Rebuttal Testimony and Exhibit
John J. Spanos

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

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

For Authority to Increase Rates
in South Dakota

Docket No. EL14-026

January 15, 2015

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Exhibits

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am associated with the firm of Gannett Fleming, Inc.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING, INC.?

A. I have been associated with the firm since college graduation in June 1986.

Q. WHAT IS YOUR POSITION WITH THE FIRM?

A. I am a Senior Vice President.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

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

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut the portions of the direct testimony of Black Hills Industrial Intervenors' witness, Mr. Lane Kollen, related to depreciation.

Q. WHAT ARE THE SUBJECTS OF YOUR REBUTTAL TESTIMONY?

A. The overall subject of my testimony is depreciation. Specifically, I will address the proper depreciation rates for the new Cheyenne Prairie Generating Station ("CPGS") and the most appropriate net salvage percentages for steam and other production accounts.

III. <u>DEPRECIATION RATES FOR CPGS</u>

Q. HAVE YOU DETERMINED DEPRECIATION RATES FOR THE NEW CPGS FACILITY?

A. Yes. The depreciation rates were set forth on page III-8 of the Depreciation Study. These rates were determined by account, based on interim survivor curves, weighted net salvage percents and a 35-year life span.

Q. DID ALL PARTIES AGREE WITH THE INITIAL PROPOSED RATES BY ACCOUNT FOR CPGS?

A. No. Most of the parties agreed in settlement with the concepts utilized in determining the parameters, however, the settlement established a change in the life span from the most commonly utilized life span of 35 years to 40 years. The 40-year life span is still considered reasonable for this type of facility.

Q. DID MR. KOLLEN AGREE WITH ALL OF THE PARAMETERS IN THE SETTLEMENT THAT PERTAIN TO DEPRECIATION?

A. No. Mr. Kollen has agreed with the 40-year life span and developed future accruals based on the negative 4 percent net salvage; however, he has incorrectly determined the remaining lives which produce inappropriate annual accrual amounts and rates.

Q. CAN YOU SHOW THE PROPER CALCULATION REFLECTING ALL THE APPROPRIATE PARAMETERS OF THE SETTLEMENT?

A. Yes. Exhibit JJSR-1 sets forth the annual accrual amounts and rates by account utilizing all the proper parameters for CPGS. These rates produce a composite rate of 2.98% and $2,097,669 in annual expense. That is $72,069 per year higher than the amount calculated by Mr. Kollen in Exhibit LK-16.

Q. IS THE COMPOSITE RATE OF 2.98% FOR CPGS AGREED UPON BY STAFF AND THE COMPANY?

A. Yes.

Q. DOES EXHIBIT JJSR-1 CLEARLY SET FORTH ALL THE PARAMETERS TO BE UTILIZED IN DETERMINING THE PROPER RATES FOR CPGS?

A. Yes. The plant in service totals $70.3M, the future accruals total $73.1M, which includes the negative 4 percent net salvage. Each account sets forth the remaining life and annual accrual amount based on the 40-year life span, negative 4% net salvage and interim survivor curve. Therefore, using the appropriate parameters, the total annual expense for CPGS when it goes into service is $2,097,669, not $2,025,600 as shown in Exhibit LK-16.

IV. <u>NET SALVAGE FOR STEAM AND OTHER PRODUCTION ACCOUNTS</u>

Q. DID MR. KOLLEN AGREE WITH YOUR NET SALVAGE PERCENTS FOR ALL ACCOUNTS?

A. No. Mr. Kollen accepted all net salvage percentages for assets in transmission, distribution and general plant, but did not accept the net salvage percentages for steam and other production plant accounts.

Q. WHAT ISSUES HAVE BEEN RAISED BY MR. KOLLEN?

A. Mr. Kollen challenged the inclusion of terminal net salvage, or the decommissioning and dismantlement of the Company's power plants, in depreciation rates. Mr. Kollen's testimony is primarily focused on terminal net salvage, although he has presented other issues related to net salvage that I address in this testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY RELATED TO NET SALVAGE.

A. The first issue I address is terminal net salvage for production plant. I will explain that, as required by the Uniform System of Accounts and authoritative depreciation texts, depreciation must incorporate net salvage. The primary depreciation issue in this case is whether the Company will experience terminal net salvage for their power plants when they are eventually retired. Experience now shows that not only will power plants be retired, but there are significant costs upon retirement related not only to the dismantlement of the plant itself, but also to the remediation of features of the site such as ash ponds. Since these costs are likely to be incurred, intergenerational equity and depreciation authorities require that they be included in depreciation and recovered over the service lives of the plants.

Throughout this testimony I address proper net salvage methodologies in general. I respond to Mr. Kollen's comments and explain that his proposals are not consistent with the Uniform System of Accounts, authoritative depreciation texts, and well established practice in almost all jurisdictions in the country.

Q. WHAT IS TERMINAL NET SALVAGE?

A. Facilities such as power plants are referred to as "life span property." Life span property is property for which an entire facility is expected to be retired at a concurrent point in time. Life span property therefore experiences two types of retirements. The first is referred to as "terminal" (or "final") retirements, which occur when the entire plant (or an entire generating unit) is retired. At the time the entire plant is retired, all assets at the site are retired as terminal retirements. However, many assets will also be retired (and replaced) throughout the life of the power plant in order to operate the plant safely and efficiently. These retirements that occur before the final date of retirement are referred to as interim retirements. The net salvage (gross salvage less cost of removal) that occurs associated with the terminal retirement of the plant (either when the plant is retired or at a later date) is referred to as "terminal net salvage" or "final net salvage". Terminal net salvage may include the decommissioning and dismantlement of the power plant itself, as well as the costs associated with the remediation of the site, such as the closure of ash ponds.

Q. WHAT IS INTERIM NET SALVAGE?

A. Interim net salvage is net salvage that is associated with the interim retirements that occur throughout the life of the power plant.

Q. WHAT HAS MR. KOLLEN RECOMMENDED REGARDING NET SALVAGE FOR GENERATING PLANTS?

A. Mr. Kollen has recommended that no terminal net salvage be included in depreciation. He further recommends that the current negative 5% net salvage be maintained, however, he applies the negative 5% net salvage percentage to all assets regardless of how they are retired.

I initially will focus on the issue related to terminal net salvage. I then turn my attention to how Mr. Kollen calculates depreciation expense with his use of interim net salvage percentages.

Q. WHAT ARE THE ISSUES RELATED TO TERMINAL NET SALVAGE?

A.
1. Based on a review of Mr. Kollen's testimony, there are two main issues regarding terminal net salvage in this proceeding that the Commission must consider. Specifically, these are as follows: Should the Company be expected to experience terminal net salvage for the facilities currently in service, and what does experience actually teach us regarding whether companies across the country incur significant costs upon the retirement of power plants?
2. Should terminal net salvage be allocated over the service life or lives of the Company's generating facilities?

As I discuss later, the second issue should not be controversial; therefore, the primary issue is whether the Company should be expected to experience terminal net salvage. Net salvage, a component of the service value of depreciable property, must be allocated over the service life of depreciable property. This concept is widely supported by the Uniform System of Accounts, authoritative depreciation texts, and decisions from other commissions. It is also consistent with ratemaking principles such as intergenerational equity, and is consistent with the approach for transmission, distribution and general plant that the Commission has previously accepted. Unfortunately, Mr. Kollen appears to have challenged this well-established practice for generating assets, therefore I will address his claims in more detail and remind the Commission of these ratemaking and accounting principles in my rebuttal testimony.

My focus will be on the appropriate terminal net salvage estimates for production plant. Since net salvage must be included in depreciation rates, the fundamental issue in this case is estimating the terminal net salvage for generating facilities. Mr. Kollen has recommended that there will be no terminal net salvage for production plant accounts, and provides testimony that attempts to cast doubt as to whether the Company will actually incur costs upon the retirement of its generating facilities. Additionally, he erroneously attempts to use the circumstances with the three recently retired steam plants as a precedent for recovery of existing facilities. As described below, experience has not only shown that coal-fired power plants are decommissioned and dismantled upon their retirement, but that these activities result in significant costs. Intergenerational equity requires that these costs be recovered over the lives of the plants, so that customers who benefit from the plants will pay for their full service value.

Q. HAVE COMPANIES EXPERIENCED TERMINAL NET SALVAGE RELATED TO RETIRED POWER PLANTS?

A. Yes. The number of retirements of coal-fired power plants has increased significantly, due in part to changing environmental regulations and the lower cost of natural gas. There are also a number of plants expected to retire in the coming years. As a result, there is far more evidence of the ultimate disposition of these facilities upon their retirement. The retirement of these plants has typically resulted in costs not only related to the dismantlement of the physical power plants, but also significant costs related to the clean-up of the site.

Q. CAN YOU PROVIDE EXAMPLES OF POWER PLANTS THAT HAVE BEEN OR ARE PLANNED TO BE DECOMMISSIONED?

A. Yes. There are many recent examples of plants that either have been or will be decommissioned and dismantled. Based on the issues in this case, it is known that Black Hills Power will decommission its Ben French, Osage and Neil Simpson I plants. Black Hills Colorado Electric is in the process of decommissioning its Canon City (W.N. Clark) plant and units 5 and 6 at its Pueblo plant. AmerenMO has decommissioned and dismantled its retired Venice power plant. Duke Energy plans to decommission a number of sites in the Carolinas, and activities related to the retirements of these sites include asbestos removal, demolition and the closure of ash ponds. Dominion Virginia Power is in the process of decommissioning coal units at its Chesapeake Energy Center, North Branch and Yorktown sites.

Q. CAN YOU DISCUSS SOME OF THESE EXAMPLES IN MORE DETAIL?

A. Yes. I will discuss the Black Hills Corporation plants as well as the Venice plant in more detail.

Q. PLEASE DISCUSS THE BLACK HILLS CORPORATION PLANTS.

A. Both Black Hills Colorado Electric and Black Hills Power have retired coal-fired generating units in recent years. The Black Hills companies have begun the process of decommissioning and dismantling these plants, and have solicited bids for this work. The MW output and the costs to dismantle and decommission these plants are provided in Table 1 below.

Table 1: Decommissioning Costs for Black Hills Plants

Plant	MW	Decommissioning Cost ($, millions)
Black Hills Power		
Ben French	25	4.0
Osage	35	4.0
Neil Simpson I	22	3.0
Black Hills Colorado		
Canon City (Clark)	40	4.1
Pueblo Units 5 and 6	29	3.8

The decommissioning costs for these plants, shown in Table 1, correspond to a terminal net salvage cost of about $100 to $160 per kW for each plant.

Q. HOW DO THE EXPERIENCES OF THE BLACK HILLS AND VENICE PLANTS IMPACT THE INCLUSION OF TERMINAL NET SALVAGE IN THIS CASE?

A. The facts surrounding the experience of these plants support that there should be expected significant costs associated with the final retirement of coal-fired power plants. These costs are not speculative, and instead experience shows that terminal net salvage costs are likely to occur.

First, consider the argument that the Company's plants can be reused for other purposes (such as future generation). Such a scenario has in fact occurred with the Venice site. The coal facility at this site was retired in 2002, and the site continues to be used for other types of generation. The reuse of the site did not prevent the company from incurring significant costs related to the retirement of the incumbent coal plant. The company has spent a net amount of approximately $15.6 million removing the retired power plant and remediating the site, over two thirds of which was related to the closure of the ash pond. Thus, this experience teaches that even when the site will be reused for new generation there will still be significant costs incurred for the retirement of the old plant. These costs therefore should be included prospectively in depreciation rates.

Regarding the argument that the estimation of terminal net salvage is speculative, the recent evidence should again disprove this sentiment. The Venice costs, as well as the other examples cited above, demonstrate that significant costs will be incurred upon retirement for coal plants.

The costs and activities associated with the retirement of the ash pond at Venice are also instructive. These are activities that are highly likely to be required upon the retirement of the Company's power plants. Recent breaches of ash ponds at sites owned by the Tennessee Valley Authority and by Duke Energy, in which the contents of the ash ponds entered waterways, have increased scrutiny related to the remediation of the ash ponds at coal plants across the country. It should therefore be expected that the costs incurred at the Company's existing coal fleet at a minimum be similar in scope to the activities that were undertaken at Venice.

Q. HOW DO THE COSTS OF DECOMMISSIONING AND DISMANTLING THE REMAINING FACILITIES COMPARE TO THE RECENTLY RETIRED PLANTS?

A. The costs for the Black Hills plants are about $100 to $160 per kW, which is within the range I have used for the remaining steam plants. The depreciation study includes a decommissioning cost of $20 per kW estimate for other production plant which is comparable to industry ranges.

Q. WHAT ARE THE ARGUMENTS MADE BY MR. KOLLEN AS TO WHY TERMINAL NET SALVAGE SHOULD BE EXCLUDED FROM DEPRECIATION?

A. There are two types of arguments made by Mr. Kollen. He first argues that net salvage for production plant should not be updated from the last study regardless of new analyses. These arguments are very much flawed and inconsistent with the prescriptions of the Uniform System of Accounts, authoritative depreciation texts, and the practice for net salvage in almost every jurisdiction in the country.

The second type of argument set forth by Mr. Kollen is intended to cast doubt on whether the Company will incur terminal net salvage costs when its plants are retired. Mr. Kollen has used this argument to support his recommendation that the Company should not accrue for net salvage while the assets are in service. This is clearly intergenerational inequity.

Q. PLEASE EXPLAIN THE ARGUMENT RELATED TO THE TERMINAL NET SALVAGE COSTS.

A. The argument presented by Mr. Kollen is that there is reason to doubt that the Company will incur terminal net salvage costs and the costs should not be recovered until after the asset is retired. This argument is not supported by recent events of Black Hills Power.

For example, Mr. Kollen states that:

> "The Company has not justified the significant increases that it proposes or provided any valid rationale to change policy. The Commission should not provide premature recovery of unknown future costs; the Company can seek recovery of decommissioning costs in the future when the method of decommissioning can be assessed and the cost can be determined based on actual bids."[1]

Mr. Kollen attempts to use the circumstances with the three recently retired Black Hills Power units as Commission policy which erroneously contradicts the concept of net salvage and recovery of the full service value of all assets.

Q. HOW HAVE YOU INCORPORATED INTERIM NET SALVAGE INTO THE DEPRECIATION RATES YOU HAVE RECOMMENDED?

A. For interim retirements, I have made estimates of interim net salvage based in part

[1] Direct Testimony of Lane Kollen, pg. 48, lines 8-13.

on the statistical analyses of the Companies' historical interim net salvage data. This process is the same as for the estimates of net salvage for transmission, distribution and general plant. The historical data are shown on pages III-121 through III-129 of the depreciation study, and the recommendations I have made for an interim net salvage estimate for steam production plant is negative 20 percent and for other production plant is negative 5 percent.

The interim net salvage estimate only applies to retirements that will occur as interim retirements, whereas terminal retirements will experience terminal net salvage. I have therefore determined the estimated percentage of the investment at each generating unit that will be retired as interim retirements and the percentage that will be retired as terminal retirements. The interim and terminal net salvage estimates are then composited based on these percentages to determine the weighted net salvage percent for each generating unit. The calculations of these weighted net salvage percentages can be found in Tables 1 and 2 on pages III-119 and III-120 of the depreciation study.

Q. **WHAT HAS MR. KOLLEN RECOMMENDED REGARDING INTERIM NET SALVAGE?**

A. Mr. Kollen has objected to the inclusion of more up to date net salvage analyses and recommends a negative 5% net salvage be maintained. He does not address any distinctions of how the past percentage was determined. Although he does not discuss in detail, Mr. Kollen's calculations apply negative 5% net salvage to all assets regardless of how they are retired.

Q. DO THE COMPANY'S HISTORICAL DATA DEMONSTRATE THAT NET SALVAGE FOR PRODUCTION PLANT SHOULD INCORPORATE INTO DEPRECIATION RATES A NET SALVAGE PERCENT DIFFERENT THAN NEGATIVE 5 PERCENT?

A. Yes. The historical interim net salvage data for steam and other production plant are shown on pages III-121 through III-129 of the depreciation study. The historical data shows that the Company has experienced interim net salvage in almost every year for which data is available. The Company has experienced a total steam negative net salvage amount of $5.5 million for $27.0 million of associated retirements or 20 percent for the full period 1997-2012. Similarly, the historical net salvage for other production is slightly less than 5 percent for the associated retirements during the 1997-2012 period.

It is clearly shown in my Study that the Company experiences interim net salvage and will continue to do so in the future. Therefore, the negative 20 percent net salvage for steam and negative 5 percent for other production assets is well supported for interim net salvage. This is only part of the net salvage component for production plant. The other component is terminal net salvage which should include costs comparable to the three recently retired Black Hills plants and industry averages for other production plant.

V. NET SALVAGE METHODOLOGY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

A. In this section, I explain that depreciation authorities and the established precedent of this and other commissions is that net salvage is to be incorporated into depreciation. First, I will discuss the prescriptions of the Uniform System of Accounts ("USofA") and explain that the USofA requires that net salvage be incorporated into depreciation. Next, I explain that with the exception of a handful of states, the vast majority of jurisdictions (including South Dakota) incorporate net salvage into depreciation. I then explain the recommendations of authoritative depreciation texts regarding net salvage. The collective discussion of these authorities should make clear that Mr. Kollen's recommendations are inappropriate, and that terminal and interim net salvage must be incorporated into depreciation for production plant facilities.

