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Direct Testimony and Schedules
Charles R. Burdick

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL14-_____
Exhibit___(CRB-1)

Overall Revenue Requirements
Rate Base
Income Statement

June 23, 2014

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Charles R. Burdick. I am a Principal Rate Analyst in the Revenue Requirements North department for Xcel Energy Services Inc. (Service Company). Xcel Energy Services Inc. is the service company for the Xcel Energy Inc. holding company system and provides services to all of the operating utility subsidiaries of Xcel Energy Inc., including Northern States Power Company (Xcel Energy, NSPM, or the Company), operating in South Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been a Principal Rate Analyst since August, 2011. Prior to that date, I worked outside the Company in technology, finance, and energy-related fields. My qualifications and experience are summarized in my resume provided as Exhibit___(CRB-1), Schedule 1.

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. My testimony also addresses the South Dakota electric jurisdiction's operational need for new incremental revenues of $15.600 million or 8.0 percent, based on a pro forma year with known and measureable changes.

In addition, the Company proposes moving some cost recovery from two of its rate riders to base rates. We are currently recovering $8.481 million through the Infrastructure Rider approved in Docket No. EL12-046. Consistent with the terms of the Settlement establishing the Infrastructure Rider, we propose to move cost recovery to base rates. Second, the Company currently recovers $558,000 in revenues through the Transmission Cost Recovery (TCR) Rider for six transmission projects that went into service before January 1, 2013, pursuant to authority granted in Docket No. EL12-035. Consistent with Commission policy, those projects will be rolled into base rates. In combination, moving cost recovery from the Infrastructure Rider and the TCR Rider eliminates $9.040 million in Infrastructure Rider and TCR Rider revenues. Consequently, the revenue requirement satisfied by base rates increases by the same $9.040 million in order to replace the lost rider revenues. Thus, $9.040 million of the base rate increase proposed in this case is revenue neutral to both our customers and the Company.

To summarize, we propose an overall increase in base rates of $24.640 million of which $15.600 million is the amount of the net incremental increase to our customers ($24.640 million – $9.040 million = $15.600 million). My testimony will also address the Company's alternative proposal to continue the Infrastructure Rider to recover $2.595 million of known and measureable changes occurring in 2015, which would lower the increase in base rates by the same amount.

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
  - D-4. Plant account working papers for previous years
  - D-5. Working papers on capitalizing interest and other overheads during construction
  - D-6. Changes in intangible plant working papers
  - D-7. Working papers on plant in service not used and useful
  - D-8. Property records working papers
  - D-9. Working papers for plant acquired for which regulatory approval has not been obtained

E. Accumulated depreciation

  - E-1. Working papers on record changes to accumulated depreciation
  - E-2. Working papers on depreciation and amortization method
  - E-3. Working papers on allocation of overall accounts

F. Working capital

- F-1. Monthly balances for materials, supplies, fuel stocks, and prepayments
- F-2. Monthly balances for two years immediately preceding pro forma year
- F-3. Data used in computing working capital

G. Cost of Capital, Long Term Debt and Stock

- G-1. Stock Dividends, Stock Splits, or Changes in Par or Stated Value
- G-2. Common Stock Information
- G-3. Reacquisition of NSPM Bonds or Xcel Energy Inc. Preferred Stock
- G-4. Earnings Per Share for Claimed Rate of Return

H. Operating and maintenance expenses

- H-1. Adjustments to operating and maintenance expenses
- H-2. Cost of power and gas
- H-3. Working papers for listed expense accounts
- H-4. Working papers for Interdepartmental Transactions

I. Operating revenue

J. Depreciation expense

- J-1. Expense charged other than prescribed depreciation

K. Income taxes

- K-1. Working papers for federal income taxes
- K-2. Differences in book and tax depreciation
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L-1. Working papers for adjusted taxes

M. Overall cost of service

N. Allocated cost of service

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, a discussion is provided with the required Schedule. Company witness Ms. Laura McCarten sponsors Statement Q, providing the required description of utility operations. Company witness Mr. James Gilroy 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, as well as information provided by various Company business areas and subject matter experts. Where applicable, I indicate in my testimony where the pro forma year cost information is based on information provided by other witnesses.

II. PRO FORMA YEAR REVENUE DEFICIENCY

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

A. Yes, a Cost of Service Study was prepared under my direction. Exhibit___(CRB-1), Schedule 2 (pages 1-5) contains a copy of the jurisdictional cost of service study for the pro forma year.

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

A. The general form for calculating the revenue requirement and revenue deficiency is as follows:

Item		pro forma Amount ($000s)	Exhibit __(CRB-1), Schedule 2 Reference
	Average Rate Base	$433,242	Page 1, Line 22
multiplied by	Cost of capital	7.84%	Page 4, Line 6
equals	**Operating Income Requirement**	$33,966	Page 4, Line 27
	Current Retail Revenue	$195,850	Page 2, Line 2
plus	Current Other Revenue	$44,306	Page 2, Sum: Line 3 & 4
equals	Current Total Revenue	$240,156	Page 2, Line 5
minus	Operating Expenses	$164,487	Page 2, Line 28
minus	Depreciation Expense	$27,874	Page 2, Line 30
minus	Amortization Expense	$741	Page 2, Line 31
minus	Taxes	$23,228	Page 2, Line 45
equals	**Total Available for Return**	$23,826	Page 2, Line 52
	Operating Income Requirement	$33,966	
minus	Total Available for Return	$23,826	
equals	Income Deficiency	$10,140	Page 4, Line 29
multiplied by	Gross Revenue Conversion Factor	1.5385	Page 4, Line 31
equals	**Revenue Deficiency**	$15,600	Page 4, Line 32
plus	Current Retail Revenue	$195,850	
equals	**Total Revenue Requirement**	$211,451	Page 4, Line 37

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

A. The jurisdictional total retail revenue requirement for South Dakota electric utility operations is $211.451 million, based on average rate base and net operating income for the pro forma year, as adjusted for known and measurable changes occurring in 2014 and 2015, as appropriate for final rates that will go into effect in 2015. The jurisdictional retail revenue requirement is also based on the average 2013 capital structure, long-term debt and 10.25 percent cost of equity, based on the return on equity (ROE) recommended by Company witness Ms. Ann E. Bulkley in her Direct Testimony. This results in an overall rate of return (ROR) of 7.84 percent.

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

A. The incremental amount of the revenue deficiency (the amount by which the rates paid by our customers increases) for the pro forma year is $15.600 million or 8.0 percent. In addition, the Company currently recovers the costs of certain capital projects through the Infrastructure Rider and the TCR Rider, which will be recovered through an increase in base rates. The result is that the revenues provided by those two riders will cease and will be replaced by an equal increase in base rates of $9.040 million, for a total increase in base rates of $24.640 million. As I will explain, the revenue deficiency includes $2.595 million in known and measureable capital project changes occurring in 2015 that, if the Commission prefers, could be recovered through a new Infrastructure Rider.

A summary of the revenue deficiency is shown in Exhibit___(CRB-1), Schedule 2 (Cost of Service Study, page 4 of 5, as a comparison of the jurisdictional revenue requirement amount for the pro forma year with the revenues under present rates as approved by the Commission in Docket No.

EL12-046.[1] In order to earn an overall rate of return of 7.84 percent, South Dakota retail electric rates need to be increased by this deficiency amount, as developed in Schedule 2.

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

A. The revenue deficiency amount represents an 8.0 percent increase in retail revenues compared to 2013 retail revenues (adjusted for fuel recovery timing and weather) at present rates as shown in Exhibit___(CRB-1), Schedule 2 (Cost of Service Study, page 4 of 5). When the revenue requirement is increased to replace the revenues from the TCR and Infrastructure Riders, the increase in base rates represents a 13.2 percent overall increase compared to 2013 base rates.

Q. IS THE COMPANY PROPOSING ANY INCREASES IN BASE RATES THAT ARE REVENUE NEUTRAL TO THE RATEPAYERS?

A. Yes. The Infrastructure Rider recovers the costs of plant additions in 2013 and 2014 for seven projects that will go into service in 2014, prior to when rates take effect in 2015. Therefore, we propose to eliminate the Infrastructure Rider and its rate on January 1, 2015. The result is that $8.481 million in revenues currently recovered through the Infrastructure Rider will need to be replaced with an equal increase in base rate revenues. In addition, the TCR Rider recovers the costs for six projects that went into service prior to January 1, 2013. We similarly propose recovering the equivalent revenues from the TCR Rider through a $558,000 increase in base rates. Thus, while

[1] Present revenues as presented in the pro forma year are 2013 weather-normal base rate and fuel revenues plus actual 2013 Transmisson Cost Recovery (TCR) and Demand Side Management (DSM) rider revenues, less the rolled-in portion of 2013 TCR revenues and less 2014 Infrastructure Rider revenues.

base rates will increase by $9.040 million as a result of replacing revenues from these two riders, the increase will be revenue neutral to our customers.

Q. WHICH PROJECT COSTS CURRENTLY RECOVERED THROUGH THE INFRASTRUCTURE RIDER WILL BE RECOVERED THROUGH BASE RATES?

A. The following seven capital projects associated with the Infrastructure Rider projects have revenue requirements that will be rolled into base rates at the time final rates take effect in 2015:

- Monticello Extended Power Uprate,
- Monticello Fire PRA Model,
- Prairie Island TN-40 Casks (30-38),
- Prairie Island Foxboro H-Line Protection,
- Prairie Island Steam Generator,
- Sherco 3 Cooling Tower, and
- Sherco 3 Held for Future Use assets.

Q. WHICH PROJECT COSTS CURRENTLY RECOVERED THOUGH THE TCR RIDER WILL BE RECOVERED THROUGH BASE RATES?

A. The six projects for which the associated 2013 revenue requirements will be rolled into base rates are

- CAPX2020 – Bemidji,
- Pleasant Valley – Byron,
- Grove Lake – Glenwood,
- Sauk Center – Osakis,
- Meadow Lake, and
- Chisago – Apple River,

The projects and Midcontinent Independent System Operator (MISO) costs that will continue to be recovered through the TCR Rider are as follows.

- CAPX2020 – Brookings,
- CAPX2020 – Fargo,
- CAPX2020 – La Cross Local,
- CAPX2020 – La Cross MISO,
- CAPX2020 – La Cross MISO–WI,
- Glenco Waconia,
- Sioux Falls Northern,
- Bluff Creek – Westgate,
- Chaska – Highway 212 Conversion,
- Minnesota Valley,
- Maple River – Red River,
- Big Stone – Brookings,
- Lake Marion – Burnsville,
- Maple Lake – Annandale,
- Wilmarth – Carver County,
- North Mankato,
- St. Cloud Loop, and
- MISO RECB – 26 and 26(a) net of revenues and expenses.

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 2011 year in Docket No. EL12-046. Consequently, I will provide a comparison to the final authorized pro forma 2011 year. Exhibit___(CRB-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 approved pro forma 2011 year.

Table 1

Case Drivers

Dollars in Millions – South Dakota Jurisdiction	**Increase over 2011 Pro Forma ($ millions)**
Plant Related	19.1
Non-Fuel O&M Expense (includes Payroll Taxes)	6.0
Subtotal	**25.1**
Margins and Net Other	(0.5)
Pro Forma Deficiency	**24.6**
Less Revenue Requirement Currently Collected Through TCR Rider	(0.6)
Less Revenue Requirement Currently Collected Through Infrastructure Rider	(8.5)
Pro Forma Net Deficiency	**$15.6**

Q. THE LARGEST INCREASE IN REVENUE REQUIREMENTS IS RELATED TO CAPITAL NEEDS. PLEASE PROVIDE ADDITIONAL INFORMATION CONCERNING THE INCREASED CAPITAL INVESTMENTS MADE BY THE COMPANY SINCE 2011.

A. Table 2 provides a high level breakdown of the principal capital investments and related costs since 2011 including known and measurable changes through 2015. These investments result in an additional revenue requirement of $19.1 million. It is important to note that $9.0 million of the increase in base revenue requirements is currently being recovered through the Infrastructure Rider and the TCR Rider.

Table 2

Case Drivers – Capital Recovery

Dollars in Millions – South Dakota Jurisdiction	**Total Revenue Requirement ($ millions)**
Generation Projects	
Nuclear	8.5
All Other Generation	2.0
Total Generation Projects	**10.5**
Transmission Projects	0.8
South Dakota Distribution Projects	1.1
Common and General	1.6
Other Increases / (Decreases)	(0.1)
Total Rate Base	**14.0**
Property Taxes	3.5
Capital Structure	1.7
Total Capital Recovery Items[2]	**$19.1**

Q. PLEASE BRIEFLY DESCRIBE THE GENERATION PROJECTS.

A. As noted in Ms. McCarten's testimony, we are in a period of significant investment to prepare our system for the future, and we are focused on doing so in the most cost-effective way. Key investments ensure balance in our generation portfolio for the long term, primarily by extending the life of our nuclear plants.

Critical improvements to nuclear facilities that are impacting the pro forma year include the completion of some on-going major projects related to the life extension of the plants (e.g., Monticello Extended Power Uprate, Prairie

[2] Numbers may not sum due to rounding.

Island Steam Generator Replacement, Fire Probabilistic Risk Assessment Models, Prairie Island Casks 30-38, Prairie Island License Renewal and associated projects), projects required by NRC regulations, and additional improvements needed to ensure safe and cost effective operation of the facilities through the extended life of the plants. New projects include generation step-up transformer replacements, a new site administration building at Prairie Island, a nuclear safety margin initiative, and electric generator replacements. All improvements with capital additions in 2014 and 2015 are described in detail in the Known and Measurable Adjustments section later in my testimony.

Non-nuclear generation plant improvements included for recovery in this case fall into three categories: operating needs, Federal and State regulatory requirements, and renewable energy generation. Example projects include emissions control projects at the Sherburne County (Sherco) generating facility, replacement of the A.S. King boiler waterwall tubes, and the construction of the Pleasant Valley and Border Winds wind energy generation projects.

In total, net generation plant in service for the South Dakota jurisdiction has increased approximately $72.6 million in the pro forma year compared to the pro forma 2011 year.

Q. PLEASE DESCRIBE THE TRANSMISSION PROJECTS.

A. The Company continues to make significant investments in transmission facilities that can be broadly categorized as either asset health or capacity expansion projects. Asset health projects focus on existing assets and include replacements of aging equipment and compliance related investments. Example projects include replacing poles, cross arms, conductors, transmission relays, transformers, circuit breakers, and remote terminal units.

Capacity or growth-related projects have been driven by the need to increase capacity and reliability of the system in areas that have been growing. They include upgrades for generation interconnections (including those required by the MISO Tariff), transmission-to-transmission and transmission-to-load interconnections, and regional expansion projects (e.g., CapX2020).

In recent years, much of the investment has been driven by the need to increase capacity and reliability of the system. Examples of such projects include new substations for Sheas Lake, Cass County, and Fenton, and new transformers for the Lawrence and Douglas County substations.

In total, net transmission plant in service for the South Dakota jurisdiction has increased approximately $18.4 million in the pro forma year compared to the pro forma 2011 year.

Q. PLEASE DESCRIBE THE SOUTH DAKOTA DISTRIBUTION PROJECTS.

A. Reliability enhancements continue to be a major driver of distribution investment in South Dakota. There are a few large projects since 2011 that should be highlighted. One project involved investment of $4.0 million to construct a 16-mile 34.5kV feeder and automated switching to improve reliability to the Dell Rapids area. Another key project involved the investment of $1.1 million in underground cable replacements of aging tap-level cable to improve reliability to residential and commercial customers. An additional $6.8 million was spent on adding capacity to growing areas of Sioux Falls. Approximately $4.9 million of this investment created the new 50 MVA Louise substation in the southwest corner of Sioux Falls, and $2.0 million was used to double substation capacity from 34 to 69 MVA at the Lincoln County substation in the northeast portion of Sioux Falls. Additionally, the Company incurred $7.7 million in storm damage to overhead facilities.

Another driver of capital investment in South Dakota has been growth in the local economy. Although energy efficiency and the location of the development in the service territory of other electricity providers mitigate sales growth, investments to connect new customers have nonetheless increased, amounting to $19.3 million in new business investment since 2011. As noted by Company witness Ms. McCarten, while we are seeing significant construction, actual sales have not been sufficient to offset the increases investment.

In total, net distribution plant in service for the South Dakota jurisdiction has increased approximately $18.2 million in the pro forma year compared to the pro forma 2011 year.

Q. PLEASE DESCRIBE THE COMMON AND GENERAL PROJECTS.

A. Common and General projects fall into three categories: Facilities, Fleet, and Business Systems (or Information Technology IT). Since 2011, 41 percent of the Common General investment has gone into Facilities, 22 percent into Fleet, and 37 percent into Business Systems (IT projects). In total, net plant in service for common/general projects for the South Dakota jurisdiction has increased approximately $8.7 million in the pro forma year compared to the pro forma 2011 year.

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

A. Table 3 compares the change in non-fuel O&M between the 2013 pro forma year and the 2011 pro forma year.

Table 3
Non-Fuel O&M Cost Drivers:
Pro Forma vs. Approved 2011 Pro Forma

Dollars in Millions – South Dakota Jurisdiction	**Increase/(Decrease) ($ millions)**
Nuclear O&M	1.8
Nuclear Outage Amort	0.7
Non-Nuclear Production	0.0
Transmission	0.3
Distribution	1.0
Pension and Insurance	0.7
IT	0.5
A&G and Other O&M	0.9
Total[3]	**$6.0**

As shown in the table, the largest increase in O&M relates to Nuclear Operations. Key drivers for nuclear O&M include: compliance with new regulatory requirements which drives a need for additional labor resources and materials; nuclear fees; security costs; and nuclear outage amortization. The second largest increase relates to the distribution function and is driven by expenses related to storm reconstruction, increased underground fault repairs,

[3] Figures may not sum to total due to rounding.

and O&M expense related to new capital projects. The increase in A&G and Other O&M can be attributed mainly to incentive pay and the known and measurable wage increases discussed in my testimony. Finally, pension costs are also contributing to the overall increase. The increase in pension costs is a function of accounting requirements to fund future obligations; there has not been any change in employee benefits.

