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January 15, 2015

Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
500 East Capitol Avenue
Pierre, SD 57501

Re: *In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates*
Docket No. EL14-026

Ms. Van Gerpen:

Commission staff submits for filing in the above-entitled matter the following documents:

♦ David E. Peterson's Testimony;
♦ Commission Staff's Confidential Memorandum and Exhibits;
♦ Commission Staff's Public Memorandum and Exhibits; and
♦ Certificates of Service.

I have served a copy of David E. Peterson's Testimony and Staff's Memorandum and Exhibits on the parties identified in the Commission's service list pursuant to the certificates of service.

Sincerely,

Karen E. Cremer

Karen E. Cremer
Staff Attorney

Enclosures

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

DOCKET NO. EL14-026

TESTIMONY OF DAVID E. PETERSON

ON BEHALF OF THE COMMISSION STAFF

JANUARY 15, 2015

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is David E. Peterson. I am a Senior Consultant employed by Chesapeake Regulatory Consultants, Inc. ("CRC"). Our business address is 1698 Saefern Way, Annapolis, Maryland 21401-6529. I maintain an office in Dunkirk, Maryland.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE IN THE PUBLIC UTILITY FIELD?

A. I graduated with a Bachelor of Science degree in Economics from South Dakota State University in May of 1977. In 1983, I received a Master's degree in Business Administration from the University of South Dakota. My graduate program included accounting and public utility courses at the University of Maryland.

In September 1977, I joined the Staff of the Fixed Utilities Division of the South Dakota Public Utilities Commission as a rate analyst. My responsibilities at the South Dakota Commission included analyzing and testifying on ratemaking matters arising in rate proceedings involving electric, gas and telephone utilities.

Since leaving the South Dakota Commission in 1980, I have continued performing cost of service and revenue requirement analyses as a consultant. In December 1980, I joined the public utility consulting firm of Hess & Lim, Inc. I remained with that firm until August 1991, when I joined CRC. Over the years, I have analyzed filings by electric, natural gas, propane, telephone, water, wastewater, and steam utilities in connection with utility rate and certificate proceedings before federal and state regulatory commissions.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN PUBLIC UTILITY RATE PROCEEDINGS?

A. Yes. I have presented testimony in 146 other proceedings before the state regulatory commissions in Alabama, Arkansas, California, Colorado, Connecticut, Delaware, Indiana, Kansas, Maine, Maryland, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, South Dakota, West Virginia, and Wyoming, and before the Federal Energy Regulatory Commission. Collectively, my testimonies have addressed the following topics: the appropriate test year, rate base, revenues, expenses, depreciation, taxes, capital structure, capital costs, rate of return, cost allocation, rate design, life-cycle analyses, affiliate transactions, mergers, acquisitions, and cost-tracking procedures.

In addition, in 2006 I testified twice before the Energy Subcommittee of the Delaware House of Representatives on consolidated tax savings and income tax normalization. Also in 2006, I presented a one-day seminar to the Delaware Public Service Commission ("Commission") on consolidated tax savings, tax normalization and other utility-related tax issues. In the spring of 2011, I co-presented along with Mr. Scott Hempling, the then-director of NRRI, a three-day seminar on public utility ratemaking principles to the Commissioners and Staff of the Washington Utilities and Transportation Commission. In 2012, I presented a one-day seminar on cost allocation and rate design to the Colorado Office of Consumer Counsel. More recently, I presented a three-day seminar on utility ratemaking, revenue requirements, cost allocation and rate design to the Delaware Public Service Commission Staff.

II. SUMMARY

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. My appearance in this proceeding is on behalf of the South Dakota Public Utilities Commission Staff ("Commission Staff").

Q. HAVE YOU TESTIFIED IN OTHER PROCEEDINGS BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION?

A. Yes, I have. I testified in a number of electric and natural gas distribution rate proceedings when I was on the Commission Staff during the period 1977 through 1980. More recently, I have assisted the Commission Staff in several rate proceedings, including those involving Black Hills Power, Inc. ("BHP" or "the Company"), wherein the issues were resolved by settlements. However, I filed testimony on behalf of the Commission Staff in Docket No. EL12-046 involving a rate increase request filed by Northern States Power Company and in Docket No. NG12-008 involving a rate increase request filed by Montana-Dakota Utilities Co.

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

A. I was asked to present the Commission Staff's support for the Settlement Stipulation reached by the Commission Staff and BHP. The Settlement Stipulation is intended to resolve all of the issues in this proceeding. My testimony also addresses certain issues raised in the testimonies presented by witnesses for the Black Hills Industrial Intervenors[1] ("BHII").

[1] Members of the Black Hills Industrial Intervenors include GCC Dakotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc. and Wharf Resources (U.S.A.), Inc.

Q. BEFORE YOU BEGIN DISCUSSING THE SETTLEMENT STIPULATION AND BHII'S ISSUES, PLEASE PROVIDE A BRIEF SUMMARY OF BHP'S RATE REQUEST IN THIS PROCEEDING.

A. BHP currently provides electric service to approximately 65,500 customers within Rapid City and other western South Dakota communities under rates approved by the South Dakota Public Utilities Commission ("the Commission"). BHP is a wholly-owned subsidiary of Black Hills Corporation ("BHC"). BHC also owns other regulated natural gas and electric utility companies operating in Colorado, Iowa, Kansas, Montana, Nebraska and Wyoming. BHC also owns non-regulated companies that generate wholesale electricity, that produce natural gas and crude oil and that mine coal.

BHP's base (i.e., non-fuel) electric rates that were in effect at the time that the Company initiated the instant proceeding were those that were approved by the Commission at the conclusion of BHP's last base rate proceeding in Docket No. EL12-061. BHP's 2012 rate proceeding was filed using an adjusted test year ended June 30, 2012. BHP had initially requested a $13.745 million annual revenue increase in that case. However, the Commission approved a settlement agreement that authorized BHP to increase annual revenues by approximately $8.831 million, effective October 1, 2013.

On March 31, 2014, BHP filed an application with the Commission seeking to increase base electric rates by approximately $14.634 million, or 9.27 percent, to be effective October 1, 2014. This effective date was chosen by the Company to coincide with the expected in-service date of the Cheyenne Prairie Generating Station ("CPGS"). BHP is a co-owner of the CPGS. BHP's current rate request was calculated from a Company-prepared revenue requirement study that relied on a test year ended September 30, 2013. On October 1, 2014, BHP placed its proposed rates into effect on an interim basis. BHP's interim rates will remain in effect until the conclusion of this proceeding.

III. SETTLEMENT STIPULATION

Q. ARE YOU THE ONLY ONE THAT ANALYZED BHP'S RATE REQUEST FOR THE COMMISSION STAFF?

A. No. The Commission Staff assembled a team of in-house analysts (Brittany Mehlhaff, Patrick Steffensen and Eric Paulson) and three outside consultants, including myself, to analyze BHP's rate increase application. The other two outside consultants are my colleagues at CRC, Robert Towers and Basil Copeland, Jr. This is essentially the same team that analyzed BHP's 2012 filing as well. Together, the Commission Staff team invested literally hundreds of hours analyzing BHP's Application, Testimony, Exhibits, Filing Statements and Workpapers. In addition, the Commission Staff propounded approximately 330 requests to BHP for additional data and information. Each response was carefully reviewed and analyzed by one or more Staff analyst. In addition, the Commission Staff carefully reviewed and analyzed information provided by BHP in response to BHII's approximately 60 discovery requests.

The Commission Staff began its investigation shortly after the Commission officially noticed BHP's rate increase Application on April 3, 2014. That investigation continued until late October 2014 when settlement discussions between the Commission Staff, BHP, BHII and another intervenor, Dakota Rural Action ("DRA")[2], commenced. Settlement discussions continued through

[2] DRA did not file testimony in this proceeding but did participate in settlement discussions that were held.

November and into the beginning of December. Ultimately, the Commission Staff and BHP reached a negotiated settlement that is intended to resolve all of the issues arising in this proceeding. A Settlement Stipulation, signed on December 8, 2014, by representatives of the Commission Staff and BHP, memorializes the terms of the settlement. BHII and DRA chose not to join the settlement. Concurrent with the filing of my testimony, the Commission Staff is also filing a Staff Memorandum Supporting Settlement Stipulation ("Staff Memorandum"). The Staff Memorandum carefully summarizes all of the Commission Staff's adjustments that are factored into the agreed-upon settlement revenue increase.

Q. WOULD IT BE FAIR TO CHARACTERIZE THE AGREEMENT REACHED BETWEEN BHP AND THE COMMISSION STAFF AS A "BLACK BOX" SETTLEMENT?

A. No. Any such characterization of the settlement would be wrong. A black box settlement typically is one where the specific resolution of issues cannot be identified. This is not what occurred in this proceeding, however. Rather, the Commission Staff prepared a detailed calculation of BHP's test year rate base, revenues and expenses, including known and measurable post-test year changes. The Commission Staff revenue requirement determination identified differences that it had with certain rate base, revenue and expense claims made by the Company and issues raised by the Commission Staff that were not mentioned in the Company's filing. The Commission Staff also carefully considered the issues and adjustments proposed by BHII in confidential settlement discussions. The end result of the Commission Staff's analyses is the Staff Memorandum, and the supporting schedules, which detail how the Commission Staff arrived at and can justify the $6,890,746 revenue deficiency reflected in the Settlement Stipulation. That document stands on its own and there is no need for me to explain in my testimony each Commission Staff adjustment. The points that I am trying to make in this discussion, however, are that the Commission Staff carefully considered all of the issues raised in this proceeding by BHP and the BHII and that the Staff Memorandum provides the Commission and the other parties a transparent roadmap showing how the Commission Staff determined that the agreed-upon annual revenue increase, $6,890,746, is consistent with South Dakota Law, prior Commission practices, and sound ratemaking principles and results in just and reasonable rates. It is for these reasons that I recommend the Commission approve the Settlement Stipulation and the terms contained therein.