A. <u>UNIFORM SYSTEM OF ACCOUNTS</u>

Q. DOES THE UNIFORM SYSTEM OF ACCOUNTS ADDRESS THE ISSUE OF HOW NET SALVAGE COSTS SHOULD BE ACCOUNTED FOR, AND IF SO, HOW?

A. Yes. The USofA prescribes that net salvage costs should be accrued over the course of an asset's service life (*i.e.*, recognized in each period in which the asset provides service) in a systematic and rational manner. Net salvage costs should not be recognized in the period in which any salvage-related costs are paid and should not be recovered after these costs are incurred.

Q. PLEASE EXPLAIN.

A. The USofA defines depreciation as follows:

> *Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[2]

Depreciation accrual rates are used to allocate, for accounting purposes, the service values of assets over their service lives. As a result, each year of service (and each generation of customers) is charged with the portion of the asset consumed or used in that year. Total annual depreciation is based on a system of depreciation accounting which aims to distribute the cost of fixed capital assets, less net salvage, over the estimated useful life of the unit, or group of assets, in a systematic and rational manner.

Q. YOU REFERRED TO DEPRECIATION AS THE "LOSS IN SERVICE VALUE." WHAT IS SERVICE VALUE?

A. Service value, as defined in the USofA, is "the difference between original cost and net salvage value of electric plant."[3]

Q. DOES THE USOFA ALSO DEFINE WHAT IT MEANS BY "NET SALVAGE VALUE?"

[2] 18 CFR, Chapter 1, Part 101 Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Definition 12.

[3] 18 CFR, Chapter 1, Part 101 Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Definition 36.

A. Yes, it does. "'Net salvage value' means the salvage value of property retired less the cost of removal."[4] Net salvage is described as "positive net salvage" if the salvage value exceeds removal costs, and described as "negative net salvage" (*i.e.*, a net cost) if removal costs exceed the salvage value.

Q. DOES THE USOFA PRESCRIBE A METHOD OF DEPRECIATION ACCOUNTING?

A. Yes. Both the electric and gas Uniform System of Accounts include General Instruction 11, "Accounting to be on accrual basis," which states, "The utility is required to keep its accounts on the accrual basis." Further, General Instruction 22, "Depreciation Accounting," pertains to electric utilities and states that "Utilities <u>must</u> use a method of depreciation that allocates in a systematic and rational manner the <u>service value</u> of depreciable property <u>over the service life of the property</u>." (Emphasis added.)

Q. PLEASE EXPLAIN WHY YOU HAVE EMPHASIZED CERTAIN PARTS OF GENERAL INSTRUCTION 22?

A. The emphasized portions in this section are definitive in stating that net salvage must be included in depreciation. The USofA states that utilities "must" use a method of depreciation that allocates the "service value" – defined as original cost less net salvage – "over the service life of the property."

Q. WHAT IS THE ACCRUAL BASIS OF ACCOUNTING REFERRED TO IN GENERAL INSTRUCTION 11?

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[4] *Id.* Definition 19.

A. Under the accrual basis of accounting, transactions are counted when the order is made, the item is delivered, or the service occurs, regardless of when any money for such orders, items, or services is actually received or paid. The accrual basis recognizes economic events without regard to when the related cash transaction occurs. Thus, net salvage costs are traditionally recognized when the service is rendered, *i.e.*, during each year of an asset's service life, rather than when the actual salvage-related costs are incurred. To recognize the costs only at the time any net salvage-related dollars change hands would be to follow the "cash" basis of accounting, contrary to the instructions of the Uniform System of Accounts.

Q. BASED ON THE FOREGOING DEFINITIONS AND INSTRUCTIONS, WHAT DO YOU CONCLUDE THE USOFA REQUIRES REGARDING NET SALVAGE?

A. The USofA, which I understand South Dakota electric utilities are required to follow, requires that net salvage, as a component of service value, must be allocated or accrued over the service life of the property in a systematic and rational manner.

Q. ARE MR. KOLLEN'S PROPOSALS CONSISTENT WITH THE USOFA?

A. No. Mr. Kollen recommends ignoring recent historical indications because net salvage has become more negative and a utility does not have the right to accrue for some net salvage while the asset is in service. Further, Mr. Kollen states in his testimony "this may represent an undisclosed proposal to change the Commission's policy for decommissioning cost recovery from recovery *after* the retirement of the plants (as is the case in this proceeding for the three retired coal-fired plants) to recovery *before* the future retirement of the plants."[5] His proposal, by his own admission, does not allocate the full service value (including all net salvage) of these assets over their service lives. His proposal is therefore not consistent with the USofA.

B. ACCEPTANCE OF NET SALVAGE METHODS

Q. IS THE CONCEPT THAT NET SALVAGE MUST BE INCORPORATED INTO DEPRECIATION WIDELY ACCEPTED IN THE U.S.?

A. Yes, it is. To my knowledge, only three states currently do not incorporate estimates of future net salvage into depreciation rates. All other states, as well as the FERC, incorporate net salvage into depreciation rates. Further, the three states that do not incorporate estimates of net salvage allow for an allowance for net salvage incurred by the utility.

Q. DOES SOUTH DAKOTA INCORPORATE NET SALVAGE INTO DEPRECIATION RATES?

A. Yes. The Company's existing depreciation rates, approved by the Commission, incorporate net salvage into depreciation rates for all plant accounts.

C. TREATMENT IN PREEMINENT DEPRECIATION TEXTS

Q. DO AUTHORITATIVE TEXTS ON DEPRECIATION ADDRESS THE ISSUE OF WHETHER NET SALVAGE SHOULD BE ACCRUED DURING THE LIFE OF THE RELATED PLANT?

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[5] Direct Testimony of Lane Kollen, p. 47, lines 16-19. (Emphasis in original).

A. Yes, they do.

Q. WHAT DO THESE TEXTS PROVIDE?

A. The National Association of Regulatory Utility Commissioner's *Public Utility Depreciation Practices* ("NARUC" or "NARUC Manual") and *Depreciation Systems* by Wolf and Fitch ("*Depreciation Systems*" or "Wolf and Fitch") are preeminent texts on the subject of depreciation, and each explains that net salvage should be ratably accrued over the life of the related property.

Public Utility Depreciation Practices, published in 1996 states the following:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.[6]

The 1994 edition of *Depreciation Systems*, another highly regarded authoritative text on depreciation matters states:

The matching principle specifies that all costs incurred to produce a

[6] NARUC, *Public Utility Depreciation Practices*, 1996, p. 157

> service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses.[7]

Q. MR. KOLLEN HAS RAISED THE ISSUES OF TERMINAL AND INTERIM NET SALVAGE. DOES EITHER OF THESE TEXTS ADDRESS THESE ISSUES?

A. Yes. NARUC discusses net salvage for life span categories on page 161. NARUC explains that estimates of both interim and final (or terminal) net salvage are made for life span property (such as power plants):

> Net salvage associated with final retirements must be composited with interim net salvage resulting from expected piecemeal retirements in order to develop an estimate of future net salvage.[8]

Q. HOW DO THESE AUTHORITIES IMPACT YOUR ANALYSIS?

A. They show that accruing net salvage costs over the life of the related asset has the virtue of being not only the majority approach accepted by the vast majority of regulatory commissions, but is also the approach supported by authoritative depreciation texts.

Q. IS THERE A DIFFERENCE IN THE NET SALVAGE COMPONENT FOR PRODUCTION PLANT THAN ALL OTHER ASSETS?

A. No. The net salvage component for all assets in the Depreciation Study represent the recovery of the full service value of the assets within the account. The only difference is the nature of when the assets are retired. For the mass accounts, you

[7] *Depreciation Systems*, W. C. Fitch and Frank K. Wolf, 1994, p. 7.
[8] NARUC, *Public Utility Depreciation Practices*, 1996, p. 161.

have retirements annually with associated cost of removal and gross salvage for each asset recorded. A percentage of the assets in each account are retired or replaced each year which is the expectation of mass property accounts. For production accounts, there are annual retirements or replacements each year, just like mass property accounts; however, there is also an expected major retirement at a concurrent date which represents the life span of the facility. Therefore, the assets in production accounts do not have perpetual life characteristics. This does not mean you do not have the opportunity to recover the portion of service value related to these assets as Mr. Kollen would make one believe.

Q. HAS MR. KOLLEN ACCEPTED ALL THE NET SALVAGE PERCENTAGES FOR TRANSMISSION, DISTRIBUTION AND GENERAL PLANT?

A. Yes.

Q. HAS MR. KOLLEN CONDUCTED A NET SALVAGE ANALYSIS FOR ANY ASSETS?

A. No. Mr. Kollen has accepted the net salvage estimates recommended in the Depreciation Study for transmission, distribution and general plant which includes statistical analyses through 2012. However, he has disregarded any statistical analyses for steam and other production assets and randomly suggested maintaining the current estimate of negative 5 percent for all accounts.

Q. WAS THE NET SALVAGE ANALYSES IN THE DEPRECIATION STUDY

FOR PRODUCTION PLANT CONDUCTED IN THE SAME FASHION AS THE OTHER PLANT ACCOUNTS?

A. Generally, yes. In all cases, the net salvage percent is based on judgment which includes as a primary factor, the statistical analyses through 2012 of retirements and their associated cost of removal and gross salvage. The process is described on pages II-26 through II-28 of the Depreciation Study and the statistical analysis is set forth on pages III-118 through III-148 of the Depreciation Study. The only difference between production plant and the other functional plant is the component for terminal net salvage. The tables which set forth how interim and terminal net salvage are derived and then weighted to produce one net salvage percent by location is set forth on pages III-118 and III-119 of the Depreciation Study.

Q. DOES THE INCLUSION OF TERMINAL NET SALVAGE JUSTIFY THE ELIMINATION OF RECENT HISTORICAL INDICATIONS?

A. Absolutely not. As a matter of fact, the tables on pages III-118 and III-119 of the Depreciation Study more accurately assign net salvage amounts to the assets which will be retired on an interim basis and those retired on a terminal basis.

Q. IS THERE CONSIDERABLE SUPPORT FOR THE NET SALVAGE PERCENTAGES UTILIZED IN THE DEPRECIATION STUDY?

A. Yes. The interim net salvage percentages are supported with the most recent 16-year period, 1997-2012. The terminal net salvage percentages are supported by the dismantlement component of other recently retired Black Hills Power facilities and industry ranges.

Q. ARE MR. KOLLEN'S CALCULATIONS IN EXHIBIT LK-20 BASED ON ALL THE PROPER PARAMETERS?

A. No. Mr. Kollen uses the same remaining lives in the depreciation study, however, he changes parameters and utilizes a different plant in service amount from a different time period. This in itself causes inconsistencies in his work.

Q. HAVE THE DEPRECIATION RATES AND PARAMETERS IN THE DEPRECIATION STUDY BEEN APPROVED BY THE WYOMING PUBLIC SERVICE COMMISSION?

A. Yes. The Wyoming Public Service Commission approved settled 2.98% composite rate for CPGS and the generating rates for all other assets which are being challenged by Mr. Kollen.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

EXHIBIT JJSR-1

BLACK HILLS POWER
CHEYENNE PRAIRIE GENERATING STATION

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHEYENNE PRAIRIE - COMBINED CYCLE INTERIM SURVIVOR CURVE.. IOWA 55-R3 PROBABLE RETIREMENT YEAR.. 10-2054 NET SALVAGE PERCENT.. -4						
2014	7,028,693.10	94,809		7,309,841	38.06	192,061
	7,028,693.10	94,809		7,309,841		192,061

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.1 2.73

BLACK HILLS POWER
CHEYENNE PRAIRIE GENERATING STATION

ACCOUNT 342 FUEL HOLDERS AND ACCESSORIES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHEYENNE PRAIRIE - COMBINED CYCLE INTERIM SURVIVOR CURVE.. IOWA 50-S0.5 PROBABLE RETIREMENT YEAR.. 10-2054 NET SALVAGE PERCENT.. -4						
2014	10,543,039.65	154,713		10,964,761	34.94	313,817
	10,543,039.65	154,713		10,964,761		313,817

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.9 2.98

BLACK HILLS POWER
CHEYENNE PRAIRIE GENERATING STATION

ACCOUNT 344 GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHEYENNE PRAIRIE - COMBINED CYCLE INTERIM SURVIVOR CURVE.. IOWA 45-R2 PROBABLE RETIREMENT YEAR.. 10-2054 NET SALVAGE PERCENT.. -4						
2014	38,657,812.05	531,901		40,204,125	35.05	1,147,051
	38,657,812.05	531,901		40,204,125		1,147,051

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.0 2.97

BLACK HILLS POWER
CHEYENNE PRAIRIE GENERATING STATION

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHEYENNE PRAIRIE - COMBINED CYCLE INTERIM SURVIVOR CURVE.. IOWA 40-S2 PROBABLE RETIREMENT YEAR.. 10-2054 NET SALVAGE PERCENT.. -4						
2014	10,543,039.65	156,248		10,964,761	34.60	316,901
	10,543,039.65	156,248		10,964,761		316,901

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.6 3.01

BLACK HILLS POWER
CHEYENNE PRAIRIE GENERATING STATION

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CHEYENNE PRAIRIE - COMBINED CYCLE INTERIM SURVIVOR CURVE.. IOWA 30-S1.5 PROBABLE RETIREMENT YEAR.. 10-2054 NET SALVAGE PERCENT.. -4						
2014	3,514,346.55	62,828		3,654,920	28.59	127,839
	3,514,346.55	62,828		3,654,920		127,839
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					28.6	3.64

Rebuttal Testimony and Exhibit
Jon Thurber

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

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

For Authority to Increase Rates
in South Dakota

Docket No. EL14-026

January 15, 2015

TABLE OF CONTENTS

Exhibits

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jon Thurber, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota 57701.

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

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

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF OF TODAY?

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

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to explain and support the portions of the Settlement Stipulation ("Settlement Agreement"), reached between Black Hills Power and the South Dakota Public Utilities Commission Staff ("Staff"), that pertain to the: (1) revenue requirement adjustments under South Dakota administrative rule 20:10:13:44; (2) decommissioning regulatory asset and amortization adjustment; (3) LIDAR adjustment, (4) employee additions/eliminations adjustment; (5) utility holdings allocation correction; (6) pension expense adjustment; and (7) new debt issuance. I also explain why the positions advanced by the Black Hills Industrial Intervenors' ("BHII") witness Mr. Lane Kollen on these subjects are not appropriate.

III. REVENUE REQUIREMENT ADJUSTMENTS UNDER SOUTH DAKOTA ADMINISTRATIVE RULE 20:10:13:44

Q. PLEASE EXPLAIN BLACK HILLS POWER'S APPROACH TO MEASURING ITS REVENUE REQUIREMENT IN THIS CASE.

A. Black Hills Power utilized a twelve month test year based on historical data, ending September 30, 2013. Adjustments for known and measurable items were then made to the historical test year to determine the pro forma costs.

Q. UNDER THE SETTLEMENT AGREEMENT, WERE ADDITIONAL ADJUSTMENTS MADE TO BLACK HILLS POWER'S REVENUE REQUIREMENT?

A. Yes, the Settlement Agreement reflects a variety of adjustments that were made to the Company's filed revenue requirement.

Q. ARE THE ADJUSTMENTS TO BLACK HILLS POWER'S REVENUE REQUIREMENT THAT ARE REFLECTED IN THE SETTLEMENT AGREEMENT CONSISTENT WITH THE REQUIREMENTS OF ARSD 20:10:13:44?

A. Yes. The Company utilized an appropriate test year and made adjustments to its book costs that were based on changes in facilities, operations, and costs that were known with reasonable certainty and measurable with reasonable accuracy and either have been or will become effective within the 24 months following the last month of the test year.

Q. PLEASE EXPLAIN THE BASIS FOR THE COMPANY'S BELIEF THAT THE ADJUSTMENTS ARE RELATED TO COSTS THAT ARE KNOWN WITH REASONABLE CERTAINTLY AND MEASURABLE WITH REASONABLE ACCURACT?

A. The end of the historic test year in this filing was September 30, 2013. As such, there have been over fifteen months of changes in facilities, operations and costs that have occurred and would be appropriately adjusted for under the Rule. Furthermore, the vast majority of the adjustments relate to costs that the Company incurred during the 12 months following the historic test year.

Q. REFERRING TO MR. KOLLEN'S DIRECT TESTIMONY, PAGE 7, LINE 16 THROUGH PAGE 8, LINE 21, DO YOU AGREE THAT THE COMMISSION SHOULD LIMIT ANY POST-TEST YEAR ADJUSTMENTS TO THE TWELVE MONTH PERIOD IMMEDIATELY FOLLOWING THE HISTORIC TEST YEAR ENDING SEPTEMBER 30, 2013?

A. No, I do not. Mr. Kollen's interpretation of ARSD 20:10:13:44 ignores the plain language of the rule that specifically states that reasonably certain and reasonably accurate adjustments which will become effective within the twenty four months following the last month of the test period are permitted.

Q. MR. KOLLEN INDICATES THAT ADJUSTMENTS ARE NOT PERMITTED UNLESS THE CORRESPONDING PROJECTED CHANGES IN REVENUE ARE INCLUDED IN THE REVENUE REQUIREMENT. PLEASE EXPLAIN WHY A RETAIL REVENUE ADJUSTMENT FOR SALES GROWTH WAS NOT INCLUDED IN THE SETTLEMENT AGREEMENT?