Q. WHAT OTHER COST DRIVERS ARE RELEVANT TO THE COMPANY'S COSTS IN 2015?

A. Between 2013 and 2015, the Company will experience a $2.3 million increase (state of South Dakota electric jurisdiction) in Transmission Interchange costs. These are costs for major transmission network upgrades in support of the NSP System that are owned by NSPW, and then approximately 85% of those costs are shared with NSPM through the Interchange Agreement. These major network upgrades enhance the transmission of electricity throughout the Upper Midwest region and therefore enhance reliability to South Dakota customers. I discuss the Interchange Agreement in greater detail in Section VI of my testimony.

We did not include this cost as a known and measurable 2015 adjustment at this time. As discussed by Ms. McCarten, this may be an appropriate cost to recover through the Infrastructure Rider. In addition, the projects may also fit the criteria for the TCR Rider. We would like, therefore, to discuss with Staff whether these costs should be recovered as a 2015 known and measureable cost recoverable in base rate, the TCR Rider, or the Infrastructure Rider.

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 in the Cost of Service Study, recovery occurs through the separate Fuel Clause Rider (FCR) mechanism and true-up process.

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 2013 (unadjusted test year) and the pro forma year that includes 2014 and 2015 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 treatment (*e.g.,* foundation administration expenses, lobbying expenses, and advertising are removed). A third set of adjustments is made to reflect standard amortizations. Finally, I make pro forma adjustments to reflect known and measurable changes occurring in 2014 and 2015 (Commission Rule 20:10:13:44 permits a period of up to 24 months from the end of the historical test period to be considered in developing known and measurable adjustments), so that final rates, which will become effective in 2015, more closely reflect the Company's revenues and expenses at the time the rates go into effect. The pro forma year Cost of Service Study is summarized in Exhibit___(CRB-1), Schedule 2.

I also provide Exhibit___(CRB-1), Schedule 2A a cost of service study for the unadjusted 2013 year showing: the actual unadjusted average rate base; unadjusted operating income; overall rate of return; the calculation of required income; the income deficiency and revenue requirements. Exhibit___(CRB-1), Schedules 6A and 6B are separate rate base and income statement bridge schedules that identify the adjustments described in my testimony to the unadjusted 2013 year that create the pro forma year.

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE TCR RIDER?

A. We propose to continue using the TCR Rider for those qualified transmission projects that have not yet gone into service. There are six projects that were included in the 2013 TCR Rider that went into service before January 1, 2013. The costs of those projects will be rolled into base rates. Because we will no longer receive revenues from the TCR Rider for those projects, I made an adjustment removing from the pro forma year the revenues of $558,000 received in 2013 through the TCR Rider for those six projects. This adjustment increases the revenue requirement that must be recovered through base rates but is revenue neutral to our customers and the Company. I also removed both the costs and the associated revenues from the pro forma year for those projects and costs that will continue to be recovered through the TCR Rider. This adjustment reflects the Commission's approval to allocate costs between the South Dakota and MISO jurisdictions. As part of our Fall 2014 TCR filing, we will propose an adjustment effective January 1, 2015 to remove the costs of the six projects we propose recovering through base rates along with a true-up of our 2014 costs and revenues for all current TCR projects.

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE INFRASTRUCTURE RIDER?

A. We propose to move the costs currently recovered through the Infrastructure Rider into base rates, as those costs are for assets that are either already in service or will be in service prior to 2015 when final rates take effect.

As I explain later, I made an adjustment to the pro forma year to remove the 2013 revenue from the Infrastructure Rider. As I further explain, I also made an adjustment to normalize the costs of additions that went into service during 2013 (including a year of depreciation); and added the cost of the 2014 incremental plant additions. This adjustment is consistent with the Commission's previously approved Infrastructure Rider recovery for 2014. As a result of these adjustments, the $8.481 million in revenues currently recovered in 2014 through the Infrastructure Rider will be recovered through a base rate increase in 2015. The shift in recovering revenues from the Infrastructure Rider to recovering the same revenues through base rates is revenue neutral to both our customers and the Company.

Finally, we normalized the cost of the 2014 plant additions to reflect a full year of their cost in 2015 (including a year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect, and would have occurred under the terms of the Rider if it were to continue in operation.

We anticipate that in the Fall 2014 we will file a request to limit the existing Infrastructure Rider to address the true up of the 2014 Infrastructure Rider costs and revenues.

Later in my testimony I offer as an alternative a new Infrastructure Rider, which would recover known and measureable costs incurred for capital projects and property taxes that go into service in 2015 as well as any prior true-up.

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE DEMAND SIDE MANAGEMENT (DSM) RIDER?

A. We will continue to recover the costs of our DSM program through the DSM Rider. Both revenues and expenses for the DSM Rider are included in the unadjusted 2013 year. After removing the $233,000 received under the Commission approved incentive program, the amount of DSM revenues and expenses is equal and, therefore, does not contribute to the test year deficiency, and avoids double recovery of these costs. Any true up of the revenues and costs during the test year occurred through the DSM Rider and, therefore, there is no need to address a change in revenue requirement in the final compliance filing. I later provide an adjustment removing the incentive payment of $233,000 in incentive-related revenues. If those revenues are not removed, they would lower the revenue requirement, rather than pay the incentive as the DSM program intended.

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE FUEL CLAUSE RIDER (FCR)?

A. We will continue to recover fuel and purchased energy costs through the FCR. Both revenues and expenses for the FCR are included in the 2013 unadjusted test year. We flow through the FCR the revenues from Production Tax Credits (PTCs), sales of Renewable Energy Credits (RECs), and non-asset based margin sharing (30 percent of non-asset based margins). These revenues act to lower the revenues from customers required to cover fuel costs. Therefore, we have removed the South Dakota jurisdiction total level of PTCs included in the unadjusted test year so as not to double count those revenues and remove the tax effects of PTCs from the Cost of Service tax calculation. From REC sales, $1.100 million is included as Other Revenue.[4] There is no need for further adjustment to the test year to reflect our treatment of RECs. Non-asset trading revenues and costs are removed from the test year so that the margin credit is handled solely through the FCR.

As in the past, we have included a revenue-neutral Fuel Lag Adjustment discussed later in my testimony.

Q. DOES THE 2013 UNADJUSTED TEST YEAR PROVIDED IN YOUR SCHEDULES 6A AND 6B (RATE BASE AND INCOME STATEMENT BRIDGE SCHEDULES) MATCH THE 2013 JURISDICTIONAL REPORT?

A. No, they are different. The rate case uses weather normalized jurisdictional allocators and reflects the loss of our last wholesale customer. In contrast, the jurisdictional report is allocated based on actual weather and includes our then existing small wholesale jurisdiction. In addition, the rate case includes cash working capital in the rate base, while the jurisdictional report does not.

[4] This level represents 90 percent of the sales. In accordance with our Commission approved tariff (Section 5, Sheet 64), 10 percent is retained by the Shareholders.

Lastly, the 2013 Jurisdictional Report includes many of the same types of normalizing and regulatory adjustments presented in the pro forma year.

V. RATE BASE

Q. IS THE PRO FORMA YEAR 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 pro forma adjustments we made, the pro forma rate base appropriately represents costs and investments in place at the time rates take effect in 2015.

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. HOW DOES THE COMPANY CALCULATE RATE BASE?

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

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

In this case, the calculation is as follows, using the 13-month average of monthly balances:

Plant	$978.0 million	(per CRB-1, Sch 2, Page 1, Line 1)
Reserve	($448.1 million)	(per CRB-1, Sch 2, Page 1, Line 2)
ADIT	($115.5 million)	(per CRB-1, Sch 2, Page 1, Lines 6-9)
Working Capital	($6.0 million)	(per CRB-1, Sch 2, Page 1, Line 12)
Other Rate Base	$24.9 million	(per CRB-1, Sch 2, Page 1, Lines 13-19)
Total Rate Base	$433.2 million	(per CRB-1, Sch 2, Page 1, Line 22)

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

A. Exhibit___(CRB-1), Schedule 6A (Rate Base Bridge) is a bridge schedule that shows the 2013 unadjusted test rate base, each proposed rate base adjustment, and the resulting proposed pro forma rate base.

Exhibit___(CRB-1), Schedule 4 (Rate Base Comparisons) provides a comparison of rate base components based on the final decision in the Company's last rate case filing (Docket No. EL12-046) to the pro forma test year assuming final rates.

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. EL12-046.

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 December 1, 2012 through December 31, 2013.

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 $529.869 million as shown on Exhibit___(CRB-1), Schedule 2, page 1. This is comprised of an average plant balance of $977.990 million minus an average depreciation reserve of $448.120 million, each shown by component on Exhibit___(CRB-1), Schedule 2, page 1.

B. Construction Work In Progress (CWIP)

Q. HAS 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 (ADIT)

Q. PLEASE DESCRIBE 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 is typically the extent to which accelerated tax depreciation exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

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

A. To the extent 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___(CRB-1), Schedule 2, page 1, $115.496 million 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 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, are 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___(CRB-1), Schedule 2, page 1, are based on the 13-month average balances for December 2012 through December 2013, respectively. The

Materials and Supplies average balance included in the pro forma year rate base equals $8.432 million. The pro forma year average rate base amount for Fuel Inventory is $5.069 million.

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

A. These balances as shown on Exhibit___(CRB-1), Schedule 2, page 1, represent the December 1, 2012 through December 31, 2013 actual 13-month average balances. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and accumulated deferred tax balances previously discussed. The net assets increase pro forma year rate base by $1.458 million.

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 2013. The net impact of these various items increase pro forma year rate base by $5.156 million as shown on Exhibit___(CRB-1), Schedule 2, page 1.

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 dates the costs of rendering the services are incurred until the related disbursements are actually made.

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE LAST SOUTH DAKOTA ELECTRIC RATE CASE (DOCKET NO. EL12-046)?

A. Yes. The average lag days are measured on the 12 months ended December 31, 2013. The methodology used for calculating the lead/lag days is consistent with the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for electric operations were incorporated into the South Dakota jurisdiction cash working capital calculations as shown on Exhibit___(CRB-1), Schedule 2 (Cost of Service Study, page 5 of 5). The lead/lag study can be found in Volume 4 of our Application.

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

A. Yes. There is a $911,000 reduction in test year Cash Working Capital requirement as compared to our last rate case. The amount included in the average rate base is negative $6.038 million, as shown on Exhibit___(CRB-1), Schedule 2, (Cost of Service Study, page 1 of 5). The pro forma adjustment of ($1.657 million) that brings the unadjusted 2013 year to the pro forma year amount is provided on Schedule 6A, column 46. 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 pro forma 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 decreases rate base and will lower the annual revenue requirement.

VI. INCOME STATEMENT

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

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

Q. IS THE COMPANY'S PROPOSED PRO FORMA INCOME STATEMENT REASONABLE FOR DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The pro forma income statement for the Company's South Dakota jurisdiction electric operations was developed on sound ratemaking principles in a manner similar to prior Company electric rate cases.

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

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

- Revenues,
- Operating and Maintenance Expenses,

- Depreciation Expense,
- Taxes, and
- Net Income.

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

A. Exhibit___(CRB-1), Schedule 5 (Income Statement Comparisons) provides a comparison of income statement components from the final decision in the Company's last rate case filing (Docket No. EL12-046) to the income statement components in the pro forma test year assuming final rates.

Exhibit___(CRB-1), Schedule 6B (Income Statement and Revenue Requirements Bridge) is a bridge schedule that shows the 2013 unadjusted test year income statement, each proposed income statement adjustment, and the resulting proposed 2013 pro forma year 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 assets and specific tariff charges including service activation fees, reconnection fees and others. One other source of revenues comes from billings to NSP Wisconsin (NSPW) under the Interchange Agreement, which I discuss in more detail below.

B. Operating and Maintenance Expenses

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

A. The Company's operating expenses can be expressed using the breakdown on pages 30-31 of the "Electric Utility Cost Allocation Manual" of NARUC as follows:

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

Other Operating Revenues (Other Rev) is an offset to expenses.

In this case, the calculation is as follows (amounts are in millions):

Operating Exp	$164.5	(per CRB-1, Sch 2, Pg 2, Line 28)
Plus Depreciation	$27.9	(per CRB-1, Sch 2, Pg 2, Line 30)
Plus Amortization	$0.7	(per CRB-1, Sch 2, Pg 2, Line 31)
Plus Other Taxes	$28.0	(per CRB-1, Sch 2, Pg 2, Line 42)
Plus Income Tax	($4.8)	(per CRB-1, Sch 2, Pg 2, Line 43)
Total Operating Exp	$216.3	(per CRB-1, Sch 2, Pg 2, Line 46)

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 2013 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.

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 Federal Energy Regulatory Commission (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 15 percent of the costs of the Company system are allocated to NSPW, and approximately 85 percent of the NSPW system costs are allocated to the Company, because approximately 85 percent of the load on the integrated system is Company load and 15 percent is NSPW load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually. The Interchange Agreement also provides for an allocation of certain non-retail revenues received by the Company and NSPW, such as revenues from off-system wholesale sales.

The 2013 unadjusted test year Interchange Revenue and Interchange Expenses have been calculated using 2013 Company and NSPW actual information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in the Company's 2011 unadjusted test year in Docket No. EL12-046.

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

Workpapers supporting the calculation for Interchange Agreement revenues (billings from the Company to NSPW) can be found in Volume 3, Section IV, Tab - R2-2, Interchange. Workpapers supporting the calculation of Interchange Agreement expenses (billings from NSPW to the Company) can be found in Volume 3, Section V, Tab – O2, Interchange. Copies of FERC filings and orders amending the Interchange Agreement since our last rates case are provided in Volume 4.

C. Depreciation Expense

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

A. The depreciation expense included in the 2013 unadjusted test year was determined using the depreciation rates approved in our last rate case, Docket No. EL12-046. In that case, we reduced depreciation rates to reflect the expected lower costs from the then future five-year depreciation study that was to be filed in June 2012. More specifically, the depreciation rates for Transmission, Distribution and General Assets were changed to incorporate the anticipated changes in average service life, in net salvage rate, and to eliminate the net surplus accumulated depreciation reserves over the average remaining lives of the assets. The five- year study was provided to the Minnesota Commission in June 2012, in Docket E,G002/D-12-858, and to South Dakota Advocacy staff in Docket No. EL12-046 through response to Data Request 4-001.

In this current case, we also propose a depreciation adjustment that has three components. One component refines the South Dakota depreciation rates for Transmission, Distribution and General Assets to reflect the results of the five- year depreciation study. The second component is to reflect the change in future removal costs for Black Dog Units 3 and 4 and the amortization of those costs over 15 years. The third component is to reflect an extension of the Sherco Unit 3 remaining life by two years for the extended outage at Sherco Unit 3 from 2011 to 2013.

Q. PLEASE DESCRIBE, IN GENERAL TERMS, THE CHANGES MADE AS A RESULT OF THE FIVE-YEAR DEPRECIATION STUDY.

A. As I explained, the depreciation rates in EL12-046 were set, in part, based on the estimated results of the then-future five-year study. In aggregate, the study supported longer average service lives to better reflect the expected useful lives of our assets, and net salvage rates became more negative to better reflect the expected higher costs of removal. It also presented the change from an average service life to an average remaining life depreciation rate to effectively spread any theoretical reserve surplus or excess over the asset's average remaining life. The pro forma adjustment refines the estimated depreciation rates from the previous case to reflect the final results from the five-year study.

Q. WHAT PRO FORMA CHANGE IS MADE WITH RESPECT TO BLACK DOG UNITS 3 AND 4?

A. The removal costs for Black Dog Units 3 and 4 estimated in 2010 did not include the cost to remove the coal pile and the ash ponds beneath the coal pile. Subsequent to completion of the 2010 study, we entered into a Voluntary Investigation and Cleanup (VIC) program with the State of Minnesota to remediate the land. The program required the Company to fully remediate the lands where the coal pile and ash pond are located. The remediation costs are being amortized over a 15-year period, effective January 1, 2013, for the increased removal costs of $33.2 million. The pro forma change reflects both the removal cost and the 15-year amortization.

Q. PLEASE DESCRIBE THE REASON FOR THE SHERCO 3 ADJUSTMENT.

A. The pro forma adjustment proposed in this case reflects the extension of the Sherco Unit 3 remaining life by two years, from 19 years to 21 years, at the beginning of 2014. This reflects the Company's determination that Sherco Unit 3's useful life was suspended during the outage period.

Q. WHERE ARE THE FINANCIAL IMPACTS OF THESE CHANGES PRESENTED?

A. The financial impacts of the depreciation adjustment is presented in Exhibit __ (CRB-1), Schedule 6A, column 1, and Schedule 6B, column 1. Together, the three components increase the revenue requirement by $399,000 as shown in Schedule 6B, column 1, line 38.

VII. JURISDICTIONAL COST OF SERVICE STUDY

A. Components of Jurisdictional Cost of Service Study

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

A. The complete jurisdictional cost of service is included in Volume 3 (Workpapers) 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 in Exhibit___(CRB-1), Schedule 2 (pages 1-5). In order to facilitate a comparison to the unadjusted 2011 test year, we have also included the 2013 unadjusted test year jurisdictional cost of service summary as Exhibit___(CRB-1), Schedule 2A (pages 1-5).

- The cover page to Schedule 2 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 10.25 percent).
- The "Rate Base Summary" for total Company electric operations and the South Dakota jurisdiction is shown on page 1 of Schedule 2.
- An "Income Statement Summary" for total Company electric operations and the South Dakota jurisdiction is shown on page 2 of Schedule 2. 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 page 3 of Schedule 2. 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 page 2 of Schedule 2.
- The "Revenue Requirement and Return Summary" for total Company electric operations and the South Dakota jurisdiction is shown on page 4 of Schedule 2. 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, shown on page 5 of Schedule 2, is carried back to the rate base on page 1 of Schedule 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 of 1.5385, using a South Dakota composite tax rate of 35 percent, is included in my exhibits on Exhibit___(CRB-1) Schedule 2 (Cost of Service Study, page 4, line 31).

