Direct Testimony
Jon Thurber

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. EL14-___

March 31, 2014

TABLE OF CONTENTS

I. INTRODUCTION & QUALIFICATIONS 1

II. PURPOSE OF TESTIMONY 2

III. REVENUE REQUIREMENT MODEL OVERVIEW 2

IV. RATE BASE 5

V. ADJUSTMENTS TO THE OPERATING EXPENSES 16

VI. ADDITIONAL CHANGES TO THE OPERATING EXPENSES 23

VII. ADJUSTMENTS TO THE OPERATING REVENUES 26

VIII. SUMMARY OF THE MODEL 27

Exhibits

None

I. INTRODUCTION & QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jon Thurber, 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, Inc. ("Utility Holdings"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"). I am Manager of Regulatory Affairs for Black Hills Power, Inc. ("Black Hills Power" or the "Company"). I am responsible for leading all aspects of the regulatory process for Black Hills Power.

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF TODAY?

A. I am testifying on behalf of Black Hills Power.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated summa cum laude from the University of Wisconsin – Stevens Point, with a Bachelors of Science Degree in Managerial Accounting, Computer Information Systems, Business Administration and Mathematics. My work experience includes working for the South Dakota Public Utilities Commission ("Commission") as a Utility Analyst from July 2008 through March 2013. At the South Dakota PUC, my responsibilities included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric and gas utilities. I began my career with Utility Holdings in April 2013 as Manager of Rates. In

February of 2014, I accepted the position of Manager of Regulatory Affairs for Black Hills Power.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to present and explain the Revenue Requirement Model (the "Model") that supports this rate case filing. The Model is presented in Volume 1 of Black Hills Power's Application, as Section 4, Statements A through R and supporting Schedules, and with Workpapers included as Section 5. In my testimony, I describe the adjustments to certain utility costs, and I support the revenue requirement.

III. REVENUE REQUIREMENT MODEL OVERVIEW

Q. PLEASE DESCRIBE YOUR ROLE IN PREPARING THE MODEL.

A. My role was to directly supervise the preparation of the per books and pro forma information, including the Statements and supporting Schedules and Workpapers.

Q. IS THE REVENUE REQUIREMENT MODEL FILED IN THIS CASE CONSISTENT WITH THE MODEL USED IN BLACK HILLS POWER'S 2012 RATE CASE?

A. Yes, the models are consistent.

Q. WHAT HAS BLACK HILLS POWER USED FOR A TEST YEAR IN THIS FILING?

A. Black Hills Power is utilizing a twelve month test year based on historical data, ending September 30, 2013, as adjusted with known and measurable changes.

Q. WHAT STATEMENTS HAVE YOU INCLUDED IN THIS FILING?

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. Utility Plant in Service
E. Accumulated Depreciation
F. Working Capital
G. Cost of Capital
H. Operation and Maintenance Expense
I. Operating Revenues
J. Depreciation Expense
K. Income Taxes
L. Taxes Other Than Income
M. Overall Revenue Requirement
N. Allocated Cost of Service by Jurisdiction
O. Allocated Cost of Service by SD Customer Class
P. Energy Cost Adjustment Factors

Q. Description of Utility Operations

R. Coal Supply Pricing Methodology

Q. WHAT SCHEDULES HAVE BEEN INCLUDED IN THE FILING?

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-21 support Statement H, Operation and Maintenance Expense. These Schedules detail the expense adjustments that have been made and summarized in Statement H.

Q. HAVE WORKPAPERS BEEN INCLUDED IN THE FILING?

A. Yes, Workpapers have been included in Volume 1 as supporting documentation for the Statements listed above. For example, Workpaper 1 supports the energy allocation incorporated in Statement N, Allocated Cost of Service by Jurisdiction.

Q. PLEASE EXPLAIN HOW THE REVENUE REQUIREMENT WAS DEVELOPED.

A. The starting point to determine the revenue requirement 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. WHAT ADJUSTMENTS WILL BE MADE TO THE TEST YEAR?

A. Black Hills Power is incorporating pro forma adjustments to the test year that are known and measurable and relate to investments that will be used and useful prior to new rates going into effect. Known and measurable adjustments to the per books financial statements include: 1) additional rate base that will be used to serve customers at the time the new rates go into effect including, but not limited to, the addition of the Cheyenne Prairie Generating Station ("CPGS"); and 2) adjusting revenues and expenses for operational changes.

