M was assigned to non-asset based trading based upon the percent of non-asset based trading as a percent of total NSP system revenues. Please see Attachment B for the actual IT O&M assigned for each year.

Next, a rate base amount associated with the above listed systems was determined. The rate base and non-asset based revenue ratio for 2009 was used to calculate a total IT systems rate base which serves as a proxy amount for all the years on Attachment B.

For the three-year period 2007 through 2009, the average annual fully allocated costs incurred to facilitate non-asset based trading allocated to the South Dakota jurisdiction were $67,896. Please see Attachment B for the actual annual amounts for 2007 to 2009 and the forecasted amounts for 2011 and 2012.

	2007	2008	2009	3 Yr Avg.	2011	2012
NSPM Operating Company						
Incremental O&M Labor Costs						
Trading	$ 309,635	$ 395,361	$ 591,221	$ 432,072	$ 412,907	$ 427,322
Risk	$ 100,396	$ 101,952	$ 99,934	$ 100,761	$ 126,254	$ 130,496
Accounting	$ 81,026	$ 84,140	$ 69,509	$ 78,225	$ 99,623	$ 101,378
Total Incremental O&M Expenses	**$ 491,057**	**$ 581,453**	**$ 760,664**	**$ 611,058**	**$ 638,784**	**$ 659,197**
Non-Asset Based Shared Margins at 25%	**$ 1,613,306**	**$ 167,197**	**$ 1,332,085**	**$ 1,037,529**	**$ 1,265,999**	**$ 1,265,999**
State of SD Jurisdictional Amounts						
Energy SD Jurisdictional Allocator	5.2117%	5.2928%	5.4553%	5.3199%	5.7150%	5.7969%
Demand SD Jurisdictional Allocator	5.1989%	5.1340%	5.3230%	5.2186%	5.5779%	5.6598%
Incremental O&M Expenses	$ 25,530	$ 29,852	$ 40,490	$ 31,889	$ 35,631	$ 37,309
Non-Asset Based Shared Margins at 25%*	$ 84,081	$ 8,849	$ 72,669	$ 55,196	$ 72,352	$ 73,389
Difference	**$ 58,551**	**$ (21,002)**	**$ 32,179**	**$ 23,307**	**$ 36,721**	**$ 36,079**

Notes:

The margin was significantly down in 2008 due to the accrual of a MISO resettlement expense in 2008, with the majority of it reversed to non-asset based margins as a reduction of expense in 2009.

Actual 2011 & 2012 margins could vary from the projected amounts provided. Non-asset margins are extremely difficult to project as they are based on the Company's opportunity to purchase power and resell that same energy at higher prices – only when arbitrage opportunities exist are non-asset based transactions made. Market conditions are dynamic and constantly changing. Other considerations that have affected non-asset margins are MISO after the fact settlements.

Northern States Power Company, a Minnesota corporation
Summary of Non-Asset Based Trading Costs and Margins
Fully Allocated Costs

Docket No. EL11-____
Exhibit___(TEK-1), Schedule 10
Attachment B

	2007	2008	2009	3 Yr Avg	2011	2012
NSPM Operating Company						
O&M Expenses						
Trading	$ 611,395	$ 686,244	$ 979,410	$ 759,016	$ 909,527	$ 935,504
Risk	$ 145,208	$ 139,147	$ 158,096	$ 147,484	$ 205,231	$ 214,927
Accounting	$ 121,183	$ 106,901	$ 108,921	$ 112,335	$ 160,803	$ 165,810
Indirect Labor Overhead	$ 89,277	$ 95,303	$ 115,957	$ 100,179	$ 107,749	$ 112,935
IT System	$ 60,593	$ 34,670	$ 25,934	$ 40,399	$ 25,934	$ 25,934
Total O&M Expenses	**$ 1,027,656**	**$ 1,062,265**	**$ 1,388,318**	**$ 1,159,413**	**$ 1,409,244**	**$ 1,455,110**
Rate Base						
IT Systems	$ 141,615	$ 141,615	$ 141,615	$ 141,615	$ 141,615	$ 141,615
Total Rate Base	**$ 141,615**	**$ 141,615**	**$ 141,615**	**$ 141,615**	**$ 141,615**	**$ 141,615**
NSPM Total Rev Req.	**$ 1,169,271**	**$ 1,203,880**	**$ 1,529,933**	**$ 1,301,028**	**$ 1,550,859**	**$ 1,596,725**
Non-Asset Based Shared Margins at 25%	**$1,613,306**	**$167,197**	**$1,332,085**	**$ 1,037,529**	**$ 1,265,999**	**$ 1,265,999**

	2007	2008	2009	3 Yr Avg	2011	2012
State of SD Jurisdictional Amounts						
Energy SD Jurisdictional Allocator	5.2117%	5.2928%	5.4553%	5.3199%	5.7150%	5.7969%
Demand SD Jurisdictional Allocator	5.1989%	5.1340%	5.3230%	5.2186%	5.5779%	5.6598%
Revenue Requirements	$60,789	$61,807	$81,438	$67,896	$86,505	$90,371
Non-Asset Based Shared Margins at 25%	$84,081	$8,849	$72,669	$55,196	$72,352	$73,389
Difference	**$23,291**	**($52,958)**	**($8,769)**	**($12,700)**	**($14,153)**	**($16,983)**

Notes:

The margin was significantly down in 2008 due to the accrual of a MISO resettlement expense in 2008, with the majority of it reversed to non-asset based margins as a reduction of expense in 2009.

