

**BEFORE THE SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION**

IN THE MATTER OF THE APPLICATION OF)
BLACK HILLS POWER, INC., A SOUTH DAKOTA) DOCKET NO. EL14-026
CORPORATION, FOR AUTHORITY TO INCREASE)
RATES IN SOUTH DAKOTA)

DIRECT TESTIMONY AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

BLACK HILLS INDUSTRIAL INTERVENORS

PUBLIC DOCUMENT

**J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA**

DECEMBER 2014

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[REDACTED] 51

DIRECT TESTIMONY OF LANE KOLLEN

1 **I. QUALIFICATIONS AND SUMMARY**

2 **Q. Please state your name and business address.**

3 A. My name is Lane Kollen. My business address is J. Kennedy and Associates,
4 Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell,
5 Georgia 30075.

6
7 **Q. What is your occupation and by whom are you employed?**

8 A. I am a utility rate and planning consultant holding the position of Vice President
9 and Principal with Kennedy and Associates.

10

11 **Q. Please describe your education and professional experience.**

12 A. I earned a Bachelor of Business Administration in Accounting degree and a
13 Master of Business Administration degree, both from the University of Toledo. I
14 also earned a Master of Arts degree from Luther Rice University. I am a
15 Certified Public Accountant, with a practice license, a Certified Management
16 Accountant, and a Chartered Global Management Accountant. I am a member of
17 numerous professional organizations.

18 I have been an active participant in the utility industry for more than thirty
19 years, both as a consultant and as an employee. Since 1986, I have been a
20 consultant with Kennedy and Associates, providing assistance to consumers of
21 utility services and state and local government agencies in the areas of utility

1 planning, ratemaking, accounting, taxes, financial reporting, financing and
2 management decision-making. From 1983 to 1986, I was a consultant with
3 Energy Management Associates, providing services to investor and consumer
4 owned utility companies in the areas of planning, financial accounting and
5 reporting, financing, ratemaking and management decision-making. From 1976
6 to 1983, I was employed by The Toledo Edison Company in a series of positions,
7 providing services in the areas of planning, accounting, financial and statistical
8 reporting, and taxes.

9 I have appeared as an expert witness on utility planning, ratemaking,
10 accounting, reporting, financing, and tax issues before state and federal
11 regulatory commissions and courts on more than two hundred occasions. In
12 addition to consumers of electricity and natural gas utility services, I have
13 represented state and local ratemaking agencies or their Staffs, including the
14 Louisiana Public Service Commission, Georgia Public Service Commission and
15 various Cities with original rate jurisdiction in Texas. I have developed and
16 presented papers at various industry conferences on ratemaking, accounting, and
17 tax issues. My qualifications and regulatory appearances are further detailed in
18 Kollen Exhibit__(LK-1).

19
20 **Q. On whose behalf are you testifying in this proceeding?**

21 A. I am testifying on behalf of GCC Dakotah, Inc., Pete Lien & Sons, Inc.,
22 Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City
23 Regional Hospital, Inc. and Wharf Resources (U.S.A.), Inc. (collectively, the

1 “Black Hills Industrial Intervenors” or “BHII”).

2

3 **Q. What is the purpose of your testimony?**

4 A. The purpose of my testimony is to address (1) the claimed base revenue
5 deficiency and requested rate increase of \$14.634 million set forth in the
6 Company’s application (the “Application”) and (2) the revised revenue
7 deficiency and requested rate increase of \$6.891 million set forth in the proposed
8 Settlement Stipulation (the “Proposed Settlement”) between the Company and the
9 Commission Staff (“Staff”) filed in this docket on December 8, 2014. I
10 recommend numerous adjustments to the base revenue deficiency in each of the
11 Application and the Proposed Settlement necessary to ensure that the Company’s
12 rates are just and reasonable.

13

14 **Q. What support has the Company and Staff provided for the Proposed
15 Settlement?**

16 A. The Proposed Settlement states how the Company and Staff have resolved certain
17 issues and incorporates various schedules. To support the Proposed Settlement,
18 the Staff developed and provided to BHII an Excel spreadsheet that provides
19 some details regarding the calculation of the rate increase in the Proposed
20 Settlement. Although the spreadsheet incorporates the adjustments reflected in
21 the Proposed Settlement, it does not include all calculations or source all
22 adjustment amounts. Nor does the spreadsheet provide any descriptions or
23 testimony in support of the adjustments that were included or the reasons why

1 certain adjustments proposed by BHII and shared during Proposed Settlement
2 discussions with the parties were not accepted.

3

4 **Q. Please summarize your testimony.**

5 A. While I agree (in whole or in part) with the resolution of certain issues reflected
6 in the Proposed Settlement, I recommend that the Commission reject both the
7 base rate increase requested by the Company in its Application and the base rate
8 increase set forth in the Proposed Settlement. Because evidence in the
9 Application and responses to BHII information requests demonstrate that the
10 Company's rates have grown increasingly uncompetitive,¹ BHII refused to sign
11 on to the Proposed Settlement. As demonstrated below, the Proposed Settlement
12 between the Company and the Staff is woefully inadequate. It fails to address or
13 properly resolve certain issues that, if addressed and resolved properly, would
14 substantially reduce the revenue requirement necessary to set rates at just and
15 reasonable levels.

16 Taken together, the recommendations set forth in my testimony support a
17 *reduction* in the Company's current base rates of at least \$5.258 million (as
18 opposed to the *significant and unnecessary increase* in base rates proposed by the
19 Company in its Application and by the Company and Staff in the Proposed
20 Settlement). Thus, I recommend that the Commission (1) reduce the \$14.634
21 million increase requested by the Company in its Application by \$19.893 million

¹ As of 2012, and compared to other investor owned utilities in South Dakota, Black Hills Power had the highest average residential rate, the highest average commercial rate, and the third highest industrial rate. Source: U.S. Energy Information Administration; <http://www.eia.gov/electricity/data.cfm#sales>

1 and (2) reduce the \$6.891 million increase agreed to by the Company and Staff in
2 the Proposed Settlement by \$12.149 million. The reductions that I recommend
3 reflect the return on equity of [REDACTED] set forth in the Proposed Settlement.

4 I recommend that the Commission adopt numerous adjustments to both
5 the Company's requested increase and the Proposed Settlement increase. I
6 summarize the revenue requirement effects of these adjustments on the following
7 table.

8 The first column in the table starts with the Company's claimed revenue
9 deficiency set forth in its Application and then shows the revenue requirement
10 effect of each adjustment to the Company's request that I recommend. If the
11 Commission starts with the Company's request, then it should adopt the
12 adjustments that I recommend in this column.

13 The second column starts with the Company's claimed revenue deficiency
14 set forth in its Application and then shows the revenue requirement effect of each
15 adjustment identified and reflected in the Proposed Settlement. I included this
16 column in the event the Commission starts with the Proposed Settlement so that it
17 can directly compare my recommendations for each issue with the comparable
18 adjustments, if any, reflected in the Proposed Settlement.

19 The third column represents the incremental effect of the adjustments that
20 I recommend, as shown in the first column, in the event the Commission starts
21 with the Proposed Settlement and the Commission adopts my adjustments and
22 quantifications.

23

Docket No. EL14-026
Black Hills Power, Inc.
South Dakota Retail Revenue Requirement
Summary of BHII Recommendations
Compared to Company's Filing and Proposed Settlement With Staff
(\$ Millions)

	BHII Recommend Compared to Company Filing	Proposed Settlement	BHII Recommend Compared to Proposed Settlement
Black Hill Power Company Requested Rate Increase	14.634	14.634	
Adjustments			
Rate Base			
Remove Company's Double Count of Spare Parts for CPGS	(0.132)		(0.132)
Remove NOL ADIT	(1.414)	(0.026)	(1.388)
Adjust Retired Steam Plants Regulatory Asset - NBV	0.043		0.043
Reduce or Remove Retired Steam Plants Regulatory Asset - Def Decom	(0.894)	0.388	(1.282)
Extend Storm Damage Amortization to Ten Years and Subtract ADIT	(0.102)	(0.179)	0.077
Remove Regulatory Asset - 69kV LIDAR Surveying Project	(0.057)	(0.046)	(0.011)
Adjust Accumulated Depr. and ADIT Related to Restatement of Net Negative Salvage	0.019		0.019
Adjust Accumulated Depr. and ADIT Related to CPGS Life Span Extension	0.006		0.006
Adjust Rate Case Regulatory Asset		(0.036)	0.036
Operating Income			
Remove FutureTrack Workforce	(0.676)	(0.344)	(0.332)
Remove Employee Additions/Eliminations Identified on Schedule H-1 Line 5	(1.266)	(0.096)	(1.169)
Remove Additional Pension Plan Expense Based on 5 Year Average	(1.247)	(0.289)	(0.958)
Remove Incentive Compensation Tied to BHC Fin'l Performance	(1.554)	(0.666)	(0.888)
Remove Proforma Increased Affiliate Allocations from BHUH	(1.846)	0.527	(2.373)
Remove Settlement Adjustment to Increase Affiliate Allocations from BHSC		1.132	(1.132)
Extend Retired Steam Plants Amortization Expense	(0.582)		(0.582)
Reduce Amortization Expense on Atlas Storm Damage Regulatory Asset	(0.414)	(0.512)	0.098
Retired Steam Plants Decommissioning Amortization Expense	(1.956)	(0.487)	(1.469)
Remove 69kV LIDAR Surveying Project Amortization Expense	(0.130)	(0.066)	(0.064)
Extend CPGS Life Span (Depr Expense)	(0.338)	(0.314)	(0.024)
Correct Steam and Other Production Net Salvage (Depr Expense)	(1.132)		(1.132)
Remove Company's Double Count of Spare Parts for CPGS (Depr Expense)	(0.033)		(0.033)
Adjust Rate Case Regulatory Asset Amortization		(0.083)	0.083
Adjustment to Weather Normalization Revenue	(0.380)	(0.380)	-
Adjustment to Allocated Neil Simpson Rent Revenue and Expense	(0.219)	(0.219)	-
Adjustment to Neil Simpson Common Steam Allocation	(0.244)	(0.244)	-
All Other Proposed Settlement Changes Combined		(0.217)	0.217
Rate of Return			
Reduce Cost of Debt to Reflect Lower Interest Rate on New Debt Issue	(0.885)	(0.925)	0.040
Reflect Proposed Settlement Capital Structure	(0.216)	(0.226)	0.010
Reduce Return on Equity - Proposed Settlement	(4.245)	(4.435)	0.191
Total Adjustments to Company's Request	(19.893)	(7.744)	
Net Rate Increase/(Reduction) Recommendation	(5.258)	6.891	
Total Differences Between BHII Recommendation and Proposed Settlement			(12.149)

1
2
3

1 **Q. In the Rate of Return section of the preceding table, the effects on the**
2 **revenue requirement for each adjustment are less pursuant to your**
3 **recommendations in the first column compared the Proposed Settlement in**
4 **the second column. Please explain why this is the case.**

5 A. The rate base that I recommend is less than the rate base reflected in the Proposed
6 Settlement. I recommend additional adjustments or different quantifications for
7 certain adjustments to rate base than the adjustments reflected in the Proposed
8 Settlement. For example, I recommend that the Commission remove the NOL
9 ADIT from rate base and show the reduction in the revenue requirement based on
10 the Company's requested rate of return. However, the Proposed Settlement does
11 not reflect a similar reduction in rate base for this issue. Thus, despite the fact
12 that the adjustments to the rate of return are the same under my recommendations
13 and pursuant to the Proposed Settlement, the effect is slightly greater pursuant to
14 the Proposed Settlement.