Q. PLEASE SUMMARIZE THE SIGNIFICANT ADJUSTMENTS THAT HAVE BEEN MADE TO BLACK HILLS POWER'S MODEL.

A. Adjustments have been made for rate base in Statements D, E, and F, and on Schedules M-1 and M-2. Expense adjustments have been included in Statements H, J, K, and L. Revenue adjustments are included in Statement I. The most significant known and measurable adjustment relates to CPGS. The adjustment includes additions to rate base, as well as changes to the cost of service expenses to reflect projected increases in operation and maintenance costs for a full year of operations.

IV. RATE BASE

Q. PLEASE DESCRIBE RATE BASE.

A. Rate base is the value established by a regulatory authority, upon which a utility is allowed to earn a specified rate of return as shown on Statement M. Rate base begins with the thirteen month average amount of all fixed asset accounts for Black Hills Power as of September 30, 2013, as shown on Statement D, Page 2, reduced by accumulated depreciation as shown on Statement E, Page 1. Additional rate base is then added to reflect expected capital additions from

September 30, 2013, through the effective date of this rate case as shown on Statement D, Page 2. Additional depreciation expense is also included, along with a corresponding increase in accumulated depreciation, thereby decreasing rate base. Rate base also includes a component of working capital as shown on Statement F. The final component of rate base is the other rate base reductions, such as deferred federal income taxes, as those reductions relate to the timing difference of book depreciation and tax depreciation expense. These amounts can be found on Schedules M-1 and M-2.

Q. ARE YOU REQUESTING CONSTRUCTION WORK IN PROGRESS AS PART OF RATE BASE?

A. No. The only plant investment in rate base will be that which is used and useful prior to rates going into effect.

A. PLANT IN SERVICE

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR CPGS.

A. Schedule D-11 shows the capital costs associated with CPGS. The adjustment for CPGS construction costs was prepared using the actual cost incurred as of December 31, 2013, together with the projected remaining costs to complete the project. Since CPGS is jointly owned by Black Hills Power and its sister company Cheyenne Light, Fuel and Power Company ("Cheyenne Light"), the adjustment only reflects Black Hills Power's ownership percentage. A more detailed explanation of these costs is included in Mark Lux's testimony.

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL ADJUSTMENTS FOR PLANT ADDITIONS?

A. Yes, there are other known and measurable adjustments for plant investments that will be used and useful prior to rates going into effect. Schedule D-10 provides a detailed list of production, sub-transmission, distribution, and general plant additions that will serve customers prior to October 1, 2014. The major plant additions are further discussed in the testimony of Mark Lux and Mike Fredrich.

Q. PLEASE EXPLAIN WHY THE COMPANY IS REQUESTING COST RECOVERY OF PLANT INVESTMENTS THAT WILL BE PLACED IN-SERVICE PRIOR TO OCTOBER 1, 2014.

A. The Commission has historically issued its final decision within six to twelve months from the date the rate case was filed. The Company assumes that this docket will be processed within approximately six months, and is requesting cost recovery of capital projects that are expected to be placed in service when final rates go into effect. If this docket takes longer than six months to process, the Company requests the opportunity to supplement this filing with additional capital projects that are used and useful prior to final rates going into effect.

Q. IS THE COMPANY REFLECTING ANY ADJUSTMENTS FOR PLANT RETIREMENTS?

A. Yes. The Ben French, Neil Simpson I, and Osage power plants were retired on or before March 21, 2014, to comply with the Environmental Protection Agency ("EPA") Area Source Rules. The facilities will no longer be providing power or capacity for customers when rates go into effect from this proceeding, and should not be included in plant in service. The plant adjustment is reflected on Statement D, page 2, and the corresponding rate base adjustments are made to accumulated depreciation on Statement E, page 1, working capital on Schedule F-1, and accumulated deferred income taxes on Schedule M-2. The net book value and associated inventory for the three units were transferred to a regulatory asset as reflected in Schedule J-2.

B. TRANSMISSION FACILITY ADJUSTMENT CLAUSE

Q. IS THE COMPANY PROPOSING TO SHIFT COST RECOVERY OF SUB-TRANSMISSION ASSETS FROM THE TRANSMISSION FACILITY ADJUSTMENT ("TFA") RIDER TO BASE RATES?