A. It is my understanding that it has been Staff's practice to exclude all revenue producing plant from the plant annualization and post-test year addition adjustments. Revenue producing plant consists primarily of distribution investments. Staff followed this practice in this case. It would therefore be inappropriate for additional revenues to be reflected in the cost of service because the investment needed to serve the sales growth is not included as well. Commission policy has been to reflect any incremental revenue or cost savings associated with post-test year adjustments in the revenue requirement.

Q. MR. KOLLEN CHARACTERIZES THE COMPANY'S ADJUSTMENTS AS OPPORTUNISTIC AND SELECTIVE. DO YOU AGREE WITH HIS CHARACTERIZATION OF THE ADJUSTMENTS THAT HAVE BEEN PROPOSED BY THE COMPANY?

A. No, absolutely not. Contrary to his characterizations, the Company included pro forma cost increases and cost reductions that occurred after the historic test year in the adjustments it made. Some of the material cost reductions, at the total company level, included in the filing were:

- Schedule H-1 Neil Simpson I labor and benefit costs - $746,475;
- Schedule H-6 FAS106 Retiree Healthcare - $168,896;
- Schedule H-6 FAS87 Pension Expense - $508,454;
- Schedule H-11 Advertising Expense - $262,517;
- Schedule H-16 Ben French Severance Expense - $180,861;
- Schedule H-18 Ben French, Osage, Neil Simpson I O&M - $3,753,186;
- Schedule H-21 Customer Service Model Adjustment - $215,934; and
- Statement J Ben French, Osage, Neil Simpson I Depreciation Removal - $1,732,526.

In total, the Company removed over $7,500,000 worth of expenses from the historic test year on an annual basis in the original filing.

Q. IN THE SETTLEMENT AGREEMENT, THE COMPANY AGREED TO UPDATE MANY ADJUSTMENTS IN THE ORIGINAL FILING THAT WERE BASED ON BUDGETS TO REFLECT RECENT ACTUAL COSTS. WERE THERE ANY MATERIAL REDUCTIONS IN EXPENSES AS A RESULT OF THESE UPDATES?

A. Yes, a few of the material cost reductions, at the total company level, were as follows:

- Updated Schedule G-3 to reflect the actual debt issuance and cost – weighted average cost of debt was reduced from 6.45% to 6.08%, for over $1,000,000;
- Updated Schedule H-6 Pooled Medical Costs – approximately $400,000; and

- Updated Schedule H-8 Generation Dispatch and Scheduling Costs – over $300,000.

Clearly, the Company reflected both cost increases and reductions in the original filing and Settlement Agreement. Mr. Kollen's characterization of the Company as opportunistic and selective lacks merit.

Q. SHOULD THE COMMISSION ACCEPT THE ADJUSTMENTS TO THE REVENUE REQUIREMENTS THAT ARE REFLECTED IN THE SETTLEMENT AGREEMENT?

A. Yes, I believe the Commission should accept the adjustments as they were made in conformance with the requirements of ARSD 20:10:13:44.

IV. <u>DECOMMISSIONING REGULATORY ASSET AND AMORTIZATION</u>

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

A. Yes. On January 9, 2014, in Docket EL13-036, the Commission issued an Order approving deferred accounting for the transfer of remaining plant balances and associated inventory for soon to be decommissioned plants to a regulatory asset.

Q. PLEASE EXPLAIN THE DECOMMISSIONING ADJUSTMENT INCLUDED IN THE COMPANY'S FILED POSITION.

A. Black Hills Power proposed to amortize the costs associated with the retirement and decommissioning of the Neil Simpson I, Ben French, and Osage facilities over five years as reflected on Schedule J-2. The unamortized balance of the regulatory asset included in the test year would then be reduced by the accumulated amortization for a full year. The costs associated with the retirement of the units included the unrecovered plant and obsolete inventory. The estimated costs associated with decommissioning the units were provided in Response to SDPUC Request No. 3-23.

Q. WHY DID BLACK HILLS POWER REQUEST RECOVERY OVER A FIVE YEAR PERIOD?

A. The time period provided a balance between the amount of time required to minimize rate impact to customers and matched the expense as best as possible with the customers who have utilized the assets being retired. The proposed amortization period achieved an annual amortization expense that is approximately equivalent to the annual amount that it would cost to continue to operate these facilities.

Q. PLEASE DESCRIBE THE DECOMMISSIONING ADJUSTMENT INCLUDED IN THE SETTLEMENT AGREEMENT.

A. The Settlement Agreement makes the following adjustments to the Company's filed position:

- The obsolete inventory balance was updated to reflect the thirteen month average balance to correlate with the amount removed from working capital.
- The contingencies were removed from the estimated decommissioning costs. The Settlement Agreement grants Black Hills Power the opportunity to seek

recovery, in a future Black Hills Power rate case, of all costs for decommissioning not otherwise recovered from customers.

- An adjustment was made to reflect the accumulated deferred income taxes associated with the decommissioning adjustment. Please refer to the rebuttal testimony of Mr. Robert Hollibaugh for details.
- The amortization period was modified from five to ten years.
- The regulatory asset included in rate base is reduced by one and one-half years of amortization expense to reflect the average unamortized balance over the first three years of the amortization period in rate base.

Q. ARE THERE ANY ADDITIONAL REVENUES ADDED TO THE TEST YEAR AS A RESULT OF THIS ADJUSTMENT?

A. There are no additional revenues as a result of retiring and decommissioning the facilities. The salvage value credit was reflected in the lump sum decommissioning bid and resulted in a lower cost to customers.

Q. MR. KOLLEN STATES THAT DECOMMISSIONING COSTS SHOULD NOT BE INCLUDED IN THE SETTLEMENT AGREEMENT BECAUSE THE COSTS WILL NOT HAVE BEEN INCURRED IN THE TWELVE MONTH PERIOD FOLLOWING THE HISTORIC TEST YEAR. DO YOU AGREE?

A. No, I disagree with Mr. Kollen for a variety of reasons. First, as I discussed above, I disagree with Mr. Kollen's interpretation of ARSD 20:10:13:44. In particular, the Rule does not limit adjustments to known and measurable costs that were incurred in the twelve months following the historic test year. Second, the vast majority of the decommissioning costs that are reflected in the Settlement Agreement are supported by a fixed price contract that was provided by the Company in response to SDPUC Request No. 3-25. Black Hills Power selected the fixed price contract through a competitive bidding process as the lowest cost proposal that met the technical specification of the request for proposal. Third, the remaining costs that are included in the Settlement Agreement are supported by the Company's engineering cost estimate that was provided in response to SDPUC Request No. 3-23. As a result, the decommissioning costs that are reflected in the Settlement Agreement are known with reasonable certainty and measurable with reasonable accuracy.

Q. HAS THE COMMISSION ACCEPTED ENGINEERING ESTIMATES FOR DECOMMISSIONING COSTS IN A RECENT APPROVED RATE CASE SETTLEMENT?

A. Yes. In Docket EL12-046, Northern States Power Company used a decommissioning cost study as the estimate to determine the appropriate decommissioning accrual for its nuclear facilities in advance of incurring the costs. After removing the contingencies, Staff accepted Northern States Power Company's study as the basis for the decommissioning accrual and included the adjustment as part of the rate case settlement ultimately approved by the Commission. Here, the Staff and the Company used the Northern States Power

Company rate case settlement as a guide for the decommissioning adjustment included in this Settlement Agreement.

Q. MR. KOLLEN STATES THAT THE ACCUMULATED DEFERRED INCOME TAX ADJUSTMENT ASSOCIATED WITH THE DECOMMISSIONING REGULATORY ASSET IS INCORRECTLY CALCULATED. DOES THE COMPANY AGREE WITH MR. KOLLEN's POSITION?

A. No. The Company believes Mr. Kollen's treatment of accumulated deferred income tax is incorrect. Mr. Robert Hollibaugh addresses the accumulated deferred income tax calculation in his rebuttal testimony.

Q. ARE THERE ANY OTHER STATEMENTS THAT MR. KOLLEN MADE PERTAINING TO DECOMMISSIONING THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. Mr. Kollen indicates in his direct testimony on page 20, lines 6 – 8, that the Settlement Agreement reflects a ten year amortization of the decommissioning regulatory asset. Then, on page 42, line 23, through page 43, line 1-3, of Mr. Kollen's direct testimony, he states that the Settlement Agreement reflects a five year amortization of the decommissioning regulatory asset. Although I do not know if this inconsistency reflects an oversight in drafting or a misunderstanding of the terms of the Settlement Agreement, to the extent that Mr. Kollen incorporates a five year amortization in his numbers, his assumption is inconsistent with the terms of the Settlement Agreement.

Q. DID THE COMPANY REQUEST AN ORDER FROM THE COMMISSION TO DEFER ANY COSTS ASSOCIATED WITH THE DECOMMISSIONING OF THE RETIRED STEAM PLANTS?

A. No. The Company and Staff filed the Settlement Agreement on December 9, 2014, that established the amortization of decommissioning costs. The Settlement Agreement also grants Black Hills Power the opportunity to seek recovery, in a future Black Hills Power rate case, of all costs for decommissioning not otherwise recovered from customers. Since the Settlement Agreement was filed prior to the end of 2014 and is being considered in this rate proceeding, it was not necessary to request an accounting authority order allowing Black Hills Power to use deferred accounting for costs associated with the decommissioning of the retired steam plants.

Q. DO YOU BELIEVE THE COMMISSION SHOULD ACCEPT THE TREATMENT OF THE DECOMMISSIONING ADJUSTMENT?

A. Yes, I believe the treatment of the decommissioning adjustment that is reflected in the Settlement Agreement is appropriate and in conformance with past practices.

V. LIDAR ADJUSTMENT

Q. PLEASE EXPLAIN THE COMPANY'S FILED LIDAR ADJUSTMENT.

A. For purposes of background, at the time that Black Hills Power filed the pending rate case, it planned to perform LIDAR (Light Detection and Ranging) imaging of all of its 69 kV and 230 kV facilities in 2014. The need for and scope of the LIDAR surveying project is discussed in the direct testimony of Mike Fredrich.

The Company's filed position reflected the estimated cost of the LIDAR surveying project on its 69 kV transmission system. The project cost of $798,000 was shared with the joint owners of the 69 kV system, and Black Hills Power's share was amortized over five years to correspond with the expected frequency of the survey. The Company requested the unamortized amount be included in rate base.

Q. DOES THE SETTLEMENT AGREEMENT REFLECT AN ADJUSTMENT FOR THE LIDAR PROJECT?

A. Yes. The LIDAR project cost was updated to reflect the least cost, competitive bid contract, and the current allocation to the joint owners of the 69 kV systems in South Dakota and Wyoming. Black Hills Power's share of the costs was amortized over five years, and one-half of the unamortized balance was reflected in rate base. The accumulated deferred income taxes associated with one-half of the unamortized regulatory asset was reflected in the Settlement Agreement. The accumulated deferred income tax adjustment is covered in more detail in the rebuttal testimony of Mr. Robert Hollibaugh.

Q. MR. KOLLEN HAS SUGGESTED THAT LIDAR COSTS ARE NOT PROPERLY INCLUDED. DO YOU DISAGREE WITH MR. KOLLEN'S POSITION ON THE LIDAR ADJUSTMENT?

A. Yes. The Company has provided evidence to support the inclusion of these costs as a known and measurable adjustment. The request for proposal selected as part of the competitive bid process for the LIDAR project and the revised pricing was provided as a Supplemental Response to SDPUC Request No. 4-34 on October 15,

2014. The supporting work papers for the allocation of LIDAR costs to Black Hills Power was provided as a Supplemental Response to SDPUC Request No. 4-36, on October 15, 2014. The calculation included the actual allocation of the joint owners of South Dakota 69 kV system using the April 1, 2014, allocation. The Company provided Staff with a revised allocation of LIDAR costs to Black Hills Power on October 21, 2014, to remove the costs associated with the joint owners of the Wyoming 69 kV using the April 1, 2014, allocation. The email and supporting work papers were provided to Staff on October 21, 2014, and were provided in discovery in the Second Supplemental Response to SDPUC Request 4-36 on January 5, 2015.

Q. WHY DOES THE LIDAR ADJUSTMENT INCLUDED IN THE SETTLEMENT AGREEMENT REFLECT A KNOWN AND MEASURABLE ADJUSTMENT?

A. The project costs are based on a fixed price contract that was competitively bid to achieve the lowest cost for customers. The actual cost was approximately half of the original budget. The allocations to the joint owners of the 69 kV system in South Dakota and Wyoming were based on the current allocations in effect. The LIDAR surveying work and data acquisition was completed in the fourth quarter of 2014.

Q. DO COSTS NEED TO BE INCURRED BY OCTOBER 1, 2014, TO BE CONSIDERED KNOWN AND MEASURABLE?

A. No, the fixed price contract with costs incurred within 24 months of the last month of the test period qualify as an appropriate adjustment under ARSD 20:10:13:44. There are no anticipated reductions to test year costs or additional revenues expected as a result of this project.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO REFLECT A TEN YEAR AMORTIZATION PERIOD?

A. No, a five year amortization period corresponds with the expected frequency of the LIDAR survey. A ten year amortization is arbitrary, and the annual amortization allocated to South Dakota of $64,107 based on a 5 year amortization is not of the magnitude that would justify a ten year amortization for rate mitigation purposes.

Q. DID THE COMPANY REQUEST AN ORDER FROM THE COMMISSION TO DEFER ANY COSTS ASSOCIATED WITH THE LIDAR PROJECT?

A. No. The Company and Staff filed the Settlement Agreement on December 9, 2014, that established the amortization of LIDAR costs for the Commission to consider. Since the Settlement Agreement was filed prior to the end of 2014 and is being considered in this rate proceeding, it was not necessary to request an accounting authority order allowing Black Hills Power to use deferred accounting for costs associated with the LIDAR project.

Q. DO YOU SUPPORT THE TREATMENT OF THE LIDAR ADJUSTMENT THAT IS REFLECTED IN THE SETTLEMENT AGREEMENT?

A. Yes, I do.

VI. EMPLOYEE ADDITION/ELIMINATION ADJUSTMENT

Q. PLEASE EXPLAIN THE COMPANY'S FILED EMPLOYEE ADDITION AND ELIMINATION ADJUSTMENT.

A. Black Hills Power planned to hire nineteen unfilled and new positions as of January 28, 2014, payroll which are necessary to provide electric service to customers. In addition, the Company reflected the elimination of two employees after the January 28, 2014, payroll. The adjustment reflects the net employees' salary and benefit costs.

Q. DID THE SETTLEMENT AGREEMENT REFLECT THE ADJUSTMENT AS FILED?

A. No. Through Staff's audit, costs were only included for positions actually hired at the time of settlement negotiations. Adjustments were also made to reflect the 2015 known and measurable wage annualization and to include only the portion of labor costs charged to expense accounts.

Q. DOES MR. KOLLEN AGREE WITH THIS ADJUSTMENT?

A. No, he does not. Mr. Kollen's recommendation is to remove all costs associated with employee additions and eliminations.

Q. MR. KOLLEN ARGUES THAT THE COMMISSION SHOULD NOT ALLOW BUDGETED EMPLOYEE ADDITIONS IN RATES BECAUSE THEY DO NOT REFLECT ACTUAL EXPERIENCE. ARE MR. KOLLEN'S CONCERNS REGARDING BUDGETED EMPLOYEE

ADDITIONS AND ACTUAL EXPERIENCE ADDRESSED IN THE SETTLEMENT AGREEMENT?

A. Yes. Staff only allowed positions that have been hired. The Company has not recovered costs associated with budgeted employees in rates, so Mr. Kollen's comparison of actual to budget headcounts are invalid.

VII. UTILITY HOLDINGS ALLOCATION CORRECTION

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN THAT THE STAFF REVENUE REQUIREMENT MODEL INCLUDES AN ERROR IN ALLOCATION TO SOUTH DAKOTA FOR TRANSMISSION LOAD DISPATCH COSTS?

A. Yes, the Company agrees that no costs associated with transmission load dispatch, FERC Account 561, should be allocated to South Dakota.

Q. DOES BLACK HILLS POWER BELIEVE THAT THE SETTLEMENT AGREEMENT SHOULD BE MODIFIED TO CORRECT THIS ERROR?

A. No, it does not. Black Hills Power supports the Settlement Agreement and the resulting revenue requirement that has been presented to the Commission. If Staff and Black Hills Power litigated this proceeding, the Company and Staff would likely advocate different positions than what is reflected in Staff's revenue requirement model. Related thereto, on page 2 of the Settlement Stipulation, under Purpose, it states, "The Parties acknowledge that they may have differing views that justify the end result, which they deem to be just and reasonable, and, in light of such differences, the Parties agree that the resolution of any single issue, whether express or implied by the Stipulation, should not be viewed as precedent setting."

Notwithstanding the differences of opinion regarding the costs that comprise the revenue requirement, the Company and Staff ultimately agreed that the total revenue deficiency is $6,890,746. The revenue deficiency is material to the Company. The Company agreed to a two year rate moratorium, which can only be negotiated as part of a Settlement Agreement. The Company used the annual revenues authorized in this Settlement Agreement to determine if it could manage its business through a rate freeze. Black Hills Power agreed to significant concessions in order to reach a comprehensive resolution of all issues in this rate proceeding and as a result believes that the revenue deficiency should be maintained as presented to the Commission.