15
16 **Q. Are there general ratemaking principles that form the basis for many of**
17 **your recommended adjustments?**

18 A. Yes. First, I recommend that the Commission limit any post-test year
19 adjustments to the twelve month period immediately following the historic test
20 year ending September 30, 2013. Adjustments beyond this twelve month post-
21 test year period are not known and measurable and, in some instances, represent
22 costs that should not be incurred or, if incurred, that should be included in a
23 subsequent rate proceeding. Such adjustments to costs are uncertain. They are

1 opportunistic and selective in that they do not represent a comprehensive or
2 consistent set of adjustments for the period two years after the actual test year.
3 More specifically, the Company did not include all potential corresponding
4 increases in revenues or reductions in costs that would offset the adjustments for
5 projected increases in costs beyond the twelve month post-test year period. By
6 failing to include such revenue increases and cost reductions in its Application,
7 the Company unjustly and unreasonably skewed the proposed base rate increase
8 upward. As discussed below, my understanding of S.D. Admin. Rule
9 20:10:13:44, is that any proposed adjustments based on projected costs beyond
10 the twelve month post-test year period must be accompanied by projected
11 changes in revenue for the same period. The Company's selective adjustments
12 beyond the twelve month post-test year period may violate South Dakota law.

13 Second, I recommend that the Commission reject proposed post-test year
14 increases in various expenses that are not justified and that the Company did not
15 demonstrate were necessary and appropriate. The Company bears a special
16 burden to demonstrate that these increases in expenses compared to the historic
17 test year are just and reasonable. Such increases tend to be self-fulfilling and
18 permanent once recovery is assured in rates.

19 Third, I recommend that the Commission reject adjustments that are not
20 consistent with Commission precedent or policy, that are not justified, and that
21 the Company did not demonstrate were necessary and appropriate.

22
23

1 **Q. How is the remainder of your testimony organized?**

2 A. The remainder of my testimony is organized so that it follows the sequence of the
3 issues in the preceding table. On each issue, I will first address the issue as it is
4 reflected in the Company's Application. I then will address the issue as it is
5 reflected in the Proposed Settlement.

6

7

II. RATE BASE ISSUES

8 A. **The Commission Should Correct the Double Counting Error in CPGS Spare**
9 **Parts Inventory**
10

11 **Q. Please describe the error in the CPGS spare parts inventory included in rate**
12 **base.**

13 A. The Company erroneously included \$2.200 million (total plant and total
14 Company) CPGS spare parts inventory in both the CPGS plant in service
15 amounts shown on Schedule D page 2, Schedule D-11, and in the materials and
16 supplies amount shown on Schedule F-4. The CPGS spare parts inventory should
17 be removed from the plant in service amounts.

18

19 **Q. What are the effects on rate base and the revenue requirement of correcting**
20 **this error?**

21 A. The correction results in a reduction in the jurisdictional rate base of \$1.152
22 million (BHP owns 58% of the plant), consisting of a reduction in plant in service
23 of \$1.157 million, a reduction in accumulated depreciation of \$0.017 million and
24 an increase in accumulated deferred income taxes ("ADIT") of \$0.012 million.

1 The calculations and sources of these amounts are detailed on my
2 Exhibit___(LK-2).

3 The correction reduces the Company's revenue requirement by \$0.165
4 million, consisting of a reduction in the return on rate base of \$0.132 million and
5 a reduction in depreciation expense of \$0.033 million.

6
7 **Q. Does the Company agree that this was an error and should be corrected?**

8 A. Yes. The Company agreed that this was an error in response to SDPUC Request
9 No. 6-42, a copy of which I have attached as my Exhibit___(LK-3).

10

11 **Q. Does the Proposed Settlement properly reflect the correction of this error?**

12 A. Yes.

13

14 **B. The Commission Should Remove the Asset Net Operating Loss ("NOL")**
15 **Accumulated Deferred Income Taxes ("ADIT") from Rate Base**

16

17 **Q. Please describe the Company's proposal to include asset NOL ADIT**
18 **amounts in rate base.**

19 A. The NOL ADIT is the tax effect of the NOL carry-forward, which is stated in the
20 form of taxable losses that can be carried forward to reduce taxable income in
21 subsequent years. The Company included \$12.373 million (jurisdictional) and
22 \$13.497 million (total Company) in asset NOL ADIT in rate base as shown on
23 Schedule M-1 (lines 12 and 27) based on a thirteen month average in the historic
24 test year, and on Schedule M-2 (line 21) to reflect certain plant additions through

1 September 30, 2014. The total Company amounts and the jurisdictional amounts
2 are detailed on my Exhibit____(LK-4).

3

4 **Q. Should the Commission include the asset NOL ADIT in rate base?**

5 A. No. First, as a conceptual matter and as a matter of regulatory principle, the NOL
6 ADIT violates the prohibition against retroactive ratemaking. The NOL ADIT is
7 the result of actual taxable losses in prior years that could not be fully utilized or
8 monetized through carrybacks. However, in prior rate cases, the Company's
9 rates were set to recover the maximum income tax expense under the assumption
10 that there would be no taxable losses. The fact that the Company subsequently
11 actually incurred taxable losses rather than taxable income does not entitle it to
12 include the tax effect of those losses in rate base and earn a return from
13 customers. This would constitute an improper retroactive true-up of a portion of
14 the Company's income tax expense incurred in prior years for ratemaking
15 purposes.

16 Second, the NOL ADIT is only temporary. The NOL carryforward will
17 be utilized as the Company generates taxable income. Nevertheless, the
18 Company's Application assumes not only that the NOL ADIT will continue to
19 exist, but that it will exist at the same level until rates are reset in the next base
20 rate proceeding. The Company's assumption is incorrect and without valid
21 foundation.

22 In fact, the Company's Schedule K page 2 indicates that the NOL
23 carryforward that gave rise to the NOL ADIT will be fully utilized *prior to or*

1 *during the first year that rates are effective.* The actual NOL ADIT at September
2 30, 2013 is equivalent to a \$16.996 million NOL carryforward, assuming a 35%
3 federal income tax rate. The Company's Schedule K page 2 indicates that the
4 Company will generate \$44.678 million in federal taxable income if its base rate
5 increase is granted in full in this proceeding. Even with zero base rate increase,
6 the Company's filing indicates that taxable income still will be more than
7 sufficient to fully utilize the NOL carryforward either before rates are reset or
8 within the twelve months after rates are reset.

9
10 **Q. What is the effect on the revenue requirement of removing the asset NOL**
11 **ADIT from rate base?**

12 A. The effect is a reduction in the revenue requirement of \$1.414 million.

13
14 **Q. As a practical matter, if the Commission decides to include the asset NOL**
15 **ADIT in rate base, then should the thirteen month average for the historic**
16 **test year be adjusted to October 1, 2014 in the same manner that the**
17 **Company adjusted other rate base components to reflect known and**
18 **measurable adjustments through October 1, 2014?**

19 A. Yes. As I noted previously, the NOL ADIT is a temporary amount that should
20 decline to \$0 when the NOL carryforwards are fully utilized. The Commission
21 should not set rates to provide a return on an asset NOL ADIT that either no
22 longer exists or has declined significantly since the historic test year. Adjusting
23 the 13-month average for the historic test year to October 1, 2014, would be

1 consistent with the Company's proposal to adjust certain of its regulatory assets
2 and to increase its plant in service amounts for allegedly known and measurable
3 changes to October 1, 2014.

4 The October 1, 2014 date is twelve months after the end of the historic
5 test year and the assumed date when rates would be reset in this proceeding. If
6 the Commission allows the Company to selectively adjust other rate base
7 components to October 1, 2014, then it also should ensure that the NOL ADIT is
8 adjusted to that same date, and should do so based on the information in the
9 Application.

10

11 **Q. Did the NOL ADIT on the Company's balance sheet decline since the**
12 **beginning of the historic test year?**

13 A. Yes. The NOL ADIT has steadily declined since October 1, 2012, the
14 beginning of the historic test year, toward a \$0 balance at October 1, 2014, twelve
15 months after the end of the historic test year. Unlike the updated amounts for
16 regulatory assets and plant in service additions, the Company used the thirteen
17 month balance during the historic test year for the NOL ADIT. This overstates
18 the NOL ADIT that remained at September 30, 2013, the end of the historic test
19 year and at October 1, 2014, because it failed to capture the decline throughout
20 the test year and the continued decline in the twelve month post-test year period.
21 As of September 30, 2013, the NOL ADIT was \$5.949 million (jurisdictional)
22 and \$6.489 million (total Company).²

1 The NOL ADIT continued to decline from that date through December
2 31, 2013, when it had declined to \$4.363 million (jurisdictional) and \$4.760
3 million (total Company).³

4
5 **Q. How much of the Company's NOL carryforward did it utilize in 2013 and**
6 **how much will it utilize going forward based on the calculation of taxable**
7 **income reflected in the Application?**

8 A. The Company had a federal NOL carryforward of \$14 million at December 31,
9 2013.⁴ During 2013, the Company utilized \$16.708 million of the federal NOL
10 carryforward at December 31, 2012. In other words, the Company had taxable
11 income of \$16.708 million, but was able to reduce that to \$0 by utilizing the NOL
12 carryforward. This pattern will repeat itself in 2014, although taxable income
13 will be greater in 2014 compared to 2013 due to the unavailability of bonus tax
14 depreciation in 2014. In other words, the Company will be able to utilize the full
15 remaining amount of the NOL carryforward in 2014, all else being equal. I
16 calculated the NOL carryforward that was utilized based on the reduction in the
17 NOL ADIT during 2013. The Company reduced the NOL ADIT during 2013 by
18 \$5.207 million (jurisdictional)⁵, and by \$5.681 million (total Company)⁶.

19 In short, based on the Company's filing, there should be no remaining
20 asset NOL ADIT at October 1, 2014. Thus, even if the Commission decides to

² Schedule M-1 page 2.

³ Black Hills Power Company 2013 FERC Form 1 page 234, attached as my Exhibit__(LK-5).

⁴ *Id.*, page 123.13, attached as my Exhibit__(LK-6).

⁵ From \$9.570 million (jurisdictional) at the beginning of the year to \$4.363 million (jurisdictional) at the end of the year.

