Direct Testimony and Exhibits
Christopher J. Kilpatrick

Before the South Dakota Public Utilities Commission of
The State of South Dakota

In the Matter of the Application of
Black Hills Power, Inc., a South Dakota Corporation

For Authority to Increase Rates
in South Dakota

Docket No. EL12-___

December 17, 2012

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EXHIBITS

I. INTRODUCTION & QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher J. Kilpatrick, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota, 57701.

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

A. I am employed by Black Hills Utilities Holdings Company as Director of Resource Planning and Rates.

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF TODAY?

A. I am testifying on behalf of Black Hills Power, Inc. ("Black Hills Power" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I am a graduate of Mount Marty College in Yankton, South Dakota, with a Bachelor of Arts Degree in Accounting. I am a Certified Public Accountant ("CPA"), a member of the American Institute of Certified Public Accountants and the South Dakota CPA Society. My work experience includes working for two public accounting firms from 1994 through 1999. The first was Wohlenberg, Ritzman, and Co. located in Yankton, South Dakota, and the second was Ketel Thorstenson, LLP located in Rapid City, South Dakota. I began my career with Black Hills Corporation ("BHC") in January 2000 in the Internal Audit Department. In August of 2003 I became the controller of Black Hills FiberCom until February 2005 when I accepted the position of Director of Accounting –

Retail Operations. In August 2008, I was hired as the Director of Rates. In 2011, I accepted an expanded role and I am now responsible for both electric rates and resource planning.

Q. BRIEFLY DEFINE YOUR DUTIES AND RESPONSIBILITIES.

A. I am responsible for the resource planning and electric rates for BHC's electric utility subsidiaries. I review financial information and verify that the financial reporting for each subsidiary is accurate and in accordance with the rules and regulations of the Federal Energy Regulatory Commission ("FERC"). Additionally, I am responsible for electric rate cases and cost adjustment filings for all the retail electric utility subsidiaries of BHC, which include Black Hills Power, Black Hills/Colorado Electric Utility Company, LP and Cheyenne Light, Fuel and Power Company.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to provide an overview of the Revenue Requirement Model (the "Model") presented in Volume 1 of Black Hills Power's Application as Statements A through R and supporting Schedules and Work Papers. I provide information on the Company's request for an accounting order for vegetation management costs. I describe changes to the energy cost adjustment tariffs. In addition, I explain a proposed new Transmission Facility Adjustment tariff.

III. REVENUE REQUIREMENT OVERVIEW

Q. WHAT IS THE AMOUNT OF ADDITIONAL REVENUE REQUESTED BY THE COMPANY?

A. The amount of additional revenue needed by the Company is $13,745,826 as shown in Schedule N-1.

Q. HAS THE COMPANY PREPARED A CLASS COST OF SERVICE STUDY?

A. Yes, as shown in Schedule O-1, the Company has developed a class cost of service study. This class cost of service study is described in and supported by the testimony of Jan Kirsch.

IV. REVENUE REQUIREMENT MODEL OVERVIEW

Q. PLEASE DESCRIBE YOUR ROLE IN PREPARING THE REVENUE REQUIREMENT MODEL.

A. My role was to directly supervise the preparation of the per books and pro forma information including the Statements, supporting Schedules and Work Papers in accordance with the rules and regulations of the South Dakota Public Utilities Commission ("Commission").

Q. IS THE REVENUE REQUIREMENT MODEL FILED TODAY CONSISTENT WITH THE MODEL USED IN BLACK HILLS POWER'S 2009 RATE CASE?

A. Yes, the models are consistent.

Q. WHAT HAS BLACK HILLS POWER UTILIZED FOR A TEST YEAR IN THE APPLICATION?

A. Black Hills Power is utilizing a twelve month test year based on historical data, ending June 30, 2012.

Q. WHAT STATEMENTS HAVE YOU INCLUDED IN THE APPLICATION?

A. The following is a list of the Statements provided in the application:

A. Balance Sheet
B. Income Statement
C. Statement of Retained Earnings
D. Cost of Plant
E. Accumulated Depreciation
F. Working Capital
G. Rate of Return
H. Operation and Maintenance Expense
I. Operating Revenues
J. Depreciation Expense
K. Income Taxes
L. Taxes Other Than Income
M. Overall Cost of Service
N. Allocated Cost of Service by Jurisdiction
O. Allocated Cost of Service by SD Customer Classes
P. Energy Cost Adjustment Factors

Q. Description of Utility Operations

R. Coal Supply Pricing

In front of each Statement is a summary overview of the information included.