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

A. The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base.

B. 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.

- *Rate Moratorium.* In the Commission-approved Settlement Stipulation in Docket EL12-046, the Company agreed to a rate moratorium such that the Company would not file a petition to increase base rates for electric service, for rates proposed to be in effect prior to January 1, 2015. This application proposes new rates to be in effect on January 1, 2015, and therefore we have complied with that requirement.
- *Post Retirement Medical Benefits (OPEBs) – Pay as You Go.* In Docket No. EL11-019 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 reflected that decision in our 2013 unadjusted test year and therefore no further adjustment is needed to conform to that requirement.
- *Non-Asset Based Margins.* The Commission's approval of the Settlement Stipulation in Docket No. EL12-046 approved a sharing mechanism under which the Company provided 30 percent of the profit margins from non-asset trading to the ratepayers through the Fuel Clause Rider. In addition, the Company was directed to update the incremental and fully allocated cost studies in this proceeding. We have complied with both requirements. I include an adjustment removing the non-asset based costs and revenues from the 2013 unadjusted test year, and the required studies are included as Exhibit __(CRB-1), Schedule 9. Those studies indicate that the 30-percent sharing mechanism provides a reasonable balance of customer and Company interests.
- *Moving Completed TCR Rider Projects to Base Rates.* In Docket No. EL11-019, the Company was directed to move the costs of completed TCR projects into the base rate revenue requirement. Six projects went into service prior to January 1, 2013 and we are moving those costs into

base rates. The adjustments needed to satisfy that requirement have been made.

- *Moving Infrastructure Rider Projects to Base Rates.* The Settlement in Docket No. EL12-046 directed us to move projects into base rates "in a future rate case." The adjustments needed to satisfy that requirement have been made.
- *Amortization.* In the Settlement Stipulation approved by the Commission in Docket No. EL12-046, the Company and Commission Staff reaffirmed the then-existing six-year amortization period for the Private Spent Fuel Storage Facility; and the five-year amortization period for SO_2 Emission Credit. The Settlement Stipulation approved by the Commission also established a two-year amortization period for Rate Case Expenses and the Black Dog Conversion Project. The Emission Credit, Black Dog, and rate case amortizations established in the Settlement Stipulation expire at the end of 2014 and the Private Fuel Storage Facility amortization expires at the end of 2015. Because this proceeding is to establish rates effective 2015 and the 2013 unadjusted test year included these amortizations, adjustments to remove the Emission Credit and rate case amortizations from the test year are required. The Black Dog Conversion Project amortization was accomplished by lowering the final rates implemented after our last rate case and no expense was recorded on our books for that amortization. Consequently, no adjustment to the 2013 year is needed to eliminate this amortization at the end of 2014. The Commission-approved Settlement also required the Company to return to ratepayers any over-recovery of amortized costs if the rates established in EL12-046 remained in effect longer than the two-year amortization period. As a

result of this pending rate case there will be no over-recovery of any amortized costs.

- *Wind PTCs*. In the Settlement Stipulation approved by the Commission in Docket No. EL11-019, the Company and the South Dakota Staff agreed that PTCs in that case and in the future would be passed through to the ratepayers through the Fuel Clause Rider. We have complied with that requirement, and consequently have removed the South Dakota jurisdiction total level of PTCs included in the unadjusted test year to avoid double counting those revenues.
- *MISO Schedule 26 Costs*. In the Settlement Stipulation approved by the Commission in Docket No. EL11-019, the Company and Commission Staff agreed that Schedule 26 expenses and revenues should be removed from the unadjusted test year and included for Commission review in the TCR Rider on a going forward-basis. We have complied with that requirement and propose continued cost recovery through the TCR Rider. Therefore, a component of the TCR Rider Removal adjustment has been made in the filing to remove from the unadjusted test year both Schedule 26 revenues and expenses.
- *Nuclear Fuel Outage Deferral /Amortization*. The Company has used the Commission-approved nuclear fuel outage deferral/amortization methodology. That methodology was included in the 2013 unadjusted test year and, therefore, no further adjustment was necessary. We continue to support this mechanism as appropriate for addressing the otherwise large annual variance in cost. We can experience between one and three outages in any given year and the deferral and amortization method smooths out those variances over the useful life of the refueling outages (generally between 18 and 24 months).

Amortizing the costs over that longer period also dampens the effect of increasing refueling outage costs.

- *Depreciation Rates.* In the Settlement Stipulation approved by the Commission in Docket No. EL12-046, the Company and Commission Staff agreed on depreciation rates established in that filing. We complied with that requirement. The depreciation rates used in this current case are based on the depreciation rates approved in Docket No. EL12-046 with three adjustments to reflect subsequent changes in depreciation expense. I discussed those adjustments earlier in my testimony. The depreciation expense includes the increased decommissioning expense approved in Docket No. EL12-046.
- *DSM Costs.* The Commission in Docket No. EL13-017 approved a separate mechanism for recovering Demand Side Management program costs and expressed a concern that the Company not double-recover these costs through base rates. As I explain earlier in my testimony, after removal of the incentive revenues, the revenues and expenses of the program are offsetting and consequently there will be no double recovery.

C. Jurisdictional Allocations

Q. SINCE THE COMPANY OPERATES ACROSS MULTIPLE JURISDICTIONS, WHAT STEPS ARE TAKEN TO ALLOCATE COSTS APPROPRIATE FOR A COST OF SERVICE STUDY FOR THE SOUTH DAKOTA ELECTRIC JURISDICTION?

A. We take three general steps, all based on cost causation as explained the Cost Assignment and Allocation Manual (CAAM). The steps are summarized here, however the CAAM is included in Volume 4 of this Application and provides additional detail.

First, costs must be allocated to the appropriate operating company. Xcel Energy has four operating companies, one of which is NSPM. Xcel Energy also has a Service Company that serves all operating companies. The pro forma year includes both costs incurred directly by the NSPM's electric operating business and costs originating outside NSPM and directly assigned or allocated to it (e.g., by the Service Company for corporate functions such as, accounting, human resources, and legal). The Service Company cost allocation and billing process is pursuant to a Utility Services Agreement between Xcel Energy and the Service Company. NSPM and NSPW operate an integrated system to generate and deliver electricity to customers of both operating companies. These costs are shared between NSPM and NSPW pursuant to the Interchange Agreement discussed earlier. According to the Interchange Agreement, approximately 15 percent of the shared costs are allocated to NSPW and the remaining 85 percent are allocated to NSPM.

In the second step, costs for NSPM, including those directly assigned or allocated to it, are directly assigned or allocated to the appropriate utility (electric or gas) or to a nonregulated business activity.

Third, costs for the NSPM Electric utility are then directly assigned or allocated to the appropriate jurisdiction (Minnesota, South Dakota or North Dakota).

Q. PLEASE SUMMARIZE THE METHODS USED TO ALLOCATE COSTS FOR ELECTRIC UTILITY OPERATIONS IN SOUTH DAKOTA, MENTIONED AS STEP THREE ABOVE.

A. Cost assignments and allocation processes were generally the same as used by the Company in the last South Dakota electric rate case (Docket No. EL12-

046), the current Minnesota electric rate case filed with the Minnesota Public Utilities Commission (MPUC Docket No. E002/GR-13-868) and the last rate case filed with the North Dakota Public Service Commission (PU-12-813).

When possible, the Company assigns costs directly attributable to a given jurisdiction to that jurisdiction. For example, electric distribution capital and expenses incurred for the service territory in South Dakota are directly assigned to South Dakota.

When costs are incurred that serve several jurisdictions, the Company applies an allocation factor to determine the portion attributable to South Dakota.

The Company develops several jurisdictional allocation factors. The different factors are designed to match cost to cost causation, such as Energy load, Capacity load (12-month coincident peak demands), Customers, Customer Bills, Transportation Studies, or the Three-Factor Allocator (revenues, utility plant in service, and supervised O&M). Each of these factors represents the ratio of the measured South Dakota portion to Company total. A summary of these factors and their values in this case is provided as Exhibit ___ (CRB-1), Schedule 7 (Allocation Factors). The selection of a particular allocation factor is matched to the nature of the cost incurred. For example, costs related to our customer service call centers are allocated based on customer counts because the cost of the service centers is affected by the number of customers served.

The result is that approximately 5.8 percent of total operating expenses are allocated to South Dakota.[5]

Additional information regarding this process and the reason for selecting a particular allocator is also included in the CAAM included in Volume 4 of this Application.

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

A. NSPM investment in production and bulk transmission facilities is allocated to jurisdictional areas based on the average of the 12-month coincident peak demands (12 CP Method) for the actual year ended December 31, 2013. It is reasonable to use coincident peak demands as a jurisdictional allocation basis, because these facilities are designed to meet peak requirements and operate as an integrated system across all jurisdictions, year round. 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. The Commission accepted this method of allocation in previous rate proceedings (Docket Nos. EL12-046, EL11-019, EL09-009, EL92-016, F-3764, and F-3780).

Q. WHAT CHANGES HAVE OCCURRED WITH RESPECT TO WHOLESALE CUSTOMERS FOR SETTING RATES IN 2015?

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[5] Exhibit __ (CRB-1), Schedule 2, page 2, line 28, ratio of SD Electric to Total.

A. The number of wholesale customers served by the Company has changed dramatically over the years. The most significant change occurred as a result of the creation of municipal power agencies (such as Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, and Minnesota Municipal Power Agency). As of 2012, the Company directly served only three traditional cost-based requirements wholesale customers: the City of Ada, City of Kasota, and Heartland Consumers Power District (HCPD) for the City of Lake Crystal. These customers comprised less than one-tenth of one percent of Company demand and energy requirements. The rates and services for sales to these customers were regulated by FERC under tariffs or contracts on file with FERC.

However, the recent recession created excess capacity and energy on a short- to mid-term basis, increasing competition in the energy market and putting downward pressure on pricing. Given the market dynamics, the Company's wholesale customers chose to purchase energy on the open market, and the Cities of Ada and Kasota terminated their cost-based requirements contracts effective January 1, 2013. In addition, the contract with HCPD for the City of Lake Crystal, the one lone remaining traditional full requirements wholesale customer for 2013, expired on December 31, 2013. Therefore, the Company will no longer have any cost-based requirements wholesale customers. Where in the past these customers mitigated energy cost volatility risk by entering into full requirements agreements with the Company, given the current market environment, they now prefer to take that risk themselves.

Q. PLEASE DESCRIBE ANY CHANGES MADE TO THE ALLOCATION FACTORS FOR USE IN THE PRO FORMA YEAR ENDED DECEMBER 31, 2013.

A. I made two changes to the allocation factors in the preparation of this case. First, the allocators were adjusted to remove the effect of weather. The allocation factors are based on actual 2013 data (coincident peak demand, energy use), that are affected by weather that is not necessarily representative of a typical or average weather pattern. Therefore, it is necessary to weather normalize the coincident peak demand data prior to calculating the allocation factors. We make the same weather normalizing adjustment to revenues in a pro forma adjustment discussed later in my testimony.

Second, as explained above, the jurisdictional allocators were adjusted to remove the one remaining wholesale customer after December 31, 2013. In 2015 when new rates go into effect, there will be no wholesale customers, and therefore it does not make sense to allocate costs to a wholesale jurisdiction.

The allocation factors used in developing data in the unadjusted and pro forma year-end December 31, 2013 may be found on Exhibit___(CRB-1), Schedule 7 (Allocation Factors). Schedule 7 provides a side-by-side comparison of the allocation factors calculated three ways. The left column presents allocation factors using the 2013 unadjusted test year. The middle column is calculated based on normal weather for demand and energy. The right column is calculated based on normal weather and adjusted for no wholesale customers in 2015.

The revenues and expenses allocated to South Dakota can be found on Exhibit___(CRB-1), Schedule 2, (Cost of Service Study, page 2 of 6) for the pro forma year and Exhibit___(CRB-1), Schedule 2A (Unadjusted Cost of Service Study, page 2 of 6) for the unadjusted test year. Both Schedule 2 and

2A were prepared using the allocation factors based on normal weather and without the wholesale customers shown in the right column of Schedule 7.

D. 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, 2013.

A. The following is a comprehensive list of all the adjustments included in the rate case to arrive at the pro forma year. It was necessary to make five types of adjustments to the 2013 actual year to make the resulting pro forma year appropriate for setting rates that will be finalized and applied to service provided in 2015. The first category involves adjustments needed to normalize the 2013 data. The second category involves adjustments necessary to reflect prior regulatory decisions on what may be appropriately included in a pro forma year. The third category includes adjustments needed to account for amortization of expenses for both prior authorized and currently requested amounts that should not be fully recovered in a single year. A fourth category includes the Infrastructure Rider Roll-In for 2015. The final category of adjustments is for known and measurable changes occurring in 2014 and 2015 that we propose to be included in order for rates to better reflect the cost of service when charged in 2015. As a result of these adjustments, it is also necessary to make a change to Cash Working Capital and to Net Operating Loss (NOL) (termed Secondary Adjustments in Schedules 6A and 6B). Finally, it is necessary to recognize the revenue credit effect of eliminating the Infrastructure Rider rate and reducing the TCR Rider rate to show the incremental effect on base rates.

Normalization of Unadjusted 2013 Base Data:

1) Depreciation Study,
2) Economic Development Labor,
3) Production Tax Credit to FCA,
4) Remove Demand Side Management Incentive,
5) 2014 Infrastructure Rider Removal,
6) TCR Rider Removal,
7) Storm Damage,
8) Tax Withheld Adjustment,
9) Vegetation Management, and
10) Weather Normalization and Fuel Lag.

Adjustments Reflecting Regulatory Practice:

11) Advertising ,
12) Association Dues,
13) Aviation Expense,
14) Chamber of Commerce Dues,
15) Customer Deposits,
16) Economic Development Donations,
17) Employee Expense,
18) Foundation Administration,
19) Incentive Pay, and
20) Remove Non-Asset Trading.

Amortizations:

21) Remove Expired Amortization Items, and
22) Current Rate Case Expense Amortization.

Currently in Rider

23) Infrastructure Rider Roll-In for 2015.

Known and Measurable Adjustments:

Projects with 2014 In-Service Dates

24) A.S. King Boiler Waterwall Tube Replacements,
25) Nuclear Plant Cyber Security,
26) Prairie Island License Renewal Phase II – Unit 1 Baffle Former Bolt Inspection,
27) Prairie Island License Renewal Phase II – Nuclear Safety Margin Implementation,
28) Prairie Island Site Administration Building,
29) Prairie Island Unit 1 Generation Step-Up Transformer Replacement,
30) Prairie Island Unit 1 Life Cycle Management Modifications,
31) Prairie Island Unit 1 Reactor Coolant Pump Seal Re-Design,
32) Prairie Island Spent Fuel Pool Heat Exchanger – Component Cooling System Protection,
33) Prairie Island License Renewal ,
34) Sherco Unit 2 Mercury Control,

Projects with 2015 In-Service Dates:

35) Property Taxes for 2014,
36) Border Winds,
37) Pleasant Valley Wind,
38) Prairie Island Casks (#39-47),

39) Prairie Island Independent Spent Fuel Storage Installation (ISFSI) Relicensing,
40) Prairie Island Unit 2 Electric Generator Replacement,
41) Prairie Island Unit 2 Generation Step-Up Transformer Replacement,
42) Sherco Unit 1 Couton Bottom Replacement,
43) Sherco Unit 1 Mercury Control,
44) Wage Adjustment, and
45) Property Taxes for 2015.

Secondary Calculations:

46) Cash Working Capital, and
47) Net Operating Loss.

Revenue Credits:

48) Infrastructure Rider Revenue Credit, and
49) TCR Rider Revenue Credit.

A list of these pro forma year adjustments is shown on Exhibit___(CRB-1), Schedule 8 (Rate Case Adjustments). I will also discuss each adjustment later in my testimony. In addition, I provide bridge schedules (Exhibit___(CRB-1), Schedule 6A (Rate Base) and Exhibit___(CRB-1), Schedule 6B (Income Statement) that show all normalized, regulatory and known and measurable change adjustments.

Q. HAS THERE BEEN A CHANGE FROM PAST RATE CASE FILINGS IN HOW YOUR SCHEDULE 6B PRESENTS THE COMPANY'S PROPOSED CHANGE IN THE COST OF CAPITAL AND ITS EFFECT ON EACH ADJUSTMENT?

A. Yes, there has been a change. In the past, we presented the revenue impact of each adjustment on the income statement bridge schedule (my Schedule 6B) assuming the previously approved cost of capital; and showed the proposed change in the cost of capital as a separate adjustment on the income statement bridge schedule. Because of a change in our financial modeling tools, we will present each adjustment with two revenue requirements. On line 34, I present the revenue requirement using the requested cost of capital of 7.84 percent. On line 38, I present the revenue requirement using the previously approved cost of capital of 7.78 percent. Therefore, we will no longer present a separate cost of capital adjustment. Instead, the total on line 39 provides the cumulative effect of the proposed change in cost of capital on the pro forma deficiency.

The following sections discuss each pro forma year adjustment in more detail (the adjustment numbers refer to corresponding column numbers in Exhibit___(CRB-1, Schedules 6A and 6B).

1. Pro Forma Normalizing Adjustments

Q. YOU MENTIONED THAT YOU MADE ADJUSTMENTS TO THE 2013 ACTUAL DATA FOR THE PURPOSE OF NORMALIZING THE EXPENSES. PLEASE EXPLAIN.

A. The purpose of the pro forma year is to set future rates based on a representative set of revenues and expenses. Consequently, it is necessary to normalize certain 2013 actual data.