⁶ From \$10.441 million (total Company) at the beginning of the year to \$4.760 million (total Company) at the end of the year.

1 allow an asset NOL ADIT in rate base, which would violate the prohibition on
2 retroactive ratemaking, the amount at October 1, 2014 should be \$0 as a practical
3 matter.

4
5 **Q. What amount of NOL ADIT was included in the rate base reflected in the**
6 **Proposed Settlement?**

7 A. The Proposed Settlement reflects a slight reduction of \$0.226 million in the NOL
8 ADIT compared to the Company's Application. This slight reduction in the NOL
9 ADIT included in rate base had the effect of reducing the Company's revenue
10 requirement by a mere \$0.026 million.

11

12 **Q. Is there any justification for including any NOL ADIT in rate base in the**
13 **Proposed Settlement?**

14 A. No, for the reasons that I previously discussed.

15

16 **C. The Commission Should Reduce Regulatory Asset - Deferred**
17 **Decommissioning on Retired Plants**

18

19 **Q. Please describe the Company's requested regulatory asset and amortization**
20 **expense for decommissioning costs on its retired coal-fired power plants.**

21 A. The Company included \$7.824 million in rate base for its estimated costs to
22 decommission the retired Osage, Neil Simpson I and Ben French power plants,
23 net of accumulated depreciation and an incorrectly calculated adjustment to
24 reduce ADIT. The Company also included \$1.956 million in amortization

1 expense based on a proposed five year amortization period. I provide the details
2 of the Company's request, including the source of the amounts that I cited, on my
3 Exhibit__(LK-7).

4
5 **Q. When does the Company plan to spend the estimated amounts?**

6 A. The Company plans to begin decommissioning activities at the Ben French plant
7 in January 2015 and complete the activities in September 2015. It planned to
8 begin activities at the Neil Simpson 1 plant in November 2014 and complete the
9 activities in June 2015. It planned to begin activities at the Osage plant in August
10 2014 and complete the activities in April 2015.⁷

11
12 **Q. Did the Company seek or obtain an order to defer decommissioning costs
13 that have been incurred to date?**

14 A. No.

15
16 **Q. Should the Commission include the estimated decommissioning costs as a
17 regulatory asset in rate base and allow amortization expense in this
18 proceeding?**

19 A. No. The Company's request is premature and overreaching. The Company had
20 not yet incurred most of the decommissioning costs that it seeks to include in rate
21 base as of October 1, 2014, twelve months after the end of the historic test year.
22 In addition, the Company's request includes estimated costs through September

⁷ Direct Testimony of Mr. Mark Lux at 18-19.

1 2015, some twenty-four months after the end of the historic test year. Thus, these
2 amounts should not be included in rate base in this proceeding.

3 Instead, the Commission should authorize the Company to defer these
4 decommissioning costs as regulatory assets and address the recovery of the costs
5 in the Company's next base rate proceeding.

6

7 **Q. Is there support in South Dakota law for excluding estimated costs that**
8 **would be incurred after the end of the 12-month historical test year?**

9 A. Yes. My understanding of S.D. Admin. Rule 20:10:13:44, is that the
10 Commission is not permitted to allow adjustments that would become effective
11 unless they are based on changes in facilities, operations, or costs which are
12 known with reasonable certainty and measurable with reasonable accuracy at the
13 time of filing. Moreover, it is my understanding that any such adjustment to
14 costs must be accompanied by expected changes in revenue for the same period.
15 The Company has not provided evidence that any estimated costs that would be
16 incurred after the end of the 12-month historical test year were known with
17 reasonable certainty or measurable with reasonable accuracy at the time that the
18 Company filed its Application, and the Company has not provided any
19 adjustments to revenue for the same period.

20

21 **Q. If the Commission allows the estimated decommissioning costs in rate base**
22 **and authorizes recovery of amortization expense, should it correct the ADIT**
23 **error?**

1 A. Yes. The Commission should correct the ADIT error. The Company incorrectly
2 calculated the ADIT offset for the regulatory assets shown on Schedule M-2 as an
3 asset ADIT of \$0.762 million (total Company). Specifically, the Company failed
4 to include the deduction for the entire decommissioning cost under the column
5 titled "tax depreciation" on line 35 of Schedule M-2. If this deduction is properly
6 reflected, the ADIT related to the regulatory asset for decommissioning should be
7 \$3.423 million (jurisdictional, using an 89.83% production plant allocation
8 factor) or \$3.811 million (total Company).

9 The Company will be able to deduct the entirety of the estimated \$10.887
10 million (total Company) decommissioning costs for income tax purposes when
11 the costs are incurred. This deduction will create a book/tax temporary
12 difference. The ADIT is equal to 35% of the book/tax temporary difference. The
13 Company estimates that it will incur all decommissioning costs related to these
14 retired plants by September 2015.

15 If the Commission includes the entirety of the costs that the Company
16 estimates it will incur by September 2015 in rate base, then the Commission
17 should also reflect the offsetting ADIT in 2015 as a subtraction from rate base.
18

19 **Q. What is the effect on the revenue requirement if the Company's ADIT error**
20 **is corrected?**

21 A. The effect is a reduction of \$0.391 million in the Company's claimed revenue
22 requirement, using the Company's requested grossed-up rate of return (\$3.423
23 million times 11.43%).

1

2 **Q. Does the Proposed Settlement correct the error in the ADIT?**

3 A. No. If the Commission adopts the Proposed Settlement, then it should modify it
4 to correct the error in the ADIT.

5

6 **Q. If the Commission allows the estimated decommissioning costs in rate base
7 and authorizes recovery of amortization expense, should it make any
8 adjustments in addition to correcting the ADIT error?**

9 A. Yes; the Commission should make two other adjustments. First, the Commission
10 should remove the contingencies from the decommissioning cost estimate. By
11 definition, contingencies are not known and measurable. If the Commission
12 allows the estimated decommissioning costs in rate base and the amortization in
13 expense, then it should use the Company's best estimate for the decommissioning
14 cost, not an inflated estimate that includes contingencies. The contingencies
15 included in the Company's estimated decommissioning costs are \$0.956 million,
16 according to the Company's response to Staff DR 3-23.

17 Second, the Commission should exercise its discretion to use a longer
18 amortization period to minimize the effect on customers. In this case, a ten-year
19 amortization period will achieve this objective. The Company's proposed five-
20 year amortization period is unnecessarily short. If the Commission includes the
21 estimated decommissioning costs in rate base, then the Company will earn a
22 return on the unamortized regulatory asset regardless of the amortization period.

23

1 **Q. What is the effect on the revenue requirement of eliminating the**
2 **contingencies and using a ten year amortization period?**

3 A. A 10-year amortization period will reduce the Company's revenue requirement
4 by \$1.162 million. The calculations are detailed on my Exhibit____(LK-8).

5

6 **Q. Does the Proposed Settlement reflect your recommendation to remove**
7 **contingencies and use a ten year amortization period?**

8 A. Yes.

9

10 **D. The Commission Should Correct Accumulated Deferred Income Taxes Due**
11 **to Regulatory Asset for Storm Costs**

12

13 **Q. Did the Company reflect the correct ADIT due to the regulatory asset for**
14 **storm costs as a reduction to rate base?**

15 A. No. The Company failed to reflect the ADIT on storm costs in excess of the
16 casualty loss deduction on Schedule M-1 or Schedule M-2.

17

18 **Q. Does the Company agree that this was an error and should be corrected?**

19 A. Yes. The Company acknowledged this error in response to BHII Request No. 26,
20 although its quantification of the error was not correct. I have attached a copy of
21 the Company's response to BHII Request No. 26 as my Exhibit__(LK-9).

22

23 **Q. Why is the Company's quantification of the ADIT error incorrect?**

24 A. The Company should have treated the entirety of the regulatory asset as a

1 temporary difference. However, in its response to BHII Request No. 26, the
2 Company reduced the temporary difference by the amount of the estimated
3 casualty loss, as well as an additional amount, apparently to reflect changes in its
4 estimated costs compared to its Application. Those amounts should be included
5 in the temporary difference.

6
7 **Q. What is the effect on the revenue requirement of correcting this error, using**
8 **the regulatory asset quantified by the Company in its Application?**

9 A. Using the Company's proposed five-year amortization period, the Company's
10 claimed revenue deficiency should be reduced by \$0.132 million. The Company
11 should have reflected \$1.159 million in ADIT as a reduction in rate base in its
12 filing, using the five-year amortization period proposed in its Application.

13 If, however, the Commission adopts a ten-year amortization period, as I
14 propose, then the Company's claimed revenue requirement should be reduced by
15 \$0.516 million, consisting of a reduction of \$0.102 million due to the net change
16 in rate base (increase in ADIT and reduction in accumulated amortization) and a
17 reduction of \$0.414 million in amortization expense to reflect the longer
18 amortization period. The calculation of these amounts is detailed on my
19 Exhibit___(LK-10).

20
21 **Q. Was this error corrected in the Proposed Settlement?**

22 A. Yes. However, the Proposed Settlement includes the effect of reducing the
23 regulatory asset amount for various costs before computing the effects of

1 including the ADIT as a reduction to rate base. The Proposed Settlement reflects
2 a reduction in the revenue requirement of \$0.179 million based upon the net
3 reduction in rate base, including the reduction in the regulatory asset and the
4 subtraction of the ADIT based on the adjusted regulatory asset.

5

6 **E. The Commission Should Remove Regulatory Asset for Estimated 69 kV**
7 **LIDAR Surveying Project Costs**

8

9 **Q. Please describe the Company's requested regulatory asset and amortization**
10 **expense for estimated LIDAR surveying costs.**

11 A. The Company included \$0.502 million in rate base for its estimated costs to
12 perform a LIDAR survey of its 69kV distribution system, net of accumulated
13 depreciation. The Company did not include any ADIT offset to the requested
14 regulatory asset even though it represents a book/tax temporary difference. The
15 Company also included \$0.137 million in amortization expense based on a
16 proposed five-year amortization period. I have provided the details of the
17 Company's request, including the source of the amounts that I cited, on my
18 Exhibit__(LK-11).

19

20 **Q. When does the Company plan to spend the estimated amounts?**

21 A. The Company planned to begin the activities and incur costs by "by the end of
22 3Q 2014," according to its response to BHII Request No. 20 dated July 7, 2014.
23 The response has not been updated. I have attached a copy of the Company's
24 response to BHII Request No. 20 as my Exhibit__(LK-12).

1

2 **Q. Has the Company sought or obtained an order to defer any costs that have**
3 **been incurred to date?**

4 A. No. According to its response to BHII Request No. 20, if the Commission does
5 not issue its decision in this proceeding before the end of 2014, the Company
6 plans to make a separate request to the Commission to defer the LIDAR costs as
7 a regulatory asset.