Q. **WOULD THE COMPANY HAVE ACCEPTED THE ALLOCATION CORRECTION DURING SETTLEMENT NEGOTIATIONS?**

A. Yes, it would have. However, the Company would also have had the opportunity to negotiate differently on other adjustments or request other adjustments to achieve the revenues necessary to recover its costs and earn a fair rate of return on investments.

Q. **DO YOU HAVE ANY EXAMPLES OF COSTS THAT HAVE INCREASED THAT WERE NOT REFLECTED IN THE SETTLEMENT AGREEMENT?**

A. Yes. After the Company reached a Settlement Agreement with Staff, it became aware that the production operations and maintenance ("O&M") costs associated with the Wyodak power plant ("Wyodak") were abnormally low during the historic test year and were not reflective of current production O&M costs. The total company Wyodak production O&M cost was $3,390,425 during the historic test year, and these costs were included in the Settlement Agreement. When compared to the costs incurred from October 2013 through September 2014, the total company Wyodak production O&M cost increased $459,738 for a total cost of 3,850,163. Please see Exhibit JTR-1 for details.

Q. PLEASE DESCRIBE THE PRODUCTION O&M COSTS ASSOCIATED WITH WYODAK?

A. Wyodak is operated by the majority owner, PacifiCorp, who invoices Black Hills Power on a monthly basis for the operating costs of the plant. The O&M costs are the routine costs of operating a power plant. Labor costs represent approximately 50% of the O&M costs, and the remainder of the costs is primarily associated with materials and outside services. Materials include production materials such as lime for environmental compliance and consumable items such as filters, piping, motors, and generators. Wyodak uses contractors for many services, such as ash hauling, security, janitorial, plant maintenance, and inspections.

Q. WERE THE ACTUAL PRODUCTION O&M COSTS ASSOCIATED WITH THE WYODAK POWER PLANT ABNORMALLY HIGH FROM OCTOBER 2013 THROUGH SEPTEMBER 2014?

A. No, please see the table below for Wyodak's production O&M costs from October 2010 through September 2014.

	10/1/10 - 9/30/11	10/1/11 - 9/30/12	10/1/12 - 9/30/13	10/1/13 - 9/30/14	4 Year Average
Wyodak O&M	3,566,605	3,560,008	3,390,425	3,850,163	3,591,800

Clearly, the historic test year was less than every other year during the four year period by at least $160,000, and adjusting the test year to the four year average would result in a total company adjustment of over $200,000. In addition, expenses associated with major maintenance outages were normalized during this time period through major maintenance accrual accounting.

Q. WOULD IT BE APPROPRIATE TO ADJUST THE HISTORIC TEST YEAR WYODAK O&M COSTS TO THE FOUR YEAR AVERAGE FROM OCTOBER 2010 THROUGH SEPTEMBER 2014?

A. No, the historic costs have not been adjusted for inflation, wage increases, and benefit changes. Known and measurable adjustments for labor and inflation would need to be reflected in the historic annual amounts in order for a normalization to reflect current costs. Applying three percent annual inflation to the October 2010 through September 2011 Wyodak production O&M expense yields a similar expense as the October 2013 through September 2014 Wyodak production O&M expense. The October 2013 through September 2014 Wyodak production O&M costs are conservative because they do not reflect the annualization of known and measurable wage and benefit changes for 2014 and 2015.

Q. HOW WOULD THE COMPANY PROPOSE TO RESOLVE THE UTILITY HOLDINGS COMPANY TRANSMISSION ALLOCATION ERROR IN STAFF'S MODEL?

A. The Company recommends making no adjustment to the Settlement Agreement. Staff's revenue requirement model reflects many concessions made by Staff and Black Hills Power. However, if the Commission modifies the Settlement Agreement to correct the transmission allocation error, the Company respectfully requests that the Commission also modify the Settlement Agreement to include an adjustment to reflect South Dakota's allocated share of Wyodak's production O&M costs from October 2013 through September 2014, as reflected on Exhibit JTR-1.

VIII. PENSION EXPENSE

Q. DID BLACK HILLS POWER PROPOSE AN ADJUSTMENT TO THE TEST YEAR LEVEL OF PENSION EXPENSE?

A. Yes. The Company proposed to reduce test year total company pension expense by approximately $508,000, as reflected on Schedule H-6. The Company's adjustment is based on a 5 year average of actual pension costs from 2010 – 2014.

Q. WHY DID THE COMPANY USE A 5 YEAR AVERAGE AS THE BASIS FOR THE ADJUSTMENT?

A. As provided in response to SDPUC Request No. 1-1, the table below summarizes the actual pension expense from 2010 to 2014:

Year	FAS 87 Cost	Year by Year Variation
2010	$2,925,853	
2011	1,819,156	-37.82%
2012	3,251,072	78.71%
2013	2,709,322	-16.66%
2014	976,122	-63.97%
Average	$2,336,305	

In particular, the annual total company pension expense has ranged between $976,122 and $3,251,072 from 2010 through 2014, and the annual percent change has ranged between a 64% decrease and a 79% increase. The Company proposed normalizing pension expenses as a result of the volatility in expense experienced from year to year.

Q. **DOES THE SETTLEMENT AGREEMENT REFLECT A 5 YEAR NORMALIZATION OF PENSION EXPENSE?**

A. Yes. As provided in the Settlement Stipulation, the Commission Staff and Black Hills Power agree this normalization period shall be used in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization period unreasonable.

Q. **IS MR. KOLLEN'S PROPOSED PENSION EXPENSE ADJUSTMENT REFLECTIVE OF NORMAL, ONGOING CONDITIONS?**

A. No, I do not believe the total company 2014 pension expense of $976,122 is reflective of normal, ongoing pension expense. The 2014 pension expense was abnormally low compared to the previous four years, and the Company expects future annual pension expense to be significantly higher than the 2014 expense.

Q. MR. KOLLEN CHARACTERIZES THE COMPANY'S PENSION EXPENSE ADJUSTMENT AS "OPPORTUNISTIC." DO YOU AGREE?

A. No, I do not agree with Mr. Kollen's characterization of this adjustment. If the Company in fact was being opportunistic, Black Hills Power would have proposed no adjustment to the test year. As previously mentioned, the Company's proposed adjustment reduced costs by approximately $508,000. In addition, the Staff and the Company agreed to normalize pension expense in future rate cases over the next five years unless there is an extraordinary event that makes a five-year normalization period unreasonable. This condition in the Settlement Stipulation displays a commitment to normalization rather than an opportunistic objective.

Q. IS THERE ANY EVIDENCE THAT PENSION EXPENSE WILL INCREASE IN FUTURE YEARS?

A. Yes. Black Hills Power's actual total company 2015 pension expense is $2,056,581. The actuarial calculation to support the expense was provided as a Supplemental Response to SDPUC 2-13. This information was not available at the time the Company and Staff reached a Settlement Agreement. If the Commission were to accept Mr. Kollen's adjustment to reflect the 2014 pension expense, the Company would be deficient in 2015 at the total company level by over $1,000,000.

The 2015 pension expense shows continued volatility in pension expense, as the 2015 expense was approximately 111% greater than the 2014 expense. The 2015 pension expense supports the reasonableness of the normalized pension expense included in the Settlement Agreement.

IX. NEW DEBT ISSUANCE

Q. PLEASE BRIEFLY DESCRIBE THE NEW DEBT ISSUANCE THAT WAS REFLECTED IN BLACK HILLS POWER'S ORIGINAL FILING.

A. In its rate case Application, the Company reflected an issuance of new bonds to finance the anticipated costs related to the Cheyenne Prairie Generating Station and other capital expenditures. At the time the Application was filed, Black Hills Power anticipated adding approximately $50 million of long-term financing with an estimated all-in cost of debt of 5.67%.

Q. HAS THE COMPANY ACTUALLY ISSUED THE NEW DEBT?

A. Yes, the Company issued $85 million of 30 year First Mortgage Bonds with a coupon rate of 4.43% and an all-in cost of debt of 4.46%. The debt issuance was authorized by the Commission in Docket EL14-034.

Q. WHY IS THE ALL IN DEBT COST DIFFERENT THAN THE COUPON RATE?

A. The all-in debt cost includes the coupon interest rate and the debt issuance costs amortized over the life of the bonds. The debt issuance costs include the underwriting, legal, accounting, and other fees associated with issuing the bonds.

Q. DOES THE SETTLEMENT AGREEMENT REFLECT THE ACTUAL COST OF THE NEW DEBT ISSUANCE IN THE WEIGHTED COST OF CAPITAL?

A. Yes, the actual cost of the new debt is reflected in the Settlement Agreement.

Q. MR. KOLLEN INDICATES THE ACTUAL DEBT COST IS 4.52% ON PAGE 50, LINES 1-2, OF HIS DIRECT TESTIMONY. IS THIS ACCURATE?

A. No, it is not. Although Mr. Kollen references Black Hills Power's response to BHII Request No. 5 as support for the actual debt cost he assumed, the response does not support his assumption. Rather, the response states "Black Hills Power entered into an agreement to issue $85 million of 30 year First Mortgage Bonds with a coupon rate of 4.43." Additionally, Mr. Kollen failed to recognize that the Company provided the actual cost of debt in a supplemental response to SDPUC Request No. 2-57 on October 13, 2014.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BLACK HILLS POWER, INC.
Wyodak O&M Adjustment
For the Test Year Ended September 30, 2013

Line No.	FERC Acct.	Description	(a) Per Books	(b) Pro Forma Adjusted (Note 1)	(c) (b) - (a) Increase/ (Decrease)	Allocation Factor	South Dakota Percent	South Dakota Amount
1		**Steam Production Operation**						
2	500	Supervision & Engineering	780,661	811,583	30,922	SALWAGPO	89.831%	27,778
3								
4	502	Steam Expense	514,641	669,478	154,837	DPROD	89.831%	139,092
5								
6	506	Miscellaneous	455,965	443,468	(12,497)	DPROD	89.831%	(11,226)
7								
8		**Total Steam Production Operation**	1,751,267	1,924,529	173,262			155,644
9								
10		**Steam Production Maintenance**						
11	510	Supervision & Engineering	27,435	14,334	(13,101)	SALWAGPM	89.831%	(11,769)
12								
13	512	Boilers	1,312,732	1,524,972	212,240	DPROD	89.831%	190,657
14								
15	513	Electric Plant	239,453	351,981	112,528	DPROD	89.831%	101,085
16								
17	514	Miscellaneous Plant	59,538	34,347	(25,191)	DPROD	89.831%	(22,629)
18								
19		**Total Steam Production Maintenance**	1,639,158	1,925,634	286,476			257,344
20								
21		**Total Steam Production Expense**	3,390,425	3,850,163	459,738			412,988
22								
23								
24								
25	Note 1: These expenses are from the third party operator's billings for the period October 2013 - September 2014.							
26								

Rebuttal Testimony
Christopher J. Kilpatrick

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

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

For Authority to Increase Rates
In South Dakota

Docket No. EL14-026

January 15, 2015

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am currently employed by Black Hills Utility Holdings, Inc. ("Utility Holdings"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as the Director of Regulatory.

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

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

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to explain and support the portion of the Settlement Stipulation ("Settlement Agreement"), reached between Black Hills Power and the South Dakota Public Utilities Commission Staff ("Staff"), that pertains to corporate allocations. I also explain why the positions advanced by Black Hills Industrial Intervenors' ("BHII") witness Mr. Lane Kollen on this subject are not appropriate.

III. UTILITY HOLDINGS ADJUSTMENT

Q. DOES BLACK HILLS POWER RECEIVE SERVICES FROM OTHER CORPORATE ENTITIES WITHIN THE BHC CORPORATE ORGANIZATION?

A. Yes. The Company receives services from Black Hills Service Company ("Service Company") and Utility Holdings, which are subsidiaries of BHC.

Q. DID YOU DISCUSS GENERALLY HOW CORPORATE ALLOCATIONS FROM THESE TWO ENTITIES ARE MADE TO BLACK HILLS POWER IN YOUR DIRECT TESTIMONY?

A. Yes, I addressed this topic on pages 18-20 of my direct testimony.

Q. PLEASE EXPLAIN THE UTILITY HOLDINGS ADJUSTMENT THAT WAS INCLUDED IN BLACK HILLS POWER'S RATE CASE APPLICATION.

A. Black Hills Power's filed position requested recovery of the estimated corporate costs charged to it from Utility Holdings after the Cheyenne Prairie Generating Station was placed in service on October 1, 2014. The request reflected the pro forma time period of October 1, 2014, through September 30, 2015.

Q. WAS THE COMPANY'S AS FILED UTILITY HOLDINGS ADJUSTMENT INCLUDED AS A COMPONENT OF THE SETTLEMENT AGREEMENT?

A. No. Black Hills Power reached a compromise with Staff that resulted in inclusion in the Settlement Agreement of actual Utility Holdings charges to Black Hills Power from September 2013 through August 2014, with two modifications. First, the adjusted customer records and collection expense included in the Settlement reflects an annualized known change in allocation that went into effect on April 1, 2014. Second, the September 2013 through August 2014 labor costs were annualized to reflect the 2014 and 2015 wage increases.

Q. DOES THE UTILITY HOLDINGS ADJUSTMENT INCLUDED IN THE SETTLEMENT AGREEMENT REFLECT CURRENT COSTS AND KNOWN AND MEASURABLE CHANGES?

A. Yes. The September 2013 through August 2014 billings from Utility Holdings are actual costs that are accurate, reliable, and verifiable. The change in customer records and collection expense allocation went into effect in April 2014, and has been annualized by applying the allocation change to the historic department costs from September 2013 through August 2014. In addition, the September 2013 through August 2014 labor costs have been annualized to reflect known salary increases that were effective after the end of the historic test year. Accordingly, the settlement adjustment reflects known and measurable changes.

Q. PLEASE EXPLAIN THE ALLOCATION CHANGE TO THE CUSTOMER RECORDS AND COLLECTION EXPENSE.

A. During the historic test year, costs from the customer service call centers that serve all BHC owned utilities were charged to Black Hills Power using direct and allocated charges. In early 2014, Utility Holdings reviewed the call volumes and call minutes from the call centers to determine if costs were being charged to the appropriate companies. The expenses incurred by these call centers are primarily related to the support of all utility customers. Based on the total call volume and total call minutes, it was determined that the cost driver for these costs is the number of customers. Therefore, the costs should be allocated based upon the Customer Count Ratio. This change in allocation is annualized in the Settlement Agreement.

Q. MR. KOLLEN PROPOSED AS AN ALTERNATIVE TO THE SETTLED TREATMENT OF THIS ADJUSTMENT THAT THE COMPANY ONLY BE PERMITTED TO RECOVER THE COSTS INCURRED DURING THE HISTORIC TEST YEAR WITH NO ADJUSTMENT. DO YOU AGREE WITH MR. KOLLEN'S PROPOSED ADJUSTMENT TO UTILITY HOLDINGS COSTS?

A. No. Mr. Kollen's proposed adjustment is flawed because the October 2012 through September 2013 Utility Holdings costs do not reflect current operations costs or any known and measurable increases that have occurred since the end of the test year.

Q. IN HIS TESTIMONY, MR. KOLLEN IS CRITICAL OF THE INFORMATION THE COMPANY SUPPLIED TO SUPPORT CORPORATE ALLOCATIONS. DID THE COMPANY PROVIDE EVIDENCE OF KNOWN AND MEASURABLE CHANGES?

A. Yes. The Company provided a description of some of the major cost drivers in the Utility Holdings budgeted increase in the Supplemental Response to BHII Request 6. In the Supplemental Response to SDPUC Request 3-96 provided on October

22, 2014, the Company also provided the actual costs from September 2013 through August 2014 with supporting work papers.

Q. HAVE THE EMAILS REFERENCED IN MR. KOLLEN'S DIRECT TESTIMONY ON PAGE 39, LINES 6 – 9, BEEN PRODUCED IN DISCOVERY?

A. Yes, the Company provided the email responses to Staff's informal discovery and the associated attachments in the Second Supplemental Response to SDPUC Request 3-96, on January 5, 2015. The emails contained the monthly Utility Holdings charges by FERC account from the general ledger for September 2013 through August 2014, a revised calculation of the customer records and collection expense allocation annualization, and the supporting work paper for the labor annualization. Notably, the information reflected in the emails is virtually identical to the information that was produced in October 2014 in the Supplemental Response to SDPUC Request 3-96.

Q. WAS MR. KOLLEN ALSO CRITICAL OF SOME OF THE COST INCREASES THAT ARE REFLECTED IN THE SETTLEMENT ADJUSTMENT?

A. Yes, he was critical of the cost increases to FERC Account 920, administrative salaries, and to FERC account 923, outside services.

Q. PLEASE EXPLAIN THE COST DRIVERS THAT INCREASED THE UTILITY HOLDING CHARGES TO FERC ACCOUNT 920, ADMINISTRATIVE SALARIES, FROM THE TEST YEAR.

A. The increase in administrative salaries is associated with an increase in headcount at Utility Holdings and the wage annualization that is reflected in the cost update. The headcount at Utility Holdings as of 9/30/2013 was 376, and increased to 389 as of 8/31/2014. The costs associated with the increased headcount were allocated consistent with the Utility Holdings Cost Allocation Manual. In addition, the update to the most recent twelve months of actual costs from October 2012 through September 2013 and for the period September 2013 through August 2014 contained a partial wage increase for 2013 and 2014.