A. Yes. Black Hills Power is requesting to move from the TFA to base rates all sub-transmission assets that are placed in-service prior to final rates going into effect. In Docket EL14-013, the Company requested cost recovery through the TFA of two 69 kV line rebuild projects, Custer to Hot Springs and Lookout to Sundance Hill, that are expected to be placed in-service prior to September 30, 2014. The recovery of these two projects and related expenses are included in the Company's base rate request in this docket.

Q. WHEN WILL THE TFA RATE BE ADJUSTED TO REFLECT THIS SHIFT IN COST RECOVERY?

A. The Company will make its annual TFA filing by February 15, 2015, to reflect the Commission's decision regarding these assets.

C. WORKING CAPITAL

Q. HOW WAS WORKING CAPITAL CALCULATED AND INCLUDED IN RATE BASE?

A. Working Capital is shown on Statement F. The first component is cash working capital as determined by a lead/lag study. The other components are materials and supplies and prepaid expenses using a thirteen month average on balances as of September 30, 2013, with known and measurable adjustments. The final adjusted Working Capital balance of $17,824,269, as shown on Statement F, is included as part of rate base.

Q. DESCRIBE HOW THE CASH WORKING CAPITAL AMOUNT WAS DETERMINED.

A. The Company prepared a per books and an as adjusted Cash Working Capital ("CWC") amount for this rate case. The per books CWC is located on Schedule F-3, page 1 and the as adjusted CWC is on Schedule F-3, page 2. The as adjusted CWC amount is used as a component of rate base. The per books and as adjusted CWC amounts were determined by preparing a Lead/Lag Study.

Q. HOW DOES A LEAD/LAG STUDY MEASURE THE AMOUNT OF CASH REQUIRED FOR OPERATING EXPENSE?

A. A lead/lag study measures the difference between: (1) the time a service is rendered and billed until the time revenues for that service are received ("lag") and (2) the time that services, materials, etc., are obtained/used and the time expenditures for those services are made ("lead"). The applicable lead period for each major category of expense is compared to the revenue lag period. The difference between those periods, expressed in days, multiplied by the average daily operating expense, yields the amount of CWC requirement.

Q. HOW WAS THE EXPENSE LEAD DAYS CALCULATED ON SCHEDULE F-3?

A. The expense lead days are the actual days between when a service is received and when payment is made for those services. To determine the expense lead days for each expense category, Black Hills Power reviewed a sample of invoices paid from that category and determined the average number of days it took to pay each of those invoices. The expense per day is calculated by taking the total expense per category divided by the number of days in the year. Finally, that expense per day for each category is multiplied by the expense lead days for that category to determine the expense dollar days for each category. Line 41 of Schedule F-3, page 2 contains the combined total of the expense dollar days and the combined total of the expense per day for all the expense categories. On Schedule F-3, the total in column (d) was divided by the total in column (b), resulting in the expense lead days of 43.34, which is shown on line 44.

Q. CAN YOU DESCRIBE HOW THE REVENUE LAG DAYS WERE CALCULATED?

A. The midpoint of service for each revenue month during the test year was first determined by dividing the total days of the year by 12 and then by 2. Then the amount of lag days between when the meter is read and when the customer is billed, was determined by using the Company's billing system and calculating that amount on a monthly basis. The monthly results are then averaged to arrive at an annual average. Next, the average number of days between billing and receipt of payment was determined. This was done by using the Company's billing system, calculating that amount on a monthly basis and then averaging the monthly results to arrive at an annual average. Finally, the sum of the results discussed above were added together to determine the total revenue lag days of 33.98, as shown on Schedule F-3, line 43.

Q. WHAT WAS THE RESULT OF THE LEAD/LAG STUDY?

A. The results of the lead/lag study demonstrate that, in aggregate, customers have supplied funds to the utility to pay for expenses prior to the utility paying for the same expenses. As a result, a rate base reduction was included in the determination of total rate base.

Q. WHAT AMOUNT OF CASH WORKING CAPITAL WAS DETERMINED?

A. The final cash working capital adjusted balance developed from the lead/lag study is ($5,839,251). The adjusted balance of cash working capital is used as a component of rate base.