8

9 **Q. Should the Commission include the estimated LIDAR survey costs as a**
10 **regulatory asset in rate base and allow amortization expense in this**
11 **proceeding?**

12 A. No. The Company's request is premature and overreaching. The Company has
13 provided no evidence that it incurred these costs prior to October 1, 2014, or
14 within the 12 months after the end of the historic test year. They are not known
15 and measurable.

16 Instead of including these costs in this proceeding, the Commission
17 should authorize the Company to defer the survey costs as a regulatory asset and
18 address the recovery of the costs in the Company's next base rate proceeding.

19

20 **Q. If the Commission allows the estimated LIDAR survey costs in rate base and**
21 **authorizes recovery of amortization expense, do you have an alternative**
22 **recommendation?**

23 A. Yes. First, the Commission should correct the ADIT error in the Company's

1 filing. The Company failed to include the related ADIT on Schedule M-1, which
2 it acknowledged in response to BHII Request No. 20. The ADIT should be
3 \$0.176 million (\$0.502 million times 35%), which will reduce the Company's
4 claimed revenue deficiency by \$0.020 million (\$0.176 million times 11.43%) if
5 the Commission adopts the Company's proposed five-year amortization period.

6 Second, the Commission should exercise its discretion to use a longer
7 amortization period to minimize the effect on customers. In this case, a ten-year
8 amortization period will achieve this objective. The Company's five-year
9 amortization period is unnecessarily short. If the Commission includes the
10 estimated survey costs in rate base, then the Company will earn a return on the
11 unamortized regulatory asset regardless of the amortization period.

12
13 **Q. What is the effect of your alternative recommendation to use a ten-year**
14 **amortization period?**

15 A. If the Commission adopts a ten-year amortization period, it will reduce the
16 Company's revenue requirement by \$0.080 million. This includes the effects on
17 amortization expense and the effects of extending the amortization period on the
18 correction of the ADIT error. The calculations are detailed on my
19 Exhibit____(LK-13).

20
21 **Q. Does the Proposed Settlement correct the error in the ADIT?**

22 A. No. If the Commission adopts the Proposed Settlement, then it should correct the
23 error in the ADIT regardless of whether it adopts a five-year or ten-year

1 amortization period.

2

3 **Q. Does the Proposed Settlement reflect your alternative recommendation to**
4 **use a ten-year amortization period?**

5 A. No. The Proposed Settlement reflects the Company's proposed five-year
6 amortization period. If the Commission adopts the Proposed Settlement, then it
7 should modify the Proposed Settlement to reflect a ten-year amortization period
8 for the reasons that I described.

9

10 **III. OPERATING INCOME ISSUES**

11 A. **The Commission Should Remove Estimated Costs for FutureTrack**
12 **Workforce Program**
13

14 **Q. Please describe the Company's request to increase payroll and related**
15 **expenses for its FutureTrack Workforce program.**

16 A. The Company proposes an increase in payroll and related expenses of \$0.676
17 million for its FutureTrack Workforce program. The Company proposes a
18 deferral mechanism so that any costs that it incurs in excess of the annual amount
19 authorized will be deferred as a regulatory asset. Ostensibly, this is a program
20 whereby the Company plans to add staffing in anticipation of future employee
21 retirements, even though the Company has experienced retirements throughout its
22 history and has historically trained and promoted employees or retained new
23 employees to replace retired employees on a recurring basis.

24

1 **Q. Doesn't the Company and don't other utilities already continually assess**
2 **their workforce requirements, hire younger and less skilled employees, train**
3 **them, and then promote them as openings become available regardless of the**
4 **reasons for the openings?**

5 A. Yes. There is nothing new here that justifies or supports the Company's request.
6 This has been and will continue to be the Company's practice and the nature of
7 the workforce planning and implementation process throughout the industry.

8
9 **Q. If there are positions that require specialized education and/or skills, what is**
10 **the current standard industry practice?**

11 A. Current standard industry practice is to hire employees with the appropriate
12 education and/or skills to meet a company's needs when they are needed. This
13 may require hiring employees who have obtained technical training at community
14 colleges with specialized programs and may require hiring employees that have
15 other specialized college and university training and expertise in professional
16 areas.

17 Typically, new employees enter a company with less experience, but in a
18 junior level position. They are promoted as they gain experience and as positions
19 open up due to other promotions, transfers, resignations/terminations, and
20 retirements.

21
22
23

1 **Q. One aspect of the Company’s proposal is to recruit high school students and**
2 **“more mature workers” and provide them with scholarships to South**
3 **Dakota vocational schools. Please comment.**

4 A. There is no reason why the Company needs to actively recruit high school
5 students or offer scholarships. Potential employees already have access to
6 technical and vocational programs. Presumably, these programs are offered
7 because there is student demand for those programs, even without such
8 scholarships. In any event, the Company has provided no evidence that the
9 practice is necessary or the only way that it can recruit or fill entry-level positions
10 at the Company. As I noted previously, the Company has been able to recruit and
11 fill entry-level positions since its inception without such a program and without
12 incurring the expense that it proposes in this proceeding.

13

14 **Q. Should the Commission allow the Company to recover its proposed**
15 **FutureTrack Workforce program costs?**

16 A. No. The Company has provided no evidence that its program and the associated
17 expenses are necessary for its public utility operations or that it cannot or will not
18 be able to hire qualified employees when they need them. There is nothing new
19 here that the Company does not already do in the normal course of business,
20 including hiring younger and less experienced employees, who then grow into
21 higher level positions when those positions are vacated for any reason, not just
22 retirements.

23 The Company has access to employees with the appropriate training and

1 experience to meet its staffing requirements. Training programs are already
2 available to students at vocational and community colleges. For example,
3 Mitchell Technical Institute (“MTI”), located in Mitchell, SD, has vocational
4 programs for electrical construction and maintenance, electric utilities and
5 substation technology, power line construction and maintenance, utilities
6 technology – power line. The link to the latter MTI program is
7 [https://www.mitchelltech.edu/programs/on-campus/energy-production-](https://www.mitchelltech.edu/programs/on-campus/energy-production-transmission/utilities-technology-power-line)
8 [transmission/utilities-technology-power-line](https://www.mitchelltech.edu/programs/on-campus/energy-production-transmission/utilities-technology-power-line). MTI also offers scholarships and
9 career services.

10 As yet another example, Lake Area Technical Institute (“LATI”), located
11 in Watertown, SD, offers a vocational program for energy operations to train
12 operations technicians.

13 In addition, on-the-job training programs are embedded into the
14 Company’s daily operations. There is no compelling evidence that these training
15 programs are insufficient or need to be expanded in the manner proposed by the
16 Company.

17 The Commission should not impose costs on the Company’s customers to
18 resolve problems that do not actually exist.

19
20 **Q. If the Commission allows the Company to recover any amount for the**
21 **FutureTrack Workforce program, should the Commission nevertheless deny**
22 **the Company’s request to defer costs in excess of the expense allowed**
23 **current recovery?**

1 A. Yes. The Commission should limit the recovery of these costs for at least three
2 reasons. First, the Company's request is inappropriately open-ended. In other
3 words, it wouldn't matter what amount was allowed in rates in this proceeding
4 because the Company could defer any amount that it incurred in excess of the
5 amount allowed and then recover it in subsequent proceedings.

6 Second, the Company has not proposed a measurement baseline that
7 defines how the payroll and related expenses associated with this program can be
8 and will be differentiated from any other payroll and related expenses. The
9 Company's proposal to "track" the costs in a regulatory asset account does not
10 address or cure this fundamental problem because the costs that will be identified
11 and tracked in this manner still will not be subject to any defined or objective
12 measurement baseline.

13 Third, the Company is not adequately incentivized to operate efficiently
14 if there is no defined measurement baseline and it can defer (and later recover)
15 any amount in excess of the allowed amount. The Company will no longer be at
16 risk for increased expenses for payroll between rate cases. Such a scenario is not
17 in the public interest. The better policy is to determine and provide recovery of
18 the just and reasonable payroll and related expenses for the test year and to allow
19 the Company to manage its payroll and related expenses between rate cases with
20 the proper incentives to ensure that the costs are minimized. Under the present
21 approach, the Company is incentivized to operate efficiently. While it cannot
22 immediately recover or defer increases in payroll and related expenses, it can
23 retain the savings from productivity gains that it achieves between rate cases.

1 Such a balancing is in the public interest.

2

3 **Q. Does the Proposed Settlement adopt the Company's proposal?**

4 A. Yes, in part. The Proposed Settlement allows the Company to recover \$0.344
5 million in FutureTrack Workforce program expense. However, the Proposed
6 Settlement does not address the Company's proposal to maintain a regulatory
7 asset account or authorize the Company to defer amounts in excess of the \$0.344
8 million that the Proposed Settlement proposes be allowed in the base revenue
9 requirement.

10

11 **Q. Even if the Commission adopts the adjustment to increase expense reflected**
12 **in the Proposed Settlement, should the Commission specifically reject the**
13 **Company's proposal to maintain a regulatory asset account and defer**
14 **amounts in excess of the amount allowed in the base revenue requirement?**

15 A. Yes, for the reasons that I previously discussed. The Commission should
16 specifically and clearly reject the Company's deferral proposal to ensure that
17 there is no ambiguity in future proceedings when the Company might seek to
18 recover such deferrals.

19

20 **B. The Commission Should Remove the Company's Adjustment for Employee**
21 **Position Additions/Eliminations**

22

23 **Q. Please describe the Company's request to increase payroll and related**
24 **expenses for additional projected employee positions.**

1 A. The Company seeks recovery of \$1.266 million in payroll and related expenses
2 for additional employee positions as shown on Schedule H-1. The \$1.266 million
3 is based on the labor and related expenses for 17 open positions.⁸

4 This request is in addition to the request for increases in payroll and
5 related expenses related to the FutureTrack Workforce program.⁹ This amount
6 does not include the Company's proposed adjustments for wage increases or the
7 Neil Simpson I labor costs also shown on Schedule H-1, which I do not address
8 in my testimony.

9 In the only testimony on this issue, Company witness Mr. Jon Thurber
10 describes the calculation of the adjustment (including the wage adjustments, Neil
11 Simpson I labor costs, and open positions): "These amounts are calculated using
12 an average of union negotiated wage increases and expected non-union wage
13 increases, together with the costs associated with open vacancies and additional
14 employees needed for operations."¹⁰

15
16 **Q. How does the Company's request to increase labor and related expenses for
17 open positions compare to its actual history of open positions?**

18 A. The Company's actual history for the last several years indicates that it is not
19 likely to fill all the open positions or actually incur the requested expense. In all

⁸ Company response to BHII Request No. 18 (Attachment 18 "Positions by Dept" tab), a copy of which is attached as my Exhibit ___(LK-14).

⁹ The Company's response to BHII Request No. 18 states "The additional costs on Schedule H-1 are for current open positions to be filled as soon as possible. They do not include any positions related to FutureTrack."

¹⁰ Direct Testimony of Jon Thurber at 17.