In the following sections of my testimony I address certain claims made by witnesses for the BHII, who did not join in the Settlement Stipulation.

IV. BHII'S REVENUE REQUIREMENT TESTIMONY

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF LANE KOLLEN ON BEHALF OF THE BHII?

A. Yes, I have.

Q. WERE YOU AWARE OF THE ISSUES RAISED BY MR. KOLLEN PRIOR TO SEEING HIS TESTIMONY?

A. Generally, yes. I was not aware of the specific details of each adjustment that Mr. Kollen recommends prior to him filing testimony, but substantially all of the issues he raises were identified and discussed in settlement discussions held earlier in this proceeding and were considered by the Commission Staff.

Q. BEGINNING AT PAGE 7 OF HIS DIRECT TESTIMONY, MR. KOLLEN DISCUSSES GENERAL RATEMAKING PRINCIPLES WHICH HE

ACKNOWLEGES FORM THE BASIS FOR MANY OF HIS RECOMMENDED ADJUSTMENTS. PLEASE COMMENT ON THE GENERAL RATEMAKING PRINCIPLES THAT HE DISCUSSES.

A. Mr. Kollen identifies and recommends the following three principles:

1. The Commission should limit any post-test year adjustment to the twelve-month period immediately following the historical test year ended September 30, 2013.

2. The Commission should reject proposed post-test year increases in various expenses that are not justified and that the Company did not demonstrate were necessary and appropriate.

3. The Commission should reject adjustments that are not consistent with Commission precedent or policy, that are not justified, and that the Company did not demonstrate were necessary and appropriate.

Initially, while I am unable to discern a difference between Mr. Kollen's second and third principles, I can find no fault in either principle. In fact, I believe that the Commission Staff's revenue requirement, as described in detail in the Staff Memorandum, is faithful to both principles.

Ironically, Mr. Kollen's first principle is inconsistent with his third. It is my understanding that the Commission's long-standing policy has been to consider post-test year adjustments up to twenty-four months, not twelve months, beyond the end of the test year provided they are known with reasonable certainty and measureable with reasonable accuracy. Indeed such a treatment is, in effect, mandated to the Commission by South Dakota Administrative Rule 20:10:13:44. In addition to ignoring the twenty-four month look-out provision, Mr. Kollen apparently interprets this administrative rule to require that any costs that are beyond twelve months post-test year must be accompanied by projected changes in revenue for the same period. This is not how the Commission and the

Commission Staff have interpreted this rule, however. Rather, it is my understanding that both the Commission Staff and the Commission have previously interpreted this rule to mean that for any post-test year change in expense or investment that has an incremental revenue component (i.e., expenses or investments made to increase sales and/or to serve new customers) a corresponding revenue adjustment must also be recognized. It is for this reason that the Settlement Stipulation does not include any costs associated with post-test year plant additions that are designed to improve sales or to serve new customers. Similarly, there is no corresponding revenue offset for any of the post-test year expense adjustments that are reflected in the Settlement Stipulation. Therefore, the Settlement Stipulation is consistent with prior Commission policy in this regard and with the governing administrative rule. By the same token, the adjustments recommended by Mr. Kollen that do not reflect this principle as I have described it are inconsistent with long-standing Commission policy.

Q. CONCERNING THE ADJUSTMENTS THAT MR. KOLLEN RECOMMENDS, ARE ANY OF THEM ALREADY REFLECTED IN THE SETTLEMENT STIPULATION?

A. Yes. Many of Mr. Kollen's recommended adjustments already are addressed in the manner described in the Staff Memorandum and are part of the agreed-upon revenue requirement by the Commission Staff and BHP. These adjustments include the following:

1. Double-count of CPGS spare parts inventory (eliminated in settlement);
2. Decommissioning regulatory asset (contingency allowance in original cost estimate has been removed by settlement);
3. Decommissioning regulatory asset (ten-year amortization reflected in settlement).

4. Storm Atlas regulatory asset deferred income taxes (corrected in settlement);
5. Retired steam plants amortization (ten-year amortization period reflected in settlement);
6. Storm Atlas regulatory asset amortization (ten-year amortization period reflected in settlement);
7. CPGS depreciation (depreciation rate reflects 40-year life span);
8. FutureTrack Workforce Program (all costs were excluded in settlement and no deferrals will be made. Rather, only the cost of employees actually hired to date are reflected in settlement); and
9. Employee additions (only the cost of employees actually hired to date are reflected in the settlement).

Q. MR. KOLLEN TESTIFIES THAT IT IS IMPROPER TO INCLUDE THE NET OPERATING LOSS ("NOL") ASSET IN RATE BASE. DO YOU AGREE?

A. No, I do not. As explained in the Staff Memorandum, over the past several years, "bonus" depreciation previously authorized by Congress significantly increased BHP's annual tax deductions. The sum of BHP's tax deduction, including the new bonus depreciation deductions, however, exceeded its taxable revenues, which resulted in an NOL for tax purposes. Because of the tax loss position, BHP was not able to utilize all of its allowable tax deductions in the year they were earned. Consistent with accounting requirements, it had recorded deferred taxes relating to these tax deductions, nevertheless. The corresponding accumulated deferred tax liability is used as an offset or reduction to BHP's rate base. Without an adjustment, BHP's rate base would be reduced (via the deferred tax liability offset) by more than the tax benefit that the Company has realized to date because of the unused tax deductions. Therefore, it is necessary to adjust BHP's rate base to reflect the unused tax deductions. The specific adjustment reflected in BHP's rate base is a deferred tax asset, to which Mr. Kollen objects. Failure to provide for the deferred tax asset in rate base, as Mr. Kollen recommends, however, risks a violation of the IRS's normalization requirements.

The U.S. Tax Code Section 168 (i) (9) concerning the Accelerated Cost Recovery System that is now being used by BHP and other utilities to determine depreciation-related tax deductions provides as follows:

(9) Normalization rules

(A) In general

In order to use a normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—

(i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and

(ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

(B) Use of inconsistent estimates and projections, etc.

(i) In general: One way in which the requirements of subparagraph (A) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (A).

(ii) Use of inconsistent estimates and projections: The procedures and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base.

In this instance, a violation identified in paragraph (B) (ii) above could result if Mr. Kollen's recommendation were to be adopted by the Commission because BHP's resulting reserve for deferred taxes for ratemaking purposes (i.e., excluding the deferred tax asset) would not match the tax benefits of the depreciation-related tax deductions that BHP has received to date because a portion of those benefits are yet unrealized due to the existence of the NOL.

Violating the IRS normalization requirements could result in the disallowance of BHP's accelerated tax depreciation deductions which will have an extremely adverse impact on South Dakota ratepayers, including members of the BHII.

Moreover, the treatment of BHP's NOL reflected in the Settlement Stipulation is the same as that approved by the Commission in BHP's last base rate case and in the base rate cases for other South Dakota utilities. For these reasons, I recommend the Commission reject Mr. Kollen's NOL rate base adjustment.

Q. WHAT WAS BHP INITIALLY REQUESTING CONCERNING ITS DECOMMISSIONING ASSETS ASSOCIATED WITH THE RETIREMENT OF THE NEIL SIMPSON I, BEN FRENCH, AND OSAGE COAL-FIRED GENERATING UNITS?

A. BHP initially proposed to amortize estimated costs, including contingency allowances, associated with the retirement and decommissioning of these three generating stations over <u>five</u> years and to include the unamortized balance in rate base.

Q. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The settlement removes all contingency allowances that had been included in BHP's cost estimates. It also provides for a <u>ten-year</u> amortization period and includes the average unamortized balance over the first three years in rate base.

Q. WHAT DOES MR. KOLLEN RECOMMEND ON THIS ISSUE?

A. Mr. Kollen objects to any rate recognition for this issue at this time. Instead, he recommends the Commission authorize BHP to defer the decommissioning costs as regulatory assets and to address recovery of the assets in the Company's next base rate case. In support of his recommendation, Mr. Kollen objects to the contingency allowance contained in BHP's cost estimate and to BHP's proposed five-year amortization period. Both of these concerns are addressed in the settlement, however. Mr. Kollen also objects to current rate recovery because he believes the decommissioning costs (1) are not known with reasonable certainty and measurable with reasonable accuracy, (2) will be incurred more than twelve months beyond the end of the test year, and (3) are not accompanied by revenue adjustments. I already discussed my issue with Mr. Kollen's interpretation of the administrative rule governing post-test year adjustments. ARSD 20:10:13:44 permits the Commission to look out twenty-four months beyond the end of the test year to recognize known and measurable revenue and cost changes; and not just the twelve months that Mr. Kollen advocates. Also, there is no revenue producing aspect to retiring the three coal-fired units. Thus, there is no merit to Mr. Kollen's second and third arguments. As for his first argument, that the decommissioning costs are not known with reasonable certainty and measurable with reasonable accuracy, again, there is no merit to Mr. Kollen's claim. The Commission Staff was comfortable with recognizing BHP's cost claims, excluding the contingency allowances, as a known change because approximately 70 percent of the estimated costs are capped by a fixed price contract for decommissioning activities. Since a majority of the costs are determined by a fixed price contract, I believe that this reasonably qualifies the adjustment as known and measurable. As for Mr. Kollen's recommendation to defer BHP's decommissioning costs until the next rate proceeding, by following that path, it is likely that BHP would not have agreed to the stay-out moratorium provision in the Settlement Stipulation. Deferring decommissioning costs also comes with a price. Unamortized decommissioning costs are included in rate base and earn a return such that future ratepayers will pay more the longer recovery is delayed. For these reasons, I support the treatment reflected in the Settlement Stipulation relating to BHP's decommissioning costs.