Q. EXPLAIN THE KNOWN AND MEASURABLE ADJUSTMENT MADE TO FUEL STOCKS.

A. The adjustment reflects a new coal stockpile at the Neil Simpson Complex associated with the Coal Redundancy project. This stockpile provides approximately 5 to 7 days of coal for generation in the event of a major malfunction with mining operations. This inventory should allow adequate time to implement back up plans to ensure the continuous delivery of coal. These costs are supported through the testimony of Mark Lux.

Q. EXPLAIN THE KNOWN AND MEASURABLE ADJUSTMENTS MADE TO MATERIALS AND SUPPLIES.

A. Several adjustments were made to materials and supplies as summarized on Statement F, line 5. The individual adjustments are itemized on Schedule F-1 and Schedule F-4.

Schedule F-1, Row 29: Row 29 reflects a spare transformer rebuild that was received in November 2013. This spare transformer is for the Neil Simpson II power plant. In case of a transformer failure, the spare transformer will allow more timely restoration of service.

Schedule F-1, Row 30: Row 30 reflects spare fan motors for the coal units at the Neil Simpson Complex. The motors are critical to the operation of the units that have no back-up or redundancy. A typical motor failure would result in a major outage of many weeks to months. The fan motors are uniquely designed for each generation unit, so there is no “off the shelf” availability from manufacturers. The lead time for ordering a replacement motor is approximately 36 weeks.

Schedule F-1, Rows 32 – 34: Rows 32 through 34 remove the inventory from the test year associated with the Ben French, Osage, and Neil Simpson I power plants. These plants were retired on or before March 21, 2014, as the most cost effective plan for EPA compliance, and the associated inventory will no longer be needed for the operation of the plants. The cost of the inventory at these plants will be transferred to the regulatory asset established for decommissioning these units.

Schedule F-4: This schedule reflects Black Hills Power's ownership percentage of critical spare parts needed at CPGS to reduce the amount of lost production time. The plant operations department provided the current market prices for each item of equipment. These costs are supported through the testimony of Mark Lux.

D. OTHER RATE BASE REDUCTIONS

Q. WHAT OTHER REDUCTIONS TO RATE BASE WERE MADE?

A. Deferred federal income taxes related primarily to accelerated depreciation, cash received for customer deposits, advances for construction, and also pension related costs are included as reductions to rate base, as shown on Schedule M-1 and M-2.

Q. ARE THESE OTHER REDUCTIONS TO RATE BASE CONSISTENT WITH THE COMPANY'S LAST RATE CASE?

A. Yes, we used a consistent approach and accounts to reduce rate base.

Q. WHAT OTHER ADJUSTMENTS DID YOU MAKE TO REDUCE RATE BASE?

A. As shown on Statement E page 1, the Company also made an adjustment to reduce rate base for additional accumulated depreciation expense. This adjustment increases accumulated depreciation to reflect one-half of the annual depreciation expense associated with new assets summarized on Statement D, Page 2 and the new depreciation rates on Statement J.

Q. WERE PRO FORMA ADJUSTMENTS MADE TO OTHER RATE BASE REDUCTIONS?

A. Yes. Schedule M-1 provides for an adjustment that reflects the thirteen month average on balances as of September 30, 2013, for Other Regulatory Assets (182), Deferred Income Tax Asset (190), Customer Advances for Construction (252), Other Regulatory Liabilities (253 and 254), Deferred Tax – Accelerated Depreciation (282), and Deferred Income Tax Liability (283) accounts. Consistent with prior rate cases, an adjustment was made for deferred taxes related to the accelerated depreciation for the pro forma capital additions to be placed in service prior to the effective date of the new rates resulting from this rate case. The Company has once again elected bonus depreciation rates for assets that were eligible. This calculation is shown on Schedule M-2 and includes an offset for a Net Operating Loss ("NOL") adjustment. This NOL is created since there is not enough taxable income to use the entire bonus depreciation. In other words, the Company is not able to receive the cash benefit for the bonus depreciation tax deduction; therefore a tax asset is created for this timing difference.