Q. WHAT SCHEDULES HAVE BEEN INCLUDED IN THE APPLICATION?

A. Schedules have been included, where applicable, to provide supporting documentation and calculations for the Statements listed above. For example, Schedules H-1 through H-17 supports Statement H, Operation and Maintenance Expense. These Schedules detail the known and measurable expense adjustments that have been made and summarized in Statement H.

Q. WHAT WORK PAPERS HAVE BEEN INCLUDED IN THE APPLICATION?

A. Work Papers 1 through 4 have been included in Section 5. These Work Papers show additional calculations in support of numbers for the Schedules.

Q. PLEASE EXPLAIN HOW THE COSTS TO PROVIDE SERVICE TO BLACK HILLS POWER'S CUSTOMERS WERE DEVELOPED.

A. The starting point to determine the cost to serve customers is the per books financial statements for the test year, kept and recorded in the normal course of business, in compliance with FERC rules and regulations. Adjustments for known and measurable items were then made to the per books financial statements to determine the pro forma costs and revenue requirement.

Q. IS BLACK HILLS POWER PROPOSING ANY ADJUSTMENTS TO THE REVENUE REQUIREMENT?

A. Yes, Black Hills Power is incorporating pro forma adjustments to the test year that are known and measurable as well as including assets that will be used and useful prior to new rates going into effect as proposed on April 1, 2013. Known and measurable adjustments to the per books financial statements include: 1) adjusting expenses to a normal expense in a normal year to serve the customer base; 2) additional non-revenue producing rate base that will be used to serve customers at the time the new rates go into effect; and 3) adjustments to revenue for a normal year.

Q. WHAT TAX ADJUSTMENTS WERE MADE TO THE CAPITAL PROJECTS INCLUDED IN THIS FILING?

A. Black Hills Power has claimed bonus depreciation expense for tax purposes with respect to the qualifying capital projects placed in service before and throughout the test period that resulted in additional accumulated deferred income taxes ("ADIT"). See Schedule M-2 for this calculation.

Q. PLEASE EXPLAIN BONUS DEPRECIATION.

A. Pursuant to the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 ("2010 Act"), qualifying investments made after September 8, 2010, and before January 1, 2012, were eligible for 100% bonus depreciation. For qualifying investments made prior to September 9, 2010, and during calendar year 2012 (calendar year 2013 for certain projects), companies were permitted to expense 50 percent of the value of the asset for tax purposes as depreciation in the first year with the remaining 50 percent subject to normal tax depreciation. Bonus depreciation does not mean that the asset receives more depreciation than any other assets; it simply means that tax depreciation is accelerated into the first year. This is similar to the American Recovery and Reinvestment Act of 2009 that allowed the Company to expense 50 percent of the value of Wygen III, for tax purposes, in the last rate case.

Q. DO CUSTOMERS BENEFIT FROM A LOWER RATE BASE AS A RESULT OF BONUS TAX DEPRECIATION UNDER THE 2010 ACT?

A. Yes. As indicated above, accelerated tax depreciation including bonus depreciation has produced additional ADIT. However, as a result of such accelerated depreciation, the Company had more tax deductions than it can utilize during the test period and, thus, generated a net operating loss ("NOL") for tax purposes for which a deferred tax asset was recorded. The NOL deferred tax asset attributable to accelerated tax depreciation, including bonus depreciation, has been added to the Company's rate base to the extent that it offsets the ADIT related to the book/tax depreciation temporary difference. This methodology is in accordance with the normalization rules as prescribed in the tax law that governs the regulatory treatment of deferred income taxes. Such treatment is consistent with the underlying premise of ADIT as a source of interest free capital being provided by the United States government. To the extent that temporary differences such as accelerated tax depreciation deductions give rise to a NOL, the interest free capital has not been funded or realized. Conversely, to the extent that interest free capital has been funded, a net rate base reduction is reflected. The portion of the NOL projected to be utilized within the test period is reflected as a reduction to the deferred tax asset in rate base. Only the levels of deductions projected to be carried forward to a future period remain as a deferred tax asset in rate base. See the adjustment on Schedule M-1 for the impact.