Q. MR. KOLLEN ALSO OBJECTS TO BHP'S PROPOSED TREATMENT OF THE 69 KV LIGHT DETECTION AND RANGING ("LIDAR") SURVEYING COSTS. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The settlement provides for an amortization of BHP's costs associated with this project over a five-year period.

Q. WHAT ARE MR. KOLLEN'S OBJECTIONS TO RECOGNIZING THESE COSTS?

A. Mr. Kollen objects to recognizing these costs in rates because they were not incurred within twelve months following the end of the test year. Moreover, to the extent that the costs are to be amortized, Mr. Kollen recommends a ten-year amortization rather than five years as provided for in the settlement.

Q. WHAT IS YOUR RESPONSE TO MR. KOLLEN'S CONCERNS?

A. BHP expected to have incurred its LIDAR surveying costs by the end of the third quarter in 2014. This is well within the twenty-four month period the

Commission typically relies on for evaluating post-test year adjustments. Moreover, as with BHP's decommissioning costs discussed earlier in my testimony, BHP's LIDAR costs are also governed and capped by a fixed rate contract. Thus, in my opinion, the costs are sufficiently known and measurable and are appropriately recognized in rates. The five-year amortization period reflected in the settlement was determined because five years is the expected frequency for LIDAR surveying activities. Therefore, it would be inappropriate to employ a ten-year amortization period as Mr. Kollen recommends and thereby burden BHP ratepayers, including BHII members, in years six through ten with costs for two different LIDAR surveys. A five-year amortization simply makes more sense for these costs.

Q. WHAT DOES MR. KOLLEN RECOMMEND CONCERNING BHP'S PROPOSED ADJUSTMENT FOR PROJECTED EMPLOYEE ADDITIONS AND ELIMINATIONS?

A. Mr. Kollen recommends the Commission disallow BHP's labor-related cost adjustments because he believes the adjustments ignore the fact that BHP historically has several open positions.

Q. HOW IS THIS ISSUE TREATED IN THE SETTLEMENT?

A. The Commission Staff shares Mr. Kollen's concern about recognizing phantom costs in rates for vacant positions. Because of this concern, the settlement includes cost allowances for only filled positions at the time of the Commission Staff's review. That is, cost allowances for vacant positions are not included in the settlement revenue requirement. This treatment should resolve Mr. Kollen's concern.

Q. HOW WAS THE PENSION EXPENSE ISSUE TREATED IN THE SETTLEMENT?

A. The following table shows BHP's pension expense over the last five years.

Table 1
BHP Annual Pension (FAS 87) Expense
2010 Through 2014

2010	**$2,925,853**
2011	**$1,819,156**
2012	**$3,251,072**
2013	**$2,709,322**
2014	**$ 976,122**
Five-year average	**$2,336,305**[3]

As shown in the table above, BHP's 2014 pension expense was unusually low when compared with the previous four years. Because of the significant variability of the expense year-to-year, BHP proposed a normalization adjustment that includes a pension expense allowance based on the average of the annual expenses over the last five years. The settlement incorporates BHP's pension normalization adjustment. The agreed-upon pension expense represents a $508,454 reduction from the test year pension expense, on a total Company basis.

Mr. Kollen considers the pension normalization adjustment "opportunistic" in that it does not reduce the test year expense far enough and it prevents BHP ratepayers from receiving the benefit from the lower pension expense in 2014 that the Company enjoyed. To support his contention, Mr. Kollen stated the Company offered no evidence that the pension expense will swing upward to the five-year average in future years.

[3] See BHP's response to Staff DR1-1; workpapers for Schedule H-6.

In truth, it is Mr. Kollen's position that is opportunistic. It is clear from the table above that BHP's pension expense can be highly variable and subject to major swings each year. Mr. Kollen's recommendation would have the Commission set rates based on BHP's lowest pension cost level in the last five years, with the knowledge based on recent experience that such costs are highly variable year-to-year. An understatement of BHP's pension costs could place the Company in a significant under-recovery position necessitating more frequent rate increases. With a highly variable cost such as the pension expense, to avoid wide swings in over-recovery and under-recovery of the underlying expense, it makes sense to employ a normalization procedure, such as that reflected in the settlement. To avoid any concern that the settlement approach is opportunistic, BHP and the Commission Staff agreed in the Settlement Stipulation to follow the five-year normalization approach for pension expense for the next five years, unless there is an extraordinary event that makes a five-year normalization method unreasonable.

Q. WHAT IS MR. KOLLEN'S CONCERN WITH INCENTIVE COMPENSATION EXPENSES?

A. Mr. Kollen believes the settlement resolution of the incentive compensation issue does not go far enough. In the settlement, $666,000 of the Company's $1.554 million total test year incentive compensation expenses is excluded. This is the amount that BHP identified as being tied to the Company's financial results. In addition to this already excluded amount, Mr. Kollen would also exclude $149,000 in performance plan expenses and $739,000 in incentive restricted stock expenses. Mr. Kollen contends that these additional amounts represent incentive awards that are similar in nature to those excluded in the settlement.

I do not necessarily disagree with Mr. Kollen's characterization of the incentive awards. In fact, I had initially pursued the same issues on behalf of the

Commission Staff earlier in this proceeding. In the end, however, the Commission Staff conceded this issue recognizing that the incentive compensation exclusion embodied in the settlement is essentially the same type of exclusion the Commission has approved for BHP in prior base rate case settlements and for other South Dakota utilities. Therefore, I support the exclusion that is contained in the settlement and recommend that the Commission reject Mr. Kollen's recommendation to expand the exclusion at this time. Of course, the Commission Staff and the BHII are free to revisit this issue in BHP's next base case given the Settlement Stipulation in this proceeding does not establish precedent on the incentive compensation issue.

Q. MR. KOLLEN OPPOSES BHP'S ADJUSTMENTS RELATING TO COSTS ALLOCATED TO IT BY TWO AFFILIATES, BLACK HILLS UTILITY HOLDINGS, INC. ("BHUH") AND BLACK HILLS SERVICE COMPANY, LLC ("BHSC"). WHAT ARE YOUR COMMENTS ON MR. KOLLEN'S CONCERNS?

A. BHP initially proposed an adjustment to test year BHUH expenses based on its post-test year operating budget. I had the same concerns as those expressed by Mr. Kollen that the adjustment lacked proper support. That is, I was not willing to recommend the Commission approve an adjustment based solely on BHP's budget projections. During our investigation, however, BHP provided a detailed summary of its most recent annualized expenses from the two affiliated companies[4]. The actual annual amounts billed to BHP are included in the settlement. Thus, the amounts billed to BHP from affiliates that are incorporated into the settlement reflect the Company's actual, known costs.

[4] See BHP's Second Supplemental Response to Staff DR3-96

Mr. Kollen also pointed out in his testimony that certain billings from BHUH were allocated to the South Dakota retail jurisdiction incorrectly on the Commission Staff's revenue requirement schedules. Mr. Kollen is correct. Properly allocating those expenses to South Dakota reduces the indicated revenue deficiency by approximately $286,000.

Q. MR. KOLLEN OBJECTS TO BHP'S PROPOSED DEPRECIATION RATE FOR THE NEW CHEYENNE PRARIE GENERATING STATION BECAUSE IT REFLECTS AN ASSUMED 35-YEAR LIFE SPAN. WHAT IS YOUR RESPONSE?

A. Commission Staff addressed this issue and the Settlement Stipulation reflects the same, longer, 40-year life span recommended by Mr. Kollen.

Moreover, it should be noted that whether it is 35 years or 40 years or some other life span, the life span that serves as the foundation for a depreciation accrual rate for CPGS *is an estimate* and a necessary departure from the principle that all elements of BHP's revenue requirement should be "known and measurable".

Q. WHY IS THAT IMPORTANT?

A. It is important because it is relevant to Mr. Kollen's other depreciation-related objections to the Settlement Stipulation – namely, the salvage estimates reflected in BHP's proposed accrual rates for other production plants and the concept of anticipating these future costs for current recovery. Beginning at page 47 of his testimony, Mr. Kollen declares that (1) the development of the salvage values are flawed and unreliable and then opines (2) that they may represent an undisclosed proposal to change the Commission's policy for recovery of retirement-related cost from after-retirement recovery to before-retirement recovery and (3) the increased negative salvage allowances are not necessary at this time because the

Commission is not required to provide for the recovery of unknown future costs in present utility service rates.

My point here is that, however desirable it might be to have all elements of the revenue requirement based on absolutely known and measurable costs, depreciation allowances must reflect estimates because neither the service life of the asset nor the cost of the act of retirement are known until the asset has been retired. Depreciation allowances represent allocations of capital costs of an asset to the time periods as the asset provides service to customers over a long period of time. In the absence of making such estimates, ratepayers benefitting from the service provided by the asset will avoid these costs and cost recovery would be shifted to future ratepayers not benefitting from that service. I know of nothing that even suggests an existing Commission policy of refusing to recognize these retirement-related costs until after the plant is retired.