Q. PLEASE EXPLAIN THE CHANGE IN UTILITY HOLDING CHARGES TO FERC ACCOUNT 923, OUTSIDE SERVICES, FROM THE TEST YEAR.

A. The increase in outside services appears high because the test year expense was abnormally low. Please see below for the outside service expense charged to Black Hills Power from Utility Holdings from October 2010 through August 2014.

Account	10/1/10-9/30/11	10/1/11-9/30/12	10/1/12-9/30/13	9/1/13-8/31/14
923 - Outside Services	$337,588	$365,339	$270,757	$426,566

If the test year expense is ignored from the four year period, the expense is trending in a predictable manner and the most recent annual expense appears reasonable.

Q. DO YOU AGREE WITH MR. KOLLEN'S CRITICISM OF THE TREATMENT OF THE COSTS IN THESE TWO FERC ACCOUNTS?

A. No. As indicated above, the costs that are reflected in FERC accounts 920 and 923 are appropriately adjusted to the Company's most recent actual costs, which are reflective of costs going forward.

Q. ALSO IN HIS UTILITY HOLDINGS ADJUSTMENT TESTIMONY, MR. KOLLEN INDICATED THAT THE STAFF REVENUE REQUIREMENT MODEL INCLUDES AN ERROR IN ALLOCATION TO SOUTH DAKOTA FOR TRANSMISSION LOAD DISPATCH COSTS. DOES THE COMPANY AGREE THAT AN ERROR WAS MADE?

A. Yes, please refer to the rebuttal testimony of Jon Thurber for the Company's proposed treatment of the error.

Q. SHOULD THE COMMISSION ADOPT THE SETTLEMENT ADJUSTMENT FOR UTILITY HOLDINGS COSTS?

A. Yes, the adjustment reflects costs and operational changes known at the time of the Settlement Agreement. In addition, the inclusion of the most recent twelve months of actual expenses adjusted for known and measurable changes is consistent with the treatment of corporate costs included in past Commission approved rate case settlements for Black Hills Power and other utilities in South Dakota.

IV. <u>SERVICE COMPANY ADJUSTMENT</u>

Q. DID BLACK HILLS POWER INCLUDE A SERVICE COMPANY ADJUSTMENT IN ITS APPLICATION?

A. No. Black Hills Power's filed position requested recovery of Service Company costs that were allocated during the historic test year.

Q. **DID THE COMPANY SUBSEQUENTLY PROPOSE AN ADJUSTMENT TO SERVICE COMPANY COSTS IN THIS DOCKET?**

A. Yes. On October 22, 2014, in its Supplemental Response to SDPUC Request 3-96, the Company indicated that it would propose an adjustment in rebuttal testimony for the corporate costs charged to Black Hills Power from Service Company. In particular, Black Hills Power indicated it would seek to reflect the actual Service Company billings from September 2013 through August 2014 for all accounts except for property insurance expense. The pro forma property insurance expense was separately addressed because it reflects the actual expense for October 2014 through September 2015.

Q. **DOES THE SETTLEMENT AGREEMENT INCLUDE THIS SERVICE COMPANY ADJUSTMENT?**

A. Yes. In addition, the Settlement Agreement also annualizes the Service Company September 2013 through August 2014 labor costs to reflect the 2014 and 2015 wage increases.

Q. **DOES THE SERVICE COMPANY ADJUSTMENT INCLUDED IN THE SETTLEMENT REFLECT A KNOWN AND MEASURABLE CHANGE?**

A. Yes. The September 2013 through August 2014 billings from Service Company are actual costs that are accurate, reliable, and verifiable. The property insurance for October 2014 through September 2015 was paid in October 2014, reflects the property insurance for the Cheyenne Prairie Generating Station, and removes the property insurance associated with Ben French, Osage, and Neil Simpson I. In addition, the September 2013 through August 2014 labor costs have been annualized to reflect known salary increases that were effective after the end of the historic test year.

Q. MR. KOLLEN PROPOSED AS AN ALTERNATIVE TO THE SETTLED TREATMENT OF THIS ADJUSTMENT THAT THE COMPANY ONLY BE PERMITTED TO RECOVER THE COSTS INCURRED DURING THE HISTORIC TEST YEAR WITH NO ADJUSTMENT. DO YOU AGREE WITH MR. KOLLEN'S PROPOSED ADJUSTMENT TO SERVICE COMPANY COSTS?

A. No. The test year Service Company costs do not reflect current operations or any known and measurable increases that have occurred since the end of the test year.

Q. IN HIS TESTIMONY, MR. KOLLEN IS ALSO CRITICAL OF THE INFORMATION THE COMPANY SUPPLIED TO SUPPORT SERVICE COMPANY COSTS. DID THE COMPANY PROVIDE ANY EVIDENCE OF KNOWN AND MEASURABLE CHANGES?

A. Yes. In the Supplemental Response to SDPUC Request 3-96, the Company provided the actual costs from September 2013 through August 2014 with supporting work papers.

Q. HAVE THE EMAILS REFERENCED IN MR. KOLLEN'S DIRECT TESTIMONY BEGINNING ON PAGE 40, LINE 20, THROUGH PAGE 41, LINE 1, BEEN PRODUCED IN DISCOVERY?

A. Yes. The Company provided the email responses to Staff's informal discovery and the associated attachments in the Second Supplemental Response to SDPUC Request 3-96, on January 5, 2015. The emails contained the monthly Service Company charges by FERC account from the general ledger for September 2013 through August 2014, and the supporting work paper for the labor annualization. Notably, the information reflected in the emails is identical to the information that was produced in October 2014 in the Supplemental Response to SDPUC Request 3-96.

Q. WAS MR. KOLLEN CRITICAL OF ANY OF THE COSTS CONTAINED IN THE SERVICE COMPANY ADJUSTMENT?

A. Yes, Mr. Kollen was critical of the cost increases to FERC Account 920, administrative salaries, and to FERC account 921, office supplies and expenses.

Q. PLEASE EXPLAIN THE COST DRIVERS THAT INCREASED THE SERVICE COMPANY CHARGES IN FERC ACCOUNT 920, ADMINISTRATIVE SALARIES, FROM THE TEST YEAR.

A. The increase in administrative salaries is associated with an increase in headcount at Service Company and the wage annualization that is reflected in the cost update. The average headcount during the historic test year at Service Company was approximately 367, and the average headcount during the September 2013 through

August 2014 was approximately 378. The costs associated with the increased headcount were allocated consistent with the Service Company Cost Allocation Manual. In addition, the update to the most recent twelve months of actual costs from October 2012 through September 2013 and for the period September 2013 through August 2014 contained a partial wage increase for 2013 and 2014.

Q. PLEASE PROVIDE AN EXPLANATION FOR THE INCREASE IN SERVICE COMPANY CHARGES TO FERC ACCOUNT 921, OFFICE SUPPLIES AND EXPENSES, FROM THE TEST YEAR.

A. The increase in office supplies appears high because the test year expense was abnormally low. Please see below for the office supplies and expenses charged to Black Hills Power from Service Company from October 2010 through August 2014.

Account	10/1/10-9/30/11	10/1/11-9/30/12	10/1/12-9/30/13	9/1/13-8/31/14
921 - Office Supplies	2,329,590	2,213,036	2,199,768	2,456,138

Using the office supplies expense from October 2010 through September 2011 as the baseline, the actual September 2013 through August 2014 expense reflects less than 2% annual inflation. The most recent twelve month of office supplies charged by Service Company is a reasonable reflection of costs going forward.

Q. DO YOU AGREE WITH MR. KOLLEN'S CRITICISM OF THE TREATMENT OF THE COSTS IN THESE TWO FERC ACCOUNTS?

A. No. As indicated above, the costs that are reflected in FERC accounts 920 and 921 are appropriately adjusted to the Company's most recent actual costs, which are reflective of costs going forward.

Q. PLEASE EXPLAIN WHY THE COMMISSION SHOULD ADOPT THE SERVICE COMPANY ADJUSTMENT REFLECTED IN THE SETTLEMENT AGREEMENT.

A. The most recent twelve months of actual Service Company expenses adjusted for known and measurable changes reflects current costs and operational changes at the time of the Settlement Agreement. In addition, the adjustment is consistent with corporate cost treatment in past Commission approved rate case settlements for Black Hills Power and other utilities in South Dakota.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Rebuttal Testimony
Robert J. Hollibaugh

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

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

For Authority to Increase Rates
In South Dakota

Docket No. EL14-026

January 15, 2015

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert J. Hollibaugh. My business address is 625 Ninth Street, Rapid City, South Dakota 57701.

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

A. I am employed by Black Hills Service Company ("BHSC"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), a public utility holding company. I am the Director of Tax.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

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

Q. DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET?

A. No, I did not file direct testimony in this docket.

II. STATEMENT OF QUALIFICATIONS

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for overseeing all tax-related matters pertaining to the consolidated group that comprises BHC including those that affect the Company. Additional responsibilities include providing regulatory support with respect to tax-related matters for all entities that comprise the regulated business segment of BHC.

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I have a Bachelor of Science degree in Business Administration with an accounting emphasis from University of Nebraska-Kearney. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants, as well as the Taxation Committee of the Edison Electric Institute. Prior to joining the Company in mid-2005, I was employed by KPMG LLP as a senior tax manager from 2002 to 2005 with clients that were primarily in the utility and energy related industries. Such client responsibilities included tax planning, mergers and acquisitions, restructurings, controversy matters (e.g., IRS audit), and tax compliance. From 1996 to 2002, I was employed as an experienced tax manager for Arthur Andersen LLP with clients that were primarily in the utility and energy related industries. Client responsibilities were identical to those for my position at KPMG LLP. Prior to joining Arthur Andersen LLP, I was employed by NorthWestern Energy Corporation (f/k/a Northwestern Public Service Company) from 1980 to 1996 with responsibilities that were primarily tax related, but also included managerial duties in accounting and finance. As part of my tax related responsibilities at Northwestern Public Service Company, I provided support for rate case filings that included the development of all income tax related schedules.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address arguments made by the Black Hills Industrial Intervenors' witness, Mr. Kollen, at pages 10-25 of his direct testimony in support of his recommendation that the Commission: (1) not allow an adjustment to rate base for accumulated deferred income taxes ("ADIT") associated with net operating losses ("NOL ADIT") that have been generated for income tax purposes; and (2) correct certain ADIT adjustments related to plant decommissioning costs and the 69KV LIDAR Surveying Project.

Q. ARE YOU SPONSORING ANY EXHIBITS AS PART OF YOUR REBUTTAL TESTIMONY?

A. No.

IV. NOL ADIT INCLUSION IN RATE BASE

Q. HOW DOES MR. KOLLEN CHARACTERIZE THE ISSUE HE RAISES WITH RESPECT TO THE NOL ADIT IN HIS DIRECT TESTIMONY?

A. Mr. Kollen characterizes the inclusion of the NOL ADIT asset in rate base as a violation of the prohibition against retroactive ratemaking. In addition, he indicates that such ADIT is temporary and the Company has demonstrated it will have generated sufficient taxable income to fully utilize any remaining NOL carryforward. Thus, he recommends that the Commission should not allow the inclusion of any portion of the NOL ADIT asset in rate base whether conceptually as a violation of the prohibition against retroactive ratemaking or quantitatively on the basis there won't be any NOL carryforward left due the generation of sufficient taxable income to utilize such carryforward.

Q. MR. KOLLEN CHARACTERIZES THE NOL ADIT REFLECTED IN THE RATE CASE AS A THIRTEEN MONTH AVERAGE FOR THE HISTORIC TEST YEAR, AND AN ADJUSTMENT TO REFLECT CERTAIN PLANT ADDITIONS ON SCHEDULE M-2 THROUGH SEPTEMBER 30, 2014. IS THIS ACCURATE?

A. No, it is not. Mr. Kollen does not accurately describe the NOL adjustment on Schedule M-2. The adjustment on Schedule M-2 was made to the thirteen month average NOL balance to reflect the estimated NOL as of October 1, 2014. The supporting work paper for the NOL adjustment on Schedule M-2 was provided in Response to SDPUC Request No. 3-99.

Mr. Kollen makes a reference to the taxable income on Schedule K page 2 and alleges that the Company did not reflect pretax income in the NOL recalculation and that proper reflection of the "taxable income will be more than sufficient to fully utilize the NOL carryforward either before rates are reset or within the twelve months after rates are reset." This is not correct. As can be seen on tab "B. TI Forecast BHP", line 7, column AL, of the work paper submitted to support the NOL adjustment on Schedule M-2, the Company reflected $49,105,020 of estimated pretax income for the pro forma time period of October 1, 2013, through September 30, 2014. This is equivalent to pretax income listed on Schedule K, page 2, line 5, column e.

Mr. Kollen failed to recognize the ADIT associated with the additional tax deductions of research and development and accelerated depreciation including bonus depreciation related to plant expenditures to be incurred during the same pro forma time period on Schedule M-2 in the NOL calculation. Mr. Kollen's description of the NOL and the associated ADIT deferred tax asset reflected in the revenue requirement is inaccurate.

The Company reflected the NOL balance as of October 1, 2014, in the Settlement Agreement, and included the revenue increase authorized in this Settlement Agreement as taxable income in computing the appropriate ADIT deferred tax asset amount.

Q. DOES THE INCLUSION OF NOL ADIT IN RATE BASE CONSTITUTE RETROACTIVE RATEMAKING?

A. No. Income tax expense in determining cost of service in prior rate cases filed by the Company where a NOL was involved has been appropriately calculated. As discussed in more detail below, the NOL generated was principally the result of accelerated depreciation including bonus depreciation. The impact on total income tax expense due to these temporary differences was zero since there was an increase in deferred tax expense due to accelerated depreciation including bonus depreciation and a similar decrease to deferred tax expense as a result of the NOL in recording the deferred tax asset (i.e., NOL ADIT). Similarly, the income tax effect of such losses generated in previous tax years that are being utilized by the Company as it produces taxable income has no effect on income tax expense because it is simply a monetization of the NOL ADIT deferred tax asset. Mr. Kollen's assertion that the inclusion of a NOL ADIT in rate base constitutes some form of a retroactive ratemaking adjustment is completely without merit. The inclusion of the appropriate amount of NOL ADIT in rate base, which the Settlement Agreement reflects, is in accordance with the normalization rules specifically prescribed in the Internal Revenue Code of 1986 ("Code") and the applicable regulations thereunder.

Q. PLEASE RESPOND TO MR. KOLLEN'S CONTENTION THAT THE COMPANY HAS GENERATED SUFFICIENT TAXABLE INCOME TO FULLY UTILIZE ANY NOL CARRYFORWARD.

A. The key fact that Mr. Kollen fails to consider is the effect on taxable income of the expected accelerated depreciation including bonus depreciation as provided on Schedule M-2. Mr. Kollen is incorrect when he indicates on lines 13 and 14 of page 14 of his direct testimony that bonus depreciation is not available for 2014. To the contrary, Schedule M-2 details the capital expenditures that the Company expected would be eligible for bonus depreciation namely in the form of certain costs incurred with respect to the Cheyenne Prairie Generating Station ("CPGS"). The Company estimated that a significant portion of the cost incurred to construct CPGS would qualify. The amount of additional tax deductions including bonus depreciation as indicated on Schedule M-2 is $43.431 million, which nearly offsets the federal taxable income of $44.678 million from Schedule K page 2 that includes the full effect of the rate increase requested. Thus, there is an amount of NOL carryforward and the associated ADIT deferred tax asset that remain.

Secondly, the NOL ADIT deferred tax asset at December 31, 2013, referred to by Mr. Kollen in Exhibit LK-5 is comparing apples to oranges. The NOL ADIT disclosed by the Company in its public documents including FERC Form-1 filings represents the amount reported for financial reporting purposes in accordance with GAAP. The NOL carryforward and associated ADIT in the regulatory context is the amount that is attributable to Black Hills Power as a stand-alone entity whereby taxable income and any NOL are determined as if it filed its own separate income tax return. As a result, the NOL ADIT that is applicable for regulatory purposes has been determined in accordance with the methodology as prescribed by IRS. Thus, the adjustment to the NOL ADIT deferred tax asset that has been reflected in the Proposed Settlement is in compliance with the normalization rules mentioned above.

Q. PLEASE EXPLAIN THE NORMALIZATION REQUIREMENTS.

A. To understand the normalization requirements, it is helpful to begin with some background information. The background information presented by this testimony is not intended to represent a legal analysis, but instead reflects a general understanding of the legal holdings and legislative developments that have occurred and are relevant to application of such normalization requirements in this rate proceeding.

To that end, the Company's review of applicable tax code history leads it to understand that Congress enacted accelerated depreciation in 1954 as a means to promote and encourage economic expansion. Accelerated depreciation provides for the deferral of taxes that a company would otherwise be required to pay. Congress perceived this deferral of taxes as an interest-free loan, which was intended to be used by companies for capital investment and expansion in an effort to stimulate the post-World War II economy.

Q. HOW DID STATE AND FEDERAL REGULATORY AGENCIES TREAT ACCELERATED DEPRECIATION AFTER CONGRESS ENACTED IT IN 1954?

A. Initially, regulators had two choices. They could choose to treat income taxes for ratemaking purposes based on either the flow-through method or the normalization method.