Q. DO CUSTOMERS BENEFIT FROM ANY OTHER INCOME TAX-RELATED ADJUSTMENTS?

A. Yes. Consistent with the Commission's order in Docket EL09-018, the tax benefit derived under the Company's method of accounting related to the timing of the tax deductibility of repairs and maintenance expenditures has been flowed-through to customers via a reduction in tax expense. The revenue requirements model was prepared consistent with the prior Commission order and Statement K reflects the flow-through benefit as a reduction to the tax expense for which recovery is sought in this filing

Q. PLEASE DESCRIBE THE PRIMARY REVENUE ADJUSTMENT MADE TO BLACK HILLS POWER'S REVENUE REQUIREMENT MODEL.

A. Revenue adjustments are included in Statement I. One of the largest adjustments relates to the removal of all energy related costs. The pro forma expenses have all generation fuel and related transportation costs, transmission costs and all purchase power costs removed. In addition to the energy related expenses being removed, the associated revenue was also removed for these costs. The current approved base energy cost in the Fuel and Purchase Power Adjustment (FPPA) clause is $0.0146 per kWh and the approved base energy cost in the Transmission Cost Adjustment is $0.0081 per kWh. These added together are $0.0227 per kWh and all retail SD energy sales have been reduced by this amount to account for the removal of those energy costs. The energy related costs will be recovered within the Energy Cost Adjustment Clauses as described later in my testimony.

Q. WHY ARE ENERGY COSTS BEING REMOVED FROM THIS RATE CASE?

A. Removing energy costs from this rate case also serves to help mitigate the impact to customers due to the increase in energy costs since the last rate case. The Company will continue to recover the energy costs in excess of the approved base energy costs through the Energy Cost Adjustment Clauses. The recovery of the approved base energy costs will be moved into the adjustment clauses and therefore all energy related costs will be recovered through the annual energy cost filings.

Q. WHERE ARE THESE ADJUSTMENTS FOUND IN THE REVENUE REQUIREMENT MODEL?

A. The revenue adjustments related to the energy costs can be found on Statement I page 5. This shows the amount of revenue removed for each retail jurisdiction and the contract sales to Montana Dakota Utilities (MDU) and Municipal Energy Association of Nebraska (MEAN).

Q. WHY ARE THE BASE ENERGY RATES DIFFERENT FOR EACH STATE AND ALSO DIFFERENT FOR CONTRACT SALES?

A. The base energy rate in column (a) on Statement I, page 5 for the retail jurisdictions is from the last approved rate case in each state. This amount per kWh is then multiplied by the pro forma energy sales for each state to reduce revenue. The removal of this base energy revenue utilizes the matching principle since all the energy costs are removed as well.

Q. HOW IS THE CONTRACT SALES BASE ENERGY RATE DETERMINED?

A. The contract sales base energy rate is determined on Statement P page 1. This shows the calculation of current energy costs for the system energy sales and converts the cost into a price per kWh. This amount on Statement P page 1, line 15 is then multiplied by the energy used for each contract and removed from the revenue credit for each contract. The remaining revenue from each contract is provided to customers as a revenue credit, thereby reducing the overall amount needed from the retail jurisdictions.

Q. DOES THE AMOUNT ON STATEMENT P, PAGE 1 INCLUDE TRANSMISSION COSTS?

A. No, this amount is calculated on Statement P, page 2 and is not part of the contract sales since these customers are responsible for their own transmission costs.

Q. IS THIS CONSISTENT WITH PREVIOUS RATE CASES?

A. Yes, the treatment of these contracts is consistent with previous rate cases by providing a revenue credit to customers.

V. REQUEST FOR ACCOUNTING ORDER FOR VEGETATION MANAGEMENT

Q. WHAT IS THE COMPANY PROPOSING REGARDING VEGETATION MANAGEMENT?

A. The Company is requesting that the Commission approve an accounting order whereby the Company will treat a portion of the expense of vegetation management as a regulatory asset. The Company expended the sum of $1,412,177 for vegetation management during the test year ended June 30, 2012 for South Dakota customers as shown on Exhibit CJK – 1. Prudent expenditures for vegetation management up to this amount will continue to be expensed by the Company. The Company is requesting that expenditures for vegetation management that exceed $1,412,177 annually over each of the next five years be a Vegetation Management Regulatory Asset ("VMRA"). Currently, the company projects the 2013 annual amount of vegetation management costs to be approximately $2,600,000.