Ironically, while objecting to the uncertainty of salvage estimates for other plant and advising that the Commission need not provide for the recovery of costs to be incurred in the future, Mr. Kollen is not reluctant to recommend a depreciation accrual rate for CPGS that includes an allowance for future retirement costs equal to 4 percent of that plant's capital costs as well as factoring in assumed allowances for interim retirements (see Remaining Lives by Account exhibited on the second page of Exhibit ___(LK-16); all are less than the 40-year life span by reason of interim retirements).

V. BHII'S COST ALLOCATION TESTIMONY

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF STEPHEN J. BARON ON BEHALF OF THE BHII CONCERNING CLASS COST ALLOCATION?

A. Yes, I have. In his testimony, Mr. Baron identified what he believes are several errors in BHP's class cost of service study ("CCOSS"). Based on his analyses, Mr. Baron recommended the Commission reject the Company's CCOSS. In spite of Mr. Baron's concerns with BHP's CCOSS, he nevertheless recommended the Commission approve the apportionment of the overall approved revenue increase to the rate classes as reflected in the Settlement Stipulation. Mr. Baron also recommended the Commission require BHP to file in its next base rate case a CCOSS reflecting the changes that he recommended in this case.

Q. BEFORE YOU DISCUSS MR. BARON'S RECOMMENDED CHANGES TO BHP'S CCOSS, DO YOU HAVE ANY INITIAL COMMENTS ON HIS TESTIMONY AND RECOMMENDATIONS?

A. Yes. Because the BHII accepts the apportionment of the overall approved revenue increase reflected in the Settlement Stipulation, there are no remaining issues to be decided by the Commission regarding the spread of the rate change among the rate classes. This is true irrespective of the issues that Mr. Baron raises with the CCOSS. In fact, Mr. Baron's testimony is unnecessary since the Company's CCOSS is not being adopted in the Settlement Stipulation and neither the Commission Staff nor BHP is asking the Commission to accept the Company's CCOSS. Only the spread of the revenue change among the rate classes is being resolved by the Settlement Stipulation and through Mr. Baron's testimony the BHII is accepting the settlement resolution concerning the spread of the revenue change. Under the Settlement Stipulation, BHP, the Commission Staff and the BHII are free to advocate whatever they choose concerning the CCOSS in BHP's next base rate proceeding. Therefore, it is not necessary for the Commission to rule on any CCOSS issue in this proceeding; nor is it necessary for the Commission to direct BHP to file a CCOSS in any particular manner in the next case. All parties' rights are preserved in the Settlement Stipulation to advocate different CCOSS allocation procedures in BHP's next base rate case, should they so choose.

Q. MR. BARON RECOMMENDED SEVERAL CHANGES TO BHP'S CCOSS. WHICH AMONG HIS RECOMMENDED CHANGES IS THE MOST SIGNIFICANT IN TERMS OF IMPACT ON CLASS RATES OF RETURN?

A. By far, the recommended change that has the most impact on class rates of return relative to those shown in BHP's CCOSS is the minimum distribution system ("MDS") approach. The impact is illustrated in the table below.

Table 2
Class Cost of Service Study Analysis
Comparison of Class Rates of Return

Rate Class	Column 1 BHC Results	Column 2 BHC with MDS	Column 3 BHII Adjustments
Residential	5.11%	4.47%	4.23%
General Service	9.85%	10.33%	9.98%
Combined GS Lg – Ind Contract	5.70%	6.50%	7.26%
Lighting	12.14%	12.19%	12.37%
Water pumping/irrigation	7.78%	9.10%	9.39%
Total SD retail	6.73%	6.73%	6.73%

Sources:
Columns 1,3: Baron Direct, page 26
Column 2: BHII's response to Staff DR-4

Column 1 on the table above presents class rates of return under BHP's CCOSS at existing base rates. Column 2 shows the resulting class rates of return if only the MDS change that Mr. Baron advocates is incorporated into BHP's CCOSS. Column 3 shows class rates of return if all of Mr. Baron's recommendations are adopted. Notice that the change in class rates of return between Columns 2 and 3 is not as significant as the change between Columns 1 and 2. The relative changes between the columns demonstrate the significance of the MDS approach to Mr. Baron's recommended results.

Q. WHAT IS THE MDS?

A. The MDS postulates that there are certain types of facilities that must be installed by the utility to provide customers access to the utility's electrical service, regardless of customer usage requirements. The MDS then classifies the cost of the minimum (or zero) size of these facilities as customer-related. For example, the MDS calculation relied on by Mr. Baron attempts to estimate the cost of a wooden pole that is essentially zero feet tall and then re-price the actual cost of all of the wooden poles presently in service to reflect the cost of the minimum size pole (zero feet). Using statistical techniques, the MDS study estimated that a wooden pole with zero height would cost $44.33. This amount was multiplied by the total number of wooden pole to determine the total cost of the minimum size system. The re-priced minimum size pole inventory divided by the total investment in poles produces the ratio or percentage of the Company's pole investment that Mr. Baron then classified as customer-related. The remainder of the pole investment was classified as a demand-related cost. A similar procedure was used to re-price BHP investments in underground conduit and conductors, overhead conductors, and line transformers.

Q. WHAT IS YOUR CONCERN WITH USING THE MDS TO CLASSIFY A PORTION OF DISTRIBUTION COSTS AS CUSTOMER-RELATED?

A. In general, my objection to the MDS approach is that it does not give appropriate consideration to BHP's actual system design, construction and operation. Having failed to give proper consideration to these important factors, the MDS fails to reflect BHP's cost of service.

Those who support classifying distribution facilities (other than services and meters) on a customer basis do so based on an assertion that some minimum investment is necessary to make electrical service available for each customer, regardless of the customer's peak or annual service requirements. Proponents then argue that this "customer-related" investment should be defined as either: a) the hypothetical cost of the current distribution system revalued using the cost of minimum-sized distribution facilities presently installed on the system (the MDS approach) or; b) the hypothetical cost of distribution plant having no load carrying capability (the so-called "zero-intercept" approach being advocated by Mr. Baron).

The minimum size distribution equipment that a utility will actually install, however, is based on expected customer loads and existing customer densities, not on the number of customers served by the utility or minimum service requirements. As for the zero-intercept approach, no utility installs distribution equipment incapable of carrying loads. Rather, the facilities that BHP installs are sized, designed, operated and maintained in order to meet the individual customers' peak and annual service and safety requirements. Neither the MDS nor the zero-intercept variant of the MDS gives appropriate consideration to actual system design, construction and operation. The MDS fails to reflect cost-causation and, therefore, is not a proper cost allocation method.

Q. APART FROM YOUR CONCEPTUAL ISSUES WITH THE ZERO-INTERCEPT APPROACH TO THE MDS THAT MR. BARON ADVOCATES, DO YOU HAVE ANY CONCERNS ABOUT THE MDS STUDY AND THE ZERO-INTERCEPT CALCULATIONS UPON WHICH MR. BARON RELIES?

A. Yes, I do. The concerns that I discuss below only begin to scratch the surface of the problems with the MDS calculations that may lie underneath. But, they are sufficient enough for the Commission to challenge and to reject Mr. Baron's blind reliance on the results of the MDS study.

Initially, it should be noted that neither Mr. Baron nor any one in his firm participated in preparing the MDS study upon which he relies. Nor does Mr. Baron have any knowledge of BHP's specific distribution design criteria.[5] Rather, Mr. Baron relies on a ten-year old study that BHP Colorado's former owner, Aquila, Inc., prepared for a 2004 rate case in Colorado. Mr. Baron never attempts to prove that the conditions in Colorado are similar to those in BHP's South Dakota service territory. Nor does Mr. Baron demonstrate the MDS study is equally valid today with the passage of so much time. The only support that Mr. Baron seems to offer for his use of Aquila's ten-year old MDS study is pointing to the fact that BHP itself used the same study in this case to develop the primary/secondary distribution facility split in its CCOSS.

Q. IS THAT A SUFFICIENT REASON FOR USING AQUILA'S 2004 MDS STUDY IN COLORADO IN THIS 2014 BHP SOUTH DAKOTA CASE?

A. No, it is not. While BHP used the same study to split the primary and secondary distribution facilities in its CCOSS, neither the MDS study nor BHP's CCOSS

[5] See BHII's response to Staff Data Request No. 7.

study and results are being adopted in this case. Mr. Baron's reliance on BHP using the same MDS study for a different purpose, therefore, is misplaced. Moreover, Mr. Baron does not have an independent basis for using that MDS study in this proceeding since it was not designed for nor does it attempt to explain the design and cost components of BHP's South Dakota service territory.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE MDS STUDY?

A. Yes. The statistics supporting the study are suspect as well. The author of the study back in 2004 used three modeled regression forms (i.e., linear, exponential, and polynomial) for each of Aquila's four distribution plant accounts that were studied. The author then chose the "best" regression form among the three. But, the only statistical parameter that he used to choose among the three modeled regression forms was R-squared. While the study employed the R-squared statistic in a consistent fashion throughout the study (i.e., always choosing the equation with the highest R-squared), in many cases the R-squared statistic was so high, and so close to the other R-squared statistics for the other regression forms, as to call into question whether meaningful statistical inferences could be obtained on the basis of R-squared alone. For example, for Account 365, Overhead Conductors, the linear model had an R-squared of 0.9984, and the polynomial model had an R-squared of 0.9994. But the intercepts (i.e., the MDS point) were quite different; the linear model had an intercept of $0.5905, and the polynomial model had an intercept that was nearly 60 percent greater at $0.9376. While the R-squared of the polynomial model was slightly higher than that of the linear model, it is possible that the difference in intercepts is not statistically significant. But we have no way of determining whether that is the case because the more relevant statistical parameters – the standard deviation of the intercepts or T-statistics – are not provided in the MDS study. This highlights a common fallacy in the use of regression models; that R-squared is a sufficient parameter for making statistical inferences. It is not. It is possible that the R-squared is low, but the regression coefficients are still statistically significant based on the standard deviations. The opposite also can be true, especially with respect to intercepts; the R-squared can be high and the intercept still not be significantly different than zero.