E. DECOMMISSIONING AND WINTER STORM ATLAS REGULATORY ASSETS

Q. DID THE COMMISSION ISSUE AN ACCOUNTING ORDER TO ESTABLISH REGULATORY ASSETS FOR THE WINTER STORM ATLAS COSTS AND COSTS ASSOCIATED WITH DECOMMISSIONING THE NEIL SIMPSON I, OSAGE, AND BEN FRENCH POWER PLANTS?

A. Yes. On January 9, 2014, in Docket EL 13-036, the Commission issued an Order Approving Deferred Accounting For Storm Damage Costs (associated with Winter Storm Atlas) and Transfer of Remaining Plant Balance for soon to be Decommissioned Plants to a Regulatory.

Q. EXPLAIN THE RATE BASE ADJUSTMENTS FOR WINTER STORM ATLAS AND DECOMMISSIONING REGULATORY ASSET.

A. The rate base adjustments for the decommissioning and Winter Storm Atlas regulatory assets are reflected on Schedule J-2 and J-3, respectively. The adjustments reflect the unamortized balance to be included in rate base until fully amortized. An adjustment to the operating income statement is being made to recognize a full year of amortization expense. Therefore, the amount of rate base being included in the test year is reduced by the accumulated amortization for a full year.

V. <u>ADJUSTMENTS TO THE OPERATING EXPENSES</u>

Q. PLEASE DEFINE OPERATING EXPENSES.

A. Total operating expenses are costs incurred by the Company in order to supply electricity to the customers of Black Hills Power. In the development of the revenue requirement, these operating costs are passed on to customers dollar for dollar; that is, without Black Hills Power earning any net income on those expenses. Expenses are reflected in the following statements:

1) Statement H shows the operating and maintenance expenses in detail by FERC account.

2) Statement J is the calculation of depreciation and amortization expense.

3) Statement K shows the calculation of federal income tax expense.

4) Statement L calculates taxes other than federal income taxes - such as federal payroll taxes.

5) All of the Statements are summarized on Statement M to show the per books and the pro forma rate of return.

Q. PLEASE EXPLAIN THE ADJUSTMENTS FOR THE EXPENSES ON STATEMENT H.

A. Several adjustments were made to the expenses as shown on Statement H, columns (b) – (s). Statement H starts with the per books information for the twelve months ending September 30, 2013, by FERC account number. Each adjustment has a column on this page and a supporting Schedule to show how the adjustment was determined.

Adjustment (b): The adjustment of $1,688,744 on Schedule H-1 represents the actual and projected wage increases and changes in personnel. These amounts are calculated using an average of union negotiated wage increases and expected non-union wage increases, together with the costs associated with open vacancies and additional employees needed for operations. The labor costs associated with Neil Simpson I personnel who will have part of their time charged to power plants not owned by Black Hills Power at the Neil Simpson Complex have been removed from the test year. Please refer to the testimony of Laura A. Patterson and Jennifer Landis for a further description of the compensation program for Black Hills Power employees, FutureTrack Workforce Development Program, and personnel changes at Ben French, Osage, and Neil Simpson I.

Adjustment (c): Schedule H-5 contains the corporate costs charged to Black Hills Power from Utility Holdings for the twelve months ending September 30, 2013. This amount is then adjusted to reflect the allocation of Utility Holdings costs to Black Hills Power after CPGS is placed in service on October 1, 2014. The adjustment is an increase of $2,303,019 to the operating expenses. These expenses are a combination of direct and indirect charges without any additional fees. The allocation methods for indirect charges are described in the Utility Holdings Cost Allocation Manual, which is included as an Exhibit to the direct testimony of Christopher J. Kilpatrick.

Adjustment (d): Schedule H-6 represents the cost increases to provide retiree healthcare, medical costs for employees, pension plan premiums, and the employer portion of the 401(k). The adjusted FAS 87 pension plan expense reflects the most recent five year average. The annual pension expense has ranged between $976,122 and $3,251,072 from 2010 through 2014, and the annual percent change has ranged between a 64% decrease and a 79% increase. The Company proposes to normalize pension expenses because these expenses fluctuate widely from year to year. These pro forma amounts are compared to the test year expense, and the difference is an increase to operating expenses of $334,319.

Adjustment (e): Schedule H-7 provides the calculation to normalize bad debt expense using a three year historical period. The average net write-offs during that three year period was then divided by the average billed revenues to determine the average uncollectable expense for the Company. This average rate was then applied to the projected new revenue amount to determine the expected bad debt expense. This was compared to the actual test year amount and a decrease to operating expenses of $20,937 was then included as an adjustment.