Q. WHY IS THE COMPANY REQUESTING THE VMRA?

A. As described in the testimony of Mr. Fredrich, increased vegetation management is critical given the extraordinary nature of the drought and the mountain pine beetle infestation. This increased vegetation management will provide a long term benefit to the Company and its customers, including the reduction of risk of a catastrophic event related to the pine beetle infestation. A certain amount of vegetation management will always be necessary, and the Company believes the test year reflects the typical amount that will be spent for standard vegetation management. Vegetation management that exceeds $1,412,177 has a long term benefit and is best treated as an asset that will be amortized over a longer period of time rather than being expensed in the year the money is spent.

Q. IS THE COMPANY REQUESTING THAT IT RECEIVE A RETURN ON THE VMRA?

A. Yes, the Company is requesting that it receive a rate of return on the balance in the VMRA, calculated on a monthly basis. The rate of return would be equal to the rate of return approved by the Commission in this rate case.

Q. WILL THE COMPANY PROVIDE ANNUAL REPORTS TO THE COMMISSION AND STAFF?

A. Yes. The Company will provide annual reports to the Commission and Staff to demonstrate the actual vegetation management costs incurred. This report will also outline the progress made on the overall five year plan and update the forecast for the remaining years based on actual progress to date. Different amounts will be spent each year on vegetation management based upon weather conditions and other factors outside the Company's control. This annual review would be similar to the review of Demand Side Management programs, where the prudency of incurred costs are determined, along with approval of the budget for the following year. Based on this review of the vegetation management plan and its costs, the Commission and Staff will be familiar with the program management, its results, and the benefits to customers. The annual review will also allow the Company the ability to verify the amount to be collected from customers in the future.

Q. WHAT HAPPENS TO THE VMRA AT THE END OF FIVE YEARS?

A. The Company requests that at the end of the five year period, the balance in the account be amortized over the next five year period to match how the costs were incurred. The Company requests that the recovery in years six thru ten of the balance of the VMRA account (as of the end of year five) commence in year six in the form of a tariff or rate increase to be approved by the Commission prior to year six.

Q. WHAT IS THE BENEFIT TO CUSTOMERS BY HANDLING THE BALANCE IN THE ACCOUNT IN THIS MANNER?

A. The customer benefit is to spread these costs over a period of time when other costs have been stabilized such as generation costs. This helps the customer mitigate the increase in rates over the next few years related to the closure of three coal fired generating facilities and replacing those assets with the new Cheyenne Prairie Generating Facility.

Q. WHAT OTHER OPTIONS WERE CONSIDERED REGARDING THE REQUEST FOR AN ACCOUNTING ORDER?

A. The Company initially considered making a pro forma adjustment to base rates for this known and measurable increase in costs. The Company also looked at the possibility of creating an adjustment clause for these costs, but decided against this method, because the effect of a new adjustment clause would impact the customers in 2014, which is the same time a new generation facility will be coming into service. The best balance between customer impacts and managing the unique, extraordinary nature of the mountain pine beetle infestation, however, is to request the accounting order, and delay the recovery of these costs. In addition, customers will obtain a long term benefit from these additional vegetation management efforts, since more aggressive vegetation management will allow the company to remove infested trees outside current rights-of-way, which will have the added benefit of preventing additional trees from becoming infested.

Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENT TO SPEND A CERTAIN LEVEL OF MONEY ON VEGETATION MANAGEMENT IN THE LAST RATE CASE.

A. In Docket EL09-018, the Company committed in the Settlement Stipulation with the Commission Staff to spend an annual average of no less than $1,064,963 for vegetation management beginning on April 1, 2010. As illustrated in Exhibit CJK – 1, the Company spent: 1) $1,166,708 for the period April 1, 2010 through March 31, 2011; 2) $1,495,437 for the next twelve month period: and 3) $1,412,177 during the test year. The Company more than fulfilled the vegetation management commitment as agreed to in the last rate case.