1) Depreciation

Q. PLEASE EXPLAIN THE DEPRECIATION ADJUSTMENT.

A. As I explained earlier, the depreciation expense included in the 2013 unadjusted test year was determined using the depreciation rates approved in our last rate case, Docket No. EL12-046. In that case, we reduced depreciation rates to reflect the estimated lower costs from the five-year depreciation study that was to be filed in 2012. More specifically, the depreciation rates for Transmission, Distribution and General Assets were changed to incorporate the anticipated change in average service life, in net salvage rate, and to eliminate the net surplus accumulated depreciation reserves over the average remaining lives of the assets. The five- year study was provided to the Minnesota Commission in June 2012 in Docket E,G002/D-12-858 and to South Dakota Advocacy staff in August 2012 in Docket No. EL12-046 through response to Data Request 4-001.

There are three components to the depreciation expense adjustment we are proposing in this case. The first component refines the South Dakota depreciation rates for Transmission, Distribution and General Assets to reflect the final results of the five-year depreciation study mentioned above. The second component reflects the change in removal costs and their amortization for Black Dog Units 3 and 4. The third component is to extend the Sherco Unit 3 remaining life by two years (which is the length of time Sherco Unit 3 was out of service). Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF1.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 1, column 1. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 1, column 1. As shown on Schedule 6B, page 1, column 1, line 38, the adjustment increases the pro forma year revenue requirements by $399,000.

2) Economic Development Labor

Q. WHAT IS THE ECONOMIC DEVELOPMENT LABOR ADJUSTMENT?

A. The Commission allows the Company to recover 50 percent of its current economic development expense up to $100,000. This recovery cap is designed to allow the Company to recover both the payments made to various organizations and also the administrative cost associated with managing the program. The Company's practice has been to provide the entire $100,000 in authorized expenses to these organizations. As such, the administrative costs for processing the contributions are over and above the Commission authorized cap and thus should not be included for recovery. Therefore the Company is making an adjustment to remove the estimated administrative labor cost associated with Economic Development activities from the unadjusted 2013 year O&M costs.

The adjustment level was based on the estimated time spent by three individuals for the South Dakota economic development activities. This calculated labor estimate is then removed from the 2013 unadjusted test year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF2.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 1, column 2. As shown on Schedule 6B, page 2, column 2, line 38, this adjustment decreases the pro forma year revenue requirements by $41,000. Later in my testimony I will provide the adjustment reducing the Economic Development donations by 50 percent.

3) Production Tax Credits to Fuel Clause

Q. WHAT IS THE PRODUCTION TAX CREDITS TO FUEL CLAUSE ADJUSTMENT?

A. The Company receives federal income tax credits based upon the actual production from eligible wind projects. In the Commission approved Settlement Stipulation in Docket No. EL12-046, the annual level of PTCs allocated to the South Dakota jurisdiction is passed on to ratepayers through the Company's Fuel Clause Rider as the credits are earned based on actual wind production.

This adjustment removes the South Dakota jurisdiction total level of PTCs included in the unadjusted test year and their effect on the income tax calculation for the pro forma year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF3.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 1, column 3. As shown on Schedule 6B, page 1, column 3, line 38, this adjustment increases the pro forma year revenue requirements by $2.043 million.

4) Demand Side Management Incentive Removal

Q. PLEASE DESCRIBE THE DEMAND SIDE MANAGEMENT INCENTIVE REMOVAL ADJUSTMENT.

A. The DSM incentive (which is 30 percent of what we spend on DSM programs) exists to encourage as much cost effective energy saving as possible to keep costs low for all of our customers. This adjustment removes the estimated performance margin from the unadjusted 2013 year operating revenues. The performance margin is equal to the difference between DSM revenues and expenses. In 2013, this amounted to $233,000. The Company records the incentive when it is earned as a negative expense for accounting purposes. Therefore, the adjustment adds to the DSM expenses to reverse the negative expense and set revenues equal to expenses. Failure to include this adjustment would understate the pro forma year operating expenses and therefore understate the revenue deficiency for the test year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF4.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(CRB-1), Schedule 6B, page 1, column 4. As shown on Schedule 6B, page 1, column 4, line 38, this adjustment increases the pro forma year revenue requirement by $233,000.

5) Infrastructure Rider Removal

Q. PLEASE DISCUSS THE INFRASTRUCTURE RIDER REMOVAL ADJUSTMENTS.

A. Consistent with the Commission approved Settlement in Docket No. EL12-046 that created the Infrastructure Rider, we are bringing into base rates the costs currently recovered and that would be recovered through the Infrastructure Rider in 2015. There are three adjustments made up of four components. The first adjustment, which is based on the first component, is to remove the revenues recovered through the Rider in 2013 from the unadjusted test year. This adjustment is needed in order to be able to continue recovering the Commission approved $4.286 million in 2013 authorized infrastructure costs including plant additions and property taxes. In other words, the costs will continue after the Rider rate is eliminated and the revenues currently provided from the Rider will need to be provided by base rates in 2015.

The detailed jurisdictional operating income impacts of the first component are reflected on Exhibit___(CRB-1), Schedule 6B, page 1, column 5, and results in an increase to the revenue requirement of $4.286 million as shown in line 38. Support for the first adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF5.

The second component (and part of the second adjustment) recovers the incremental 2014 revenue requirement for these projects of $2.736 million. This is an update of the $3.612 million incremental 2014 costs forecasted in October 2013 and currently being recovered through the Infrastructure Rider[6]. No adjustment for the associated revenues is needed because the 2014 revenues are not part of the 2013 unadjusted test year.

The combined effect of the first two components is to increase the base rate revenue requirement by $7.021 million[7]. While the revenue requirement associated with base rates increases by that amount, the change is revenue neutral to both our customers and the Company, i.e., revenues previously

[6] $7.898 million total revenue requirement approved for Infrastructure Rider recovery in 2014 (not including the carry over balance) less the $4.286 of approved revenue requirement included in the 2013 test year equals $3,612 million.

[7] $7.021 million is the sum of the $4.286 million, which is the first component, plus the second component of $2.736 million (allowing for rounding).

received through the rider will now be recovered through base rates offsetting the increase in the revenue requirement. We anticipate a filing in Fall 2014 to limit the rider to implementing the 2014 true-up.

The third component (and part of the second adjustment) is to reflect the 2015 normalized costs for those capital additions made during 2014. We normalized the cost of the 2014 plant additions to reflect a full year of their cost in 2015 (including a year of depreciation). The impact of this component results in a decrease to the revenue requirement of $277,000. Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect, and would have occurred under the terms of the Rider if it were to continue in operation.

The second adjustment, which reflects the combined effect of the second and third components on operating income, is reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 23 and results in an increase to the revenue requirement of $2.459 million as shown in line 38.

Support for the second adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF23.

A third adjustment related to the fourth and final component of the infrastructure rider roll-in moves into base rates the incremental increase in property taxes that are currently recovered through the Infrastructure Rider. The incremental property tax revenue requirement, amounting to $1.516 million, is addressed separately in adjustment number 35 discussed later in my testimony.

The combined effect of all three adjustments related to the infrastructure rider roll-in is an increase in the base rate revenue requirements of $8.260 million. This is the $8.481 currently being recovered through the Infrastructure Rider as updated to better reflect current 2014 costs and further adjusted to reflect 2015 costs.

6) TCR Rider Removal

Q. WHAT IS THE PURPOSE OF THE TCR REVENUE AND COST REMOVAL ADJUSTMENT?

A. The Company currently recovers its revenue requirement for approved transmission projects through the TCR Rider. Those projects and their associated revenue requirement were approved in Docket Nos. EL12-035 (2012 rate factor and tracker), EL13-006 (2013 rate factor and tracker), and EL14-016 (2014 rate factor and tracker). The 2013 unadjusted test year data included both revenues and costs recovered through the TCR Rider. Our adjustment has two components. First, six projects went into service before January 1, 2013, and as explained earlier, we will move cost recovery for those projects from the TCR Rider to base rates. Therefore, it is necessary to remove the $558,000 in revenues associated with those projects from the pro forma year. This adjustment increases base rates but it is revenue-neutral to both our customers and the Company. The remaining TCR Rider-qualified projects were not yet in service as of January 1, 2013 and the costs associated with those projects will continue to be recovered through the TCR Rider. For those projects (and MISO Schedule 26 costs), the second component of the adjustment removes both costs and the revenues received through the TCR

Rider from the unadjusted 2013 year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF6.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 1, column 6. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 1, column 6. As shown on Schedule 6B, page 1, column 6, line 38, this adjustment increases the pro forma year revenue requirements by $528,000.

7) Storm Damage

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

A. In accordance with the Settlement Agreement in Docket No. EL09-009, I normalized annual storm damage based upon the five-year average of the actual experience. This same process was also followed in last two rate cases. Consequently, I normalized the annual storm damage by replacing the actual storm damage costs in the 2013 unadjusted test year with the average storm damage costs for the five-year period from 2009 through 2013. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF7.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 1, column 7. As shown on Schedule 6B, page 1, column 7, line 38, this adjustment decreases the pro forma year revenue requirements by $210,000.

8) Tax Withheld

Q. PLEASE DESCRIBE THE TAX WITHHELD ADJUSTMENT?

A. The Company experiences a timing difference between receipt of funds for sales taxes and employee withholding taxes and when the Company remits those funds to the taxing authorities. Consistent with a similar adjustment made in Docket No. EL12-046, the Company has included a rate base adjustment to reflect the cash flow related benefit it receives due to this timing difference. This adjustment only takes into account those tax dollars related to employees and customers in the South Dakota jurisdiction. Since these forms of tax collection do not flow through the Company's income statement, they are not part of the traditional lead lag study, and are thus addressed separately with this adjustment. Support for this calculation can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF8.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 1, column 8. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 2, column 8. As shown on Schedule 6B, page 2, column 8, line 38, this adjustment decreases the pro forma year revenue requirements by $45,000.

9) Vegetation Management

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

A. The Commission-approved settlement agreement in Docket No. E09-009 included normalized tree trimming based upon the five-year average of the actual experience. The same methodology has been followed and approved in our last two rate cases. Therefore, I applied the same methodology, and replaced the 2013 actual year vegetation and tree trimmings costs with the average tree trimming costs for the five-year period from 2009 through 2013. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF9.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(TEK-1), Schedule 6B, page 2, column 9. As shown on Schedule 6B, page 2, column 9, line 38, this adjustment decreases the pro forma year revenue requirements by $83,000.

10) Weather Normalization and Fuel Lag

Q. WHAT IS THE WEATHER NORMALIZATION AND FUEL LAG ADJUSTMENT?

A. Adjustments are used to ensure that revenues reflect a representative year and do not include factors that vary widely from year to year. This adjustment addresses two such factors: weather and fuel lag. I will explain each separately.

Our 2013 unadjusted test year reflects actual sales, which are affected by weather that may not be representative of a typical or average weather pattern. Therefore, it was necessary to weather normalize the retail sales level when setting rates to be in effect in 2015. In 2013, warmer than average temperatures resulted in a higher level of sales than would have occurred under normal weather conditions. Under normal conditions, the Company would have sold 25,169 fewer MWhs. Therefore, we make an adjustment to lower the unadjusted test year revenues and associated fuel costs to reflect a non-weather affected pro forma year.

The second component of this adjustment accounts for fuel lag, or the difference between calendar-month and billing-month accounting.

Non-fuel unadjusted test year revenues are recorded on a calendar-month basis. However, the unadjusted test year reflects fuel revenues on a billing-month basis, which include a recovery lag of approximately 2.5 months. A pro forma adjustment was made to adjust the timing of fuel revenue to an actual 2013 calendar-month basis.

Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF10.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(CRB-1), Schedule 6B, page 2, column 10. As shown on Schedule 6B, page 2, column 10, line 38, this adjustment increases the pro forma year revenue requirements by $2.054 million.

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

A. No. It would not be appropriate to make an adjustment for the 2014 sales forecast because that would amount to a complete adjustment to revenues as compared to limited adjustments to costs, resulting in a mismatched pro forma year.

2. Pro Forma Adjustments Reflecting Regulatory Practice

11) Advertising

Q. WHAT ADVERTISING ADJUSTMENT DID YOU MAKE?

A. The Company is required to reduce general and administrative expense for certain advertising expenses that are not allowed for recovery from South Dakota customers. In general, unrecoverable advertising expenses relate to brand and image advertising. Recoverable advertising expenses relate primarily to the dissemination of customer information or information on safety. Representative advertisements for which we are asking for recovery and the relative dollar values are included in Statement H in Volume 1.

In 2013, unrecoverable advertising expenses amounted to $184,690. This adjustment removes those dollars from the 2013 unadjusted 2013 test year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF11.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 2, column 11. As shown on Schedule 6B, page 2, column 11, line 38, this adjustment decreases the pro forma year revenue requirements by $185,000.

12) Association Dues

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

A. We are requesting recovery of our association dues, excluding the portion of the dues that pays for social organizations or lobbying activities. There are no lobbying costs included in the test year cost of service or the corresponding South Dakota allocated expenses. All lobbying expenses are recorded in

FERC account 426.4 "Expenditures for certain civic, political and related activities," which is considered a below the line expense for ratemaking and therefore not included in our utility cost of service process. Nor are there any political donations included in the test year cost of service or the corresponding South Dakota allocated expenses. All donations are recorded in FERC account 426.1 "Donations," which is considered a below the line expense and therefore not included in our utility cost of service process.

This adjustment brings appropriate association dues above the line for inclusion in the pro forma year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF12.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 2, column 12. As shown on Schedule 6B, page 2, column 12, line 38, this adjustment decreases the pro forma year revenue requirements by $4,000.

13) Aviation Expense

Q. WHY HAVE YOU INCLUDED AN AVIATION EXPENSE REDUCTION?

A. The Commission-approved Settlement Stipulation in Docket No. EL12-046 included an aviation expense reduction for the South Dakota jurisdiction that was consistent with similar adjustments made in both the Minnesota and North Dakota jurisdictions. The adjustment effectively allows for cost recovery of expenses associated with one leased corporate aircraft. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF13.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 2, column 13. As shown on Schedule 6B, page 2, column 13, line 38, this adjustment decreases the pro forma year revenue requirements by $64,000.

14) Chamber of Commerce Dues

Q. WHY DID YOU MAKE AN ADJUSTMENT FOR CHAMBER OF COMMERCE DUES?

A. The Company has included membership dues paid to various Chambers of Commerce in South Dakota in the pro forma year. Chambers of Commerce provide an essential link between the Company and the communities it serves, allowing for improved utility service. Membership in these organizations provides benefits to all South Dakota customers, and therefore recovery of membership dues paid to Chambers of Commerce is reasonable. These expenses are recorded below the line and are not part of the O&M expense data for ratemaking. We make this adjustment to move them above the line, and thus eligible for recovery. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF14.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 2, column 14. As shown on Schedule 6B, page 2, column 14, line 38, this adjustment increases the pro forma year revenue requirements by $4,000.

15) Customer Deposits

Q. WHY DID YOU MAKE AN ADJUSTMENT FOR 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. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF15.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 2, column 15. As shown on Schedule 6B, page 2, column 15, line 38, this adjustment increases the pro forma year revenue requirements by $1,000. An adjustment to rate base is not needed because the 2013 unadjusted test year rate base already reflects a reduction for customer deposits.

16) Economic Development Donations

Q. HOW HAVE YOU TREATED ECONOMIC DEVELOPMENT DONATIONS?

A. The Commission-approved Settlement Stipulation in Docket No. E09-009 allowed the Company to recover 50 percent of its annual economic development expense up to $100,000 incurred for the benefit of South Dakota communities. The same methodology has been followed and approved in our last two rate cases. The Commission approved the Company's 2013 Economic Development Report in Docket No. EL14-024. In that Docket the Company also confirmed that none of the Economic Development funds were used for lobbying purposes. Consequently, $50,000 of the 2013 economic development costs has been included in the pro forma year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF16.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 16. As shown on Schedule 6B, page 3, column 16, line 38, this adjustment increases the pro forma year revenue requirements by $50,000. I earlier described the separate adjustment removing the labor expense associated with the Economic Development activities.

17) Employee Expenses

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

A. The employee expense adjustment accounts for employee expenses that appear inconsistent with the guidelines in our Employee Expense Policy, or identified as generally not being needed for the provision of utility service. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF17.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 17. As shown on Schedule 6B, page 3, column 17, line 38, this adjustment decreases the pro forma year revenue requirements by $7,000.

18) Foundation Administration

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

A. In Docket No. EL09-009, the Company was denied recovery of the Xcel Energy Foundation administration expenses. The same treatment of this expense has been applied in our last two rate cases. Therefore, an adjustment was made to remove these costs from the 2013 unadjusted test year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF18.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 18. As shown on Schedule 6B, page 3, column 18, line 38, this adjustment decreases the pro forma year revenue requirements by $24,000.

19) Incentive Pay

Q. WHAT ADJUSTMENT DID YOU MAKE REGARDING 2013 INCENTIVE PAY?

A. Incentive compensation can vary from year to year based upon the actual results for the year compared to the plan objectives and goals. This adjustment is designed to normalize AIP costs based upon actual payments multiplied by the performance indicators other than financial for the payout periods 2010 through 2013. This treatment of incentive pay is consistent with the Settlement Stipulations in Docket Nos. EL11-019 and EL12-046. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF19.

The detailed jurisdictional operating income impact of this adjustment is reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 19. As shown on Schedule 6B, page 3, column 19, line 38, this adjustment decreases the pro forma year revenue requirements by $755,000.

20) Non-Asset Based Trading

Q. WHAT TREATMENT OF ASSET-BASED AND NON-ASSET BASED MARGINS WAS INCLUDED IN THE SETTLEMENT STIPULATION APPROVED BY THE COMMISSION IN DOCKET NO. EL12-046?

A. The Commission-approved Settlement Stipulation provided for the flow back to rate payers of 100 percent of any asset based margins and 30 percent of any non-asset based margins through the Fuel Clause Rider.

Q. WHAT IS THE COMPANY RECOMMENDING IN THIS CASE REGARDING THE ASSET/NON ASSET MARGIN SHARING MECHANISMS?

A. The Company recommends continuing the existing sharing mechanism that was agreed to in the Settlement Stipulations approved by the Commission in Docket Nos. EL12-046, EL11-019, and EL09-009[8] as an appropriate balance of ratepayer and Company interests.