Actual 2011 & 2012 margins could vary from the projected amounts provided. Non-asset margins are extremely difficult to project as they are based on the Company's opportunity to purchase power and resell that same energy at higher prices – only when arbitrage opportunities exist are non-asset based transactions made. Market conditions are dynamic and constantly changing. Other considerations that have affected non-asset margins are MISO after the fact settlements.

<u>2010 SD Electric Rate Case Expenses</u>	**SOUTH DAKOTA JURISDICTION**
Consulting Fees	$ 80,000
Rate of Return - Concentric Energy Advisors	
Outside Legal Fees	175,000
Moss & Barnett	
State Agency Fees	110,000
Administrative Costs (transcripts, inserts, admin)	23,500
Sub - TOTAL	**$ 388,500**
Remove percent for unregulated business (.1019%)	(396)
TOTAL	**$ 388,104**

Northern States Power Company, a Minnesota corporation
Electric Utility - State of South Dakota
COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2010
($000's)

Docket No. EL11-____
Exhibit___(TEK-1), Schedule 12

Line No.	Description	General Rate Case Filing Docket No. EL09-009 (A)	General Rate Case Filing Docket No. EL11-____ (B)	Change (C) = (B) - (A)
	Electric Plant as Booked			
1	Production	$344,334	$428,406	$84,072
2	Transmission	82,643	97,259	14,616
3	Distribution	169,400	180,529	11,129
4	General	13,458	17,445	3,987
5	Common	21,141	23,970	2,829
6	TOTAL Utility Plant in Service	$630,976	$747,609	116,633
	Reserve for Depreciation			
7	Production	$204,127	$236,656	$32,529
8	Transmission	27,268	32,562	5,294
9	Distribution	65,548	72,024	6,476
10	General	5,091	6,866	1,775
11	Common	11,690	14,938	3,248
12	TOTAL Reserve for Depreciation	$313,724	$363,047	$49,323
	Net Utility Plant in Service			
13	Production	$140,207	$191,750	$51,543
14 1	Transmission	55,375	64,697	9,322
15 2	Distribution	103,852	108,505	4,653
16 3	General	8,367	10,579	2,212
17 4	Common	9,451	9,032	(419)
18 5	Net Utility Plant in Service	$317,252	$384,563	$67,311
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$0	$0	$0
21	Less: Accumulated Deferred Income Taxes	$54,988	$76,523	$21,535
22	Cash Working Capital	($2,041)	($2,976)	($935)
	Other Rate Base Items:			
23	Materials and Supplies	$5,091	$6,260	$1,169
24	Fuel Inventory	6,174	4,816	(1,358)
25	Non-Plant Assets & Liabilities	(2,637)	(2,603)	34
26	Prepayments	850	1,122	272
27	Customer Advances	(15)	(157)	(142)
28	Interest on Customer Deposits	(63)	(156)	(93)
29	Nuclear Outage Amortization	1,925	3,090	1,165
30	SD Private Fuel Amortization	505	933	428
31	SD Rate Case Expense Amortization	134	244	110
32	SD SO2 Emission Allowance Sales Amortization	(110)	(202)	(92)
33	SD AFUDC Amortization	4,092	4,715	623
34	Other Working Capital	224	266	42
35	Total Other Rate Base Items	$16,170	$18,328	$2,158
36	Total Average Rate Base	$276,393	$323,392	$46,999

Test Year Ending December 31, 2010
($000's)

Line No.	Description	2010 Actual	2010 Test Year Unadjusted	2010 Pro Forma Adjusted
	Electric Plant as Booked			
1	Production	$394,510	$394,510	$428,406
2	Transmission	97,917	97,917	97,259
3	Distribution	180,529	180,529	180,529
4	General	17,445	17,445	17,445
5	Common	23,970	23,970	23,970
6	TOTAL Utility Plant in Service	$714,371	$714,371	$747,609
	Reserve for Depreciation			
7	Production	$236,566	$236,566	$236,656
8	Transmission	32,575	32,575	32,562
9	Distribution	72,024	72,024	72,024
10	General	6,866	6,866	6,866
11	Common	14,938	14,938	14,938
12	TOTAL Reserve for Depreciation	$362,969	$362,969	$363,047
	Net Utility Plant in Service			
13	Production	$157,944	$157,944	$191,750
14	Transmission	65,342	65,342	64,697
15	Distribution	108,505	108,505	108,505
16	General	10,579	10,579	10,579
17	Common	9,032	9,032	9,032
18	Net Utility Plant in Service	$351,402	$351,402	$384,563
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$0	$0	$0
21	Less: Accumulated Deferred Income Taxes	$69,077	$75,503	$76,523
22	Cash Working Capital	$0	($2,794)	($2,976)
	Other Rate Base Items:			
23	Materials and Supplies	$6,260	$6,260	$6,260
24	Fuel Inventory	4,816	4,816	4,816
25	Non-Plant Assets & Liabilities	(2,603)	(6,495)	(2,603)
26	Prepayments	1,122	1,122	1,122
27	Customer Advances	(157)	(157)	(157)
28	Interest on Customer Deposits	(156)	(156)	(156)
29	Nuclear Outage Amortization	3,090	3,090	3,090
30	SD Private Fuel Amortization	933	933	933
31	SD Rate Case Expense Amortization	244	244	244
32	SD SO2 Emission Allowance Sales Amortization	(202)	(202)	(202)
33	SD AFUDC Amortization	4,715	4,715	4,715
34	Other Working Capital	266	266	266
35	Total Other Rate Base Items	$18,328	$14,436	$18,328
36	Total Average Rate Base	$300,653	$287,541	$323,392