VI. ENERGY COST ADJUSTMENT CLAUSES

Q. WHAT ENERGY COST ADJUSTMENT CLAUSES EXIST AT THE PRESENT TIME?

A. Pursuant to the Settlement Stipulation in the Company's last rate case, the Company presently has two adjustment clauses for the recovery of costs related to fuel, purchased power and transmission. The first adjustment clause is the Fuel and Purchased Power Adjustment (FPPA) and the second adjustment clause is the Transmission Cost Adjustment (TCA).

Q. PLEASE DESCRIBE THE PRESENT FPPA.

A. The FPPA determines the cost to serve customers for generation fuel and purchase power. These costs are called the Annual System Fuel and Purchased Power costs (FPP) and then are reduced by 65% of the Power Marketing Operating Income to determine the amount to be collected from customers that are in excess of the approved base FPP.

Q. WHAT CHANGES TO THE FPPA ARE BEING PROPOSED BY THE COMPANY?

A. We have proposed three changes to the FPPA, as follows: 1) collect the base FPP costs through the FPPA effective April 1, 2013 instead of in base rates; 2) include re-agents (including lime, lime freight, ammonia and chemicals) in the FPP costs; and 3) remove the SD Surplus Energy Phase-out. All of these changes are set forth in Tariff Section No. 3C Sheets No. 1-4 and 11.

Q. WHY IS THE COMPANY MOVING BASE FPP ENERGY COSTS INTO THE FPPA TARIFF?

A. The Company is moving the FPP energy costs into the FPPA tariff so customers are not impacted by the increase in fuel and purchase power on April 1, 2013. In the last rate case, customers were significantly impacted by increasing base energy costs, and also having to pay the historical energy costs. By moving the FPP base energy costs into the FPPA, customers will not see an overlap of costs related to the increase in costs. This is another example of how Black Hills Power is working to keep the costs to our customers reasonable and reducing the impact to our customers with this rate case. The Company will bill customers the same base energy cost, $0.0146 per kWh, effective April 1, 2013 (see Tariff Section No. 3C Sheet 11) and the difference from that cost to current costs will be recovered through the same annual FPPA filing schedule. For example, the costs incurred above the base energy costs from April 1, 2012 through March 31, 2013 will be collected from customers June 1, 2013 through May 31, 2014. The costs above the base $0.0146 per kWh for the period April 1, 2013 through March 31, 2014 will be recovered from customers starting on June 1, 2014.

Q. PLEASE DESCRIBE THE CHANGE REGARDING RE-AGENTS IN GREATER DETAIL.

A. At the present time, there are certain re-agents that are not included in the calculation of FPPA. The proposed change would include re-agents in the calculation of the FPP in the FPPA. "Re-agents" is a phrase used to describe the chemicals and catalyst that are combined with the flue gas to create a chemical reaction that reduces power plant emissions' levels. These re-agents are necessary and used in conjunction with fuel in the generation of electricity. For example, lime is used to reduce sulfur oxide emissions. Because of the use of these re-agents in the generation process, these re-agents should properly be used in the calculation of fuel for purposes of the automatic adjustment clause.

Q. DO THESE RE-AGENT COSTS RELATE TO SOUTH DAKOTA CODIFIED LAWS (SDCL) SECTION 49-34A-25 AND IF SO, HOW?

A. Yes. This SD Statute allows for the automatic adjustment of rates for changes in energy, fuel and gas costs. Due to emission standards, the Company must incur re-agent costs to deliver energy to our customers. These re-agent costs are directly related to the delivered cost of fuel used in the generation of electricity since the energy cannot be created or delivered without incurring the costs of re-agents. Since the primary driver in these re-agents costs is lime, and lime is a commodity similar to coal and other fuel, these costs are subject to the same market conditions that impact other commodities. With the increase in emission standards, we believe the demand for lime and other re-agent costs will continue to increase beyond our control. Based on the facts stated above, including re-agent costs in the cost of delivered energy costs is in compliance with SDCL 49-34A-25.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL REGARDING ELIMINATING THE SOUTH DAKOTA SURPLUS ENERGY PHASE-OUT AND EXPLAIN THE COMPANY'S REASONING FOR PROPOSING THAT CHANGE.

A. The Company is removing the South Dakota Surplus Energy Phase-out from the FPPA and moving the amount of it related to the Wygen III facility into base rates; these are not energy costs. Thus, this amount will become part of base rates instead of being included in the FPPA. The SD Surplus Energy Phase-out was originally ordered to be fully recoverable by the company beginning in April 2013. By removing this amount from the FPPA and including the same amount in base rates, customers see no change in the financial impact associated with the shift. The only change is how these costs are recovered.