Adjustment (f): Schedule H-8 provides for Black Hills Power's costs related to generation dispatch and scheduling. These costs are in accordance with the Generation Dispatch and Energy Agreement effective July 1, 2012, that has been filed with the FERC. This agreement allocates costs to the parties contracting for services based on the total capacity of each company. Based on the current Generation Dispatch and Scheduling costs, the expense adjustment is $107,964.

Adjustment (g): Schedule H-9 removes all the costs that are collected through the Energy Cost Adjustment ("ECA") from the test year. The Commission approved separating the ECA costs from base rates in Black Hills Power's last rate case, Docket EL12-061. The adjustment decreases operating expenses by $51,252,370.

Adjustment (h): Schedule H-10 shows Black Hills Power's pro forma adjustments for the Neil Simpson Complex Shared Facilities Agreement. Total expenses are provided along with the calculation of Black Hills Power's share of these expenses based on pooled expensed net capacity allocators. This adjustment reflects the retirement of Neil Simpson I on or before March 21, 2014. These 2014 revenue and expense amounts are compared to the per book amounts with the difference representing the adjustment.

Adjustment (i): Schedule H-11 represents the removal of costs associated with unallowable advertising. The adjustment eliminates costs associated with brand and image advertisements, and sponsorship of community organizations. The advertising included in the cost of service are those designed to promote safety, inform and educate consumers on the utility's financial services, and disseminate information on a utility's corporate affairs to its owners. The adjustment decreases operating expense by $262,517.

Adjustment (j): The adjustments in Schedule H-12 relate to Power Marketing activities of Black Hills Power. Adjustments made represent costs for energy sold by Power Marketing for marketing purposes which are not used to serve Black

Hills Power's load and thus, not included in the cost of service. The total expense that is eliminated from the test year is $28,035,682.

Adjustment (k): Schedule H-13 is a detailed listing of outside consulting costs related to this rate case and certain consulting costs associated with the 2012 rate case and phase in plan rate dockets. The Settlement Stipulation ("Stipulation") approved in Docket EL12-061 allows for the rate case costs incurred in Dockets EL12-061 and EL12-062 in excess of $261,813 to be recovered in this case. The Company proposes amortizing these costs over a three year period with the unamortized amount included in rate base.

Adjustment (l): Schedule H-14 adjusts test year vegetation management expenses to reflect the amount approved in the Stipulation in Docket EL12-061. The settlement establishes the annual vegetation management expense included in base rates, and this adjustment reduces the test year amount in accordance with the Stipulation. The adjustment reduces operating expenses by $401,420.

Adjustment (m): Schedule H-15 provides a detailed listing by FERC account of projected expense amounts to operate and maintain CPGS during a normal year. The adjustment is $2,781,469 for Black Hills Power's ownership percentage of CPGS. This adjustment is covered in more detail in the testimony of Mark Lux.

Adjustment (n): Schedule H-16 reflects the removal of severance expense during the test year for Ben French plant employees. The employee severance expense associated with the Ben French plant reflects a non-recurring event that needs to be removed from the test year to emulate normal, ongoing conditions. The total expenses eliminated were $180,861.

Adjustment (o): Schedule H-17 reflects Black Hills Power's allocation of expenses related to the operation and maintenance of Neil Simpson Complex ("NSC") common steam facilities. The NSC common steam facility expense is allocated based on capacity at the complex and Black Hills Power is responsible for the capacity associated with Neil Simpson II and its ownership percentage of Wygen III. The allocations reflect the retirement of Neil Simpson I, and the costs are based on the 2014 amounts. This was compared to the actual test year amount and an increase to operating expenses of $324,962 was then included as an adjustment. The employee retention efforts associated with this adjustment are addressed in the testimony of Laura A. Patterson.

Adjustment (p): Schedule H-18 adjusts for the removal of operating and maintenance expenses related to the discontinuance of operations at the Ben French, Osage, and Neil Simpson I power plants. The primary contributors to the expense reduction are fuel costs, fuel transportation costs, employee benefits costs, and materials used in the operation of the plants. The test year labor costs at the three plants are adjusted in Schedule H-1. The net adjustment reduces operating expenses by $3,753,186.