Q. COULD YOU EXPLAIN THESE TWO METHODS OF HANDLING ACCELERATED DEPRECIATION?

A. Yes. The flow-through method allows customers to benefit immediately from the income tax savings associated with accelerated depreciation. In other words, the flow-through treatment of income tax expense allowed for ratemaking purposes essentially matched the income tax expense that resulted from the taxable income being reported on the utility's income tax return. In the early years of an asset's useful life, the benefit of lower income taxes resulting from accelerated depreciation was allowed to "flow-through" to the utility's customers. Under this method, future customers will bear a higher tax expense because the assets become depreciated more rapidly and less depreciation expense is available as a deduction claimed for income tax purposes.

Q. PLEASE EXPLAIN THE OTHER METHOD KNOWN AS "NORMALIZATION."

A. The normalization method spreads out, or normalizes, the tax benefit associated with depreciation expense to match the depreciation being used in setting rates. In other words, under the normalization convention, income tax expense reflected in the utility's cost of service is based on the amount of tax the utility would have paid had its taxes been calculated using the same method of depreciation and useful life adopted for ratemaking purposes. Under this method, the utility recovers in its rates more in income taxes than it actually incurs during the early years of an asset's useful life. If straight-line depreciation is used for ratemaking, the income tax benefits resulting from accelerated depreciation are effectively deferred evenly throughout the useful life of the asset. The income tax effect of the book/tax temporary difference is recorded in an ADIT account, as prescribed by the interperiod tax allocation method of accounting. This accounting is described in General Instruction No. 16 of the FERC Uniform System of Accounts, 18 C.F.R. Part 101, "Comprehensive Interperiod Income Tax Allocation." Deferred income taxes reverse in the later years of an asset's life when the utility will pay higher taxes than it is permitted to recover from its customers in rates.

Q. UNDER THE NORMALIZATION METHOD, IS IT CORRECT TO SAY THAT THE UTILITY RETAINS THE "INTEREST-FREE LOAN" CREATED BY THE INTERNAL REVENUE CODE?

A. No. Under the normalization method, the utility does not keep the full "principal" of the "interest-free loan" because the amount of ADIT is deducted from rate base, resulting in a lower revenue requirement and, consequently, reduced rates for customers. The utility, however, still has the unrestricted use of the funds to allow it to reinvest in the form of additional plant facilities, as intended by Congress. The reduction in rate base resulting from the ADIT decreases in later years as previously deferred taxes are paid by the utility.

Q. WHICH METHOD DID REGULATORY AGENCIES TEND TO ADOPT, THE FLOW-THROUGH METHOD OR THE NORMALIZATION METHOD, FOR RATEMAKING PURPOSES?

A. After Congress approved accelerated depreciation, regulatory agencies were not consistent with respect to rate treatment. Different regulatory agencies handled accelerated depreciation differently, depending upon how they viewed accelerated depreciation and whether the benefits of this tax treatment should accrue to customers or to the utility. In addition, it depended upon the regulator's view of the need to match income tax expense reflected in cost of service to the amount of taxes paid by the utility.

Q. DID THE APPROACH OF ALLOWING REGULATORS TO CHOOSE CHANGE?

A. Yes. Ultimately, Congress became concerned that "flow-through" decisions by regulators resulted in a "doubling of the Government's loss of revenue, from the use of accelerated methods of depreciation for tax purposes." H.R. Rep. No. 91-413 (1986), reprinted in 1969 U.S.C.C.A.N. 1645, 1782. Congress reasoned that this was because the flow-through of the tax reduction reduces the rates charged to customers, which in turn reduces the utility's taxable income and therefore reduces its income tax. This second level of tax reduction is passed on to the utility's customers.

Q. HOW DID CONGRESS ADDRESS THE CONCERN RELATED TO FLOW- THROUGH TREATMENT BY REGULATORS?

A. In the Tax Reform Act of 1969 (Pub. L. No. 91-172), Congress added Section 167(l) to the Code, which was subsequently re-codified at Sections 168(f)(2) and 168(i)(9). This provision essentially provided that, in order for a taxpayer to be entitled to claim accelerated depreciation on public utility property, it must be permitted normalization treatment in the setting of rates. Otherwise, for tax purposes, it must use the straight-line method of depreciation and generally longer useful life (i.e., book method) when determining its depreciation expense for federal income tax purposes. At one point, Congress considered no longer permitting utilities to use accelerated depreciation. Congress, however, believed that precluding regulated utilities from using accelerated depreciation would place them at an unfair competitive disadvantage both in terms of pricing with respect to the sale of their products and services and their ability to attract capital from bondholders and equity investors. The legislative history reflects congressional intent to remove the regulatory agencies' ability to require flow-through of income taxes resulting from accelerate depreciation. As stated in the legislative history, regulatory agencies "will be permitted to, in effect, force the taxpayer to straight line depreciation by not permitting normalization. The regulatory agency will not, in such cases, be permitted to require flow through of deferred taxes." H.R. Rep 91-413, 91st Congress, 1st Sess 1969 at 133. Thus, Congress eliminated any customer benefit from a regulatory agency's decision to adopt the flow-through method by removing the utility's ability to use accelerated depreciation for tax purposes in the event the regulator mandated the flow-through method.

Q. ARE THERE ANY ADDITIONAL SIGNIFICANT LEGISLATIVE CHANGES RELATED TO INCOME TAX NORMALIZATION?

A. Yes. There are two other significant developments in the tax laws that affected tax normalization: 1) the Economic Recovery Tax Act of 1981 ("1981 Act"); and 2) the normalization regulations as originally issued by Treasury.

Q. WHAT IS THE COMPANY'S UNDERSTANDING OF THE 1981 ACT AND THE U.S. TREASURY REGULATIONS AS THEY RELATE TO NORMALIZATION?

A. The Company's understanding of the 1981 Act is that it required normalization by regulators as a condition for accelerated depreciation by public utilities for qualified property placed in service after December 31, 1980. S. Rep. No. 97-144 (1981), reprinted in 1981 U.S.C.C.A.N. 105, 161. Similar to Congress' objective in 1954, Black Hills Power believes that the purpose of the 1981 amendment was to provide an investment stimulus that was viewed as essential for economic expansion. Congress considered accelerated depreciation as a way of spurring investment and encouraging businesses to replace old machinery and equipment with modern and more efficient assets that reflected improved technology. The legislative history explains that passage of the 1981 Act was an attempt by Congress to restructure the system of determining tax depreciation as a way to stimulate capital formation, increase productivity and improve the nation's competitiveness in international trade.

Congress was also trying to simplify the depreciation rules. For example, it is apparent to the Company from reading the legislative history of the 1981 Act that Congress viewed "deferred taxes" as an interest-free loan to the utility. That section of the legislative history notes that a utility is able to use funds that otherwise would have to be obtained by borrowing or raising equity capital. Thus, Congress did not want to allow accelerated depreciation for tax purposes unless the regulatory body used the normalization method to account for it. This explains the provision in the 1981 Act that states the amount of capital to be deducted from rate base must not exceed the amount of deferred taxes recorded on the books with respect to accelerated depreciation in order to be in compliance with tax normalization.

The Treasury Regulations, which were issued in Treasury Decision (T.D.) 7315 and released on June 7, 1974, provided additional guidance with respect to the law enacted in the Tax Reform Act of 1969 that defined the normalization method of accounting. For example, they provide that the reserve established for public utility property should reflect the total amount of tax deferral resulting from the use of different depreciation methods for tax and ratemaking purposes. The Treasury regulations also require that the ADIT balance be used as a reduction to the utility's rate base and must be determined by reference to the same historical period as used for determining ratemaking tax expense. The utility may use historical or projected data in calculating these two amounts, but they must be done consistently. Lastly, the Treasury regulations describe the consequences to the utility if found in violation of the normalization rules.

Q. WITH THAT BACKGROUND, PLEASE EXPLAIN HOW THE COMPANY UNDERSTANDS THE NORMALIZATION RULES AS THEY APPLY TO BLACK HILLS POWER.

A. The normalization method of accounting as presently prescribed under Treasury Regulations Section 1.167(l)-1(h) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the actual tax liability. In other words, if the regulatory agency uses straight-line depreciation in setting rates, a utility that uses accelerated depreciation for tax purposes must use the straight-line method of depreciation (i.e., the straight-line method and estimated useful life used in calculating annual book depreciation expense) in computing its income tax expense for purposes of determining the cost of service for ratemaking purposes. The Treasury Regulations further require the utility to calculate the annual tax effect of this book/tax temporary difference and record the increase or decrease on its books and records in a deferred tax account (i.e., ADIT). Additionally, the regulations require that the ADIT balance be used as a reduction to the utility's rate base and must be determined by reference to the same historical period as used for determining ratemaking tax expense. The utility may use historical or projected data in calculating these two amounts, but they must be done consistently.

Q. WHAT ARE THE CONSEQUENCES IF THE UTILITY VIOLATES THE TAX NORMALIZATION RULES?

A. As stated above, the Company believes that Congress originally enacted the normalization rules to ensure that the capital formation benefits of accelerated depreciation be retained by the utility and for customers to benefit from lower rates through the reduction to rate base. The intent behind the normalization rules is to prevent regulators from assigning the tax benefits of accelerated depreciation to customers by reducing the income tax allowance used in developing cost of service. The normalization rules dictate that accelerated depreciation, determined under Code Section 168, does not apply to any utility property if the taxpayer does not use the normalization method of accounting. Violation of the normalization rules will preclude the utility from being able to claim accelerated depreciation in current and future years. Thus, the utility would not get the benefit of tax deferral from accelerated depreciation and the cost free capital associated with this book/tax temporary difference.

Q. DOES ACCELERATED DEPRECIATION INCLUDE BONUS DEPRECIATION?

A. Yes, it does.

Q. PLEASE DESCRIBE THE NATURE OF BONUS DEPRECIATION.

A. Bonus depreciation is the expensing, for income tax purposes, of either 50% or 100% of the cost of the asset in the year it is placed in service. For assets subject to the 50% bonus depreciation, the remaining balance is depreciated in accordance with the existing modified accelerated cost recovery system ("MACRS") tables starting with the current year. For assets subject to 100% bonus depreciation, there is no remaining balance to be depreciated. It does not mean that the asset receives more depreciation than any other assets; it simply means that tax depreciation is accelerated into the first year.

Bonus depreciation was originally enacted under the Job Creation and Worker Assistance Act of 2002 in an attempt to spur an economy that was significantly impacted by the events of September 11, 2001. Qualified assets placed in service after September 10, 2001, were eligible for 30% bonus depreciation. It was subsequently reinstated under the Economic Stabilization Act of 2008, whereby certain assets placed in service between December 31, 2007 and January 1, 2009 qualified for 50% bonus depreciation. Through enactment of the American

Recovery and Reinvestment Act of 2009, Congress extended this bonus depreciation to cover qualifying assets placed in service between December 31, 2008 and January 1, 2010. The Small Business Jobs Act of 2010 was enacted in September 2010, which allowed companies to use bonus depreciation for qualified capital additions placed in service after December 31, 2009 and before January 1, 2011. In December 2010, Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act ("2010 Act") was passed into law. The 2010 Act contained a provision extending bonus depreciation to certain assets placed in service after September 8, 2010 and before January 1, 2013. It also increased the amount of bonus depreciation for assets placed in service from September 9, 2010 through December 31, 2011, from a 50% deduction to a 100% deduction. Bonus depreciation reverted back to 50% for assets placed in service in 2012 and for certain assets with a long production period that were placed in service in 2013. Subsequently, with the passage of the American Taxpayer Relief Act of 2012 in early January 2013, 50% bonus depreciation was extended another year and made available to qualified assets placed in service in 2013 and for certain qualified assets with a long production period that are placed in service in 2014. Recent passage of the Tax Increase Prevention Act of 2014 ("2014 Act") once again extended 50% bonus depreciation for another year and is made available to qualified assets placed in service in 2014 and for certain qualified assets with a long production period that are placed in service in 2015. The effect of the 2014 Act was not reflected in this rate case, however, the one year extension of 50%

bonus depreciation is expected to result in the generation of a NOL for 2014 for the Company.

Q. DO THE NORMALIZATION RULES ALSO APPLY TO BONUS DEPRECIATION?

A. Yes, they do. As mentioned above, the normalization rules were originally codified in Code Section 167 and the regulations thereunder. Presently, such rules reside in Code Section 168 including a provision specific to bonus depreciation.

Q. WHAT IMPACT HAS ACCELERATED DEPRECIATION INCLUDING BONUS DEPRECIATION HAD IN DETERMINING THE COMPANY'S NET INCOME FOR TAX PURPOSES?

A. If a utility has more tax deductions than taxable income in a given tax year, it results in a NOL. For Black Hills Power, the effect of accelerated depreciation including bonus depreciation has resulted in tax deductions in excess of taxable income for certain years. The Company generated a NOL for each of the tax years 2008 through 2011and expects such NOLs to completely unwind during the 20-year carry-forward period, as prescribed under the Code. It is appropriate under generally accepted accounting principles ("GAAP") to record a deferred tax asset associated with a NOL if the company can demonstrate the ability to timely unwind the NOL by offsetting future taxable income. The deferred tax asset attributable to the NOL resulting from accelerated tax depreciation, including bonus depreciation, is added to rate base to the extent that it offsets the ADIT, or some portion thereof, related to the book/tax depreciation temporary difference resulting in a NOL ADIT. Specific guidance previously issued by the IRS in the form of Private Letter Ruling ("PLR") 8818040 prescribed this approach as acceptable with respect to determining the NOL ADIT. This approach has been recently reiterated by the IRS in PLRs 201436037, 201436038, and 201438003. Such treatment is consistent with the underlying premise of ADIT as a source of an interest free loan being offered by the United States government. To the extent that temporary differences such as accelerated tax depreciation deductions including bonus depreciation give rise to a NOL, the interest free loan has not yet been funded or realized. The amount of the increase in ADIT liability is then partially offset by the NOL ADIT deferred tax asset.

Q. WHAT DOES THIS MEAN FOR BLACK HILLS POWER IN THIS RATE CASE?

A. The Settlement Agreement reflects the necessary adjustment to ADIT as a result of accelerated depreciation including bonus depreciation, where applicable, and the NOL ADIT deferred tax asset. Schedule M-2 details the capital expenditures that will be eligible for bonus depreciation namely in the form of certain costs incurred with respect to the Cheyenne Prairie Generating Station ("CPGS"). The Company estimates that a significant portion of the cost incurred to construct CPGS should qualify, which resulted in a sizeable ADIT adjustment in reducing rate base. As discussed above, an increase in accelerated depreciation including bonus depreciation had an effect on the NOL ADIT as well. The NOL carryforward and associated ADIT in the regulatory context is the amount that is attributable to

Black Hills Power as a stand-alone entity whereby taxable income and any NOL are determined as if it filed its own separate income tax return. As a result, the NOL ADIT that is applicable for regulatory purposes is determined in accordance with the methodology as prescribed by IRS. Thus, the adjustment to ADIT and ADIT NOL deferred tax asset that have been reflected in the Settlement Agreement are in compliance with the normalization rules as described above including the guidance previously issued by IRS specific to NOLs.

V. <u>ADIT ADJUSTMENT RELATED TO PLANT DECOMMISSIONING COSTS</u>

Q. IS MR. KOLLEN CORRECT IN HIS ASSERTION THAT THERE IS AN ERROR IN THE CALCULATION OF ADIT?

A. No. However, Mr. Kollen is correct in that the Company will not be entitled to a deduction for income tax purposes until the decommissioning costs have been incurred. Such costs are expected to be incurred by September 2015. The timing of the deductibility should determine the ADIT consequence when the temporary difference between book and tax is created, which is consistent with the approach that has been applied to the losses for income tax purposes that will be realized and recognized related to the retirement of the plant facilities and disposition of applicable obsolete inventory. Alternatively, should the Commission agree with Mr. Kollen's recommendation of reflecting the deferred tax liability as a reduction to rate base, the additional tax deduction would result in less utilization of the NOL carryforward. Restoration of the NOL carryforward results in a corresponding adjustment in the NOL ADIT. As discussed above in connection with the impact to taxable income of the additional tax deductions identified on Schedule M-2, an imputed tax deduction of approximately $10 million related to decommissioning costs would certainly result in less NOL carryforward being utilized. Thus, to be consistent with Mr. Kollen's reasoning of matching the ADIT with the inclusion in rate base of the regulatory asset, an associated NOL ADIT deferred tax asset should likewise be included providing effectively an offset to the increased ADIT liability.

VI. <u>ADIT ADJUSTMENT RELATED TO 69KV LIDAR SURVEYING PROJECT</u>

Q. IS MR. KOLLEN CORRECT IN HIS ASSERTION THERE IS AN ERROR IN THE CALCULATION OF ADIT?

A. No. There seems to be a disconnect in the cost information that Mr. Kollen used in the development of his Exhibit LK-13. Updated cost information provided by Black Hills Power to Commission Staff as reflected on Staff Exhibit PJS -1 Schedule 5 indicates allocable costs of $337,919 as opposed to the $685,000 shown in Exhibit LK-13. Based on the revised cost information, Schedule M-2 appropriately reflects the ADIT adjustment that has been incorporated into the Settlement Agreement.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Rebuttal Testimony and Exhibits
Kyle D. White

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

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

For Authority to Increase Rates
In South Dakota

Docket No. EL14-026

January 15, 2015

EXHIBIT
BHP
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EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kyle D. White, 625 Ninth Street, P.O. Box 1400, Rapid City, South Dakota.