VII. TRANSMISSION COST ADJUSTMENT (TCA) TARIFF CHANGES AND REQUESTED NEW TARIFF

Q. PLEASE DESCRIBE THE PRESENT TCA TARIFF.

A. The present TCA tariff recovers the expenses related to delivering energy to customers through FERC expense account 565 Transmission of Electricity by Others. These are the only costs recovered from the Company's customers that are included in the TCA.

Q. WHAT IS THE COMPANY PROPOSING REGARDING ITS TCA TARIFF?

A. The Company is proposing to collect the approved base transmission costs ($0.0081 per kWh) through the TCA tariff instead of base rates. Collection of the approved base transmission costs will begin on April 1, 2013 (see Tariff Section No. 3C Sheet 11) and any difference from this amount will be collected through the normal TCA filing method.

Q. WHAT OTHER CHANGES IS THE COMPANY PROPOSING FOR TRANSMISSION TYPE COSTS?

A. The Company is requesting approval of a new tariff establishing a Transmission Facility Adjustment tariff ("TFA") as a cost recovery mechanism for investment in new transmission facilities with a design capacity of 34.5 kilovolts or more and which are more than five miles in length including associated facilities such as substations and transformers. The new TFA tariff seeks approval of a tariff mechanism for the automatic annual adjustment of charges for jurisdictional costs of new or modified transmission facilities. The new TFA tariff would be implemented and combined with the other Energy Cost Adjustments.

Q. WHY IS THE COMPANY PROPOSING THIS NEW TARIFF?

A. The proposal is designed to allow for timely recovery of the jurisdictional costs of new or modified transmission facilities by the Company, thus eliminating unnecessary carrying costs to the Company and reducing rate shock to customers. The new tariff is necessary, in part, because aging electrical lines require updating.

Q. IS THERE STATUTORY AUTHORITY THAT ALLOWS THIS REVISION?

A. Yes, the proposed revision seeks to implement the intent of SDCL 49-34A-25.1 – 4.

Q. PLEASE EXPLAIN THE DESIGN AND APPLICATION OF THE PROPOSED TFA TARIFF?

A. The new TFA tariff is designed to recover the cost of new transmission facilities (typically 69kV lines) in accordance with SDCL 49-34A-25.1 – 4. The recovery of these costs is based on the following timeline: The Company will file on or before February 15th of each year for the previous calendar year actual costs for new transmission facilities that are not part of base rates for South Dakota customers. In addition to the previous year actual costs, the filing on February 15th will include the forecasted costs for new projects through May 31st of the next year in order to correspond with the effective date of the rates. For example, the filing on February 15, 2014 would include any actual costs not included in base rates for transmission projects that qualify. In addition, this filing would also include the projects for January 1, 2014 through May 31, 2015. The projects during this time period would include an amount for recovery of CWIP. Therefore these projects would not include AFUDC in the project costs under the TFA. Rates would then be effective from June 1, 2014 through May 31, 2015.

Q. DOES THE COMPANY PROPOSE SEPARATE TFA RATES FOR DIFFERENT CUSTOMER CLASSES?

A. Yes. The Company proposes separate TFA rates for each retail customer class, including Residential, Small General Service, Large General Service, Industrial Contract Service and Lighting Service at a rate per kWh. The allocation to each retail customer class will be based on the current TCA tariff sheet and consistent with the Environmental Improvement Adjustment tariff. The TFA described and proposed in this filing would be implemented as a component of the Company's Energy Cost Adjustment summary tariff, which is a separate line item on customer bills.

Q. WILL TRANSMISSION PROJECTS PLACED IN SERVICE PRIOR TO APRIL 1, 2013 BE RECOVERED THROUGH THE TFA?

A. No. All transmission projects placed in service prior to April 1, 2013 for which the Company seeks cost recovery are included in this general rate case and are expected to be included in base rates. The earliest the Company expects to recover costs through the TFA would be June 1, 2014.