There is yet further indication of problems with Aquila's MDS study. Take Account 365 – Wood Poles, for example. Each of Aquila's R-squared values for this account are high, ranging between 0.9451 and 0.9981. The intercepts vary from -$569.89 (linear model) to +$801.43 (polynomial model). But is the intercept not statistically different from zero? We cannot answer that question because the relevant statistical parameters to evaluate this are not included in the MDS study.

The Wood Pole regression analysis points out yet another problem with this type of analysis. If you look at the graph provided in the MDS study for Wood Poles, there are no data points below a pole height of 30 feet. That is of course because pole heights of say five feet are unheard of. But the regression model assumes that such a thing really exists. The issue here is that of extrapolating out of the observed range. The NARUC Electric Cost Allocation Manual referenced by Mr. Baron in support of the MDS approach recognizes this shortcoming in the MDS approach.[6] Statistically, extrapolating out of an observed range is always questionable, and standard deviations are absolutely essential to make any kind of a meaningful inference about estimates outside the range of observations. But, this is precisely what the MDS approach requires; hypothesizing about costs that never have been, or ever will be, observed in the real world because real world

[6] See Baron Exhibit ___(SJB-3), page 13 of 17.

electrical distribution engineers do not design for minimum or zero-load conditions.

It is my understanding that the Commission has never before adopted the MDS approach for any utility in South Dakota. I am loathe to recommend the Commission adopt such a significant change in its long-standing practice based on a ten-year old study prepared by another utility in another state where the analyses are incomplete. Moreover, the author of the original study upon which Mr. Baron relies is not even a participant in this proceeding. Thus, it is not possible for the Commission Staff to ask questions about the study. In sum, the MDS study relied on by Mr. Baron raises more questions than it answers and should not be deemed reliable by the Commission for rate setting purposes.

Q. MR. BARON ALSO RAISES AN ISSUE CONCERNING ENERGY LOSS FACTORS NOT BEING REFLECTED IN BHP'S CURRENT ENERGY COST ADJUSTMENT ("ECA") FACTOR. DO YOU HAVE ANY COMMENT ON THIS?

A. I am not aware if the Commission Staff has taken a position on loss factors in connection with the ECA. Regardless, however, to the extent that the BHII feels it has a legitimate concern with this issue, it is being raised in the wrong forum. Mr. Baron acknowledges that ECA revenues and expenses are excluded in BHP's base rates. Therefore, if the BHII wishes to pursue this issue it should do so in connection with a review of BHP's ECA.

VI. CONCLUSION

Q. ON PAGE 4 OF HIS DIRECT TESTIMONY, MR. KOLLEN STATES: "AS DEMONSTRATED BELOW, THE PROPOSED SETTLEMENT BETWEEN THE COMPANY AND THE STAFF IS WOEFULLY INADEQUATE." DO YOU CARE TO COMMENT ON MR. KOLLEN'S STATEMENT?

A. Mr. Kollen's disparaging characterization of the settlement marginalizes the hundreds of hours that were devoted to the rate investigation by the Commission Staff in analyzing BHP's rate request and in crafting a resolution of all issues through a negotiated settlement. As is evident by the Staff Memorandum, the Commission Staff arrived at its settlement position based on a thorough analysis of all issues while relying on long-standing Commission practices and requirements imposed by South Dakota Administrative Rules governing ratemaking practices in the State. Obviously, there was give-and-take between the Commission Staff and BHP in settlement negotiations. Staff did not receive all that it hoped for; neither did BHP. In fact, BHP agreed to accept less than one-half (47 percent) of its original requested revenue increase. Moreover, the settling parties agreed to a stay-out provision that restricts BHP's ability to seek another base rate increase prior to October 1, 2016. The two-year rate moratorium has real value to BHP customers, including the members of the BHII.

As shown in my testimony above, the Settlement Stipulation addresses many of the revenue requirement issues that Mr. Kollen raised. Other issues raised by Mr. Kollen are inconsistent with long-standing Commission practices and the requirements of South Dakota Administrative Rules governing public utility ratemaking. And while Mr. Kollen raised some legitimate concerns with a few of his issues, those issues were addressed in confidential settlement negotiations and were part of the give-and-take therein. As for Mr. Baron's testimony, it seems unnecessary given that no party is asking the Commission to accept the Company's CCOSS and that the BHII supports the apportionment of the revenue increase to the rate classes that is reflected in the settlement. Whatever issue the BHII has with cost allocation can be addressed in BHP's next rate proceeding given that any resolution at this time will not have any impact on the outcome of this proceeding.

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

STAFF MEMORANDUM SUPPORTING SETTLEMENT STIPULATION

DOCKET EL14-026

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation (Settlement) of December 8, 2014, between Staff and Black Hills Power Company (BHP or Company) in the above-captioned matter.

BACKGROUND

On March 31, 2014, the Company filed an application with the South Dakota Public Utilities Commission (Commission) requesting approval to increase rates for electric service to customers in its South Dakota retail service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month.

BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and a 8.48% overall rate of return on rate base.

The Commission officially noticed BHP's filing on April 3, 2014, and set an intervention deadline of June 6, 2014. On April 11, 2014, BHP filed revisions to certain pages originally filed in the application. On April 16, 2014, the Commission issued an Order Assessing Filing Fee. On June 6, 2014, a Petition to Intervene of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) was filed. On June 6, 2014, Dakota Rural Action (DRA) also filed a Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention to Black Hills Industrial Intervenors. On June 26, 2014, the Commission granted intervention to Dakota Rural Action subject to its filing an affidavit, which was filed on June 27, 2014. On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates effective on and after October 1, 2014.

On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement, Confidential Settlement Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority (SDSTA), including the associated Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and SDSTA, and relevant exhibits. On September 10, 2014, Staff filed its memorandum regarding the Contracts with Deviations. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis.

Settlement discussions between Staff, BHP, BHII, and DRA commenced on October 28, 2014. Thereafter, Staff and BHP (jointly, the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. Ultimately, the Parties reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA are not parties to the settlement. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. On December 12, 2014, the Commission issued a Scheduling Order setting this matter for hearing on January 27-29, 2015. On December 30, 2014, the Commission issued an Order for and Notice of Hearing.

BHII filed Direct Testimony and Exhibits of Lane Kollen and Direct Testimony and Exhibits of Stephen J. Baron on December 30, 2014. No testimony was filed by DRA. This Memorandum supports Staff's view of the settlement. Staff Witness Dave Peterson's direct testimony addresses specific items discussed in Mr. Kollen's testimony and Mr. Baron's testimony.

OVERVIEW OF SETTLEMENT

Staff based its revenue requirement determination on its comprehensive analysis of BHP's filing and information obtained during discovery. Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that do not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in BHP's filed case.

Company and Staff positions were discussed thoroughly at the settlement conferences. As a result, some positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues. Staff believes the settlement is based on sound regulatory principles and avoids additional costly and unnecessary litigation.

The Parties agree BHP's revenue deficiency is approximately $6,890,746, which results in an approximate 4.35% increase in retail revenue. This revenue requirement and supporting calculations described in this Memorandum and attachments depict Staff's positions regarding all components of BHP's South Dakota jurisdictional revenue requirement.

STAFF OVERVIEW OF SETTLEMENT

Staff's determination of the settlement revenue requirement begins with total Company test year costs for the twelve months ended September 30, 2013, and allocates those total Company amounts to the South Dakota retail jurisdiction. Staff then adjusted the September 30, 2013, test year results for known and measurable post-test year changes. Staff Exhibit___(BAM-1), Schedule 3 illustrates Staff's determination of BHP's *pro forma* operating income under present rates. Staff Exhibit___(BAM-2), Schedule 2 illustrates Staff's calculation of BHP's South Dakota retail rate base, and Staff Exhibit___(BAM-1), Schedule 2 and Staff Exhibit___(BAM-2), Schedule 1 summarize the positions. Staff Exhibit___(BAM-1), Schedule 1 summarizes Staff's determination of BHP's revenue deficiency and total revenue requirement collected through base rates.

The base revenue increase by rate schedule is shown on Staff Exhibit___(PJS-2), Schedule 1. Staff Exhibit___(PJS-2), Schedules 2-1 through 2-5 reflect the settlement base rates for each rate schedule. The comparison between present and settlement rates and resulting bill impacts for the Residential Service rate schedules is shown on Exhibit___(PJS-2), Schedule 3.

Unless otherwise noted, all of the changes discussed below are changes from the Company's filed position.

RATE BASE

Average Rate Base – Both the Company and Staff arrived at a test year average rate base based on an average of the 13 month-end account balances, September 30, 2012, through September 30, 2013.

CPGS Plant Addition – BHP proposed an adjustment to increase plant in service for projected capital costs associated with the Cheyenne Prairie Generating Station (CPGS). The Company included in rate base the actual costs incurred as of December 31, 2013, and estimates of the remaining completion costs. The settlement determination revises the Company's adjustment to reflect actual costs as of October 31, 2014, and reasonably known and measurable changes after October 31, 2014. The settlement also reflects the associated accumulated deferred income taxes. The net effect of these changes is to reduce rate base by approximately $2,156,000.