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

A. I am currently employed by Black Hills Service Company ("Service Company"), a wholly-owned subsidiary of Black Hills Corporation ("BHC"), as Vice President of Regulatory Affairs. My areas of responsibility include regulatory affairs for the regulated utility subsidiaries of BHC.

Q. FOR WHOM ARE YOU TESTIFYING ON BEHALF OF TODAY?

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

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THIS DOCKET?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to support the Settlement Stipulation ("Settlement Agreement"), reached between Black Hills Power and the South Dakota Public Utilities Commission Staff ("Staff"). I specifically address: (1) the status of settlement; (2) the FutureTrack Workforce Development program; (3) incentive compensation; and (4) class cost of service. I also explain why the positions taken by the opposing parties on these topics are unpersuasive. Lastly, I address why the Company may not object if the Commission elects to modify specifically articulated terms reflected in the Settlement Agreement.

III. SETTLEMENT STATUS

Q. IS THERE A SETTLEMENT OF ALL RATE CASE ISSUES PENDING BEFORE THE COMMISSION?

A. Yes. On December 8, 2014, Black Hills Power entered into a Settlement Agreement with Staff regarding all issues pertaining to the Company's application for authority to revise electric rates. The Black Hills Industrial Intervenors ("BHII") and Dakota Rural Action ("DRA") chose to not be parties to the Settlement Agreement.

Q. DOES BLACK HILLS POWER CONSIDER THE SETTLEMENT TO BE COMPREHENSIVE?

A. Yes. The Settlement Agreement represents the culmination of months of substantial formal and informal discovery regarding the Company's operations. It resulted from extensive negotiations between Commission Staff and the Company, which at times also included all parties to this docket.

Q. DOES THE SETTLEMENT AGREEMENT CONTAIN TERMS THAT BENEFIT BHII?

A. Yes, it does. Customers that comprise the BHII were primary beneficiaries of the rate mitigation plan that is reflected in the Settlement Agreement. As a result, the bill increases for BHII members are in a range of two to five percent.

Additionally, under the terms of the Settlement there will be no additional change in base rates for at least two years.

Q. DID BHII AND DRA FILE ANSWER TESTIMONY IN OPPOSITION TO THE SETTLEMENT AGREEMENT?

A. Yes and no. BHII filed testimony from two consultants, Mr. Steven J. Baron and Mr. Lane Kollen. DRA did not file testimony in opposition to the Settlement Agreement.

Q. THROUGH ITS ANSWER TESTIMONY, DO YOU BELIEVE THAT BHII HAS RAISED ISSUES THAT SUPPORT REJECTION OF THE SETTLEMENT AGREEMENT?

No, I do not. Although introducing new areas for the Commission to consider, the answer testimony largely supports the numerous compromises reflected in the Settlement Agreement. As an example, after 32 pages of testimony regarding the class cost of service, Mr. Baron recommends that the Commission adopt the apportionment of the overall revenue increase to the rate classes as reflected in the Settlement Agreement. As illustrated in my rebuttal testimony, and the rebuttal testimony of Black Hills Power's other rebuttal witnesses, in the areas in which BHII's consultants' disagree with the terms of the Settlement Agreement the BHII consultants' analysis is flawed. As a consequence, the BHII answer testimony provides no evidence that would warrant the Commission rejecting the Staff and its consultants' comprehensive assessment and complete settlement of all issues.

Q. DOES THE COMPANY FULLY SUPPORT THE SETTLEMENT AGREEMENT?

A. Yes. The revenue requirement reflected in the Settlement Agreement is consistent with the utility's cost to meet its obligation to serve its South Dakota customers. If approved, the Settlement Agreement will result in just and reasonable rates. As a result, the Company fully supports the Settlement Agreement that is presently before the Commission.

However, as indicated later in my testimony and the testimony of Jon Thurber, there are opportunities before the Commission to modify specific terms of the Settlement Agreement that would not likely be opposed by the Company. Those areas include possible changes to the rate treatment of certain customers and an adjustment for O&M costs associated with the Wyodak facility.

Q. IF THE COMMISSION APPROVED THE SETTLEMENT AGREEMENT, WOULD THE APPROVAL SET PRECEDENT FOR FUTURE RATE CASE DOCKETS?

A. No, it would not.

IV. FUTURETRACK WORKFORCE PROGRAM

Q. DOES THE SETTLEMENT WITH STAFF REQUEST APPROVAL OF THE FUTURE TRACK PROGRAM THAT WAS INCLUDED IN THE COMPANY'S FILED POSITION?

A. No. Settlements generally do not address questions of policy, like the innovative eight-year Future Track workforce development proposal, unless there has been prior Commission guidance or direction provided in previous decisions and orders. The Settlement only provides for rate recovery of employees hired in 2014. It does not include future expenses, the tracking of expenses, or reporting requirements as contemplated by the proposed program.

Q. NOTWITHSTANDING THE FACT THAT THE PROGRAM IS NOT INCLUDED IN THE SETTLEMENT AGREEMENT, DOES MR. KOLLEN PROPERLY EXPLAIN IN HIS TESTIMONY THE FUTURETRACK WORKFORCE PROGRAM THAT THE COMPANY INCLUDED IN ITS FILED POSITION?

A. No. The Commission should review the testimony of Black Hills Power witness Jennifer Landis if it wants to fully understand the proposed workforce development program, the circumstances that have created the need to modify traditional approaches to attracting and developing new employees into key operational roles, and the need to mitigate the operational and safety risks associated with replacing an unprecedented number of employees from the Company's experienced workforce.

Q. MR. KOLLEN STATES ON PAGE 27 OF HIS TESTIMONY, "IN ANY EVENT, THE COMPANY HAS PROVIDED NO EVIDENCE THAT THE PRACTICE IS NECESSARY OR THE ONLY WAY THAT IT CAN RECRUIT OR FILL ENTRY-LEVEL POSITIONS AT THE COMPANY." DO YOU AGREE?

A. No. Ms. Landis' testimony provides extensive evidence that supports the need to be more thoughtful and aggressive in ensuring Black Hills Power's customers have the benefit of a qualified and cost-effective workforce in the future. Curiously, Mr. Kollen directs the Commission to learn about the programs available to students at Mitchell Technical Institute as evidence that new employees will be available for hire by Black Hills Power. What he fails to recognize is the information contained in Ms. Landis' testimony that indicates, "…approximately 25 companies are working with Mitchell Technical Institute ("MIT") to provide scholarships for MIT students that require employment with the sponsoring company following graduation."

While Mr. Kollen is correct that the Future Track Program is not the only way to attract the needed employees, Future Track only focused on replacing retiring employees in positions critical to maintaining safe and reliable service. The Company would still be in the "market' looking for employees related to normal employee turnover, which may increase due to expected higher industry demand for employees with the desired skill sets. Since the employees included in the proposed Future Track program would be in high-skill technical positions which require significant training (often years) to become qualified, it would likely be necessary to increase staffing and compensation levels in order to maintain the appropriate staffing levels required to meet operational and safety standards.

Q. DID MR. KOLLEN PROPERLY DESCRIBE THE PROPOSED REGULATORY ASSET AND THE TRACKING OF PROGRAM COSTS?

A. No, he says the "request is inappropriately open-ended." This is false. The program identified specific positions that would be open solely due to retirements, identifies specific trackable cost categories (like scholarships and training), a specific time frame (8 years) and the opportunity for the Commission to review program costs for reasonableness on an annual basis.

He also says, "The Company has not proposed a measurement baseline that defines how the payroll and related expenses associated with this program can and will be differentiated from any other payroll and related expenses." This again is false, Ms. Landis on page 13 describes in detail how program costs would be tracked and charged to the regulatory account. She also provides program specifics through Exhibit JCL-1.

Finally, Mr. Kollen claims, "The Company is not adequately incentivized to operate efficiently if there is no defined measurement baseline and it can defer (and later recover) any amount in excess of the allowed amount." This claim is also false. The final paragraph of Exhibit JCL-1 states:

"**Program Expense True-Up**: Retirement decisions are highly personal and workers may decide to alter their retirement plans to either work longer or retire sooner. Because of this, the cost of the program is expected to fluctuate over time. In addition to reporting the program's status to the Commission annually, we recommend a true-up audit be performed in 5 years. Any expenses planned for but not realized will be returned to Black Hills Power customers. Likewise, any reasonable and documented expenses that exceed the approved Future Track regulatory account will be brought before the Commission for reimbursement."

V. INCENTIVE COMPENSATION

Q. HAVE ANY OF THE PARTIES TO THIS RATE CASE DEMONSTRATED THAT INCENTIVE COMPENSATION IS AN "IMPRUDENT" EXPENSE FOR INCLUSION IN BLACK HILLS POWER'S REVENUE REQUIREMENT?

A. No, the BHII's have only alleged through Mr. Kollen's testimony that for subjective reasons the Commission should reject board and management decisions regarding the required compensation practices needed to staff the organization and meet the obligation to serve. No evidence was presented that the total compensation paid to employees was imprudent or unreasonable based upon what the market pays employees for similar positions.

Q. IS IT COMMISSION PRECEDENT TO DENY RECOVERY OF INCENTIVE COMPENSATION EXPENSE TIED TO OPERATING AND FINANCIAL PERFORMANCE, AS MR. KOLLEN STATES ON PAGE 35 OF HIS TESTIMONY?

A. Although I am not aware of a specific Commission decision regarding the inclusion of incentive compensation for determining a utility's revenue requirement, I do know that the Commission has approved rate case settlements where the revenue requirement included expenses for employee incentive compensation. In fact, some of Mr. Kollen's clients in this docket have been parties to prior settlements approved by the Commission that included incentive compensation expense within the revenue requirement.

Q. MR. KOLLEN STATES ONE OF THE REASONS TO DENY RECOVERY OF INCENTIVE COMPENSATION EXPENSE IS THAT, "THE COMPANY'S FINANCIAL PERFORMANCE IS A DIRECT FUNCTION OF THE REVENUES RECOVERED FROM CUSTOMERS, INCLUDING THE RATE INCREASES THAT ARE AUTHORIZED BY THE COMMISSION." DO YOU SHARE THIS VIEW?

A. Revenues are an important component of the financial performance of all businesses. What Mr. Kollen has failed to acknowledge is that a company's ability to serve customers and meet customer demands is also a direct function of the revenues recovered from customers. If revenues are inadequate to support the needs of the business, then changes to the business must occur or customer and or owner expectations will not be met. He also fails to acknowledge that the financial performance of any company is also a direct function of how well the company controls costs and expenses. Effective cost controls in a business where revenue levels are regulated is a critical aspect of avoiding even higher rate requests in the future.

Q. ON PAGE 36 OF MR. KOLLEN'S TESTIMONY HE STATES, "THERE IS AN INHERENT CONFLICT BETWEEN LOWER RATES AND GREATER FINANCIAL PERFORMANCE." DO YOU AGREE?

A. No. Financial performance is not solely the result of rate increases. Financial performance (profitability) for a utility is primarily influenced by the level of its expenses. Profitability can be enhanced through efficiency and lowering of costs, increasing sales or increasing prices.

Q. ANOTHER POINT MR. KOLLEN MAKES IS THAT, "THE REVENUE REQUIREMENT SHOULD NOT EMBED RECOVERY OF AN EXPENSE THAT IS BASED ON PERFORMANCE" BECAUSE, "IF THE COMPANY IS ENSURED RECOVERY OF THE EXPENSE FROM CUSTOMERS, THEN THERE IS NO PERFORMANCE THAT IS AT RISK OR THAT MUST BE ACHIEVED IN ORDER TO RECOVER THAT EXPENSE." DO YOU AGREE?

A. No, I do not. The Company's incentive compensation practices are designed to incent and reward employees for achieving planned operating and financial results. The practices are designed to encourage employee initiative and other behaviors that will result in a sustainable and successful company. There are numerous benefits for customers when a company's employees receive incentive income to achieve these results.

Q. MR. KOLLEN TELLS THE COMMISSION IT "SHOULD NOT INCENTIVIZE THE COMPANY TO SEEK GREATER RATE INCREASES AND ACT AGAINST THEIR CUSTOMERS' INTERESTS." DO YOU BELIEVE THAT FUTURE SOUTH DAKOTA REGULATORS WOULD FAIL TO SET JUST AND REASONABLE RATES IF THE

COMMISSION APPROVED A SETTLEMENT THAT INCLUDES EXPENSES FOR INCENTIVE COMPENSATION?

A. No. The Staff and the Commission have demonstrated exceptional competence in auditing and assessing Black Hills Power's business and ensuring that rate changes are just and reasonable. If Mr. Kollen's premise is that incentive compensation leads to more frequent rate increases, then this would have come to be true once the Company began utilizing incentive compensation practices. Black Hills Power's rate case history does not support this outcome.

Q. MR. KOLLEN STATES ON PAGE 36 OF HIS TESTIMONY, "THIS FORM OF INCENTIVE COMPENSATION IS PRIMARILY DIRECTED TOWARD ACHIEVING SHAREHOLDER GOALS, NOT CUSTOMER GOALS." DO YOU AGREE?

A. No. As explained in the direct testimony of Laura Patterson, incentive compensation is a component of most utilities' and corporations' direct compensation paid to attract and retain qualified employees. Our employment locations are frequently in the less populated locations of the Country. This means employees coming to these locations will have few local employment options if they choose to leave. Their spouses will also see their employment options limited. Historically, we could expect employees to stay and "earn" their pension. This retention mechanism has diminished since the Corporation froze its defined benefit pension plan. With these factors already in play, a competitive total direct compensation offering is essential for meeting our obligation to serve South Dakota electric customers.

Q. MR. KOLLEN STATES THAT BOTH THE RESTRICTED STOCK EXPENSE AND THE PERFORMANCE PLAN EXPENSE ARE TIED TO THE COMPANY'S FINANCIAL PERFORMANCE. IS THE RESTRICTED STOCK EXPENSE TIED TO FINANCIAL PERFORMANCE?

A. No. As explained in Ms. Patterson's direct testimony on page 14, "restricted stock is granted to key employees and vests ratably over a 3-year period. The purpose of the 3-year vesting period for both the restricted stock and the performance shares is to get retention of key employees." Once restricted stock is granted to a key employee the only requirement for pay-out is the employee's continued employment.

Q. HAS BLACK HILLS POWER BEEN GRANTED RECOVERY OF INCENTIVE COMPENSATION EXPENSES IN OTHER JURISDICTIONS?

A. Yes, last summer the Wyoming Public Service Commission approved a settlement with the Office of Consumer Advocate that included 100% of the requested incentive compensation in the revenue requirement.

Q. DOES THE SETTLEMENT WITH STAFF INCLUDE 100% OF THE COMPANY'S INCENTIVE COMPENSATION COSTS?

A. No, as Mr. Kollen points out, $666,000 has been removed from expense for determining the proposed revenue requirement.

Q. IF THE COMMISSION ACCEPTED MR. KOLLEN'S POSITION AND REMOVED THE REMAINING INCENTIVE COMPENSATION FROM THE UTILITY'S REVENUE REQUIREMENT, WHAT WOULD BE THE RESULT?

A. I believe he has recommended, on page 35, that the entire incentive compensation expense be disallowed. This would be the equivalent of the Commission lowering Black Hills Power's authorized return on equity by in excess of 20 basis points. The substance, depth and nature of Mr. Kollen's testimony in no way justifies a punitive outcome for the Company for utilizing normal and reasonable employee compensation practices that are prevalent across the utility industry and other companies in the Black Hills region. For the Commission to remove from the Settlement Agreement incentive compensation expense would be contrary to the principle of utility regulation which requires a utility be allowed a reasonable opportunity to recover actual costs prudently incurred in providing service to its customers. The Settlement Agreement as presented will result in just and reasonable rates for Black Hills Power's South Dakota customers.

VI. <u>CLASS COST OF SERVICE</u>

Q. MR. WHITE, HAVE YOU READ THE ANSWER TESTIMONY FILED ON BEHALF OF BHII BY MR. BARON?

A. Yes, I have.

Q. DOES MR. BARON RECOMMEND THAT THE COMMISSION REJECT THE CLASS COST OF SERVICE THAT IS REFLECTED IN THE SETTLEMENT AGREEMENT?

A. No, he does not. After 32 pages of testimony on the subject, Mr. Baron recommends that the Commission adopt the apportionment of the overall revenue increase to the rate class as reflected in the Settlement Agreement.

Q. IF MR. BARON DOES NOT OPPOSE THE CLASS COST OF SERVICE, THEN WHAT ACTIONS HAS HE RECOMMENDED THAT THE COMMISSION TAKE ON THIS SUBJECT?

A. Mr. Baron identifies a number of alternative methodologies that he believes should be utilized by the Company in its class cost of service. While he characterizes his proposed alternative as corrections of "errors" in the Company's class cost of service, in most instances the changes he proposed are simply different approaches that he believes could be taken. Ultimately, Mr. Baron states, "The commission should require BHP to file a class cost of service study in its next base rate case reflecting the corrections that I have discussed in my testimony. At a minimum, the Company should be required to file an alternative class cost of service study (in addition to its preferred method) reflecting the corrections that I am recommending. The changes to the company's study that I have presented provide a more appropriate basis to evaluate the reasonableness of the Company's rates."

Q. DO YOU SUPPORT MR. BARON'S REQUEST THAT BLACK HILLS POWER BE ORDERED TO PREPARE A CLASS COST OF SERVICE

STUDY THAT INCORPORATED BHII'S RECOMMENDATIONS FOR ITS NEXT BASE RATE APPLICATION?