1 months, at least since January 2011, the Company has had open positions.¹¹ The
2 number of open positions ranged from 5 to 42 in any one month and averaged 19
3 each month since January 2011. The open positions ranged from 18 to 42 and
4 averaged 26 each month during the test year.¹²

5

6 **Q. What should the Commission conclude?**

7 A. The Commission should conclude that the request to increase payroll and related
8 expenses is not justified. It is not consistent with the Company's actual
9 experience. The Company has consistently maintained an average of 19 open
10 positions, which is more than the 17 reflected in its adjustment to increase labor
11 and related expenses.

12

13 **Q. Is there another factor that the Commission should consider?**

14 A. Yes. The Company's request represents an 11% increase in labor and related
15 expense compared to the labor expense without the proposed adjustment. Thus,
16 the Company is requesting an 11% increase simply assuming away its history of
17 maintaining a significant number of open positions.

18

19 **Q. What is your recommendation?**

20 A. I recommend that the Commission reject this adjustment. It is not justified and it
21 is contrary to the Company's history of 19 to 26 open positions on average. The
22 Commission should not assume that the Company will change its historic practice

¹¹ Company's response to SDPUC Request No. 5-14.

¹² *Id.*

1 going forward.

2

3 **C. The Commission Should Remove the Company's Adjustment to Increase**
4 **Pension Expense Based on Five-Year Average**

5

6 **Q. Please describe the Company's request to increase pension expense based on**
7 **a new methodology compared to the 2014 known and measurable expense.**

8 A. The Company proposes a new, five-year average methodology to calculate
9 pension expense instead of using the 2014 pension expense, which is known and
10 measurable and consistent with the Commission's historic approach to reflect
11 such changes within the twelve month post-test year period.

12 The pension expense in the test year was \$2.608 million (\$2.845 million
13 total Company). The Company's new methodology results in adjusted pension
14 expense of \$2.142 million. In contrast, the actual known and measurable 2014
15 pension expense is \$0.895 million. The Company's request exceeds the actual
16 known and measurable 2014 pension expense by \$1.247 million without
17 justification.

18

19 **Q. Should the Commission adopt a new methodology for pension expense in this**
20 **proceeding?**

21 A. No. First, the Company's proposed adjustment is nothing more than an
22 opportunistic response to the reduction in the expense in 2014. The Company
23 has offered no evidence that the pension expense will swing upward to the five
24 year average in future years. Thus, the proposed adjustment reflects nothing

1 more than speculation. It certainly does not reflect a known and measurable
2 change. The actual 2014 expense is the best evidence of the post-test year known
3 and measurable change in the expense compared to the historic test year.

4 Second, the Commission should be careful not to adopt an adjustment in
5 this proceeding to accommodate the Company that could be considered precedent
6 for other utilities.

7 Third, the Company has already received the benefit of the lower pension
8 expense this year and will unjustly continue to receive the benefits of lower
9 pension expense if it is allowed excessive recovery based on its new
10 methodology. The Company has not offered to defer the difference between the
11 pension expense reflected in its rates and the actual pension expense this year or
12 to share it with customers. The Company has proposed a new methodology
13 solely to recover more in revenues than its most recent actual pension expense.

14

15 **Q. Does the Proposed Settlement reflect the Company's proposed new**
16 **methodology?**

17 A. Yes. If the Commission adopts the Proposed Settlement, then the Commission
18 should revise the pension expense to the actual 2014 expense for the reasons
19 previously described.

20

21

1 **D. The Commission Should Remove All Incentive Compensation Tied to**
2 **Financial Performance From Base Rates**
3

4 **Q. Please describe the Company's incentive compensation expense tied to BHC**
5 **financial performance.**

6 A. The Company seeks recovery of \$1.554 million in incentive compensation
7 expense tied to operating and financial performance. In response to discovery,
8 the Company provided the South Dakota incentive compensation expense and the
9 portion of the expense that was "tied to operating and financial criteria for the test
10 year."¹³ In its response, the Company listed the total expense for BHP, Black
11 Hills Service Company, LLC ("BHSC"), allocated to BHP, and Black Hills
12 Utility Holdings, Inc. ("BHUH"), allocated to BHP for each incentive
13 compensation plan and listed the portion of the expense that it determined was
14 "tied to operating and financial criteria for the test year." The expenses identified
15 by the Company as meeting the operating and financial criteria summed to
16 \$0.666 million and included a portion of the performance plan expense.
17 However, the Company excluded 0.149 million in performance plan expenses
18 and the entirety of the \$0.739 million in incentive restricted stock expense.

19
20 **Q. Is it Commission precedent to deny recovery of incentive compensation**
21 **expense tied to operating and financial performance?**

22 A. Yes. This is appropriate for several reasons. First, the Company's financial
23 performance is a direct function of the revenues recovered from customers,

¹³ SDPUC Request No. 2-11 (Confidential Attachment G).

1 including the rate increases that are authorized by the Commission. There is an
2 inherent conflict between lower rates and greater financial performance.
3 Incentive compensation tied to operating and financial performance. The
4 Commission should not incentivize the Company to seek greater rate increases
5 and act against their customers' interests. This expense should be a shareholder
6 cost.

7 Second, the revenue requirement should not embed recovery of an
8 expense that is based on performance, regardless of whether it is based on
9 operating or financial performance. If the Company is ensured recovery of the
10 expense from customers, then there is no performance that is at risk or that must
11 be achieved in order to recover that expense.

12 Third, this form of incentive compensation is primarily directed toward
13 achieving shareholder goals, not customer goals. Thus, the cost should be borne
14 by shareholders, not customers.

15
16 **Q. Are the restricted stock expense and the performance plan expense tied to**
17 **the Company's financial performance?**

18 A. Yes. The restricted stock expense and performance plan expense represent
19 awards of stock, units, or cash based on the performance measures listed in the
20 Company's Confidential 2005 Omnibus Incentive Compensation Plan in Section
21 12.1, which consist primarily of financial performance measures.¹⁴
22

¹⁴ Id., Confidential Attachment 2-11A.

1 **Q. Should the Commission deny recovery of the incentive compensation**
2 **expense tied to the Company’s “operating and financial criteria,” including**
3 **the restricted stock expense and the entirety of the performance plan**
4 **expense?**

5 A. Yes, for the reasons that I previously cited.

6
7 **Q. Does the Proposed Settlement reflect any adjustment to remove incentive**
8 **compensation expense?**

9 A. Yes. However, the Proposed Settlement removes only the \$0.666 million in
10 incentive compensation expense “tied to operating and financial criteria”
11 identified by the Company in response to SDPUC 2-11. Inexplicably, the
12 Proposed Settlement allows the Company to include \$0.739 million in incentive
13 restricted stock expense and \$0.149 million in performance plan expenses in its
14 revenue requirement, despite the fact that these are incentive compensation
15 expenses that are similar in nature to the expenses that were removed. The
16 Commission should be consistent and remove all similar incentive compensation
17 expense tied to the financial performance of the Company, BHC, and BHUH.

18
19 **E. The Commission Should Remove Company Adjustment to Increase Affiliate**
20 **Allocations from BHUH**
21

22 **Q. Please describe the Company’s request to increase the test year affiliate**
23 **allocations from BHUH.**

24 A. The Company proposes to increase the affiliate allocations from BHUH by

1 \$1.846 million compared to the historic test year. The Company provided
2 adjustments by FERC account on Schedule H-5, although it did not provide any
3 other support for these adjustments in its filing. The Company provided a further
4 breakdown of the adjustments between direct and allocated expenses in response
5 to BHII Request No. 6. The Company appears to have started with projected
6 expenses for the twelve months ending September 2015 and then adjusted those
7 expenses. The Company provided no additional workpapers in support of its
8 proposed adjustments in this response.

9
10 **Q. What is the magnitude of the proposed increase in affiliate allocations from**
11 **BHUH?**

12 A. The Company proposes a 19% increase over the historic test year expense, based
13 on Schedule H-5. The largest dollar increases are in account 920 “administrative
14 salaries” (21%) and account 923 “outside services” (56%). Based on these
15 numbers, the adjustments apparently reflect additional staffing and/or salary
16 increases and increased use of outside services.

17
18 **Q. Should the Commission adopt this adjustment?**

19 A. No. There is no justification for the proposed increase and the magnitude of the
20 increase is unreasonable on its face. The best evidence of the reasonable expense
21 is the test year itself unless there are identifiable known and measurable changes
22 that should be reflected. However, the Company did not provide any evidence of
23 any identifiable known and measurable changes in its filing or in response to

1 BHII discovery.

2

3 **Q. Does the Proposed Settlement reflect any reduction in the Company's**
4 **proposed increase to the affiliate allocations from BHUH?**

5 A. No. To the contrary, the Proposed Settlement inexplicably *increases* the
6 Company's proposed adjustment by \$0.527 million to \$2.373 million. The
7 Proposed Settlement spreadsheet refers to emails from Jon Thurber to the Staff in
8 support of the adjustments reflected in the Proposed Settlement, but these have
9 not been provided to BHII, or otherwise included in the record. In addition, the
10 Proposed Settlement spreadsheet appears to incorrectly include an allocation to
11 SD of transmission load dispatch costs in account 561 that was not allocated to
12 SD in the Company's Application.¹⁵ The SD allocation for account 561 is shown
13 as \$0 on Schedule N-1 page 13 line 64 of the Company's Application. The
14 incorrect allocation in account 561 adds \$0.286 million to the Proposed
15 Settlement revenue requirement.

16

17 **Q. Should the Commission adopt the Proposed Settlement adjustment?**

18 A. No. There is no justification for the proposed increase and the magnitude of the
19 increase is unreasonable on its face. The best evidence of the reasonable expense
20 is the test year itself unless there are identifiable known and measurable changes
21 that should be reflected. However, the Company did not provide any evidence of
22 any identifiable known and measurable changes in its filing or in conjunction

¹⁵ Refer to Exhibit___(DEP-1) Schedule 2 line 4 of the Proposed Settlement spreadsheet.

1 with its supplemental response to Staff discovery. However, if the Commission
2 adopts the Proposed Settlement adjustment, then it should at least correct the
3 apparent allocation error in account 561 that I described previously.

4
5 **F. The Commission Should Remove Proposed Settlement Adjustment to**
6 **Increase Affiliate Allocations from BHSC**
7

8 **Q. Did the Company propose an adjustment for increases in affiliate allocations**
9 **from BHSC in its filing?**

10 A. No.

11

12 **Q. Does the Proposed Settlement include increases in affiliate allocations from**
13 **BHSC?**

14 A. Yes. But to my knowledge the Company never notified the parties that it would
15 seek to further increase its base rates to include increases in affiliate allocations
16 from BHSC. The Company informed the parties in a supplemental response to
17 SDPUC Request No. 3-96 that it planned to propose a new adjustment in its
18 rebuttal testimony and attached a revised Schedule H-4 that detailed the proposed
19 new adjustment by FERC account in the same manner that it filed Schedule H-5.
20 However, the Company provided no additional detail in that response. Based on
21 the Proposed Settlement, it appears that the Company provided the Staff with
22 additional information and changes to the revised Schedule H-4 in a series of
23 emails. None of those emails were shared with BHII during settlement
24 negotiations, they have not been provided to BHII since, and they are not

1 included in the record.