($000's)

		Pro Forma 2010					
		Total Utility			South Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$7,049,696	$605,613	$7,655,309	$394,510	33,896	$428,406
2	Transmission	1,755,389	(658)	1,754,731	97,917	(658)	97,259
3	Distribution	2,953,003	0	2,953,003	180,529	0	180,529
4	General	304,346	0	304,346	17,445	0	17,445
5	Common	414,215	0	414,215	23,970	0	23,970
6	TOTAL Utility Plant in Service	$12,476,649	$604,955	$13,081,604	$714,371	$33,238	$747,609
	Reserve for Depreciation						
7	Production	$4,229,405	$1,611	$4,231,016	$236,566	$90	$236,656
8	Transmission	583,802	(13)	583,789	32,575	(13)	32,562
9	Distribution	1,190,951	0	1,190,951	72,024	0	72,024
10	General	119,722	0	119,722	6,866	0	6,866
11	Common	257,359	0	257,359	14,938	0	14,938
12	TOTAL Reserve for Depreciation	$6,381,238	$1,598	$6,382,836	$362,969	$77	$363,046
	Net Utility Plant in Service						
13	Production	$2,820,291	$604,002	$3,424,293	$157,944	$33,806	$191,750
14	Transmission	1,171,587	(645)	1,170,942	65,342	(645)	64,697
15	Distribution	1,762,052	0	1,762,052	108,505	0	108,505
16	General	184,624	0	184,624	10,579	0	10,579
17	Common	156,856	0	156,856	9,032	0	9,032
18	Net Utility Plant in Service	$6,095,411	$603,357	$6,698,768	$351,402	$33,161	$384,563
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$0	$0	$0	$0	$0	$0
21	Less: Accumulated Deferred Income Taxes	$1,287,871	$36,604	$1,324,475	$75,503	$1,020	$76,523
22	Cash Working Capital	($68,088)	$1,248	($66,840)	($2,794)	($182)	($2,976)
	Other Rate Base Items:						
23	Materials and Supplies	$111,130	$0	$111,130	$6,260	$0	$6,260
24	Fuel Inventory	86,048	0	86,048	4,816	0	4,816
25	Non-Plant Assets & Liabilities	(113,676)	68,617	(45,059)	(6,495)	3,892	(2,603)
26	Prepayments	19,815	0	19,815	1,122	0	1,122
27	Customer Advances	(1,217)	0	(1,217)	(157)	0	(157)
28	Interest on Customer Deposits	(2,617)	0	(2,617)	(156)	0	(156)
29	Nuclear Outage Amortization	55,216	0	55,216	3,090	0	3,090
30	SD Private Fuel Amortization	933	0	933	933	0	933
31	SD Rate Case Expense Amortization	244	0	244	244	0	244
32	SD SO2 Emission Allowance Sales Amortization	(202)	0	(202)	(202)	0	(202)
33	SD AFUDC Amortization	4,715	0	4,715	4,715	0	4,715
34	Other Working Capital	3,977	0	3,977	266	0	266
35	Total Other Rate Base Items	$164,366	$68,617	$232,983	$14,436	$3,892	$18,328
36	Total Average Rate Base	$4,903,818	$636,618	$5,540,436	$287,541	$35,851	$323,392

($000's)

		Pro Forma 2010					
		Total Utility			South Dakota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	$625,326	$95,327	$720,653	$36,873	$4,193	$41,066
2	Transmission	237,220	(1,614)	235,606	13,227	(189)	13,038
3	Distribution	399,961	4,709	404,670	23,936	(36)	23,900
4	General	35,454	0	35,454	2,044	(21)	2,023
5	Common	33,592	0	33,592	1,945	(34)	1,911
6	Non-Plant Related	(43,682)	0	(43,682)	(2,521)	1,577	(944)
7	Net Operating Loss Carryforward (NOL)	0	(61,818)	(61,818)	0	(4,470)	(4,470)
8	TOTAL Accum Deferred Income Taxes	$1,287,871	$36,604	$1,324,475	$75,503	$1,020	$76,523