Test Year Plant In Service Annualization – The Company proposed an adjustment to annualize test year non-revenue producing plant additions that were completed during the test year. The settlement determination revises the Company's adjustment to: 1) Remove the amounts related to eight projects that appear to be revenue producing; and 2) Reduce the amounts related to two projects for contributions made by CenturyLink. The settlement also includes accumulated deferred income taxes arising from these projects. The net effect of these changes is to reduce rate base by approximately $90,000.

Post-Test Year Plant Additions – The Company proposed an adjustment to increase South Dakota test year plant in service for projected non-revenue producing post-test year capital additions anticipated to be in service prior to October 1, 2014. The settlement determination revises the Company's adjustment to reflect actual costs for completed projects in-service as of November 6, 2014. The settlement also includes accumulated deferred income taxes on the post-test year plant additions that are reflected in rate base. The net effect of these changes is to increase rate base by approximately $423,000.

Ben French, Neil Simpson I, & Osage Retirements – BHP proposed an adjustment to remove from rate base the amounts related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Accumulated Depreciation – The Company proposed an adjustment to increase accumulated depreciation (and thereby to reduce rate base) to reflect one-half of the annual depreciation expense associated with new assets and its new depreciation rates. The settlement revises the Company's adjustment to synchronize the depreciation reserve with the plant additions that are to be included in rate base and to reflect a depreciation rate of 2.98% for CPGS in lieu of the Company's proposed 3.29% rate. The net effect of these changes is to increase rate base by approximately $44,000.

Cash Working Capital – BHP's proposed rate base included an allowance for cash working capital based on a lead-lag analysis. A lead-lag analysis examines the timing of the Company's receipt of service revenues from customers in relation to the Company's payment of expenses to vendors and employees. The Company's cash working capital allowance also included a rate base deduction for tax collections which the Company receives in advance of turning the related payments over to the taxing authorities. Staff carefully examined BHP's revenue lag and expense lead day determinations and made the following modifications, which are consistent with Staff adjustments in prior rate cases:

1. Revised the expense lead days for net payroll, service/holding company charges, other operating and maintenance, FICA, federal income tax, gross receipts tax, federal withholding, and sales tax;
2. Included a separate expense lead for vacation pay;
3. Included a separate expense lead for incentive compensation;
4. Included a separate expense lead for uncollectible accounts expense;
5. Revised revenue lag days to remain consistent with past Staff practice and state statute, and to more accurately reflect the South Dakota jurisdictional revenue lag; and
6. Revised expenses per day to incorporate into the lead-lag analysis the impacts of Staff's recommended adjustments to *pro forma* operating expenses.

These modifications increase rate base by approximately $5,161,000.

Rate Case Expense – Rate case expense included in Docket EL12-061, which includes costs incurred for both Docket EL12-061 and EL12-062 as of July 2, 2013, was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the Docket EL12-061 rate case expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062, all amortized over a three-year period. BHP also proposed an unamortized amount of $750,046 be included in rate base. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014, for docket EL14-026 and $412,797 in actual, unrecovered costs for EL12-061 and EL12-062, for a total amount of $625,657. One-half of the rate case costs, or $369,191, is included in rate base, representing the average unamortized balance over the three year period. The net effect of these changes reduces rate base by approximately $381,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs, if any, associated with docket EL14-026 in BHP's next rate case.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the Environmental Protection Agency (EPA)'s National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In

Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants into a regulatory asset account.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of these three generating plants over five years and include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement removes all contingencies that had been included in BHP's decommissioning estimates, revises the amount included for obsolete inventory to agree with the amount removed from working capital, amortizes the regulatory asset over ten years, and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,806,000.

Storm Atlas Regulatory Asset – Winter Storm Atlas (Atlas) occurred October 3-5, 2013, causing the worst outages in BHP's 130-year history. Heavy snow and high winds, combined with fully leafed trees, caused significant damage to BHP facilities and left as many as 41,800 customers without power. Repairing this widespread damage far exceeded BHP's normal storm-related costs. In Docket EL13-036, the Commission issued an order allowing BHP to use deferred accounting for costs incurred as a result of Atlas.

In this docket, BHP proposed to include actual costs through December 31, 2013 arising from Atlas, as well as costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection driven by Atlas. BHP proposed to amortize these costs over five years and to include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only the incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,566,000.

Tax Return True-up – BHP's proposed test year allowance for income taxes included "true-up" adjustments to eliminate certain tax events that were recorded during the test year but which were related to periods prior to the test year. It is important to purge from test year operating results for transactions that relate to periods outside of the test year. Therefore, Staff accepts BHP's Tax Return True-up adjustments. Those adjustments are included in the Settlement revenue requirement determination.

NOL Adjustment – Over the past several years, bonus depreciation previously approved by Congress significantly increased BHP's annual tax deductions. The increased deductions, however, exceeded BHP's income resulting in a tax loss. Because of the tax loss position, BHP was not able to utilize all of its allowable deductions in the year they were earned. It had recorded deferred taxes relating to these tax deductions, nevertheless. The accumulated deferred taxes are used as an offset to BHP's rate base. Therefore, it was necessary to adjust BHP's rate base to reflect the unused tax deductions. BHP will now be able to utilize more of its previously unused tax deductions given the revenue increase agreed to by the Parties. The impact of this greater utilization of tax deductions on BHP's rate base has been reflected in the settlement revenue requirement. The result of recalculating this adjustment to reflect the effect of other adjustments incorporated in the settlement is to increase rate base by approximately $641,000.

Other Working Capital – BHP proposed this rate base adjustment to accurately reflect recent investments in a spare transformer for Neil Simpson II, in spare fan motors at the Neil Simpson Complex, in critical spare parts at Cheyenne Prairie Generating Station, and in a new coal stockpile at the Neil Simpson Complex, while removing the test year inventories at the recently retired Ben French, Neil Simpson I, and Osage generating units. The settlement accepts this adjustment while modifying for actual costs and reflecting a more recent 13-month average for materials and supplies, fuel stocks, and customer advances. These modifications increase rate base by approximately $969,000.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system, and BHP proposed to amortize costs associated with the project over five years and to include the unamortized balance, or four-fifths of the cost, in rate base. The settlement reflects a reduction for accumulated deferred income taxes associated with the project, an update to actual project costs and actual contributions from joint owners, and includes the average unamortized balance, or one-half of the cost, in rate base. The result of Staff's revisions reduces rate base by approximately $399,000.

Customer Service Model – This Staff proposed adjustment reflects the rate base reduction for BHP's customer service model changes. With the Belle Fourche and Newell customer service and electric operation service centers being consolidated and moved to Spearfish and Sturgis, respectively, the Newell office is no longer needed. Removing the remaining amounts associated with the Newell office reduces rate base by approximately $9,000.

Sturgis Office & Operations Center – BHP built a new service center in Sturgis to consolidate operations and business offices into one location in the northern hills. As a result, the two existing facilities in Sturgis will be closed. The settlement removes the amounts related to these two facilities as they are no longer needed. This adjustment reduces rate base by approximately $308,000.

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses, including employee additions. The settlement includes a rate base adjustment associated with one-half of the amount of annual employee salaries charged to capital projects. This adjustment increases rate base by approximately $79,000.

Other Rate Base Reductions – The Company's filing included *pro forma* rate base reduction for: 1) the flow-through of the income tax benefit associated with the repairs deduction that should not be included in rate base; 2) deferred taxes and federal effect of the state NOL that should be removed from rate base since South Dakota does not impose a state income tax; 3) deferred tax liability associated with regulatory asset – unit of property account that should not be included in rate base since the amount in the regulatory asset – unit of property is not included in rate base; and 4) the addition of accumulated deferred income tax associated with the plant that is allocated to BHP from BHSC and BHUH because the assets allocated to BHP are included in rate base. The settlement accepts this adjustment.

OPERATING INCOME

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses. These adjustments included 1) using 01/28/2014 annualized payroll as a starting point as it was the most recent payroll at the time BHP completed its adjustment; 2) removing the labor costs associated with Neil Simpson I plant personnel who will have part of their time charged to power plants not owned by BHP at the Neil Simpson Complex; 3) a 2014 union wage increase of 3.25%, a 2014 non-union wage increase of 3.50%, a partial year of a 3.5% 2015 union wage increase, and a partial year of a 3.5% 2015 non-union increase; 5) adding the costs associated with open vacancies and additional employees needed for operations; and 6) removing costs associated with employee eliminations.

Staff agreed with the Company's adjustment, except for the amounts included for the 2014 non-union and 2015 union and non-union wage increases and employee additions. The settlement revises the Company's adjustment to 1) reflect a 2014 non-union wage increase of 3.25% in lieu of the Company's proposed budgeted 3.5%; 2) reflect a full year of the 2015 union wage increase of 3.25% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; 3) reflect a full year of the 2015 non-union wage increase of 3.0% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; and 4) reflect employee additions for actual employees hired, including only the portion of employee salaries charged to O&M and adjusting the salaries for the 2015 wage increases. This adjustment reduces operating expenses by approximately $130,000.

Black Hills Corp. / Black Hills Utility Holdings Intercompany Charges – BHP proposed a $2.3 million adjustment to total company test year expenses for charges billed to it from Black Hills Utility Holdings (BHUH) (Adjustment H-5). Staff objected to this adjustment because it did not reflect a known and measurable change in BHP's costs; rather, it was merely BHP's estimate of future costs. Consistent with the Parties' treatment of other operating expenses, including expenses billed to BHP by BHSC, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, excluding amounts associated with vegetation management and reflecting an annualization for customer records and collection expenses associated with a change in allocation factors. The *pro forma* utility holdings costs also reflect an annualization of wage increases for both 2014 and 2015. The effect of these changes is to increase South Dakota operating expenses by approximately $527,000.