Q. WHAT IS THE PURPOSE OF THE NON-ASSET BASED TRADING ADJUSTMENT?

A. The non-asset based trading adjustment removes from the base data 100 percent of both the revenues and costs directly associated with non-asset based transactions. This includes revenues generated by the transactions, the costs of goods sold, joint operating agreement effects, and mark to market effects. The net of these revenues and costs is equal to the margins generated by non-asset based trading transactions.

For fiscal year 2013, the Company had positive non-asset margins of $165,111. Thirty percent of these margins, or $49,553, will flow back to rate payers through the Fuel Clause Rider per the above discussed margin sharing

[8] The level of margin sharing was initially implemented at 25 percent and increased to 30 percent in subsequent rate cases.

mechanism. The adjustment ensures that both the Company's portion is retained and the customers' portion is reflected solely through the Fuel Clause Rider. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF20.

The detailed jurisdictional operating income impacts of the non-asset based trading adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 20. As shown on Schedule 6B, page 3, column 20, line 38, this adjustment increases the pro forma year revenue requirements by $165,000.

Q. HAS THE COMPANY CONDUCTED THE INCREMENTAL AND EMBEDDED COST STUDIES AGREED TO UNDER THE SETTLEMENT STIPULATION, AND IF SO, WHAT WERE THE RESULTS?

A. Yes, it has. Exhibit___(CRB-1), Schedule 9 provides the results of the studies. The incremental costs are those that would cease to be incurred if the non-asset based business were to be terminated. The fully embedded costs include all incremental costs as well as an assignment of overhead costs, which costs would not go away if the Company ceased non-asset based trading. Table 4 below shows the results of those two studies and compares them to the existing 30 percent sharing mechanism. Because of the large variability in margins from period to period, a three-year average of 2011 to 2013 was used for this analysis.

Table 4

South Dakota Jurisdictional

Results from Incremental and Embedded Cost Studies

Three Year Average (2011-2013)	Incremental Cost Method	Fully Allocated Cost Method
30% Margin Sharing	$73,015	$73,015
Cost Estimate	$29,080	$60,934
Sharing Compared to Cost	$43,936	$12,081

Based on a three-year average, the 30 percent sharing mechanism exceeds both the incremental and fully allocated costs. Therefore, the current sharing mechanism has benefitted and should continue to benefit customers, providing a reasonable balance of interest.

Q. DOES THE COMPANY REQUEST ANY CHANGE IN THE FILING REQUIREMENTS FOR THE NEXT RATE CASE?

A. Yes. We request that the Company not be required to file both an Embedded and Incremental Cost study. The development of each study is time consuming and we believe the Embedded Cost study provides more complete information when evaluating the value of the sharing mechanism.

3. Amortization Pro Forma Adjustments

Q. WHAT AMORTIZATION ITEMS WERE INCLUDED IN THE 2013 UNADJUSTED TEST YEAR DATA, AND HOW ARE THEY BEING TREATED IN THIS CASE?

A. Amortizations being recovered in 2013 rates under the terms of the Docket No. EL12-046 Settlement Stipulation include: SO_2 Emission Credit, Rate Case Expenses, Private Fuel Storage Expense, and Black Dog Conversion Project.

The SO_2 Emission Credit and Rate Case Expense amortizations expire at the end of 2014. Therefore, an adjustment is necessary to remove these items and their rate base components from the base data used to set rates in 2015. This adjustment is discussed below. The Private Fuel Storage amortization will continue through December 2015. Therefore, no adjustment is necessary.

With respect to the Black Dog Conversion Project the Commission approved recovery of $43,000 in project cancellation expenses associated with Black Dog Conversion Project that were recorded in the 2011 unadjusted base data in the Docket No. EL12-046 Settlement Stipulation. Recovery of this 2011 expense was achieved by reducing the 2011 pro forma year by one half of the expense booked in 2011 and setting rates accordingly. Thus, no actual expense was recorded in 2013 for this item. Current rates were set at levels necessary to recover these expenses over a two-year period in 2013 and 2014. These rates will expire on January 1, 2015 when new rates take effect ensuring there is no over-recovery of these expenses. Since no 2013 actual expenses were recorded and the amortization expires before 2015, no additional adjustment for the pro forma year is necessary.

Table 5 below provides the key information for each amortization item and identifies any necessary adjustments for the pro forma test year.

Table 5

Amortization Adjustments

Item	Amount Amortized	Amort. Period	Annual Expense[9]	Expiration Date	Adjustment for Pro Forma Year
Rate Case Expenses	$695,000	2	$347,500	December 2014	Removed from unadjusted test year data
SO_2 Emission Credit	($219,000)	5	($44,000)	December 2014	Removed from unadjusted test year data
Private Fuel Storage	$1,010,000	6	$168,000	December 2015	No adjustment necessary
Black Dog Conversion Project	$43,000	2	$21,500	December 2014	No adjustment necessary

21) Expired Amortization Items

Q PLEASE DESCRIBE THE ADJUSTMENT TO REMOVE EXPIRED AMORTIZATION ITEMS FROM THE TEST YEAR DATA FOR RATE CASE EXPENSE AND THE SO2 EMISSION CREDIT.

A. The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit__(CRB-1), Schedule 6A, page 3, column 21. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 21. As shown on Schedule 6B, page 3, column 21, line 38, this adjustment decreases the pro forma year revenue requirements by $334,000. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF21.

[9] In the case of Black Dog Conversion Project, recovery was achieved through an adjustment to revenues rather than the booking of an amortization expense.

22) Current Rate Case Expenses

Q. IS THE COMPANY PROPOSING ANY OTHER ADJUSTMENTS RELATED TO AMORTIZATIONS THAT HAVE AN IMPACT ON THE PRO FORMA YEAR REVENUE REQUIREMENT?

A. Yes. The Company is proposing an adjustment to include the amortization of rate case expenses associated with this filing in the pro forma year.

Q PLEASE DESCRIBE THE CURRENT RATE CASE EXPENSE AMORTIZATION ADJUSTMENT YOU HAVE INCLUDED IN THE PRO FORMA YEAR.

A. The Company is projecting direct expenses associated with this rate case docket of $551,000. We propose to amortize these expenses over a one-year period because we reasonably expect to file our next electric rate case in June, 2015, with rates in effect on January 1, 2016, one year after the rates from this current rate case go into effect. Amortizing these expenses over a one-year period results in an annual amortization of $551,000. In the event that we do not file our next rate case by July 1, 2015 and over-recover rate case expense, we will defer the amount of the over-recovery and return it to the ratepayers through our next rate case. The development of our projected rate case costs is shown on Exhibit___(CRB-1), Schedule 10 (Rate Case Expenses). Because these costs will be amortized over one year only, no corresponding rate base adjustment is necessary. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF22.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 3, column 22. As shown on Schedule 6B, page 3, column 22, line 38, this adjustment increases the pro forma year revenue requirements by $551,000.

4. Currently In Rider

23) Infrastructure Rider Roll-In for 2015

Q. PLEASE EXPLAIN THE INFRASTRUCTURE RIDER ROLL-IN FOR 2015 ADJUSTMENT.

A. This adjustment was explained previously in my testimony in conjunction with the Infrastructure Rider Removal adjustment (pro forma adjustment #5). The detailed jurisdictional rate base impacts of this adjustment are reflected in Exhibit___(CRB-1), Schedule 6A, page 3, column 23. The detailed jurisdictional income statement impacts of this adjustment are reflected in Schedule 6B, page 3, column 23. This adjustment increases the pro forma year revenue requirement by $2.459 million

5. Known and Measurable Pro Forma Adjustments

Q. DID YOU FURTHER ADJUST THE BASE 2013 DATA TO DEVELOP THE PRO FORMA YEAR?

A. Yes. I made additional pro forma known and measurable adjustments to the 2013 unadjusted test year data. These adjustments are necessary to have final rates reflect the cost of service at the time the final rates become effective.

Q. PLEASE DESCRIBE IN GENERAL TERMS THE REASONS FOR THE KNOWN AND MEASUREABLE ADJUSTMENTS.

A. We are requesting 20 known and measureable adjustments, each of which is discussed in detail later in my testimony. All but one of the adjustments are nuclear plant or production plant related. Thirteen of the 20 adjustments are nuclear related and fall into the following four categories:

- *The Prairie Island License Renewal Project and the Commitments Made to the NRC*. Three of the projects fall within this category. They are:
    - The License Renewal Project,
    - Prairie Island Unit 1 LCM Modifications, and
    - Phase II – Unit 1 Baffle Former Bolt Inspection.
- *Projects Related to Nuclear Operational Safety*. While numerous projects fit within this category, we have identified three projects that are specifically driven by the need to provide safe nuclear energy:
    - Nuclear Safety Margin Improvement (which is also one of the commitments made to the NRC as part of the Prairie Island Relicensing),
    - Nuclear Plant Cyber Security (which is also driven by NRC regulations), and
    - The Prairie Island Spent Fuel Pool Heat Exchanger – Cooling System Protection.
- *Projects Required by NRC regulations*. While many of the projects address NRC regulations, we have identified one that is specifically driven by an NRC regulation:
    - Prairie Island Independent Spent Fuel Storage Installation Relicensing.
- *Projects Related to Nuclear Plant Operating Needs*. These are:
    - The Prairie Island Administration Building,
    - Prairie Island Unit 1 and Unit 2 Generation Step-up Transformer Replacements,
    - Prairie Island Unit 2 Electric Generator Replacement,
    - Prairie Island Reactor Coolant Pump Seal Redesign, which is also driven by safety concerns, and

    - Prairie Island TN-40 Casks.

Production plant needs fall within three categories and are responsible for the following six known and measureable adjustments:

- *Projects Related to Operating Needs.* These are:
    - The A.S. King Boiler Waterwall Tube Replacement, and
    - Sherco Unit 1 Boiler Couton Bottom Replacement.
- *Projects Related to Federal and State Regulatory Requirements.* These are:
    - Sherco Unit 1 Mercury Control, and
    - Sherco Unit 2 Mercury Control.
- *Projects Related to Renewable Energy Generation.* These are:
    - Pleasant Valley Wind, and
    - Border Winds.

The only additional known and measureable adjustments reflect changes to Union and Non-Union wages and increases in property taxes.

Q. WHAT STANDARD DOES THE COMMISSION APPLY WHEN ASSESSING WHETHER TO MAKE AN ADJUSTMENT FOR A KNOWN AND MEASURABLE CHANGE?

A. The purpose of a rate case is to establish rates that reasonably reflect the revenues and expenses that will be experienced at the time rates go into effect. A historical test period, here 2013, is good at providing certainty as to past revenues and expenses but does not, by itself, reflect the revenues and expenses at the time rates go into effect in 2015. Therefore, it is necessary to adjust the 2013 historical information to reflect known and measureable changes that will occur in 2014 and 2015. The process of using a historical test period adjusted for known and measureable changes occurring within 24 months of the end of the historical period is expressly authorized by Commission Rule 20:10:13:44, which provides in part:

> However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are **known with reasonable certainty and measurable with reasonable accuracy** at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period. (Emphasis added.)

For each of the requested known and measureable changes I provide discussion of the facts that make the project known with reasonable certainty and measureable with reasonable accuracy.

Factors making the projects known with reasonable certainty include:

- Commitments made to the NRC as part of the Prairie Island license renewal.
- Requirements to improve operational safety (e.g., Prairie Island Spent Fuel Pool Heat Exchanger – Cooling System Protection and Prairie Island Reactor Coolant Pump Seal Redesign.)
- Requirements to comply with government regulations (e.g., Cyber Security; Mercury Control; and Prairie Island Independent Spent Fuel Storage Installation Relicensing.)
- Significant construction or other work already completed (e.g., Prairie Island Administration Building; Replacement Generator Step-Up Transformer Replacement; A.S. King Boiler Waterfall Tube Replacement; Prairie Island Unit 2 Electric Generator Replacement Project; and Sherco Unit 1 Boiler Couton Bottom Replacement.)

- Purchase and sale agreement or other contract executed (e.g., Pleasant Valley Wind and Border Winds Project; Prairie Island TN-40 Casks; Prairie Island Reactor Coolant Pump Seal Redesign; and Wage Adjustment.)

Factors making the projects measureable with reasonable accuracy include:

- Adjustments that normalize 2013 cost (e.g., some Prairie Island License Renewal components and Wage Adjustment).
- Use of competitive bids (e.g., Prairie Island Administrative Building; Prairie Island Heat Exchanger Component Cooling System Protection; Prairie Island Generation Step-Up Transformer Replacement; A.S. King Boiler Waterfall Tube Replacement; Prairie Island Unit 2 Electric Generator Replacement Project; and Sherco Unit 1, Boiler Couton Bottom Replacement).
- Contracts with vendors or other parties (e.g., Prairie Island TN-40 Casks; Pleasant Valley Wind; Border Winds Project; and Wage Adjustment).
- Industry, vendor or Company specific experience (Cyber Security; Prairie Island License Renewal Phase II – Unit 1Baffle Former Bolt Inspection Project; Prairie Island License Renewal Phase II – Nuclear Safety Margin Improvement; Prairie Island Unit 1 LCM Modifications; Sherco Mercury Control; and Prairie Island Independent Spent Fuel Storage Installation Relicensing).

I have organized my discussion of these known and measurable adjustments into two sections: Known and Measurable Projects with 2014 In-Service

Dates and Known and Measurable Projects with 2015 In-Service Dates. The Known and Measurable Adjustments are:

a. Known and Measurable Projects with 2014 In-Service Dates:

- A.S. King Boiler Waterwall Tube Replacements,
- Nuclear Plant Cyber Security,
- Prairie Island License Renewal Phase II – Unit 1 Baffle Former Bolt Inspection,
- Prairie Island License Renewal Phase II – Nuclear Safety Margin Improvement,
- Prairie Island Site Administration Building,
- Prairie Island Unit 1 Generation Step-Up Transformer Replacement,
- Prairie Island Unit 1 Life Cycle Management Modifications,
- Prairie Island Unit 1 Reactor Coolant Pump Seal Re-Design,
- Prairie Island 122 Spent Fuel Pool Heat Exchanger – Component Cooling System Protection,
- Prairie Island License Renewal,
- Sherco Unit 2 Mercury Control, and
- Property Taxes for 2014.

b. Known and Measurable Projects with 2015 In-Service Dates:

- Border Winds,
- Pleasant Valley Wind,
- Prairie Island Casks (#39-47,)
- Prairie Island Independent Spent Fuel Storage Installation (ISFSI) Relicensing,

- Prairie Island Unit 2 Electric Generator Replacement,
- Prairie Island Unit 2 Generation Step-Up Transformer Replacement,
- Sherco Unit 1 Couton Bottom Replacement,
- Sherco Unit 1 Mercury Control,
- Wage Adjustment, and
- Property Taxes for 2015,

Each of the known and measurable adjustments is discussed in more detail in the sections that follow (the adjustment numbers refer to corresponding column numbers in Exhibit___(CRB-1), Schedules 6A and 6B).

a. Known and Measurable Projects with 2014 In-Service Dates

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO CAPITAL PROJECTS THAT WENT INTO SERVICE IN LATE 2013 OR WILL GO INTO SERVICE IN 2014?

A. I made adjustments to reflect the 2014 and 2015 revenue requirements for capital projects that went into service either late in 2013 or in 2014. A detailed description of each project follows. I wish to note that dollar amounts are first presented on an NSPM basis followed by the State of South Dakota jurisdictional amount in parenthesis, unless otherwise noted.

24) A.S. King Boiler Waterwall Tube Replacements

Q. PLEASE DESCRIBE THE A.S. KING BOILER WATERWALL TUBE REPLACEMENT PROJECT.

A. The A.S. King Boiler Waterfall Tube Replacement project, occurring in 2014, involves the replacement of the boiler waterwall tubes, which have thinned due to erosion and thermal fatigue. As a result of these conditions, discovered during the spring 2013 overhaul, the boiler tubes must be replaced to reduce the risk of forced outages from tube leaks. The boiler waterwall tubes form the walls of the boiler and provide a conduit for boiling water to create steam that is sent to the turbine.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. Our forecasted costs for this project were derived from past experience with boiler waterwall tube replacements at the plant. In addition, during the 2013 overhaul, the Company invited prospective vendors to tour the boiler in order to ensure that submitted bids were as accurate and detailed as possible. Three vendors submitted proposals, and selection of the winning bid was based on price, quality, and a proven ability to deliver projects on time and on budget.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $8.6 ($0.5) million with a scheduled in service date in June 2014. The table below provides a breakdown of the costs for the entire project.

Table 6

A.S. King Boiler Waterwall Tube Replacement Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[10]	**$8.573**

[10] Figures may not sum to total due to rounding.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The project is on schedule and on budget. Construction began in early March 2014 and the project was completed in early May 2014. The start-up occurred on May 22nd and the unit is fully operational. The project was completed slightly ahead of schedule and slightly under budget.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital-related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment accounts for the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF24.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 24. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), 6B, page 4, column 24. As shown on 6B, page 4, column 24, line 38, this adjustment increases the pro forma year revenue requirements by $53,000.

25) Nuclear Plant Cyber Security

Q. PLEASE DESCRIBE THE NUCLEAR PLANT CYBER SECURITY PROJECT.

A. On March 31, 2009, the NRC published a new regulation establishing cyber security requirements at nuclear plants. The new regulation, Title 10, Part 73, "Physical Protection of Plants and Materials, Section 73.54, Protection of Digital Computer and Communication Systems and Networks," requires that licensees provide high assurance that digital computer and communications systems and networks are adequately protected against cyber attacks, up to and including design basis threat as described in 10 CFR part 73, Section 73.1. The Monticello and Prairie Island plants formally submitted their Cyber Security Plan in a License Amendment Request to the NRC on July 20, 2010, and approval was received on July 29, 2011. The Nuclear Plant Cyber Security project implements that plan.