2

3 **Q. What is the magnitude of the proposed increase in affiliate allocations from**
4 **BHSC reflected in the Proposed Settlement?**

5 A. The Proposed Settlement incorporates a 6.0% increase over the historic test year
6 expense, based on Schedule H-4. The largest increases are (1) a 7.5% increase in
7 account 920 “administrative salaries” and (2) an 11.7% increase in account 921
8 “office supplies and expenses.” These adjustments apparently reflect additional
9 staffing and/or salary increases and increased “office expenses.”

10

11 **Q. Should the Commission adopt this adjustment?**

12 A. No. There is no justification for the proposed increase and the magnitude of the
13 increase is unreasonable on its face. The best evidence of the reasonable expense
14 is the test year itself unless there are identifiable known and measurable changes
15 that should be reflected. However, the Company has not provided any evidence
16 of any identifiable known and measurable changes in its filing or in response to
17 BHII discovery.

18

19 **G. The Commission Should Extend the Retired Steam Plants Amortization**
20 **Expense**

21

22 **Q. Please describe the Company’s proposal for the amortization of the**
23 **regulatory asset for the remaining net book value of the retired steam plants**
24 **and the obsolete inventory for those plants.**

1 A. The Company proposes \$1.163 million (\$1.295 million total Company) in
2 amortization expense to amortize the regulatory asset for the retired steam plants
3 over five years.

4
5 **Q. Should the Commission use a five-year amortization period?**

6 A. No. The Commission should use a ten-year amortization period. The
7 Company's proposed five-year amortization period is unnecessarily short. If the
8 Commission includes the regulatory asset in rate base, then the Company will
9 earn a return on the unamortized regulatory asset regardless of the amortization
10 period. When it has discretion, as it does in this case, the Commission should use
11 a longer amortization period to minimize the effect on customers. In this case, a
12 ten-year amortization period will achieve this objective.

13
14 **Q. What is the effect of your recommendation to use a ten-year amortization
15 period?**

16 A. Using a ten-year amortization period on the regulatory asset for the retired steam
17 plants and obsolete inventory will reduce the Company's revenue requirement by
18 \$0.539 million, consisting of a reduction of \$0.582 million in amortization
19 expense, net of an increase in the return on rate base (net reduction in
20 accumulated amortization and increase in ADIT) of \$0.043 million. The
21 calculations are detailed on my Exhibit____(LK-15).

22
23 **Q. Does the Proposed Settlement reflect a ten-year amortization period?**

1 A. No. The Proposed Settlement reflects the five-year amortization period proposed
2 by the Company. If the Commission adopts the Proposed Settlement, then it
3 should modify it to use a ten-year amortization period.

4
5 **H. The Commission Should Reduce the Company's Amortization Expense on**
6 **the Regulatory Asset for Storm Damage**
7

8 **Q. Please describe the Company's request for amortization expense on the**
9 **regulatory asset for storm damage.**

10 A. The Company proposes \$0.828 million for amortization expense based on a five-
11 year amortization period. I provide the details of the Company's request,
12 including the source of the amounts that I cited, on my Exhibit___(LK-10).

13
14 **Q. Should the Commission use a five-year amortization period?**

15 A. No. The Commission should use a ten-year amortization period. The
16 Company's proposed five-year amortization period is unnecessarily short. If the
17 Commission includes the regulatory asset in rate base, then the Company will
18 earn a return on the unamortized regulatory asset regardless of the amortization
19 period. When it has discretion, as it does in this case, the Commission should use
20 a longer amortization period to minimize the effect on customers. In this case, a
21 ten-year amortization period will achieve this objective.

22
23 **Q. What is the effect of your recommendation to use a ten-year amortization**
24 **period?**

1 A. Using a ten-year amortization period will reduce the Company's revenue
2 requirement by \$0.414 million to reflect the reduction in amortization expense of
3 an equivalent amount. The rate base effects from the adjustment, along with the
4 reduction for ADIT, are discussed in the rate base section of my testimony. The
5 calculations are detailed on my Exhibit____(LK-10).

6

7 **Q. Does the Proposed Settlement reflect a ten-year amortization period?**

8 A. Yes.

9

10 **I. The Commission Should Remove the Retired Steam Plants Decommissioning**
11 **Amortization Expense**

12

13 **Q. Did you previously address this issue in the Rate Base Issues section of your**
14 **testimony?**

15 A. Yes.

16

17

1 **J. The Commission Should Remove the 69kV LIDAR Surveying Project**
2 **Amortization Expense**
3

4 **Q. Did you previously address this issue in the Rate Base Issues section of your**
5 **testimony?**

6 A. Yes.

7 **K. The Commission Should Extend the CPGS Life Span for Depreciation**
8 **Expenses**
9

10 **Q. Please describe the Company's proposed life span for the CPGS**
11 **depreciation rate and expense.**

12 A. The Company proposes a life span for the CPGS of 35 years, a depreciation rate
13 of 3.29%, and \$2.726 million in depreciation expense (\$3.035 million total
14 Company).

15
16 **Q. Is the proposed 35-year life span reasonable?**

17 A. No. A 35-year life span is unnecessarily short. A longer life span of 40 to 45
18 years is within the range of reasonableness supported by the Company's
19 depreciation expert's own analysis. The longer life span reflects the estimated
20 and actual service lives of similar facilities owned by other utilities.¹⁶ The
21 Company's depreciation expert, Mr. John Spanos, in consultation with the
22 Company during his depreciation analysis, determined that an appropriate life

¹⁶ Company response to BHII Request No. 11 (Spanos workpapers and source documents).

1 span for the facility was 40 years, which the Company appears to have
2 confirmed.¹⁷ Mr. Spanos offered no explanation in his testimony as to why he
3 changed the 40 years set forth in his analysis to the 35 years set forth in the
4 depreciation study attached to his testimony.

5

6 **Q. What is the effect on the revenue requirement of using a 40-year life span?**

7 A. A 40-year life span for the CPGS depreciation rate and expense will reduce the
8 Company's revenue requirement by \$0.332 million, consisting of a reduction of
9 \$0.338 million in amortization expense, net of an increase in the return on rate
10 base (net reduction in accumulated amortization and increase in ADIT) of \$0.006
11 million. The calculations are detailed on my Exhibit____(LK-16).

12

13 **Q. Does the Proposed Settlement reflect a 40-year life span?**

14 A. Yes.

15

16 **L. The Commission Should Correct the Steam and Other Production Plant Net**
17 **Salvage for Depreciation Expenses**

18

19 **Q. Please describe the changes in steam and other production plant net salvage**
20 **reflected in the Company's proposed depreciation rates.**

21 A. The Company proposes significant increases in net negative salvage for its steam
22 and other production plant accounts. Net negative salvage refers to the net of
23 estimated salvage income and cost of removal. Net negative salvage means that

¹⁷ *Id.*, Attachment 11U - BHP and CLFP Projected Plant retirements updated 9-24-13, a copy of which I have attached as my Exhibit____(LK-17).

1 the projected salvage income is less than the projected cost of removal.

2 Mr. Spanos applied the net salvage rates to the entire plant balance, which
3 covers not only interim retirements, but also terminal retirements (for
4 decommissioning). Increases in net negative salvage have the effect of increasing
5 the depreciation rates.

6 The present depreciation rates reflect -5% net salvage rates.¹⁸ The
7 Company proposes to increase these rates to -13% to -22% depending on the
8 plant. I have replicated a summary schedule from the Company's depreciation
9 study showing the net salvage rates and depreciation rates for each plant and each
10 plant account as my Exhibit ___(LK-18).

11

12 **Q. Is this significant increase in net negative salvage for the production plant**
13 **accounts appropriate?**

14 A. No. First, the basis for the calculation of the terminal net salvage is flawed and
15 unreliable, resulting in an excessive net negative salvage cost and percentage.

16 Second, this may represent an undisclosed proposal to change the
17 Commission's policy for decommissioning cost recovery from recovery *after* the
18 retirement of the plants (as is the case in this proceeding for the three retired coal-
19 fired plants) to recovery *before* the future retirement of the plants.

20 Third, the increase in net negative salvage is not necessary at this time.

21 The Commission is not required to provide recovery of unknown future costs in

¹⁸ Present depreciation rates were adopted in Case No. E09-018 based on a depreciation study performed for the Company by Black and Veatch (Exhibit LWL-1 in that proceeding). I have attached pages illustrating the -5% used in that study and reflected in present depreciation rates as my Exhibit ___(LK-19).

1 present rates. The Commission's current policy appears to be determine the
2 appropriate manner of decommissioning (and associated costs) *after* plants are
3 retired. This policy is prudent for ratepayers and still ensures that the Company
4 recovers its costs.

5

6 **Q. How should the Commission proceed on this issue?**

7 A. The Commission should use the same -5% net salvage rate for these production
8 plant accounts that is reflected in the present depreciation rates. The Company
9 has not justified the significant increases that it proposes or provided any valid
10 rationale to change policy. The Commission should not provide premature
11 recovery of unknown future costs; the Company can seek recovery of
12 decommissioning costs in the future when the method of decommissioning can be
13 assessed and the cost can be determined based on actual bids.

14

15 **Q. Have you quantified the effect on the revenue requirement of your
16 recommendation?**

17 A. Yes. Using a -5% net salvage rate reduces depreciation rates and reduces
18 depreciation expense and the revenue requirement by \$1.132 million. I provide
19 the calculation of the depreciation rates using the -5% net salvage rate and the
20 effects on depreciation expense on my Exhibit__(LK-20).

21

22

1 **M. Other Proposed Settlement Issues**
2

3 **Q. Are there other issues specifically identified in the Proposed Settlement with**
4 **which you agree and that you recommend the Commission adopt?**

5 A. Yes. The Proposed Settlement includes an adjustment of \$0.380 million to
6 increase revenues for the effects of weather normalization, an adjustment of
7 \$0.219 million to reduce the allocation of the Neil Simpson rent revenue and
8 expense, and an adjustment of \$0.244 million to reduce the allocation of the Neil
9 Simpson common steam plant. I recommend that the Commission adopt those
10 proposed adjustments.
11

12 **IV. MISCELLANEOUS ISSUES**

13 **A.** [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED]
22 [REDACTED]
23 [REDACTED]
24 [REDACTED]

1 [REDACTED]

2 [REDACTED]

3

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

7

8 [REDACTED]

9 [REDACTED]

10 [REDACTED]

11

12 [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19

20 [REDACTED]

21 [REDACTED]

22 [REDACTED]

¹⁹ BHP response to BHII 5, a copy of which is attached as my Exhibit___(LK-21).