Employee Pension & Benefits Adjustment – BHP proposed a $334,319 total company adjustment to test year employee benefits expenses (Adjustment H-6). Within this adjustment, BHP normalized its test year pension expense by averaging the annual expense over the past five years. This normalization adjustment reduced the test year pension expense by $508,454 on a total company level. Staff agreed to BHP's pension expense normalization adjustment if it is to be applied consistently in future rate cases. Staff disagreed with the remainder of BHP's proposed employee benefits adjustment because it is based on estimated future costs rather than known cost changes. The settlement reflects known post-test year changes in employee benefits costs rather than BHP's estimates. It also reflects a normalized level of pension costs based on a five-year average of BHP's actual pension expense. The effect of these changes is to reduce South Dakota operating expenses by approximately $289,000.

Bad Debt Analysis – BHP proposed an adjustment to decrease bad debt expenses based on a three year uncollectible rate average. The settlement decreases bad debt expense based on a five year uncollectible rate average applied to retail revenues. The net effect of this change increases jurisdictional operating expense by approximately $6,000.

Generation Dispatch & Scheduling – BHP proposed an adjustment to update costs for generation dispatch and scheduling in accordance with the Generation Dispatch and Energy Management

Agreement (GDEMA) which allocates costs to the parties contracting for services based on total capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year-end August 2014 costs, while allowing known and measurable increases to labor and labor overhead. Staff also corrected errors to the capacities provided for Black Hills Power and Black Hills/Colorado Electric. The result of Staff's revisions reduces jurisdictional operating expense by approximately $106,000.

Energy Cost Adjustment Expense Elimination – The Company proposed an adjustment to remove all costs that are collected through the Energy Cost Adjustment (ECA) from the test year. The settlement accepts this adjustment.

Neil Simpson Complex Shared Facilities – BHP proposed an adjustment to update revenues and expenses for shared facilities in accordance with the Neil Simpson Complex Shared Facilities Agreement which allocates revenues and expenses to the parties based on net capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual costs. The result of Staff's revisions reduces jurisdictional operating expense by approximately $74,000 and reduces jurisdictional operating revenue by approximately $136,000.

Removal of Unallowed Advertising – BHP proposed an adjustment to remove advertising expenses that should not be recovered from ratepayers. The settlement accepts this adjustment and further removes additional advertising costs which do not contribute to the provision of safe, adequate, and reliable electric service for South Dakota ratepayers. The effect of this adjustment reduces operating expenses by approximately $4,000.

Power Marketing Adjustment – BHP's adjustment to remove power marketing expenses from the base rate regulated cost of service is found on Statement H, Schedule H-12. The revenue adjustment found in Statement I, page 1, removes the corresponding power marketing revenues from the base rates. The settlement revises the expense adjustment to correct the labor-bonus costs removed and accepts the revenue adjustment. The effect of this adjustment reduces operating expenses by approximately $9,000.

Rate Case Expense – Rate case expense included in Docket EL12-061 (consisting of costs related to Docket EL12-061 and EL12-062) was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062, amortized over a three-year period. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014 for docket EL14-026 and $412,797 in actual, unrecovered amounts for EL12-061 and EL12-062, for a total three-year amortization allowance of $625,657. The net effect of these changes is a reduction in operating expenses by approximately $188,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs associated with docket EL14-026 in the next rate case filing.

Vegetation Management Expense – BHP proposed to adjust its test year vegetation management expenses to reflect the amount approved in the stipulation in Docket EL12-061. The settlement accepts this adjustment with a slight modification which updates the allocator to conform to what BHP filed in its Statement N. The result of Staff's revision increases jurisdictional operating expense by approximately $1,000.

CPGS O&M – The Company proposed an adjustment to reflect projected operation and maintenance expense for CPGS during a normal year. The settlement reflects the Company's proposed adjustment, less reagent costs which are recovered through the ECA. This adjustment reduces operating expenses by approximately $28,000.

Ben French Severance Expense – BHP proposed an adjustment to remove the employee severance expense associated with the Ben French plant. The settlement accepts this adjustment.

Neil Simpson Complex Common Steam Allocation – BHP proposed an adjustment to update costs for the operation and maintenance of Neil Simpson Complex common steam facilities where BHP is responsible for costs relating to the capacity associated with Neil Simpson II and its ownership percentage of Wygen III. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year end August 2014 costs, while allowing known and measurable increases to labor and benefits. Staff also corrected errors in the capacity shares provided for Black Hills Power and MDU, City of Gillette & Other. The result of Staff's revisions reduces jurisdictional operating expense by approximately $243,000.

Ben French, Osage, & Neil Simpson I O&M Elimination – BHP proposed an adjustment to remove the test year operating and maintenance expenses related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Future Track Workforce Development – BHP proposed a $721,861 total company expense adjustment (Adjustment H-19) to implement its eight-year Future Track Workforce Development Program. Included in the Company's proposal was a request to defer as a regulatory asset for future recovery all costs associated with the program that exceed the amount included in base rates.

Staff objected to the Company's proposal, both as to the expense to be included in base rates and to BHP's proposal to defer expenses in the future. The Parties agreed to reflect in rates BHP's actual costs for newly hired employees under the Future Track program, without deferrals. The effect of this change is to decrease South Dakota operating expenses by approximately $344,000. The settlement also eliminates the annual reporting requirements proposed in BHP's filing.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system. BHP's share is amortized over five years to correspond with the expected frequency of the survey. Staff's adjustment reflects actual costs of the survey and actual contributions from the joint owners. The result of Staff's revision reduces jurisdictional operating expense by approximately $66,000.

Customer Service Model Adjustment – This adjustment reflects the cost reductions BHP achieved as a result of their customer service model changes. The Belle Fourche and Newell customer service and electric operation services centers were consolidated and moved to Spearfish and Sturgis, respectively. This adjustment removes the salaries and benefits of three customer service representatives and eliminates Belle Fourche and Newell facility costs. The settlement also removes further costs associated with telephone, janitorial labor, and depreciation expense. The result of Staff's revision reduces jurisdictional operating expense by approximately $7,000.

Remove City of Gillette – BHP proposed an adjustment to remove the City of Gillette revenue as it relates to replacement energy. The associated costs are removed as part of the Power Marketing adjustment. The settlement accepts this adjustment.

Unbilled Revenue and Provision for Rate Refunds – Unbilled Revenue reflects an accounting accrual made each month to reflect a portion of the current month usage which is billed in the following month. These accrual entries are reversed out the following month. Provision for Rate Refunds reflects the balance related to interim rates in Dockets EL12-061 and EL12-062. These adjustments remove the entire per books amounts from these two accounts to reflect normal levels. The settlement accepts these adjustments.

Removal of Energy Cost Revenue – The Company proposed an adjustment to remove revenue associated with the ECA as associated energy costs were also removed from the test year. The settlement accepts this adjustment.

PIPR Rate Annualization – The test year revenues contain only a portion of the Phase In Plan Rate revenues established in Docket EL12-062. This known and measurable adjustment is needed to reflect the proper level of revenue and properly match what customers were paying at the end of the test year, thus reducing the revenue deficiency. The settlement accepts this adjustment.

Weather Normalization – BHP's filing contained a weather normalization adjustment of ($644,705). Staff undertook an independent weather normalization analysis and concluded that an adjustment of ($264,403) would be appropriate. Staff's adjustment updated BHP's data to reflect the latest NOAA weather normals for the thirty year base period 1981-2010. Staff also included June in the analysis of cooling load sensitivity, and measured sensitivity in absolute value as a departure from normal, rather than relative variation from monthly normals. Sensitivity was based on regression coefficients correlating usage with departure from normal. BHP accepted Staff's adjustment for settlement purposes. The effect of these changes increases operating revenues by approximately $380,000.

Industrial Contract Service Accrual – BHP proposed this known and measurable adjustment to properly match revenues with test year usage for three of their industrial customers on contract rates. The settlement accepts this adjustment.

EL12-061 Rate Increase Annualization – The test year revenues are based on the rates established in Docket EL09-018; however, rates were changed in Docket EL12-061, effective October 1, 2013. This is a known and measurable change to test year operating results. BHP proposed this adjustment to reflect the proper level of revenue to be received from customers based on the recently approved rates. The settlement accepts this adjustment.

Interest Synchronization – The settlement synchronizes the tax deduction for interest expense with the weighted cost of long-term debt and the historical test year rate base as adjusted for known and measurable changes.

Depreciation Expense – In its March 31, 2014 rate filing, BHP claimed a total company depreciation expense allowance of $3,035,046 related to the Cheyenne Prairie Generating Station based on the then-estimated $92,250,624 total company plant investment at its expected in-service date of October 1, 2014. The expense allowance reflected a composite depreciation accrual rate of 3.29% that assumed a 35-year life span for the plant, allowances for retirements of plant components during the life span and an estimate of removal costs amounting to 4% of the plant investment at the time of its retirement.

The settlement reduces the CPGS depreciation allowance by $349,819 to $2,685,227, on a total company level, to reflect BHP's agreed-upon actual investment in the plant and a composite depreciation accrual rate of 2.98%. The 2.98% composite rate was derived by extending the assumed life span of CPGS from 35 years to a more realistic 40 years judging by life estimates made by other utilities for combined cycle generating units. Other parameters reflected in the 2.98% rate (interim retirements and removal costs) are consistent with the parameters reflected in BHP's existing depreciation accrual rates for its other generating facilities.