Q. DOES THE PROPOSED TFA TARIFF MEET THE REQUIREMENTS OF SDCL 49-34A- 25.2?

A. Yes. The proposed TFA tariff allows the Company to recover on a timely basis the costs of certain transmission facilities; it allows a return on investment at a level approved in the Company's last general rate case; it provides a current return on construction work in progress; it allocates project costs appropriately between wholesale and retail customers; and it terminates once costs have been fully recovered or have otherwise been reflected in the Company's general rates.

Q. HAS THE COMPANY DESCRIBED THE UPCOMING ELIGIBLE TRANSMISSION PROJECTS?

A. Yes, the upcoming eligible transmission projects are described in the testimony of Michael J. Fredrich.

Q. DOES THE COMPANY INTEND TO FILE ANNUAL RATE ADJUSTMENTS, AND IF SO, WHAT INFORMATION WILL BE PROVIDED AT THAT TIME?

A. Yes, the Company will file annual rate adjustments, and will provide at a minimum, all of the information required by SDCL 49-34A-25.3, including: 1) a description of and context for the facilities included for recovery; 2) an implementation schedule of applicable projects; 3) the Company's costs for these projects; 4) a description of the Company's efforts to ensure the lowest reasonable costs to ratepayers for the project; and 5) calculations to establish that the rate adjustment is consistent with the terms of the tariff. The tariff sheet for the proposed TFA is attached as Exhibit CJK – 2.

Q. WILL THE COMPANY PROVIDE EVIDENCE THAT THE COSTS INCLUDED FOR RECOVERY THROUGH THE TFA WERE PRUDENTLY INCURRED AND ACHIEVE SYSTEM IMPROVEMENTS AT THE LOWEST REASONABLE COST TO CUSTOMERS?

A. Yes. The Company will provide evidence in each annual rate adjustment filing that 1) the costs included for recovery through the tariff were or are expected to be prudently incurred; and 2) achieve transmission system improvements at the lowest reasonable cost to customers.

Q. WHAT ACCOUNTING MECHANISM DOES THE COMPANY INTEND TO USE AS THE ACCOUNTING METHOD FOR ELIGIBLE TFA PROJECT COSTS?

A. The Company proposes to use a balancing account as the accounting mechanism for eligible transmission cost recovery project costs. The balancing account worksheet and system will track and account for the retail revenue requirements until all costs related to a project have been fully recovered or reflected in base rates as a result of a general rate case. The revenue requirements to be included in the balancing account will only be those related to South Dakota's share of eligible projects. By performing this cost allocation process, the Company can ensure that electric customers in other jurisdictions are allocated a share of transmission costs recovery project revenue requirements, consistent with the Company's allocation of similar costs in a general rate case. The balancing account will track the amounts recovered through the TFA from South Dakota retail customers and the monthly revenue requirements. The difference will be recorded in the balancing account as the amount of over- or under-recovery.

VIII. ENVIRONMENTAL IMPROVEMENT ADJUSTMENT CLAUSE

Q. WILL THERE BE ANY CHANGES TO THIS ADJUSTMENT CLAUSE?

A. Yes. We will be moving the current rates in place into customer base rates since the associated assets are also included in our base rate calculation.

Q. WHAT WILL HAPPEN TO AMOUNTS REMAINING IN THE BALANCING ACCOUNT, IF ANY?

A. At most, the Company expects that a small account would remain in the balancing account after transferring recovery to base rates. This is because there is low monthly variability of customer usage and revenue requirement related to the Environmental Improvement Adjustment Clause. The balancing account will be reviewed, however, at the time base rates go into effect. If the amount remaining in the balancing account is small, the balance will be transferred to the TFA for recovery through this mechanism. This would ensure that this small amount is spread consistently to the appropriate customer classes. If there is an unexpectedly large amount remaining in the balancing account, however, recovery will continue to occur through the Environmental Improvement Adjustment Clause.

IX. CONCLUSION

Q. DOES THE MODEL RESULT IN JUST AND REASONABLE RATES?

A. Yes. The Model uses the per books financial statements for the test year ending June 30, 2012, which contains known and measurable adjustments. The Company has modified the adjustment clauses to appropriately reflect the cost of doing business and has also deferred costs to help mitigate the impact to customers with these new base rates. The effect is a straight forward application for a requested increase in base rates, changes to adjustment clauses, and approval for an accounting order. The increase is requested to be applied to rates commencing April 1, 2013. The package of updated and new tariffs and the accounting order result in just and reasonable rates for Black Hills Power's customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.