Adjustment (q): Schedule H-19 reflects the annual test year expense associated with BHC's FutureTrack Workforce Development Program. For additional information on the program and the Company's ratemaking proposal, please refer to the testimony of Laura A. Patterson, Jennifer Landis, and Christopher J. Kilpatrick. The adjustment increases operating expenses by $721,861.

Adjustment (r): Schedule H-20 adjusts for Black Hills Power's LIDAR surveying project on its 69 kV transmission system. The project cost is shared with the joint owners of the transmission system, and Black Hills Power's share is amortized over five years to correspond with the expected frequency of the survey. The Company requests the unamortized amount be included in rate base. The LIDAR surveying project is further discussed in the testimony of Mike Fredrich. The adjustment increases operating expenses by $136,920.

Adjustment (s): Schedule H-21 reflects the cost reductions as a result of Black Hills Power's customer service model changes. Black Hills Power completed a thorough review of its customer service model. The study found that most customers prefer self-service options via Black Hills Power's website or other automated services. Walk-in traffic has declined 45% since 2008 and that trend is expected to continue. Customers are adopting electronic payment options which will require Black Hills Power to better align its resource to provide support for these business channels. As a result, the Belle Fourche and Newell customer and electric operation services will be consolidated and moved to Spearfish and Sturgis, respectively. The new customer service strategy will allow Black Hills Power to provide better service at a lower cost to customers. The adjustment removes the salaries and benefits associated with three customer service representatives from the test year, and also eliminates the Belle Fourche and Newell facility costs. The net effect reduces operating expenses by $215,934.

Q. PLEASE EXPLAIN HOW THE EXPENSES ASSOCIATED WITH THE TRANSMISSION FACILITIES THAT CONNECT CPGS TO CHEYENNE LIGHT'S 115 kV SYSTEM ARE INCORPORATED IN THE COST OF SERVICE.

A. The CPGS transmission facilities are owned by Cheyenne Light, and Black Hills Power will be a transmission customer. The transmission expense will be based on the revenue requirement associated with the CPGS transmission assets and allocated to Black Hills Power to reflect its ownership percentage of CPGS. The expense will be recorded to FERC Account 565 and recovered from customers through the Energy Cost Adjustment.

VI. ADDITIONAL CHANGES TO THE OPERATING EXPENSES

Q. WHAT ADDITIONAL ADJUSTMENTS DID YOU MAKE TO THE OPERATING EXPENSES?

A. The depreciation expense was adjusted, as shown on Statement J, to account for the new depreciation rates as established in the depreciation study completed by Gannett Fleming in November 2013. We also calculated the depreciation expense for CPGS and other subsequent plant additions for a full year of operation. The retirements of the Ben French, Neil Simpson I, and Osage power plants are reflected by removing each plant's test year depreciation expense from the cost of service. The net result of these adjustments is an increase to depreciation expense of $3,584,757. The depreciation study is discussed in the testimony of John J. Spanos and the study is provided as Exhibit JJS-2.

Q. HOW ARE THE DEPRECIATION ADJUSTMENTS CALCULATED ON STATEMENT J?

A. The depreciation adjustment is calculated by using the new depreciation rates, as determined by our depreciation study, multiplied by the adjusted plant in service. The adjusted expense is then compared to the per books amount for the test year and the difference is recorded on Statement M as the adjusted depreciation expense and an increase in accumulated depreciation.

Q. EXPLAIN THE ADJUSTMENT FOR THE AMORTIZATION OF THE DECOMMISSIONING REGULATORY ASSET.

A. Black Hills Power is proposing to amortize the costs associated with the retirement and decommissioning of Neil Simpson I, Ben French, and Osage over five years. Schedule J-2 provides the calculation of the $3,472,714 increase to amortization expense. Please refer to the testimony of Mark Lux and Christopher J. Kilpatrick for a further description of the decommissioning costs and associated amortization.