A. No.

Q. WHY ARE YOU NOT SUPPORTIVE OF MR. BARON'S REQUEST?

A. First, I disagree with Mr. Baron's suggestion that the proposed alternative methodologies are "corrections" to the class cost of service study.

Second, the Company has the burden of proof regarding the reasonableness of its rates and should be free to determine the evidence it believes is necessary and appropriate to support its future applications. Mr. Baron's approach, particularly the requirement of an "alternative study" to Black Hills Power's "preferred method," only works to burden the Company and its customers with the costs that should be borne by BHII as part of its review of the application and litigation preparation. I believe our other customers already shoulder too much of the litigation cost resulting from BHII's participation in Black Hills Power's base rate case proceedings.

Third, I don't agree with many of Mr. Baron's conclusions and as a result, the Company would not want to have to work around class cost of service requirements designed to benefit a handful of large customers.

Q. GIVEN THE NUMEROUS PROPOSED MODIFICATIONS THAT MR. BARON IDENTIFIES IN HIS TESTIMONY, WHY DO YOU THINK HE SUPPORTS STAYING WITH THE CLASS COST OF SERVICE THAT IS REFLECTED IN THE SETTLEMENT AGREEMENT?

A. I don't know, but I believe that it is fair to assume that his clients are benefitting through lower cost allocations by the Company's approach and the rate increase mitigation it has implemented.

Q. MR. WHITE, GIVEN THAT MR. BARON HAS SUGGESTED THAT THE COMMISSION ORDER THE COMPANY TO MAKE MODIFICATIONS TO ITS CLASS COST OF SERVICE STUDIES IN THE FUTURE, WOULD YOU CARE TO RESPOND TO SOME OF MR. BARON'S FINDINGS REGARDING BLACK HILLS POWER'S CLASS COST OF SERVICE?

A. Yes, I first will address the suggested modifications that the Company agrees should be changed.

Q. WHAT AREAS OF AGREEMENT DO YOU HAVE WITH MR. BARON'S TESTIMONY?

A. The Company agrees, as he suggests on page 11 of his testimony, that it would have been more appropriate to determine the annual system load factor using a single coincident peak demand. The Company also agrees, as pointed out on page 11, that it was an oversight to not include "excess demand" for our total-electric customers. The Company also accepts his recommendation on page 23 that a separate allocation of 69kV sub transmission costs should occur in the manner that is demonstrated in my CONFIDENTIAL Exhibit KDWR-1.

Q. DOES THE COMPANY ACCEPT MR. BARON'S SUGGESTION THAT ACCOUNT 369 SERVICES SHOULD BE ALLOCATED UTILIZING MORE OF A CUSTOMER-RELATED ALLOCATOR?

A. The Company agrees that the allocation should not be based on non-coincident peak. For purposes of this docket a customer count allocation is acceptable. For its next rate case application the Company intends to utilize a customer oriented allocation.

Q. IF THE COMPANY WERE TO FILE A CLASS COST OF SERVICE STUDY IN THE FUTURE, WOULD THESE SUGGESTED CHANGES BE MADE?

A. Yes. In addition, the changes are also reflected in CONFIDENTIAL Exhibit KDWR-1.

Q. DO YOU HAVE A RECOMMENDATION REGARDING HOW BEST TO ALLOCATE 69KV SUB TRANSMISSION FACILITIES AND RELATED COSTS?

A. Yes. There are two customers that receive service at 69kV. One customer is currently served under a Business Development Service agreement. The other has contracted for service under the Industrial Contract Service tariff. For much of my career, General Service Large and Industrial Contract Service were separate classes for allocating costs. Based upon Mr. Baron’s desire to ensure that his 69kV service client is not allocated distribution costs, I would recommend returning to a separate Industrial Contract Service class.

Q. DO YOU HAVE AN EXHIBIT THAT SHOWS THE CLASS COST OF SERVICE THAT RESULTS FROM THIS CHANGE?

A. Yes, CONFIDENTIAL Exhibit KDWR-1 shows how this would work in this case and includes the other recommended modifications that I have indicated above that the Company supports.

Q. DOES THAT CONCLUDE THE AREAS OF AGREEMENT?

A. Yes.

Q. ARE THERE MODIFICATIONS THAT MR. BARON HAS SUGGESTED THAT YOU DO NOT SUPPORT?

A. Yes. I disagree with Mr. Baron's recommendations that the Commission make changes to future class cost of service studies for a "minimum Distribution System" and for curtailable/interruptible loads.

Q. DOES THE COMPANY AGREE THAT A MINIMUM DISTRIBUTION SYSTEM APPROACH SHOULD BE USED FOR ALLOCATING DISTRIBUTION COSTS BETWEEN CUSTOMER CLASSES?

A. No. Black Hills Power believes that the historic approach should be continued for purposes of the South Dakota class cost of service studies. Consistency can be important in rate making and we see no material overall benefit in determining just and reasonable rates that would result from this change.

Q. DOES BLACK HILLS POWER HAVE ANY SIGNIFICANT INTERRUPTIBLE LOAD ON ITS SYSTEM?

A. No.

Q. DOES MR. BARON REPRESENT THAT THE COMPANY HAS [redacted] OF INTERRUPTIBLE/CURTAILABLE LOAD ON ITS SYSTEM?

A. Yes.

Q. WHY DO YOU THINK HE BELIEVES THIS?

A. [redacted], Mr. Baron's analysis is flawed for two reasons. First and foremost, [redacted] Second, as I explain below, Mr. Baron's conclusion that the load in question constitutes interruptible load is incorrect.

Q. NOTWITHSTANDING THE FACT THAT MR. BARON IS INCORRECT IN HIS BELIEF THAT THERE IS INTERRUPTIBLE LOAD ON BLACK HILLS POWER'S SYSTEM, DO YOU WANT TO ADDRESS HIS TESTIMONY ON THIS TOPIC?

A. Yes, I would like to address his testimony on this topic to ensure that the Commission has accurate information before it upon which it can base the decisions that it will make in this docket.

Q. DOES BLACK HILLS POWER HAVE [redacted] OF LOAD THAT COULD BE VIEWED AS CURTAILABLE?

A. Yes, the Company confirmed this in response to [redacted]

Q. PLEASE EXPLAIN HOW YOU DIFFERENTIATE BETWEEN INTERRUPTIBLE AND CURTAILABLE SERVICE.

A. Interruptible service is where the utility has complete control over whether the defined electric load is served. This often is accomplished with a remote disconnect that is operated solely by the utility. The customer has no ability to maintain utility provided electric service if the utility determines that the load should be interrupted for the benefit of the electric system.

Curtailable service occurs when a customer has contracted to reduce its load by a specified amount or to a specified level when requested to do so by the utility. Compliance with the request is at the discretion of the customer and failure to do so frequently results in a financial consequence to the customer. The level of financial consequence is determined by the customer's willingness to pay and the utility's perspective regarding whether the curtailable load is viewed as a firm long-run resource or a vehicle to justify pricing concessions. Black Hills Power has experience treating curtailable load both ways. Our experience has also been that our customers like the pricing provisions but not the curtailments.

Q. DO YOU DEFINE THE [redacted] LOAD IN QUESTION AS AN INTERRUPTIBLE LOAD?

A. No. The utility does not have direct control over whether the load referred to by Mr. Baron is served by its electric system.

Q. DO YOU CONSIDER THIS TO BE A CURTAILABLE LOAD?

A. It has curtailable characteristics, but the [redacted] has limitations as long-run curtailable load. The curtailments are constrained, [redacted]

[redacted]

Q. WHAT IS THE HISTORY OF HOW THIS PROVISION CAME INTO EXISTENCE?

A. [redacted].

[redacted]

Q. DO YOU CONSIDER THIS ARRANGEMENT TO BE ONE THAT WARRANTS BEING VALUED AS AVOIDING FUTURE COMBUSTION TURBINE INVESTMENTS, AS MR. BARON RECOMMENDS?

A. No. The provision does not create a long-run reliable resource for meeting Black Hills Power's obligation to serve.

Q. IN PREPARING ITS CLASS COST OF SERVICE, DID BLACK HILLS POWER INCLUDE ALL OF THE BILLING UNITS AND ASSOCIATED REVENUES FOR THE [redacted] CUSTOMER'S FIRM LOAD WITHOUT A REDUCTION FOR THE NON-STANDARD NATURE OF THE BILLING ARRANGEMENT?

A. Yes. The [redacted] Customer's load is not interruptible and there is no "revenue credit" for the [redacted] of expected load reduction. The [redacted] Billing Capacity is billed whether the customer's [redacted] monthly metered demand is below or above this amount. It is the "deemed" on-peak demand.

Q. [redacted]

A. [redacted]

Q. WHAT ACTIONS DO YOU RECOMMEND THE COMMISSION TAKE WITH RESPECT TO THE CLASS COST OF SERVICE?

A. Black Hills Power fully supports the Settlement Agreement. However, the Company would likely not object if the Commission elected to make the modifications that I addressed above in my testimony and are reflected in CONFIDENTIAL Exhibit KDWR-1.

Q. WHAT IS THE RESULT IF THE COMMISSION ELECTS TO MAKE THE MODIFICATIONS DEPICTED IN CONFIDENTIAL EXHIBIT KDWR-1?

A. [redacted]

VII. <u>CONCLUSION</u>

Q. WHAT IS THE COMPANY'S VIEW REGARDING POSSIBLE COMMISSION MODIFICATION TO ITS SETTLEMENT OF ALL RATE CASE ISSUES WITH COMMISSION STAFF?

A. Normally, I would be advocating only for a bench decision of approval of the settlement and related electric tariffs without Commission modification. This would be required because all parties had agreed to comprehensive settlement of all contested issues. This often is referred as a "package deal" and is defended because of the compromise of the parties to reach a common agreement. To change one component of the settlement could diminish the perceived and/or expected value of one of the parties to the settlement.

In this case, Black Hills Power's primary interest is in the agreed upon $6.89 million increase to its revenue requirement, along with a reasonable expectation that the Commission approved rates and tariffs will allow for the recovery of this revenue requirement from South Dakota electric customers. In this situation, where the rate case is being litigated by some of the parties, the Company, with Staff's support, can more readily accept changes in cost allocations to the customer classes, along with rate schedule and tariff changes. In fact, a litigated case such as this may afford the Commission the opportunity to reduce inter and intra class subsidies, along with consolidation of legacy rate schedules or pricing practices that it believes are no longer warranted by today's circumstances.

Q. WHAT LEGACY PRICING PROVISIONS WOULD YOU LIKE THE COMMISSION TO BE AWARE OF?

A. There are three. The first is a substantial under recovery of one customer's cost of service. This has been highlighted in my rebuttal testimony where I propose [redacted] (refer to CONFIDENTIAL Exhibit KDW-1). [redacted]

The second is the Large Power Contract Service tariff where, with the exception of the pricing, minimum service capacity of 6,000 kVA and the term of service provisions, the tariff largely mirrors the General Service Large (Optional Combined Account Billing). The sole customer receiving service under this tariff combined loads [redacted] and are not distinctly different from those of the customers receiving service under the General Service

Large (Optional Combined Account Billing). [redacted] In this situation, the Commission could close the rate schedule, set the rate equal to the General Service Large (Optional Combined Account Billing) and require the Company to give the appropriate notice to terminate the service agreement.

The third legacy pricing provision is [redacted] This customer's service and load characteristics today also are not distinctly different from the customers receiving service under the General Service Large (Optional Combined Account Billing). [redacted] In this case, the Commission could order a modification [redacted] to remove legacy base rate pricing provisions.

Q. ARE YOU ASKING THE COMMISSION TO MAKE THESE MODIFICATIONS TO THE SETTLEMENT AGREEMENT PRIOR TO APPROVING IT?

A. No, I am only advising the Commission that it has this opportunity and that the Company would likely not oppose changes of this nature.

Q. ARE THERE OTHER MODIFICATIONS TO THE SETTLEMENT AGREEMENT THAT THE COMPANY MAY SUPPORT?

A. Yes, as discussed in the testimony of Jon Thurber, the Company would also be supportive of an adjustment to the O&M costs associated with the Wyodak facility.

Q. ARE YOU ASKING THE COMMISSION TO MAKE THESE MODIFICATIONS TO THE SETTLEMENT AGREEMENT BEFORE APPROVING IT?

A. No. I am only advising the Commission that the Company may not object if the Commission thought these modifications were justified.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL14-026
RATE CASE

REQUEST DATE : April 29, 2014

RESPONSE DATE : October 13, 2014

REQUESTING PARTY: SDPUC Staff

SDPUC Request No. 2-57:

According to the financing application (EL14-034), BHP is planning to issue up to $110 million, to finance its "approximately $93 million" interest in CPGS, and to recall the Series 2004 Campbell County bonds ($12.2 million). Please explain why the pro-forma adjustments to capital structure on Statement G, Page 3 of 5, do not reflect the full $110 million.

Response to SDPUC Request No. 2-57:

In Docket EL14-026, the pro forma adjustments to the capital structure on Statement G, Page 3 of 5, do not reflect the full $110 million of additional debt because the Company may not issue the full amount. The Company requested authority to issue up to $110 million in additional first mortgage bonds, and $50 million would fall within the Company's request. Statement G will be updated during discovery in Docket EL14-026 to reflect the actual debt transaction.

The amount of debt the Company ultimately issues will depend on market conditions. When the Company was preparing Docket EL14-026, forecasted interest rates were higher than current interest rates.

Supplemental Response to SDPUC Request No. 2-57:

Please see attachment 2-57 for the revised Statement G, page 3 to reflect the cost of the debt issuance authorized in Docket EL14-034.

Attachment: 2-57 Revised Statement G Pg 3

BLACK HILLS POWER, INC.
PRO FORMA DEBT CAPITAL
FOR THE PRO FORMA TEST YEAR ENDED SEPTEMBER 30, 2013

	(a)	(b)	(c)	(d)	(e)	(f)	(g) (f) / (d)	(h) (e)	(i)	(j) (h) + (i)	(k)	(l)	
Line No.	Title	Issue	Maturity	Amount Issued	Coupon Rate	Purchase Price	Per Unit	Yield to Maturity	Amortization of DFC & Other costs	Cost of Money	Principal Outstanding	Annual Cost	
1	**BLACK HILLS POWER**												
2	FIRST MORTGAGE BONDS:												
3	Series AE	8/13/2002	8/15/2032	75,000,000	7.23%	74,343,750	0.9913	7.29%	0.13%	7.42%	75,000,000	5,566,612	
4	Series AF	10/27/2009	11/1/2039	180,000,000	6.13%	178,300,800	0.9906	6.19%	0.04%	6.23%	180,000,000	11,216,244	
5	Series Y (1)	6/15/1988	6/15/2018	6,000,000	9.49%	5,906,578	n/a	n/a	0.19%	0.19%	-	11,109	(1)
6	Series Z (1)	5/29/1991	5/29/2021	35,000,000	9.35%	34,790,305	n/a	n/a	0.24%	0.24%	-	84,828	(1)
7	Series AB (1)	9/1/1999	9/1/2024	45,000,000	8.30%	44,507,250	n/a	n/a	0.26%	0.26%	-	116,828	(1)
8	Series AG (2)	10/1/2014	10/1/2044	85,000,000	4.43%	85,000,000	1.0000	4.43%	0.03%	4.46%	85,000,000	3,789,663	(2)
9	OTHER BONDS:												
10	Series 94A Gillette (3)	6/15/1994	6/1/2024	3,000,000	(3)	2,930,057	0.9767	(3)	0.08%	1.25%	2,855,000	35,672	(3)
11	Series 2004 Campbell County due 2024 (7)	10/1/2004	10/1/2024	12,200,000	5.35%	12,062,750	n/a	n/a	0.31%	0.31%	-	37,260	
12													
13	Total Outstanding										342,855,000	20,858,217	
14													
15	Weighted Average Cost of Debt											6.08%	
16													
17	**BLACK HILLS CORP. DEBT**												
18	$525MM Notes Due 2023 (4)	11/19/2013	11/30/2023	525,000,000	4.25%	522,532,500	0.9953	4.31%	0.09%	4.40%	525,000,000	23,113,911	
18	$200MM Notes Dues 2020 (5)	7/16/2010	7/15/2020	200,000,000	5.88%	200,000,000	1.0000	5.88%	0.08%	5.96%	200,000,000	11,917,126	
19	$275M Term Loan (6)	6/21/2013	6/19/2015	275,000,000	(6)	275,000,000	(6)	(6)	0.00%	(6)	275,000,000	-	
20													
21	(1) Identified bonds have been paid off. However, FERC allows for DFC or LRD costs to be amortized over the original life of the bond. Annual costs reflect actual costs incurred.												
23	(2) New tranche closed October 1, 2014 to finance BHP's portion of new Cheyenne Prairie Generating Station.												
22	(3) The Series 1994A bonds have a variable component that resets weekly. The proforma cost of money is the average all-in interest rate for the test year period.												
24	(4) Note was issued by BHC in November 2013. Proceeds used to finance BHE Utilities and BHC non-regulated business segment.												
25	(5) Note was issued by BHC in July 2010, but is allocated to Colorado Electric.												
26	(6) Term loan is used to finance BHWand BH-IPP. Cost of borrowing has a fixed (1.125%) and variable rate component (libor). Rate as of Sept. 30, 2013 was 1.3125%.												
27	(7) Redeemed bondholders on Oct. 1, 2014 using proceeds of new Series AG bonds issued on same day.												