The project includes the following activity highlights:

1. Assess approximately 1,200 Critical Digital Assets (CDAs) at Monticello and 800 CDAs at Prairie Island against approximately 800 controls.
2. Fully implement the Cyber Security Incident Response plan.
3. Fully implement controls for Portable Media and Mobile Devices (PMMD) at both Monticello and Prairie Island.
4. Verify via walk down, that no bypasses to data diodes or other cyber security defensive architecture boundaries exist.
5. Develop training for the various groups with specialized knowledge requirements associated with the Cyber Security program.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget was based on previous experience with similar projects and compiled using the work breakdown structure of the project and cost based on product pricing and resource costs.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Capital additions for the entire project are expected to be $12.7 ($0.8) million. Over 98 percent of the additions, or $12.4 ($0.8) million, will go into service in 2014. The remaining $293,426 ($17,922) will go into service in 2015. Table 7 below provides a breakdown of the costs for the entire project.

Table 7

Nuclear Plant Cyber Security Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[11]	**$12.719**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The cyber security project has many parts, many of which have already been completed. Components of the project will be placed in service as they are completed. We are currently completing the CDA assessments and we are on track for completion as scheduled, with the vast majority of the project elements going into service in 2014 and final completion in 2015.

[11] Figures may not sum to total due to rounding.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment includes the impact of the 2015 capital additions as well as the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a full year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF25.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 25. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 4, column 25. As shown on Schedule 6B, page 4, column 25, line 38, this adjustment increases the pro forma year revenue requirements by $102,000.

26) Prairie Island License Renewal Phase II – Unit 1 Baffle Former Bolt Inspection

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND LICENSE RENEWAL PHASE II – UNIT I BAFFLE FORMER BOLT INSPECTION PROJECT.

A. As part of the Prairie Island license renewal approval, one of the commitments we made was to follow industry guidance on reactor vessel inspection and evaluations, including the baffle former bolts. Baffle former bolts hold the reactor core baffle plates together. The baffle plates hold the fuel assemblies in position and provide a boundary between cool water coming into the reactor and hotter water passing through the reactor core. Because of their location near the core, these components could experience corrosion and cracking due to exposure to radiation. The work scope for this project includes performing ultrasonic inspections of the 728 internal hex-type baffle former bolts and performing remote visual inspections of the reactor vessel internal components (e.g., core barrel assembly, baffle former assembly, control rod guide tube assembly, upper support ring or skirt, thermal shield assembly).

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. We developed the budget for this project based on industry experience and a quote from Westinghouse. We benchmarked our budget with similar work completed at Point Beach within the last 12 months. We work closely with Point Beach when possible to evaluate work needed and costs to complete the work because the plants are very similar and of the same vintage.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $7.6 ($0.5) million, all of which will go into service in 2014. Table 8 below provides a breakdown of the costs for the entire project.

Table 8

Prairie Island License Renewal Phase II – Unit 1 Baffle Former Bolt Inspection Costs

Project Line Item	Total Estimate at Completion ($millions)
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[12]	**$7.621**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The Unit 1 Baffle Former Bolt inspections will be performed during the fall 2014 refueling outage. Subsequent inspections will be performed on a recurring basis, approximately every ten years.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment accounts for the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and

[12] Figures may not sum to total due to rounding.

2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF26.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 26. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 4, column 26. As shown on Schedule 6B, page 4, column 26, line 38, this adjustment increases the pro forma year revenue requirements by $59,000.

27) Prairie Island License Renewal Phase II – Nuclear Safety Margin Improvement

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND LICENSE RENEWAL PHASE II – NUCLEAR SAFETY MARGIN IMPROVEMENT PROJECT.

A. The Prairie Island License Renewal Phase II – Nuclear Safety Margin Improvement includes review of the design and licensing of components identified as risk-significant to ensure that they are capable of performing their intended design and safety functions during the renewed license period. This project is a condition of the renewed license approved by the NRC, and as such, it is treated as a capital asset.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The scope of this project involves heat calculations in the Auxiliary Building and Turbine Buildings and 25 corresponding calculations in rooms housing equipment within these buildings. Engineering estimates to perform these analyses were completed, which included contractor support and internal labor to manage the project.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $15.9 ($1.0) million, all of which will go into service in 2014. Table 9 below provides a breakdown of the costs for the entire project.

Table 9

Prairie Island License Renewal Phase II – Nuclear Safety Margin Improvement Costs

Project Line Item	Total Estimate at Completion ($millions)
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[13]	**$15.887**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The Nuclear Safety Margin Improvement project is on track to be in-serviced by December 31, 2014. All resources have been procured through external organizations, and all sub-projects are on schedule. The following statistics show progress through April 2014.

-Dollars spent to date = $11,780,638

-Percent of Dollars spent to date = 64 percent

-Percent of project complete = 63 percent

[13] Figures may not sum to total due to rounding.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment accounts for the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF27.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 27. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 4, column 27. As shown on Schedule 6B, page 4, column 27, line 38, this adjustment increases the pro forma year revenue requirements by $116,000.

28) Prairie Island Site Administration Building

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND SITE ADMINISTRATION BUILDING PROJECT.

A. This project will result in a new 77,000 square foot office building to house 300 existing and future plant personnel. Currently, staff is dispersed across multiple structures including permanent buildings and temporary trailers brought in over the years to accommodate growing staff levels needed to meet evolving operational and regulatory requirements. For example, Projects and Nuclear Oversight (NOS) Personnel are housed in trailer offices while Security, Performance Assessment, Licensing, Information Technology, Drafting, and Human Resources are all housed in metal buildings and pole buildings that have been adapted for use as offices, but were never intended for that use. This dispersal of staff creates inefficiencies, leading to mark downs on Prairie Island's performance evaluations from the NRC. Furthermore, the collective capacity of all current Prairie Island Nuclear Generating Plant office buildings will not accommodate the 2014-15 projected staffing total needs.

Additionally, the existing facilities do not comply with the American Disabilities Act, and lack conference room space, and lunchroom/cafeteria facilities for employees. This building project will establish a work place that meets present day industry standards, complies with Federal and State Building codes, and is conducive to a safe, secure and productive work environment.

Finally, we expect the new building to reduce future operating costs by about $28.3 million over the life of the facility by reducing heating and cooling costs as well as reducing septic system maintenance costs.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The construction of the building was competitively bid, and the Company received two qualifying bids. We selected the bidder based on cost and quality and the ability to enter into a fixed-price contract for the construction, which limits the possibilities for cost increases during the project.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $26.5 ($1.6) million with $23.3 ($1.4) million going into service in 2014 and an additional $3.2 ($0.2) million going into service in 2015 (see detailed project schedule below). Table 10 below provides a breakdown of the costs for the entire project.

Table 10

Prairie Island Site Administration Building Costs

Project Line Item	Total Estimate at Completion ($millions)
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[14]	**$26.533**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The date for the Site Administration Building project to be completed and turned over for occupancy is December 31, 2014. This is also the in-service date used for calculating revenue requirements.

The competitive bids and the final fixed bid contract were based on the Certificate of Occupancy occurring in December of 2014. As part of the fixed bid contract, the vendor is currently working and tracking to the schedule presented in Table 11 below.

[14] Figures may not sum to total due to rounding.

Table 11

Schedule of the Prairie Island Site Administration Building Project

Construction Activity	Completion Date	Status
Excavation / Footings	March 2014	Completed
Foundation Pours	April 2014	Completed
Concrete Slab Pours (all floors):	May 2014	Completed
Water tight building	July 2014	On Schedule
Electrical, Plumbing and HVAC Duct (Rough Install)	July 2014	On Schedule
Septic System completion	September 2014	On Schedule
Lighting completion	October 2014	On Schedule
Sprinkler System completed	November 2014	On Schedule
Certificate Of Occupancy	December 2014	On Schedule
Staff move to SAB	March 2015	On Schedule
Project Closeout	May 2015	On Schedule

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment includes the impact of the 2015 capital additions as well as the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a full year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF28.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 28. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 4, column 28. As shown on Schedule 6B, page 4, column 28, line 38, this adjustment increases the pro forma year revenue requirements by $208,000.

29) Prairie Island Unit 1 Generation Step-Up (GSU) Transformer Replacement

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND UNIT 1 GSU TRANSFORMER REPLACEMENT PROJECT.

A. The purpose of the Prairie Island Unit 1 GSU Transformer Replacement Project is to increase the voltage of the power produced by the plant generator from 20,000 volts to 350,000 volts for more efficient transmission to customers. The current GSU transformer has been in service for over 40 years and is considered at the end of its operating life. This project involves procuring and installing a new GSU transformer and disposing of the old GSU. The new GSU will ensure reliable delivery of the power produced at Prairie Island Unit 1 to customers during the 20-year life extension. If the GSU transformer is not replaced, we would expect the existing transformer to eventually fail, resulting in a plant shutdown and months of down time.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget for this project is the result of a competitive bidding process. The vendor was selected based on price and prior experience demonstrating quality and ability to meet schedule requirements. The project was awarded to a single vendor along with the Unit 2 GSU Transformer Replacement and Unit 2 Electric Generator Replacement projects (described later in my testimony), which saved approximately $3 million compared to separate vendors.

The project scope includes fabrication and installation of the new GSU transformer, disposal of the old GSU transformer, updating plant documentation, and internal project management and oversight costs. The project costs also include replacement of the fire protection system for the old transformer with a new fire protection system that is compatible with the new transformer.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $13.0 ($0.8) million. $12.4 ($0.8) million will go into service in 2014. The final $650,000 ($39,702) will go into service in 2015. Table 12 below provides a breakdown of the costs for the entire project.

Table 12

Prairie Island Unit 1 GSU Transformer Replacement Project Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[15]	**$13.041**

The GSU Transformer Replacement project cost is based on the firm price competitive bid amount of **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]**. Other GSU Transformer project related contracts were also competitively bid; including contracts for engineering staff and design engineering services. The External Design Organization contract amounts to approximately **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]** (total contract is approximately **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]** for both units). Staff augmentation engineer positions were also bid.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Contracts for the majority of project cost have been awarded, significant engineering analysis has been completed, the GSU Transformer has been built, and factory testing is complete. The Unit 1 GSU Transformer is scheduled to arrive at Prairie Island in June 2014. Work completed to date

[15] Figures may not sum to total due to rounding.

represents approximately 39 percent of the total project. The project is on track to be completed during the Unit 1 Fall 2014 refueling outage with an expected in-service date in December 2014.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment includes the impact of the 2015 capital additions as well as the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a full year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF29.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 29. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 4, column 29. As shown on Schedule 6B, page 4, column 29, line 38, this adjustment increases the pro forma year revenue requirements by $88,000.

30) Prairie Island Unit 1 Life Cycle Management Modifications

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND UNIT 1 LCM MODIFICATIONS.

A. The Prairie Island life extension work will involve numerous capital projects to support extended operations. The scope of the Prairie Island Unit 1 Life Cycle Management Modifications project includes the following analytical work necessary to meet the requirements under the extended license period:

- *Leak Before Break License Amendment Analysis and Implementation:* This project includes revised analysis techniques to reduce the risk of pipe failures.
- *Spent Fuel Pool Criticality License Amendment Analysis and License Implementation:* This allows more variability in the spent fuel pool and increases the margin for safety in the pool. This allows us to use the higher burn-up fuel type and reduce the number of outages over the remaining life of the plant.
- *Alternate Source Term License Amendment Analysis and License Implementation:* The source term is an input to the overall calculation which estimates the level of radiation that could be released in the event of an incident. The purpose of the project is to develop a more realistic radiation dose assessment based on revised source terms, increasing the margin for safety for both on- and off-site dose rates. This will reduce costs by requiring reduced testing for the control room. More accurate assessments of off-site dose also provide more accurate emergency planning responses with respect to evacuations and sheltering in place decisions.

- *Beacon Technical Specification Monitoring (TSM) System:* This project simplifies the job of site engineers. It reduces costs by eliminating the number of on-line activities.

The Beacon TSM System project was put into service in November 2012. The other three components of this parent project will go into service in 2014.

To complete the activities for these LCM modifications, supporting analyses were performed, a License Amendment Request was developed and submitted to the NRC for review, and responses to the NRC's requests for additional information were completed to support NRC approval. Finally upon approval, the NRC-approved plant analysis will be incorporated into the plant design and licensing basis via the Engineering Change process.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. We built a bottom-up estimate based on typical tasks required for modification, related labor hours, and past experience. The budget includes the analysis to support the License Amendment Request and responses to requests for information, as well as NRC fees to review the License Amendment Request.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $8.5 ($0.5) million with the final $6.6 ($0.4) million going into service in 2014. $1.9 million of the project costs went into service in 2012 and therefore is included in the 2013 unadjusted test year. Table 13 below provides a breakdown of the costs for the entire project.

Table 13

Prairie Island Unit 1 Life Cycle Management Modifications Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[16]	**$8.478**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The necessary NRC approval for the life cycle management activities has been received and will be incorporated into the plant's design and licensing basis during 2014.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment accounts for the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and

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[16] Figures may not sum to total due to rounding.

2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF30.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 30. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 4, column 30. As shown on Schedule 6B, page 4, column 30, line 38, this adjustment increases the pro forma year revenue requirements by $40,000.

31) Prairie Island Unit 1 Reactor Coolant Pump (RCP) Seal Redesign

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND UNIT 1 RCP SEAL REDESIGN PROJECT.

A. The RCP Seal Redesign is a project to eliminate leakage in the reactor coolant pump while also incorporating a new three-stage seal design, which is industry best practice.

The new seal will improve plant operating reliability. Poor seal performance resulted in a mid-cycle forced outage in 2011 and resulted in a 10-day outage extension in 2009 to replace a seal. The new seals have a “zero leakage seal,” which are achieved by incorporating additional barriers for leaking and flooding. The improved design requires fewer periodic adjustments and replacements. The prior seals required replacement at six-year intervals at a cost of approximately $1 million per replacement effort. The new seals require replacement at 10-year intervals.

The project helps the plant fulfill NFPA 805 requirements, Fukushima modifications, and multiple NRC regulatory safety rules in one modification approach, reducing the total implementation costs for these independent requirements.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The contract services portion of our budget is based on supplier quotes. The materials costs are based on our current contracts in place as well as costs for additional materials procured through our internal supply chain. The labor costs were put together based on experience with our Unit 2 project and historical labor rates for each discipline. Our budget for this project is consistent with the actual spend for the Unit 2 RCP Seal Improvement Project, Parent Number 11812334, which was installed in December 2013. The final capital addition for the Unit 2 project was $6.9 million, which is consistent with our budget of $6.4 million for the Unit 1 work in this case.

The project scope includes material, design, and installation. Design costs include incorporating the new seal design into the plant's probabilistic risk assessment with an industry peer review of the modeling. Installation includes the development of plant modification and work procedures. Approximately 120 plant procedures will be affected by this project.

Major equipment cost for the RCP Seal Redesign project is detailed in contract 48311 between Xcel Energy and Flowserve, with the current contract being **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]** for supply of the N-9000 seals and housings. In addition to the contract with Flowserve, we have a Design Engineering contract with Zachry, a Probabilistic Risk Assessment (PRA) modeling contract with Enercon, and an Install and Removal contract with

Westinghouse. The costs of these contracts are included in the below costs, along with internal labor for some of the installation work that will be performed internally.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be approximately $6.4 ($0.4) million. Approximately $6.39 (0.4) million will go into service in 2014 and $21,938 ($1,340) will go into service in 2015. Table 14 below provides a breakdown of the costs for the entire project.

Table 14

Prairie Island Unit 1 RCP Seal Redesign Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[17]	**$6.416**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The new reactor coolant pump seals (Flowserve N9000) have been purchased. Installation is set to occur on Unit 1 in the fall 2014 refueling outage.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

[17] Figures may not sum to total due to rounding.

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment includes the impact of the 2015 capital additions as well as the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a full year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF31.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 3, column 31. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 4, column 31. As shown on Schedule 6B, page 4, column 31, line 38, this adjustment increases the pro forma year revenue requirements by $50,000.

32) Prairie Island 122 Spent Fuel Pool Heat Exchanger – Component Cooling System Protection

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND 122 SPENT FUEL POOL HEAT EXCHANGER – COMPONENT COOLING SYSTEM PROTECTION PROJECT.

A. This project involves the installation of fast-closing valves that will isolate the Component Cooling Water system in the event that it is damaged and prevent the potential damage from impacting the operation of the Unit 1 #22 Spent Fuel Pool Heat Exchanger. The spent fuel pool heat exchanger removes residual heat generated from spent fuel stored in the spent fuel pool. This project will address a vulnerability identified by the Company involving potential damage to the Component Cooling system in the event of a severe tornado strike, which could result in a loss of the ability to cool the spent fuel pool.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget was based on careful evaluation of the scope of the project and the results of a detailed request for proposals (RFP) process. We ultimately selected the winning bid based on price, quality, and ability to perform.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $11.8 ($0.7) million, all of which is scheduled to go into service no later than September 2014. Table 15 below provides a breakdown of the costs for the entire project.

Table 15

Prairie Island 122 Spent Fuel Pool Heat Exchanger – Component Cooling System Protection Costs

Project Line Item	Total Estimate at Completion ($millions)
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[18]	**$11.845**

[18] Figures may not sum to total due to rounding.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Detailed engineering design is complete, and the modification package was approved on May 22, 2014. Fieldwork is expected to take approximately two months and will commence in mid-July. All project work is necessary to support the upcoming Unit 1 refueling outage which begins in Fall 2014. Through May 2014, the project is considered to be about 50 percent complete.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment accounts for the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a year of depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF32.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 32. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 32. As shown on Schedule 6B, page 5, column 32, line 38, this adjustment increases the pro forma year revenue requirements by $84,000.

33) Prairie Island License Renewal

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND LICENSE RENEWAL PROJECT.