1 [REDACTED]

2 [REDACTED]

3

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8

9 [REDACTED]

10 [REDACTED]

11

12 [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]

20

21 **Q.** Does that complete your testimony?

22 **A.** Yes.

**BEFORE THE SOUTH DAKOTA
PUBLIC UTILITIES COMMISSION**

IN THE MATTER OF THE APPLICATION OF)
BLACK HILLS POWER, INC., A SOUTH DAKOTA) DOCKET NO. EL14-026
CORPORATION, FOR AUTHORITY TO INCREASE)
RATES IN SOUTH DAKOTA)

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF

BLACK HILLS INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2014

77872079.4 0064944-00002

EXHIBIT __ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE**1986 to****Present:**

J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to**1986:**

Energy Management Associates: Lead Consultant.

Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to**1983:**

The Toledo Edison Company: Planning Supervisor.

Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.

Construction project cancellations and write-offs.

Construction project delays.

Capacity swaps.

Financing alternatives.

Competitive pricing for off-system sales.

Sale/leasebacks.

J. KENNEDY AND ASSOCIATES, INC.

RESUME OF LANE KOLLEN, VICE PRESIDENT

CLIENTS SERVED**Industrial Companies and Groups**

Air Products and Chemicals, Inc.	Lehigh Valley Power Committee
Airco Industrial Gases	Maryland Industrial Group
Alcan Aluminum	Multiple Intervenors (New York)
Armco Advanced Materials Co.	National Southwire
Armco Steel	North Carolina Industrial
Bethlehem Steel	Energy Consumers
CF&I Steel, L.P.	Occidental Chemical Corporation
Climax Molybdenum Company	Ohio Energy Group
Connecticut Industrial Energy Consumers	Ohio Industrial Energy Consumers
ELCON	Ohio Manufacturers Association
Enron Gas Pipeline Company	Philadelphia Area Industrial Energy
Florida Industrial Power Users Group	Users Group
Gallatin Steel	PSI Industrial Group
General Electric Company	Smith Cogeneration
GPU Industrial Intervenors	Taconite Intervenors (Minnesota)
Indiana Industrial Group	West Penn Power Industrial Intervenors
Industrial Consumers for	West Virginia Energy Users Group
Fair Utility Rates - Indiana	Westvaco Corporation
Industrial Energy Consumers - Ohio	
Kentucky Industrial Utility Customers, Inc.	
Kimberly-Clark Company	

**Regulatory Commissions and
Government Agencies**

Cities in Texas-New Mexico Power Company's Service Territory
 Cities in AEP Texas Central Company's Service Territory
 Cities in AEP Texas North Company's Service Territory
 Georgia Public Service Commission Staff
 Kentucky Attorney General's Office, Division of Consumer Protection
 Louisiana Public Service Commission Staff
 Maine Office of Public Advocate
 New York State Energy Office
 Office of Public Utility Counsel (Texas)

RESUME OF LANE KOLLEN, VICE PRESIDENT

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation

Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

**Expert Testimony Appearances
of
Lane Kollen
as of November 2014**

Date	Case	Jurisdic.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.

J. KENNEDY AND ASSOCIATES, INC.

**Expert Testimony Appearances
of
Lane Kollen
as of November 2014**

Date	Case	Jurisdic.	Party	Utility	Subject
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.

J. KENNEDY AND ASSOCIATES, INC.

**Expert Testimony Appearances
of
Lane Kollen
as of November 2014**

Date	Case	Jurisdct.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19 th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.

J. KENNEDY AND ASSOCIATES, INC.

**Expert Testimony Appearances
of
Lane Kollen
as of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.

J. KENNEDY AND ASSOCIATES, INC.

**Expert Testimony Appearances
of
Lane Kollen
as of November 2014**

Date	Case	Jurisdict.	Party	Utility	Subject
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Rebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95	U-21485 (Supplemental Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
12/95	U-21485 (Surrebuttal)				
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

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Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

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Date	Case	Jurisdic.	Party	Utility	Subject
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.

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Date	Case	Jurisdic.	Party	Utility	Subject
4/99	99-02-05	Ct	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.

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Date	Case	Jurisdic.	Party	Utility	Subject
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.

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Date	Case	Jurisdic.	Party	Utility	Subject
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPSCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

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Date	Case	Jurisdct.	Party	Utility	Subject
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas- New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPSCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPSCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.

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Date	Case	Jurisdct.	Party	Utility	Subject
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider, Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow-through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.

J. KENNEDY AND ASSOCIATES, INC.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.

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06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.

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Date	Case	Jurisdict.	Party	Utility	Subject
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09	U-21453, U-20925 U-22092 (Sub J) Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	Rebuttal				
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct- Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U- 20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.

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Date	Case	Jurisdic.	Party	Utility	Subject
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
03/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation expense and effects on System Agreement tariffs.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.

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Date	Case	Jurisdct.	Party	Utility	Subject
04/10	2009-00458, 2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: SO2 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: SO2 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.

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Date	Case	Jurisdic.	Party	Utility	Subject
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11	ER10-2001 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPSCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11	38306 Direct	TX	Cities Served by Texas- New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	Suppl Direct				
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPSCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Direct Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.

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Date	Case	Jurisdickt.	Party	Utility	Subject
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.

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Date	Case	Jurisdic.	Party	Utility	Subject
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.

J. KENNEDY AND ASSOCIATES, INC.

EXHIBIT __ (LK-2)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Remove Double Count of Spare Parts for CPGS
(\$ Millions)

	<u>Total Company</u>	<u>South Dakota Retail %</u>	<u>South Dakota Retail</u>			
Source: Statements E and J - Response to Staff 6-42						
Double Count of PIS to Remove \$2.220 million x 58% BHP Ownership %	(1.288)	89.831% PRODPLT	<u>(1.157)</u>			
As Adjusted CPGS Average Depreciation Rate	2.88%	Based on 40 Year Life Span				
Reduce Depreciation Expense to Remove Double Count	<u>(0.037)</u>	89.831% PRODPLT	<u>(0.033)</u>			
Accumulated Depreciation One Half of Depreciation Expense Reduction (See Statement E Note 3)	(0.019)					
Decrease Accumulated Depreciation for Expense Reduction The Effect Increases Rate Base	<u>0.019</u>	89.831% PRODPLT	<u>0.017</u>			
Accumulated Deferred Income Taxes (See Schedule M-2) Book Depreciation Expense Reduction (100% of Expense Reduction x Tax Rate)	(0.037)					
Federal Income Tax Rate	<u>0.35</u>					
Increase ADIT for Expense Reduction The Effect Decreases Rate Base	<u>(0.013)</u>	89.831% PRODPLT	<u>(0.012)</u>			
Computation of Adjusted Depreciation Rate See BHII 15 Attach b for Computed Rates						
	<u>Original Cost</u>	<u>Future Book Accruals</u>	<u>Rem Life at 35 Year Span</u>	<u>Rem Life at 40 Year Span</u>	<u>Annual Accrual</u>	<u>Rate</u>
Acct 341	7,028,693	7,309,841	33.75	38.57	189,521	2.70%
Acct 342	10,543,040	10,964,761	31.5	36	304,577	2.89%
Acct 344	38,657,812	40,204,125	31.61	36.13	1,112,763	2.88%
Acct 345	10,543,040	10,964,761	31.78	36.32	301,893	2.86%
Acct 346	<u>3,514,347</u>	<u>3,654,920</u>	<u>27.37</u>	<u>31.28</u>	<u>116,845</u>	<u>3.32%</u>
	<u>70,286,931</u>				<u>2,025,600</u>	<u>2.88%</u>

EXHIBIT __ (LK-3)

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

REQUEST DATE : August 12, 2014

RESPONSE DATE : September 5, 2014

REQUESTING PARTY: SDPUC Staff

SDPUC Request No. 6-42:

Cheyenne Prairie Generating Station

Refer to the Company's response to Staff DR 3-34, Attachment 3-34 – Cheyenne Prairie Generating Station.xlsx, CC Detail tab. Regarding the spare parts of \$2,220,000 found on line 76:

- a) Provide a breakout of the individual spare parts included.
- b) Are the spare parts included in the capital costs the same as any spare parts included on Schedule F-4?
- c) Explain why these spare parts are capitalized and other spare parts are included as working capital on Schedule F-4.

Response to SDPUC Request No. 6-42:

- a) Please refer to the response to SD PUC Request No. 5-3 and Attachment 5-3X for the spare parts inventory.
- b) Yes. The spare parts were inadvertently included on both the Cheyenne Prairie Generating Station capital schedule on Schedule D-11 and as materials and supplies on Schedule F-4. This oversight will be corrected and updated schedules will be provided.
- c) The spare parts should be included only as part of working capital and will be removed from the capital schedule.

Attachments: None

EXHIBIT __ (LK-4)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Remove NOL Carryforward ADIT from Rate Base
(\$ Millions)

Source: Schedule M-1 and M-2	<u>Total Company</u>	<u>South Dakota Retail %</u>	<u>South Dakota Retail</u>
Remove Acct 190.175 ADIT for NOL Carryforward	(4.765)	91.673%	(4.368)
Remove Acct 190.520 ADIT for NOL Carryforward	(9.188)	SALWAG 91.673%	(8.423)
Remove Sch M-2 Adjustment for NOL ADIT	<u>0.455</u>	SALWAG 91.673%	<u>0.418</u>
Remove Acct 190 ADIT for NOL Carryforward	<u><u>(13.497)</u></u>	SALWAG	<u><u>(12.373)</u></u>

EXHIBIT __ (LK-5)

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)

Black Hills Power, Inc.

Year/Period of Report

End of 2013/Q4

Name of Respondent 20140418-8029 FERC PDF (Unofficial) Black Hills Power, Inc.	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) //	Year/Period of Report End of 2013/Q4
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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	DEFERRED COMPENSATION	394,211	358,102
3	VACATION PAYABLE	200,410	150,955
4			
5	FAS 109	191,905	109,128
6			
7	Other	30,260,843	17,010,150
8	TOTAL Electric (Enter Total of lines 2 thru 7)	31,047,369	17,628,335
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	31,047,369	17,628,335

Notes

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Non-qualified Pension Plan	\$ 474,783
Retiree Healthcare	3,126,435
PEP AOCI	355,645
Line Extension Deposits	(302,106)
Bad Debt Reserve	547,808
Pension	14,367,933
NOL Carryforward	10,440,671
State Rate Refund Liability	306,672
Other	238,921
Bonus Comp	704,083
Total	30,260,845

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Non-qualified Pension Plan	\$ 504,797
Retiree Healthcare	2,726,843
PEP AOCI	258,159
Line Extension Deposits	(290,134)
Bad Debt Reserve	(78,596)
Pension	7,395,989
NOL Carryforward	4,759,905
State Rate Refund Liability	497,613
Other	622,251
Bonus Comp	613,323
Total	17,010,150

EXHIBIT __ (LK-6)

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. ____

Form 1 Approved
 OMB No.1902-0021
 (Expires 12/31/2014)
 Form 1-F Approved
 OMB No.1902-0029
 (Expires 12/31/2014)
 Form 3-Q Approved
 OMB No.1902-0205
 (Expires 05/31/2014)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Black Hills Power, Inc.	Year/Period of Report End of <u>2013/Q4</u>
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Black Hills Power, Inc.	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2013/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

	2013	2012	2011
Federal statutory rate	35.0%	35.0%	35.0%
Amortization of excess deferred and investment tax credits	(0.3)	(0.3)	(0.4)
Equity AFUDC	—	(0.1)	(0.6)
Flow through adjustments *	(2.5)	(3.5)	(3.4)
Prior year deferred adjustment **	—	3.6	—
Tax credits	(0.8)	—	—
Other	(0.6)	(0.1)	0.1
	<u>30.8%</u>	<u>34.6%</u>	<u>30.7%</u>

* The flow-through adjustments relate primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs that continue to be capitalized for book purposes. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to our customers in the form of lower rates as a result of a rate case settlement that occurred during 2010. A regulatory asset was established to reflect the recovery of future increases in taxes payable from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit consistent with the flow through method.