The settlement further revises the Company's depreciation adjustment to reflect the effect of the other plant adjustments included in the settlement. The net effect of these changes is to decrease South Dakota jurisdictional operating expenses by approximately $87,000.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the EPA's National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants to a regulatory asset.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of Neil Simpson I, Ben French, and Osage over five years. The settlement removes all contingencies, revises the amount included for obsolete inventory to agree with the amount removed from working capital, and amortizes the regulatory asset over ten years, reducing the annual South Dakota amortization expense by approximately $1,651,000. BHP may track the actual costs incurred and seek recovery, in a future rate case, of decommissioning costs not recovered from customers.

Storm Atlas Regulatory Asset – BHP proposed to include its actual Atlas-related costs through December 31, 2013, and its estimated costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection necessitated by Atlas. BHP proposed to amortize these costs over five years. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years. The net effect of these changes is to reduce the annual South Dakota amortization expense by approximately $512,000.

Charitable Contributions – The settlement removes approximately $16,000 in charitable contributions.

Storm Damage – The settlement normalizes storm damage costs to a five-year average. As Atlas was the only major storm event in 2013 and its costs are recovered in a separate adjustment, this normalization adjustment would need to include $0.00 for the 2013 expense, and Staff was concerned that using $0.00 would not reflect an accurate value of normal storm damage expense. Thus, Staff chose the 2008 through 2012 timeframe for this adjustment and increased operating expense by approximately $31,000.

Incentive Compensation – BHP's proposed revenue requirement included approximately $3.8 million for incentive compensation, including amounts billed from the affiliate service company. For settlement purposes, the Parties agreed that incentive compensation paid for achieving financial performance goals will be excluded from BHP's South Dakota revenue requirement. This adjustment reduces South Dakota operating expenses by approximately $666,000.

Economic Development – The Company proposed 100% recovery of economic development expenses included in the test year. The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. The adjustment reduces operating expenses by approximately $27,000.

Association Dues – The settlement removes approximately $6,000 in association dues costs associated with donations, lobbying, and various other activities that do not provide for the provision of safe, adequate, and reliable electric service for South Dakota ratepayers.

Custer to Hot Springs Cooperatives Revenues – BHP has a joint ownership agreement with Rushmore Electric and its two members, Black Hills Electric Cooperative and Butte Electric Cooperative, for the co-owned portions of the 69 kV sub-transmission system. Rushmore Electric Power Cooperative, on behalf of itself and its members, pays BHP a monthly fee to ensure that customers of all parties are fairly and accurately responsible for their use of the jointly owned facilities. The settlement includes an adjustment to account for the additional annual revenues BHP will receive associated with the Custer to Hot Springs line. The effect of this adjustment is to increase operating revenues by approximately $90,000.

Workers Compensation – During discovery, BHP proposed an adjustment to normalize workers compensation costs to a five-year average of the costs. The settlement accepts this adjustment, increasing operating expenses by approximately $172,000.

Black Hills Corp./ Black Hills Service Co. Intercompany Charges – BHP's filed case included test year expenses billed to it by its affiliate service company, approximately $20.4 million, without adjustment. Consistent with the parties' treatment of other operating expenses, including expenses billed to BHP by BHUH, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, except for property insurance which is BHP's actual costs for the year October 2014 through September 2015. The pro forma service company costs also reflect an annualization of wage increases for both 2014 and 2015. The net effect of these changes is to increase South Dakota operating expenses by approximately $1,132,000.

Income Tax Adjustment – The Company's filing included pro forma adjustments to income tax for true-up items and items that are not part of the regulated operations of BHP that should therefore not be included in the computation of federal income tax. The settlement accepts this adjustment.

COST OF CAPITAL AND RATE OF RETURN

BHP's initial filing sought an overall rate of return of 8.48 percent, which included an embedded debt cost of 6.45 percent and a capital structure of 53.32 percent equity and 46.68 percent debt. The requested rate of return on equity was 10.25 percent. Staff's analysis initially challenged all three components of the overall rate of return: (1) embedded cost of debt, (2) the capital structure, and (3) the required return on equity.

[Begin Confidential] [redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[End Confidential]**, the settlement overall rate of return is 7.76 percent.

RATE DESIGN ISSUES

The parties agree in principle on all issues regarding rate design and the class revenue distribution. The settlement position reached between Staff and BHP is discussed below.

Class Cost of Service/Spread of the Increase – BHP's filed case included a class cost of service study ("CCOSS"). A CCOSS is useful in assigning revenue responsibility to each rate class that BHP serves in

South Dakota and in designing rates within each class. The allocation methods reflected in BHP's CCOSS are basically the same as those that were reflected in previous CCOSS studies filed by BHP and accepted by Staff and the Commission. In this proceeding, however, BHP introduced the results of a new customer load study based primarily on data obtained from the Company's new AMI meters. The new load data was used in developing the class demand allocation factors used in the CCOSS. The new load data incorporated into the CCOSS indicated that base rates for two of the five customers classes should be increased significantly (Residential – 19.26% and General Service Large/Industrial Contract – 15.44%); base rates to the Water Pumping/Irrigation class should be increased by a small amount (3.45%); and base rates for the remaining two classes should be decreased (General Service – 6.37% and Lighting Service – 15.74%). Rather than implementing these indicated rate changes, BHP proposed a rate moderation plan to avoid adverse rate impacts to the Residential and General Service Large/Industrial Contract customers. Under BHP's moderation plan, no class is to pay less than 75 percent of the system-wide percentage increase and no class is to pay more than 120 percent of the system-wide percentage increase.

Without agreeing specifically with either the results of the CCOSS or BHP's underlying new load research results, the Parties agreed to accept BHP's proposed rate moderation plan by implementing a 75% to 120% percent collar around the system-wide percentage increase. Under this approach, the following class increases result:

Settlement Class Revenue Increases

Class	Percent Increase
Residential	5.04%
General Service	3.46%
General Service Large/Industrial Contract	4.55%
Water Pumping/Irrigation	3.11%
Lighting Service	3.45%
Total	**4.35%**

Rate Design (Residential Customer Service Charge) – BHP's currently effective monthly customer service charge for the Residential class is $8.75. BHP proposed to increase the present rate to $10.00. In settlement, the parties agreed to increase the Residential monthly customer service charge to $9.25. This represents a 5.71 percent increase in that charge, which is within the range agreed to among the parties for the Residential class as a whole. Staff also believes that a $9.25 monthly service charge is supported by the underlying costs to serve Residential customers.

OTHER ISSUES

Economic Development – The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. Under the terms of the settlement the following conditions apply:

- $100,000 total paid equally by ratepayers ($50,000) and shareholders ($50,000);

- Expenses shall include but not be limited to, all South Dakota labor, expenses and monetary contributions deemed to be a benefit to economic development in the BHP South Dakota electric territory;
- On an annual basis, no later than March 1 of each year, BHP will submit for the Commission's approval a filing that describes the actual cost, design and individual benefits of each cost to BHP's Economic Development programs in the previous calendar year and the projected cost, design and individual benefits of each cost to BHP's Economic Development programs in the current calendar year;
- The Commission may determine that some of the programs are not appropriate for purposes of 50% rate recovery;
- If the remaining programs cost less than $100,000 at the end of a program year, the unspent costs shall be "carried over" into the next program year for Commission approval of expenditure or refund; and
- No carry-over shall occur for any amounts spent annually in excess of $100,000.

Energy Cost Adjustment – The Company proposed the following change to the Fuel and Purchased Power Adjustment (FPPA), which is a component of the ECA: 1) to include any difference in ad valorem or property taxes from what is reflected in base rates; 2) to credit 100% of the Company's wholesale contract revenue on October 1, 2014, as agreed to in Docket No. EL12-062; 3) to eliminate the power marketing credit minimum; and 4) to recover 100% of the costs related to short-term planning reserve capacity purchases and sales. Staff agreed with items 1, 2, and 4, but took issue with the elimination of the power marketing credit minimum. The Parties agreed for settlement purposes to reduce the power marketing credit minimum from $2 million to $1 million and increase the power marketing sharing from 65% to 70%.

Major Maintenance Accrual – BHP requested approval of a modification to the major maintenance account to expense a portion of the plant overhaul costs each year based on a plant's planned maintenance cycle. In Docket EL09-018, the settlement allowed BHP to establish a major maintenance account and a regulatory liability for steam plant maintenance and a 7-year cycle was established. The work previously done during the seven year overhaul is now split into two overhauls. There is no change in the existing accrual at this time. The settlement defines major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

Implementation of Rates – The tariffs shown on Exhibit 1 attached to the Settlement are to be implemented for service rendered on or after March 1, 2015. Customer bills will be prorated so that usage prior to October 1, 2014, is billed at BHP's previously effective rates (i.e., the base rate in effect immediately prior to the interim rates implemented on October 1, 2014), and usage on and after October 1, 2014, is to be billed at the new rates established by the settlement.

Interim Rate Refund – Interim rates were implemented on October 1, 2014. Approval of the Settlement will authorize a rate increase less than the interim rate level. The Company agrees to refund customers the difference between interim rates and new rates established by the settlement for usage during the period October 1, 2014 through February 28, 2015. As part of the refund, BHP will include interest, calculated by applying a 7% annual interest to the average refund balance for each month that interim revenues were collected. The Company's Interim Rate Refund Plan is attached to the Settlement as Exhibit 3.

Contract with Deviations – On September 4, 2014, BHP filed a Contract with Deviations between BHP and SDSTA. The Commission approved this Contract with Deviations on an interim basis. Now that the cost of service and class cost of service study review is complete, Staff and BHP agree the Contract with Deviations may now be finally approved by the Commission, without condition.

RECOMMENDATION

Staff recommends the Commission approve the Settlement for the reasons stated above.