A. When the NRC approved the renewed operating license for Prairie Island and issued its Safety Evaluation Report, the NRC identified and accepted over 40 commitments for further work from the Company. These commitments are conditions of the renewed operating license and must be completed prior to entering the period of extended operation. Prairie Island Unit 1 began the extended period of operation on August 9, 2013 and Prairie Island Unit 2 will begin its extended period of operation on October 29, 2014. Prior to beginning the period of extended operation, the NRC has and will perform inspections to ensure that the Company's commitments have been fulfilled. The remaining work associated with the Prairie Island License Renewal project involves completing those commitments and demonstrating to the NRC that they have been completed.

The commitments were to develop and implement programs to oversee, assess, and repair or replace aging components as necessary. The programs primarily assess aging passive components – cables, tanks, pipes, concrete, bolts, and similar items that are not active components of the reactor, but are nonetheless fundamental to the safe operation of the plant.

The programs include identifying areas of inspection and developing frequencies to repeat the inspections. The work identified by these inspections is thereafter treated as a separate project as necessary. For example, the Baffle Former Bolt Inspection work discussed earlier in my Testimony is a project identified through these programs.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget for this project was based on a thorough review of engineering requirements to estimate the quantity of work orders, the number of resulting procedures necessary to complete the work, and estimated labor hours for the field work to be performed. In addition, the Company relied on lessons learned during the implementation of similar activities completed prior to beginning extended operations at the Monticello facility.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Capital additions for the entire project are expected to be $59.5 ($3.6) million with the final $6.2 ($0.4) million going into service in 2014. Table 16 below provides a breakdown of the costs for the entire project.

Table 16

Prairie Island License Renewal Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Fees/Dues	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[19]	**$59.476**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The NRC inspection of the commitments for Unit 1 was successfully completed and Unit 1 began extended operation on August 9, 2013. The

[19] Figures may not sum to total due to rounding.

NRC License Renewal Phase 1 inspection was completed in December of 2013 and the Renewal Phase 2 inspection will take place over the course of a week beginning July 14, 2014. Currently all deliverables are expected to meet that inspection date. Once the Phase 2 Inspection is complete, the Company will complete any follow-up activities required to begin the extended operation period prior to October 29, 2014.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions as well as the normalized cost of the 2013 capital additions to reflect a full year of their cost in 2014 (including a full year of depreciation). The 2015 component of the adjustment accounts for the normalized cost of the 2014 capital additions. Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF33.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 33. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 33. As shown on Schedule 6B, page 5, column 33, line 38, this adjustment increases the pro forma year revenue requirements by $63,000.

34) Sherco Unit 2 Mercury Control

Q. PLEASE DESCRIBE THE SHERCO UNIT 2 MERCURY CONTROL PROJECT.

A. In order to comply with both federal and state Environmental Protection Agency (EPA) mercury emissions limitations, we are in the process of installing a sorbent injection system on Sherco Units 1 and 2 using activated carbon as the sorbent, which will reduce mercury emissions. In addition to installing mercury removal technology on the Unit 1 and 2, the project involves upgrading the ductwork and installing a milled activated carbon injection system to achieve approximately 90 percent removal of mercury. The installation of mercury control systems must be completed to comply with federal EPA mercury emissions limits by April 15, 2015. The Sherco Unit 2 mercury controls will go into service in 2014 while the Sherco Unit 1 mercury controls will go into service in 2015. While the projects are the same for Units 1 and 2, I discuss the costs of the project for Unit 2 here because it will be in service in 2014, and discuss the costs for Unit 1, which will go into service in 2015, along with other capital projects that go into service in 2015.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. In addition to relying on our own industry experience, the Company also engaged third-party engineering consultants to provide scoping and costing estimates.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $6.6 ($0.4) million with $6.3 ($0.4) million going into service in 2014 and $350,000 ($21,378) going into service in 2015. Table 17 below provides a breakdown of the costs for the entire project.

Table 17

Sherco Unit 2 Mercury Control Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[20]	**$6.649**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. We have completed full-scale testing to validate that the sorbent injection system will effectively remove mercury from Units 1 and 2. Construction has begun and the foundations are in place. The Unit 2 project is on schedule to go into service as planned in December 2014.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. The 2014 component of the adjustment captures the impact of the 2014 capital additions. The 2015 component of the adjustment includes the impact of the 2015 capital additions as well as the normalized cost of the 2014 capital additions to reflect a full year of their cost in 2015 (including a full year of

[20] Figures may not sum to total due to rounding.

depreciation). Normalizing the costs in this manner better reflects the cost of service in 2015 when the final rates will go into effect. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF34.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 34. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 34. As shown on Schedule 6B, page 5, column 34, line 38, this adjustment increases the pro forma year revenue requirements by $75,000.

35) Property Taxes for 2014

Q. PLEASE DESCRIBE THE PROPERTY TAXES FOR 2014 ADJUSTMENT?

A. Property taxes incurred in the prior year are paid out in the current year. Thus, property taxes incurred in 2013 will be paid in 2014, and property taxes incurred in 2014 will be paid out in 2015. This adjustment captures the incremental increase in property tax payments for 2014 compared to those expenses incurred in the unadjusted 2013 year. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF35.

There are no jurisdictional rate base impacts associated with this adjustment. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 35. As shown on Schedule 6B, page 5, column 35, line 38, this adjustment increases the pro forma year revenue requirements by $1.516 million.

b. Known and Measurable Projects with 2015 In-Service Dates

Q. WHAT ADJUSTMENTS DID YOU MAKE WITH RESPECT TO CAPITAL PROJECTS THAT BECOME OPERATIONAL IN 2015?

A. As permitted by Commission Rule 20:10:13:44, the Company is requesting recovery of the 2015 revenue requirements associated with ten projects that have planned in service dates in 2015.

36) Border Winds

Q. PLEASE DESCRIBE THE BORDER WINDS PROJECT.

A. Border Winds is a 150 MW wind farm located in northeastern Rolette County, North Dakota immediately south of the U.S.-Canadian Border. The project will be made up of 75 wind turbines that are 2 MW each. RES Americas is developing and constructing the project, and upon completion, will transfer ownership to Xcel Energy, which will operate the facility.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The cost estimates are based on our past experience with build/own Purchase and Sale Agreement (PSA) transactions and known additional costs. In addition, as discussed above, we conducted a rigorous and fair competitive RFP process. The RFP process resulted in the identification of four projects for further consideration and potential development, including Border Winds.

The budget includes the PSA agreement costs for Border Winds as well as Xcel Energy development oversight and ownership transfer costs. Finally, we included additional funds in the budget to cover anticipated transmission interconnection costs the Company may need to absorb. The budget reflects the total costs of the project.

With respect to interconnection costs, preliminary study work identified that certain network upgrades, approaching as much as $50 million in cost, to the Roseau County Substation and elsewhere on the 500 kV line to Winnipeg, may be required as a result of the interconnection of the Rugby – Glenboro 230 kV transmission line. To deal with this unknown transmission cost risk, the PSA accounts for Shared Interconnection Costs (shared equally by RES Americas and Xcel Energy) of **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]**. If the Shared Interconnection Costs exceed that amount, the Company may also be responsible for **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]** in additional transmission costs, after which any additional transmission costs would trigger the Company's right to terminate the PSA. The current estimate for total transmission costs expected to be incurred by Xcel Energy is **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]**.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $272.7 ($16.7) million, including transmission costs, which will go into service in 2015. A small remainder of $20,681 will go into service after 2015 and is not being requested for recovery in this case. Table 18 below provides a breakdown of the costs for the project.

Table 18

Border Winds Costs

Project Line Item	Total Estimate at Completion ($millions)
	[CONFIDENTIAL DATA BEGINS
Purchase Price per PSA	
Transmission Interconnection	
Development Oversight and Ownership Transfer Costs	
Indirect Cost Contingency	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[21]	**$272.7**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Our PSA with RES Americas anticipates a closing date for the transaction in late 2015. While the contract has provisions that would allow for a later closing under certain conditions, the need to capture federal PTCs to effectuate the closing will assure that RES Americas completes the project in 2015. Currently, project development is on schedule to meet a 2015 in-service date. RES Americas anticipates beginning construction in Summer 2014 with the erection of the wind turbines in 2015. With respect to interconnection, the Engineering and Procurement agreement for the construction of the interconnection substation was signed in February 2014, and the Generator Interconnection Agreement will be executed by May 15, 2014. Construction on the substation will begin in June of 2014 and completed by end of July 2015 in time for interconnection in October 2015.

[21] Figures may not sum to total due to rounding.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small 2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF36.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 36. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 36. As shown on Schedule 6B, page 5, column 36, line 38, this adjustment increases the pro forma year revenue requirements by $627,000.

37) Pleasant Valley Wind

Q. PLEASE DESCRIBE THE PLEASANT VALLEY WIND PROJECT.

A. The Pleasant Valley Wind project is a 200 MW wind farm to be located near Austin, Minnesota. The project will include 100 wind turbines that are 2 MW each. It is being developed and constructed by RES Americas. Once construction is complete, RES Americas will transfer ownership to Xcel Energy, which will operate the facility.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. We developed our cost estimates based on our past experience with build/own PSA transactions and known additional costs. In addition, we conducted a competitive RFP process. In early February 2013, we announced that we were issuing an RFP for approximately 200 MW of wind resources in an effort to take advantage of the recently extended federal PTC. We structured the RFP to ensure, to the degree possible, that any projects selected could meet the PTC requirements to have significant construction underway by the end of 2013. To demonstrate transparency of the bid process, we engaged an independent auditor to monitor and report on the conduct of the process.

The RFP generated proposals for 57 projects comprising approximately 6,300 MW of distinct resources and presenting a wide range of PPA and ownership options. The Purchased Power Group, the Business Development Group and the Transmission Access Group evaluated the proposals to determine which projects might be suitable for further development. Proposals were evaluated primarily on the basis of levelized cost and ease of interconnection. Out of 14 proposals that met the levelized cost threshold, two own/operate projects, Pleasant Valley Wind and Border Winds (discussed previously), and two PPA projects, Odell and Courtenay, were selected for further development. As a result of those efforts we entered into a PSA with RES Americas for the Pleasant Valley project.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The budget includes the PSA costs as well as Xcel Energy development oversight and ownership transfer costs. The budget also includes additional funds to cover anticipated transmission interconnection costs the Company may need to absorb. Total capital additions for the project (including transmission interconnection) are expected to be $345.1 ($20.2) million almost all of which will go into service in 2015 (a small remainder of $109,311 will go into service after 2015 and is not being requested for recovery in this case). (The transmission piece of the project is, for accounting purposes, included in a separate project, but is presented here as part of the single project.) Table 19 below provides a breakdown of the costs for the project.

Table 19

Pleasant Valley Wind Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Purchase Price per PSA	
Transmission Interconnection	
Development Oversight and Ownership Transfer Costs	
Indirect Cost Contingency	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[22]	**$345.1**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Our PSA with RES Americas anticipates a closing date for the transaction in late 2015. While the contract has provisions that would allow for a later closing under certain conditions, the need to capture federal PTCs to effectuate the closing will help assure that RES Americas completes the project in 2015. Currently, project development is on schedule to meet a 2015 in-service date, and all milestones have been met to date to maintain eligibility

[22] Figures may not sum to total due to rounding.

for the PTC. RES Americas anticipates beginning construction in Summer 2014 with the installation of the wind turbines in 2015.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small 2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF37.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 37. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 37. As shown on Schedule 6B, page 5, column 37, line 38, this adjustment increases the pro forma year revenue requirements by $793,000.

38) Prairie Island Casks (#39-47)

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND CASKS PROJECT.

A. The Prairie Island Casks (#39-47) project will result in the loading and transfer of nine total casks containing 360 total fuel assemblies from the spent fuel pool in the plant to dry cask storage. Each cask has a capacity of 40 fuel assemblies, resulting in the use of nine casks to house the fuel assemblies.

Casks 30-38 are being installed currently with a completion date of 2014, casks 39-40 will be installed in 2015, and the remaining casks (41-47) will be installed over a period from 2016-2021.

In order to refuel the Unit 1 and Unit 2 reactors at Prairie Island, space needs to be available in the spent fuel storage pool to discharge fuel assemblies from the reactor that have reached the end of their useful lives. Spent fuel storage space in the pool is limited by our NRC operating license and the federal government's lack of an alternative for removing spent fuel from Prairie Island.

Storage capacity in dry casks is the only means available to supplement the storage space available in the pool for continued operation of the units. For safety reasons, the Company maintains full-core offload capacity at both Monticello and Prairie Island. Additional casks are necessary to ensure that capability is available into the future. In addition, we have used temporary re-racking in the past to meet this full-core offload capability when additional dry cask storage was not yet available. The addition of these casks will eliminate the need for the temporary re-racking, avoiding the associated re-racking costs and the potential for additional dose exposure to our employees. The project includes the acquisition, loading, and placement of the dry casks in the ISFSI.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The project budget was developed by reviewing the experience and costs of placing the first 38 casks in the ISFSI from 1994 through 2014. The contract for the fabrication, manufacture, and delivery of casks 39 through 47 was established working with the same vendor that provided casks 1 through 38 – Areva TN (formerly Transnuclear).

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project (through the five year budget period ending in 2018) are expected to be $51.6 ($3.2) million. $14.2 ($0.9) million will go into service in 2015 with the installation of casks 39 and 40. Table 20 below provides a breakdown of the costs for the entire project.

Table 20

Prairie Island Casks (#39-47) Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[23]	**$51.573**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Xcel Energy Contract No. 33321 between Xcel Energy and Areva TN, has a contracted delivery date of **[CONFIDENTIAL DATA BEGINS CONFIDENTIAL DATA ENDS]** for Casks 39-40. Xcel Energy currently has the loading scheduled to be completed and Casks 39-40 placed in-service in June 2015. The fabrication schedule from Areva's supplier, Kobe Steel, shows fabrication completed and casks shipped to meet the contracted delivery date.

[23] Figures may not sum to total due to rounding.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small 2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF38.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 38. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 38. As shown on Schedule 6B, page 5, column 38, line 38, this adjustment increases the pro forma year revenue requirements by $116,000.

39) Prairie Island Independent Spent Fuel Storage Installation Relicensing

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND ISFSI RELICENSING PROJECT.

A. This project involves the completion of all work necessary to renew the ISFSI operating license at Prairie Island which permits the Company to store spent nuclear fuel in on-site casks. The NRC issued the Prairie Island ISFSI operating license on October 31, 1993 for a period of 20 years, or until October 31, 2013. The Company submitted an application to the NRC to renew the ISFISI operating license (NRC Material License Number: SNM-2506) on October 20, 2011, fulfilling the NRC requirement to submit a license renewal application more than two years in advance of the license expiration date. Regulations currently allow requests for ISFSI license renewal periods of up to 40 years.

The license renewal application requires an assessment of potential aging of the components that make up the ISFSI and require the licensee to demonstrate that any potential aging will be effectively managed for the duration of the requested renewal period. In addition to the technical work needed to demonstrate effective management of aging during the renewal period, the licensee is also required to complete an environmental assessment to identify any environmental impacts associated with the ISFSI license renewal and extended operating period.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget for this project was estimated based on our experience with similar work performed in the past, the experience of other ISFSI license renewals in the industry, and estimated labor hours needed to complete the work.

The budget includes the cost of submitting the ISFSI License Renewal Application, including costs to complete an Aging Management Review and inclusion of identified items into an Aging Management Program. The budget also includes costs associated with the preparation of responses to Requests for Additional Information from the NRC Staff, NRC review fees, support of the hearings held by the NRC Atomic Safety and Licensing Board including engineering support to respond to questions, and legal costs associated with the hearings.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $6.9 ($0.4) million with an expected in service date in June 2015. Table 21 below provides a breakdown of the costs for the entire project. The current cost estimate reflects actual costs associated with the preparation and submittal of the application.

Table 21

Prairie Island ISFSI Relicensing Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[24]	**$6.911**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. It was anticipated at the time of the application that the NRC review would be completed prior to the license expiration date in October 2013. Subsequently, in June 2012, the U.S. Circuit Court of Appeals for District of Columbia vacated the NRC's Waste Confidence Decision and Temporary Storage Rule (WCD/TSR), which precludes the NRC from issuing the renewed license until it completes an Environmental Impact Statement (EIS). The NRC is expected

[24] Figures may not sum to total due to rounding.

to complete the EIS to reinstate the WCD/TSR in September 2014. The Prairie Island ISFSI license renewal decision has been delayed until the WCD/TSR has been reinstated. Consequently, the in-service date is June 2015.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small 2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF39.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 39. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 5, column 39. As shown on Schedule 6B, page 5, column 39, line 38, this adjustment increases the pro forma year revenue requirements by $53,000.

40) Prairie Island Unit 2 Electric Generator Replacement

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND UNIT 2 ELECTRIC GENERATOR REPLACEMENT PROJECT.

A. The Prairie Island Unit 2 Electric Generator has reached the end of its useful life and a replacement generator is needed to support continued operations at the plant. The project will replace the existing generator, exciter, and seal oil system. It will also replace the interfacing instrumentation and support system equipment necessary to achieve the objective of reliable generator operation.

We had initially planned a rewind of the existing generators but found, upon receiving responses to our RFPs, that replacement was a better option and would result in lower long-term costs. We anticipate that the replacement option will allow for more favorable pricing of the equipment itself as well as lower operations and maintenance expenses. In addition, a rewound generator must undergo performance testing on-site during the outage when it is installed, which increases the outage duration and introduces additional risk to the project. In contrast, a new generator is tested at the manufacturer and needs to undergo less extensive testing on-site to synchronize with our system during the outage when it is installed.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The costs of the generator, exciter, seal oil system and supporting installation equipment and labor were determined following a competitive bid process. The bid process was conducted in conjunction with the bid process for the Unit 1 and Unit 2 GSU Replacement projects, and the winning bidder was chosen based on price, quality, and ability to perform. As mentioned previously, by combining the projects, we were able to realize savings of approximately $3 million for our customers.

The budget includes design, procurement, removal, and replacement of the generator, exciter, seal oil system, interfacing instrumentation, and support system equipment, as well as internal labor to oversee and manage the project.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $52.7 ($3.2) million with $50.9 ($3.1) million going into service in the fall of 2015. The remainder is expected to go into service in 2016, thus we are not seeking recovery of those investments here. Table 22 below provides a breakdown of the costs for the entire project.