Q. EXPLAIN THE ADJUSTMENT FOR THE AMORTIZATION OF THE WINTER STORM ATLAS REGULATORY ASSET.

A. Please refer to Vance Crocker's testimony for a description of the Winter Storm Atlas and line inspection costs. The Winter Storm Atlas damage costs include actual expenses through December 31, 2013, and estimated costs through the end of February 2014. The line inspection costs include contract labor costs for the inspection and an estimate for repair costs. Since the need for a system wide line inspection is driven by Winter Storm Atlas, the Company proposes to include the line inspection costs in the Winter Storm Atlas amortization. Black Hills Power is proposing to amortize these costs over five years. Schedule J-3 provides the calculation of the $827,702 increase to amortization expense.

Q. PLEASE EXPLAIN THE REMAINING CHANGES TO OPERATING EXPENSES.

A. On Statement L, additional payroll taxes were calculated based on the known and measurable adjustments described on Schedule H-1. The net payroll change was multiplied by the federal and state payroll tax rates to determine the adjustment of $22,257 to payroll taxes as shown on Schedule L-1.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO THE SOUTH DAKOTA PUC TAX.

A. The adjustment is based on the South Dakota pro forma retail revenue adjustments and the additional revenue requirement for South Dakota, multiplied by the gross receipts tax, resulting in an additional cost shown on Statement L.

Q. HOW IS THE FEDERAL INCOME TAX CALCULATED?

A. Federal income taxes are calculated based on the adjusted rate base amount on Statement M and Statement G debt and equity ratios. As shown on Statement K, the adjusted operating income before tax amount from Statement M, column (e), is then reduced by the adjusted interest expense as provided on Statement K, page 3.

This taxable income is multiplied by the federal income tax rate. This amount is adjusted for the permanent tax differences found on Statement K, Page 1, line 16, and tax additions and deductions found on Statement K, Page 2, lines 58 through 67, for the adjusted federal income tax expense.

VII. ADJUSTMENTS TO THE OPERATING REVENUES

Q. WHERE DO YOU GET THE PER BOOKS REVENUE ON STATEMENT I, PAGE 1?

A. The per books revenue is from the billing system for the customers of Black Hills Power for the test year ended September 30, 2013.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO SOUTH DAKOTA RETAIL REVENUE?

A. There are four adjustments to South Dakota retail revenue. First, the Phase In Plan Rate Rider revenue is adjusted as reflected on Schedule I-2 and discussed in Christopher J. Kilpatrick's testimony. Second, residential retail sales were affected by weather. Therefore, it was necessary to normalize sales to reflect revenue based on normal weather. Third, an adjustment is made to annualize the rate increase in Docket EL12-061 that was effective during the test period. The annualization properly calculates pro forma revenues as if the rates had been in effect for the entire test period. Please refer to the testimony of Charles Gray for further discussion on the weather normalization adjustment and the Docket EL12-061 rate annualization adjustment. Fourth, revenue associated with the ECA was removed from retail revenues as reflected on Statement I, Page 4. This relates to the matching principle as delivered energy costs were also eliminated in Schedule H-9.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO OTHER NON-FIRM REVENUE ON STATEMENT I, PAGE 1.

A. The other non-firm revenue adjustment represents the removal of revenue associated with Power Marketing. The removal of expenses associated with Power Marketing is shown on Schedule H-12.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO CITY OF GILLETTE REVENUE.

A. The City of Gillette revenue was removed as it relates to replacement energy. The associated costs are included in the Power Marketing adjustment on Schedule H-12.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO RENT FROM ELECTRIC PROPERTY.

A. The revenue from rental of electric property is increased to reflect the Neil Simpson Complex Shared Facilities adjustment as shown on Schedule H-10.

VIII. SUMMARY OF THE MODEL

Q. WHAT IS THE REQUESTED AMOUNT OF THE SOUTH DAKOTA INCREASE IN ELECTRIC BASE RATES?

A. Black Hills Power is seeking to increase its electric base rates to recover $14,634,238 in additional annual revenues, or an increase of 9.27%. This increase is calculated based on Black Hills Power's pro forma revenue requirement using a test year of the twelve months ending September 30, 2013. This revenue requirement is based on the jurisdictional allocation prepared on Schedule N-1.

Q. DOES THE MODEL RESULT IN A JUST AND REASONABLE REVENUE REQUIREMENT?

A. Yes. The Model uses the per books financial statements for the test year ending September 30, 2013, which contains known and measurable adjustments. The effect is a straight-forward application supporting the requested increase in base rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.