Table 22

Prairie Island Unit 2 Electric Generator Replacement Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[25]	**$52.693**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

[25] Figures may not sum to total due to rounding.

A. The design has been completed and procurement of the equipment has been competitively bid. Removal and replacement activities are scheduled to occur during the Unit 2 refueling outage in September 2015.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small 2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF40.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 40. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 40. As shown on Schedule 6B, page 6, column 40, line 38, this adjustment increases the pro forma year revenue requirements by $124,000.

41) Prairie Island Unit 2 Generation Step-Up Transformer Replacement

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND UNIT 2 GSU TRANSFORMER REPLACEMENT PROJECT.

A. The purpose of the Prairie Island Unit 2 GSU Transformer project is to increase the voltage of the power produced by the plant generator from

20,000 volts to 350,000 volts for more efficient transmission to customers. The current GSU transformer has been in service for over 39 years and is considered at or near the end of its operating life. Similar to the replacement of the PI Unit 1 GSU transformer in 2014, the purpose of this project is to procure and install a new GSU transformer for Unit 2 and to dispose of the old GSU.

The project scope also includes updating plant documentation, internal project management and oversight, and replacement of the fire protection system of the old transformer with a new fire protection system that is compatible with the new transformer. The new GSU transformer will help enable reliable delivery of the power produced at Prairie Island Unit 2 to customers during the 20-year life extension.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget for this project was developed along with that of the Unit 1 GSU transformer and resulted from the same competitive bidding process previously described. As noted earlier, by combining this work with the Unit 1 GSU Transformer and Unit 2 Electric Generator Replacement projects, we were able to achieve approximately $3 million in savings for our customers.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $14.2 ($0.9) million with $13.4 ($0.8) million going into service in 2015. The remainder is expected to go into service in 2016, thus we are not seeking recovery of those investments here. Table 23 below provides a breakdown of the costs for the entire project.

Table 23

Prairie Island Unit 2 Generation Step-Up Transformer Replacement Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[26]	**$14.230**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Significant engineering analysis has been completed, the GSU transformer has been built, and factory testing is complete. Contracts for the majority of project cost have been awarded (transformer procurement, external design, staff augmentation). The Unit 2 GSU transformer is scheduled to arrive at Prairie Island in June 2014. The work completed to date represents approximately 38 percent of the total project for the Unit 2 GSU transformer. The current schedule and completion rate supports installation and in-servicing during the fall 2015 refueling outage.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small

[26] Figures may not sum to total due to rounding.

2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF41.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 41. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 41. As shown on Schedule 6B, page 6, column 41, line 38, this adjustment increases the pro forma year revenue requirements by $40,000.

42) Sherco Unit 1 Boiler Couton Bottom Replacement

Q. PLEASE DESCRIBE THE SHERCO UNIT 1 BOILER COUTON BOTTOM REPLACEMENT PROJECT.

A. A boiler couton bottom acts to capture bottom ash after coal is combusted. The unit began operating in 1976. We have continuously repaired the couton bottom, and the many repairs have made it difficult to inspect and harder to repair. The couton bottom is also significantly pitted and therefore more likely to causing unplanned outages at Unit 1. The boiler couton bottom is 38 years old and has reached the end of its life. Replacement of the couton bottom will mitigate this potential failure point. The Unit 1 boiler couton bottom replacement will take place during the Spring 2015 overhaul. The Unit 2 couton bottom replacement was performed in 2006.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The work for the Unit 1 couton bottom replacement was bid together with the work for the Unit 2 couton bottom replacement project. The Unit 2 bottom couton was replaced before the Unit 1 bottom couton replacement. Consequently, the budget for the Unit 1 replacement was budgeted based on the actual replacement costs for Unit 2 along with escalations in commodity and labor pricing.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $12.1 ($0.7) million which will go into service in 2015. Table 24 below provides a breakdown of the costs for the entire project.

Table 24

Sherco Unit 1 Boiler Couton Bottom Replacement Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[27]	**$12.078**

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. We plan to implement this project during the Unit 1 overhaul scheduled for 2015. The schedule was developed based on vendor fabrication schedules and engineering/design schedules and construction time. We have a robust process that develops schedules with project milestones such as engineering

[27] Figures may not sum to total due to rounding.

procurement, equipment manufacturing, delivery to site, and construction for all of our large projects. The engineering phase has been completed, and the boiler tubing has been ordered. The project is currently on schedule.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small 2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF42.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 4, column 42. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 42. As shown on Schedule 6B, page 6, column 42, line 38, this adjustment increases the pro forma year revenue requirements by $96,000.

43) Sherco Unit 1 Mercury Control

Q. PLEASE DESCRIBE THE SHERCO UNIT 1 MERCURY CONTROL PROJECT.

A. As previously discussed in the Unit 2 Mercury Control project description, we are in the process of installing and testing a sorbent injection system on Sherco Units 1 and 2 in 2014 using activated carbon as the sorbent, which will reduce mercury emissions. The Sherco Unit 2 mercury controls will go into service in 2014 while the Sherco Unit 1 mercury controls will go into service in 2015. These projects are part of our compliance plan for both the federal EPA and state mercury control requirements. In addition to installing mercury removal technology on the Unit 1 and 2 scrubbers, the project involves upgrading the ductwork and installing a milled activated carbon injection system to achieve approximately 90 percent removal of mercury.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. In addition to drawing on our own industry experience, we also engaged third-party engineering consultants to provide advice with scoping and costing estimates.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. Total capital additions for the project are expected to be $6.6 ($0.4) million which will go into service in 2015. Table 25 below provides a breakdown of the costs for the entire project.

Table 25

Sherco Unit 1 Mercury Control Costs

Project Line Item	**Total Estimate at Completion ($millions)**
	[CONFIDENTIAL DATA BEGINS
Contract Services	
Materials	
Labor	
Utility/Other	
AFUDC	
	CONFIDENTIAL DATA ENDS]
Total[28]	**$6.633**

[28] Figures may not sum to total due to rounding.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. We have completed full-scale testing to validate that the sorbent injection system will effectively remove mercury from Units 1 and 2. Construction has begun and the foundations are in place. The project is on schedule with initial testing expected to begin for both units in early fall 2014.

Q. WHAT ARE THE JURISDICTIONAL RATE BASE AND OPERATING INCOME IMPACTS OF THE ADJUSTMENT ASSOCIATED WITH THIS PROJECT?

A. The known and measurable adjustment for this project captures the incremental 2014 and 2015 capital related revenue requirements. While there are no capital additions associated with this project in 2014, there is a small 2014 component of the adjustment to account for deferred taxes. The 2015 component of the adjustment captures the impact of the 2015 capital additions. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF43.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 5, column 43. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 43. As shown on Schedule 6B, page 6, column 43, line 38, this adjustment increases the pro forma year revenue requirements by $51,000.

44) Wage Adjustment

Q. PLEASE EXPLAIN THE WAGE ADJUSTMENT.

A. This adjustment accounts for increases in both Union and Non-Union wages. We have completed contract negotiations with our union employees and the wage increases for both 2014 and 2015 are known and measurable. The increase for 2014 is 2.6 percent and for 2015 it is 2.5 percent. These wage increases were applied to the actual union labor costs for 2013 to arrive at the adjustment amount.

Non-Union wage increases are announced and implemented each March. Therefore, we know that the increase for 2014 is 3 percent. We will not know the percent increase for 2015 until March of 2015. Therefore, we are not seeking an adjustment to account for any potential non-union wage increase in 2015. Support for this adjustment, including a breakout of the 2014 and 2015 components of the adjustment, can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF44.

The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 44. As shown on Schedule 6B, page 6, column 44, line 38, this adjustment increases the pro forma year revenue requirements by $802,000.

45) Property Taxes for 2015

Q. PLEASE DESCRIBE THE PROPERTY TAXES FOR 2015 ADJUSTMENT?

A. As explained earlier in relation to the 2014 property taxes adjustment, property taxes incurred in the prior year are paid out in the current year.

Thus, property taxes incurred in 2014 will be paid out in 2015. This adjustment captures the expected incremental increase in property tax payments for 2015 compared to 2014. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF45.

There are no jurisdictional rate base impacts associated with this adjustment. The detailed jurisdictional operating income impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 45. As shown on Schedule 6B, page 6, column 45, line 38, this adjustment increases the pro forma year revenue requirements by $693,000.

6. Secondary Calculations

Q. WHAT IS THE NATURE OF THE SECONDARY CALCULATIONS?

A. Secondary Calculations include an adjustment for Cash Working Capital and an adjustment for Net Operating Loss. In both cases, the adjustment is dependent on the cumulative effect of all of the other adjustments in the case. The impacts of these adjustments are explained and quantified below. However, each adjustment will be recalculated once the final list of Commission-approved adjustments is complete to determine the final impact.

46) Cash Working Capital

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL ADJUSTMENT.

A. Certain categories of revenues and expenses have different working capital days between the account receivable or payable being issued and the cash receipt for that receivable or payable. If the cash working capital requirement is negative, then the balance of working capital is sourced from customer-supplied funds. If cash working capital is positive, then the balance is supplied by shareholder-provided funds. We include this negative or positive amount in rate base so that rates recognize this balance between customer-supplied and shareholder-supplied funds.

All of 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 incorporating the effects of those adjustments. Once the final Commission approved adjustments are known, the cash working capital balance will be recalculated, and this adjustment will be revised as necessary. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF46.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 5, column 46. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 46. As shown on Schedule 6B, page 6, column 46, line 38, this adjustment decreases the pro forma test year revenue requirements by $173,000.

47) Net Operating Loss

Q. WHAT IS A NET OPERATING LOSS?

A. Tax law changes over the past few years have resulted in the Company generating a larger amount of tax depreciation and more deductions than the Company can utilize in the current period. The result is the generation of a NOL for 2013.

Q. PLEASE EXPLAIN THE NOL ADJUSTMENT.

A. Because the Company has more tax deductions than it can utilize in 2013 (creating an NOL), the unused tax deductions need to be carried forward to a future period. The Company has determined the value of the NOL and made appropriate pro forma adjustments to both current and deferred tax items. The 2013 unadjusted test year has been adjusted to reduce the accumulated deferred income taxes and deferred income tax expense. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF47.

The detailed jurisdictional rate base impacts of this adjustment are reflected on Exhibit___(CRB-1), Schedule 6A, page 5, column 47. The detailed jurisdictional operating income impacts of the adjustment are reflected on Exhibit___(CRB-1), Schedule 6B, page 6, column 47. As shown on Schedule 6B, page 6, column 47, line 38, this adjustment increases the pro forma test year revenue requirements by $763,000.

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

A. Yes. The Company did include the additional revenues it is seeking in this proceeding when calculating the NOL adjustment.

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 the tax depreciation deductions, annual deferred tax expense, and the accumulated deferred tax balance.

7. Revenue Credits

Q. WHAT IS THE PURPOSE OF THE REVENUE CREDIT ADJUSTMENTS?

A. These adjustments convert the revenue requirement into the lower revenue deficiency to more accurately reflect the actual rate increase we are asking our customers to pay. The base rate revenue requirement of $24.640 million includes the need to increase base rates by $9.040 million as a result of eliminating the current revenues provided by the Infrastructure Rider and eliminating the revenues provided by the TCR Rider for the six transmission projects being moved out of the TCR Rider. The revenue credit adjustment credits the $9.040 million base rate revenue replacement and calculates the resulting lower revenue deficiency of $15.600 million. It is the resulting revenue deficiency that represents the actual incremental increase in payments from our customers as a result of this rate case.

48) Infrastructure Rider Revenue Credit

Q. PLEASE EXPLAIN THE INFRASTRUCTURE RIDER REVENUE CREDIT?

A. As shown on Exhibit___(CRB-1), Schedule 6B, page 7, column 48, line 38, this adjustment reduces the base rate revenue deficiency by the $8.481 million in revenue replacement needed because an equal amount of revenues are being eliminated from the Infrastructure Rider. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF48.

49) TCR Rider Revenue Credit

Q. PLEASE EXPLAIN THE TCR RIDER REVENUE CREDIT?

A. As shown on Exhibit___(CRB-1), Schedule 6B, page 7, column 49, line 38, reduces the base rate revenue deficiency by the $558,000 in revenue replacement needed because an equal amount of revenues are being eliminated from the TCR Rider. Support for this adjustment can be found in the Workpapers contained in Volume 3, Section VIII, Tab – PF49.

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.

E. Alternative Proposal – Mechanics of the Infrastructure Rider Option

Q. PLEASE DESCRIBE THE ALTERNATIVE TO RENEW THE INFRASTRUCTURE RIDER.

A. As I explained earlier, Commission Rule 20:10:13:44 permits a period of up to 24 months to be considered in developing known and measurable adjustments. In our most recent rate case (Docket No. E12-046), we requested that final rates reflect 24 months of known and measureable changes. In their testimony in that case, Commission Staff originally proposed limiting known and measureable changes to those occurring within 12 months. The Settlement Stipulation allowed known and measureable changes occurring after 12 months and within 24 months, but used a mechanism that recovered those costs based on actual costs.

Q. PLEASE EXPLAIN THE MECHANISM THAT ALLOWED THE RATES RECOVERING SUCH COSTS TO BE BASED ON ACTUAL COSTS.

A. The mechanism that established rates based on actual costs used a two-step process. First, the capital projects with known and measureable costs occurring during the 12 to 24 months after the close of the test period were segregated from the overall revenue deficiency, and a separate rate rider based on the forecasted cost for those capital projects was developed. Second, a true-up mechanism was used to adjust the rate for any change between the forecasted and actual cost or changes in the in-service date. The details of the mechanism were presented in our Tariff Section 5, Sheets 74 and 75.

Q. WHICH PROJECTS DOES THE COMPANY SUGGEST FOR POSSIBLE COST RECOVERY THROUGH THIS ALTERNATIVE PROPOSAL?

A. We propose using the alternative Infrastructure Rider recovery mechanism for the following capital projects that have a 2015 in-service date:

- Prairie Island ISFSI Relicensing,
- Prairie Island Unit 2 Electric Generator Replacement,
- Prairie Island Unit 2 Generation Step-Up Transformer Replacement,
- Prairie Island Casks (#39-47),
- Sherco Unit 1 Boiler Couton Bottom Replacement,
- Sherco Unit 1 Mercury Control,
- Pleasant Valley Wind, and
- Border Winds.

We also propose recovering the increase in 2015 property taxes through the alternative Infrastructure Rider (property tax increases were included in the current Infrastructure Rider). All together, the proposed rider would include all known and measurable adjustments in the 2015 In-Service Dates category discussed previously in my testimony, with the exception of the Wage Increase adjustment. Union contracts are already in place for 2014 and 2015, and the 2014 Non-Union wage increases having already taken effect meaning these adjustments are fully known and measurable. For this reason, we propose recovering these wage increases in base rates, whether or not this alternative proposal is adopted. As I explained earlier, we have made no 2015 adjustment for non-union wages.

The standalone revenue requirement for the proposed alternative rider recovery mechanism is $2.595 million, and is developed on Exhibit __ (CRB-1), Schedule 11 (2015 Infrastructure Rider Summary). Schedule 12 (Alt Proposal – Cost of Service Study) provides the resulting cost of service if this alternative proposal is adopted. Similarly, Schedules 13A and 13B provide rate case and income statement bridge schedules assuming the alternative proposal is adopted. These schedules incorporate revised secondary calculations for Cash Working Capital and NOL.

Q. HAVE YOU PREPARED AN AMENDMENT TO THOSE TARIFF SHEETS IN THE EVENT THE COMMISSION WISHES TO CONTINUE THAT PROCESS FOR RECOVERING CAPITAL PROJECT COSTS OCCURRING WITHIN THE 12 TO 24 MONTH PERIOD AFTER THE CLOSE OF THE TEST YEAR.

A. Exhibit __(CRB-1), Schedule 14 provides example tariff language illustrating how we would amend the tariff sheets in the event the Commission elects to use this process for our 2015 known and measureable capital projects and the 2015 incremental property taxes as outlined above.

Q. ARE YOU PROPOSING ANY CLARIFICATIONS WITH RESPECT TO THE INFRASTRUCTURE RIDER TRUE-UP PROCESS?

A. Yes. To reflect the approved resolution of an interpretation issue related to jurisdictional allocators during the review of our October 1, 2013 Infrastructure Rider Annual Compliance Filing and Update, we propose using forecasted allocation factors (rather than the 2013 allocation factors used in this rate application) in the subsequent October compliance filing(s), which updated allocation factors will themselves be subject to being updated to reflect actual jurisdictional allocation factors.

Q. IS THE COMPANY WILLING TO CONSIDER OTHER CHANGES TO THIS PROPOSAL?

A. Absolutely. We look forward to discussing this proposal with Commission Staff and the Commission to develop an acceptable mechanism that properly balances customer and Company interests.

VIII. CONCLUSION

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend that the Commission determine an overall retail revenue requirement of $211.451 million and an incremental revenue deficiency of $15.600 million or 8.0 percent, based on a pro forma year with known and measureable changes. In addition, the Company is currently recovering $8.481 million through the Infrastructure Rider approved in Docket No. EL12-046. Consistent with the terms of the Settlement establishing the Infrastructure Rider, we propose to move cost recovery from the Infrastructure Rider to base rates. In addition, the Company proposes to recover through base rates the cost of six transmission projects currently being recovered through the

TCR Rider, increasing the base rate revenue requirement by $558,000. In combination, these changes in Rider recovery result in a need to replace $9.040 million in Rider revenues with an equal increase in base rate revenues. Thus, there is an overall increase in base rate revenue requirement of $24.640 million of which $15.600 million is the amount of the increase in overall rates paid by our customers. My testimony also addressed the Company's alternative proposal to continue the Infrastructure Rider to recover $2.595 million of known and measureable changes occurring in 2015, which would lower the increase in base rates by the same amount.

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

A. Yes, it does.