** The adjustment was a non-recurring unfavorable true-up attributable to property related deferred income taxes. The removal of the impact of such an adjustment is more appropriately reflective of the effective rate on a recurring basis.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in Other deferred credits and other liabilities on the accompanying Balance Sheet (in thousands):

	2013	2012
Unrecognized tax benefits at January 1	\$ 2,078	\$ 3,595
Reductions for prior year tax positions	(155)	(1,586)
Additions for current year tax positions	520	69
Unrecognized tax benefits at December 31	<u>\$ 2,443</u>	<u>\$ 2,078</u>

The reductions for prior year tax positions relate to the reversal through otherwise allowed tax depreciation. The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is approximately \$0.5 million.

It is our continuing practice to recognize interest and/or penalties related to income tax matters in income tax expense. During the years ended December 31, 2013 and 2012, the interest expense recognized was not material to our financial results.

We file income tax returns in the United States federal jurisdictions as a member of the BHC consolidated group. We do not anticipate that total unrecognized tax benefits will significantly change due to settlement of any audits or the expiration of statutes of limitations prior to December 31, 2014.

At December 31, 2013, we have federal NOL carry forward of \$14 million, expiring in 2031. Ultimate usage of this NOL depends upon our ability to generate future taxable income, which is expected to occur within the prescribed carryforward period.

EXHIBIT __ (LK-7)

Docket No. EL14-026
Black Hills Power, Inc.

BHII Adjustment to Remove Estimated Decommissioning Costs as a Regulatory Asset
(\$ Millions)

	<u>Total Company</u>	<u>South Dakota Retail %</u>	<u>South Dakota Retail</u>
Source: Schedule J-2			
Company's Estimated Decommissioning Costs			
Ben French	3.960		
Osage Units 1-3	3.952		
Neil Simpson	2.975		
Total Estimated Costs Set Up as Regulatory Asset	<u>10.887</u>		
Company's Proposed Amortization Period in Years	<u>5</u>		
Company's Proposed Annual Amortization Expense	<u>2.177</u>	89.83%	<u>1.956</u>
Company's Proposed Unamortized Regulatory Asset	<u>8.709</u>	89.83% PRODPLT	<u>7.824</u>
Remove Annual Amortization Expense for Estimated Decommissioning Costs	<u>(2.177)</u>	89.83% PRODPLT	<u>(1.956)</u>
Remove Unamortized Regulatory Asset for Estimated Decommissioning Costs	<u>(8.709)</u>	89.83% PRODPLT	<u>(7.824)</u>

EXHIBIT __ (LK-8)

Docket No. EL14-026

Black Hills Power, Inc.

**PHI Adjustment to Remove Contingency from Estimated Decommissioning Costs and Amortize Over 10 Year
(\$ Millions)**

	<u>Total Company</u>	<u>South Dakota Retail %</u>	<u>South Dakota Retail</u>
Source: Schedule J-2			
Company's Estimated Decommissioning Costs			
Ben French	3.960		
Osage Units 1-3	3.952		
Neil Simpson	2.975		
Total Estimated Costs Set Up as Regulatory Asset	<u>10.887</u>		
Less: Contingencies - See Response to Staff DR 3-23	<u>(0.956)</u>		
Estimated Costs Less Contingencies	9.931		
Alternative Change in Amortization to 10 Years	<u>10</u>		
Company's Proposed Annual Amortization Expense	<u>0.993</u>	89.83%	<u>0.892</u>
As Filed Amortization Expense	<u>2.177</u>	PRODPLT	
Reduction in Amortization Expense From Filing	<u>(1.184)</u>	89.83%	<u>(1.064)</u>
		PRODPLT	
As Adjusted Unamortized Regulatory Asset	<u>7.754</u>	89.83%	<u>6.965</u>
		PRODPLT	
As Filed Unamortized Regulatory Asset	<u>8.709</u>	89.83%	<u>7.824</u>
		PRODPLT	
Change in Unamortized Regulatory Asset Estimated Decommissioning Costs	<u>(0.956)</u>	89.83%	<u>(0.859)</u>
		PRODPLT	
As Filed Grossed Up ROR			<u>11.43%</u>
Reduction in Return on Rate Base			<u>(0.098)</u>
Reduction in Revenue Requirement			<u>(1.162)</u>

EXHIBIT __ (LK-9)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 28, 2014
RESPONSE DATE : July 7, 2014
REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 26: Reference Schedules J-3, M-1, and M-2. The following questions relate to accumulated deferred income taxes (“ADIT”) associated with the proposed regulatory asset amounts for Winter Storm Atlas and the System Inspection Costs.

- a. Please indicate whether the Company included ADIT in rate base associated with each of these regulatory assets.
- b. If the Company did include the associated ADIT in rate base, please indicate where in the filing this is shown.
- c. If the Company did not include the associated ADIT in rate base, please explain why it did not.
- d. Please confirm that the Company already has taken some or all of the income tax deductions for the Winter Storm Atlas costs and provide a schedule that shows the amount of the deductions in the 2013 tax year already taken for (1) casualty losses, (2) O&M expenses, and (3) tax depreciation. Please provide the Company’s calculations of these deductions, including electronic spreadsheets with formulas intact. Please reconcile the deductions that have been taken to the amounts the Company included in the regulatory asset.
- e. Please provide a schedule that shows the amount of the income tax deductions for the Winter Storm Atlas costs in the 2014 tax year that already have been or are estimated to be taken for (1) casualty losses, (2) O&M expenses, and (3) tax depreciation. Please provide the Company’s calculations of these deductions, including electronic spreadsheets with formulas intact. Please reconcile the deductions that have been taken to the amounts the Company included in the regulatory asset.

Response to BHII Request No. 26:

- a. The reconciliation referred to in response to request d. below provides an itemization of costs included in the rate filing on Sched J-3. A portion of these costs were estimated to be treated as a casualty loss. The deferred income tax effect associated with such treatment has been included in line 47 of Sched M-1 as part of the property related ADIT. The difference between the unamortized regulatory asset and estimated casualty loss deduction does result in a temporary difference for which an ADIT adjustment increasing net deferred tax liabilities will be made. That adjustment should

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 28, 2014
RESPONSE DATE : July 7, 2014
REQUESTING PARTY: Black Hills Industrial Intervenors

have been reflected on Sched M-1 and inadvertently it was not. Such an adjustment is determined to be \$792,771 (35% times (\$3,310,806-\$1,045,745)).

- b. Please see the response in a. above.
- c. Please see the response in a. above.
- d. At the time the rate case was filed, an evaluation of Storm Atlas costs was being conducted to make sure there will be proper reporting on the tax return. An analysis of the information that was available at December 31, 2013 indicated an estimated casualty loss of \$1,045,745, repair costs of \$1,000,000, and capitalized costs of \$1,900,000 as a result of Storm Atlas. These costs and the reporting of such costs will be trued up with the filing of the 2013 income tax return in September 2014. Please see Attachment 26d.1 for an estimate of the deductions and costs reflected in the tax accrual. In addition, Attachment 26d.2 provides a reconciliation of the Storm Atlas costs to Schedules D-10 and J-3 included in the rate filing. Also, the schedule indicates how these costs are expected to be accounted for on the 2013 income tax return.
- e. The schedules referenced in response d. above reflect the expenses associated with Storm Atlas that will be deducted on the 2013 tax return. Certain operation and maintenance costs and accelerated tax depreciation will be deducted in the 2014 tax year.

Attachments:

- 26d.1 – Winter Storm Atlas Costs
- 26d.2 - Amortization

EXHIBIT __ (LK-10)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Extend Amortization to 10 Years for Winter Storm Atlas Regulatory Asset
And to Include ADIT in Rate Base
(\$ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Schedule J-3			
Company Estimated Winter Storm Atlas Reg Asset from Winter Storm Atlas Reg Asset	4.139		
Company's Proposed Amortization Period in Years	<u>5</u>		
Company's Amortization Expense	<u>0.828</u>	100.00%	<u>0.828</u>
		Direct Assign	
BHII Recommended Amortization Period in Years	<u>10</u>		
BHII Recommended Amortization Expense	<u>0.414</u>	100.00%	<u>0.414</u>
		Direct Assign	
BHII Recommended Decrease in Amortization Expense	<u>(0.414)</u>	100.00%	<u>(0.414)</u>
		Direct Assign	
BHII Increase in Unamortized Regulatory Asset Balance	<u>0.414</u>	100.00%	<u>0.414</u>
		Direct Assign	
ADIT on Remaining Regulatory Asset Balance			
Company Proposed Reg Asset Balance	4.139		
Less: Adjustment from Above	<u>(0.414)</u>		
Remaining Regulatory Balance After Adjustment	3.725		
Federal Income Tax Rate	<u>35.0%</u>		
ADIT on Regulatory Asset Balance	<u>(1.304)</u>	100.00%	<u>(1.304)</u>
		Direct Assign	
Total Reduction to Rate Base			<u>(0.890)</u>
As Filed Grossed Up ROR			<u>11.43%</u>
Reduction in Return on Rate Base			<u>(0.102)</u>
Reduction in Revenue Requirement			<u>(0.516)</u>

EXHIBIT __ (LK-11)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Remove Estimated 69kV Surveying Project as a Regulatory Asset
(\$ Millions)

	<u>Total Company</u>	<u>South Dakota Retail %</u>	<u>South Dakota Retail</u>
Source: Schedule H-20			
Total Estimated BHP Portion of Costs	0.685		
Company's Proposed Amortization Period in Years	<u>5</u>		
Company's Proposed Annual Amortization Expense	<u>0.137</u>	94.855%	<u>0.130</u>
		Acct 593	
Company's Proposed Unamortized Regulatory Asset	<u>0.548</u>	91.67%	<u>0.502</u>
		SALWAG	
Remove Annual Amortization Expense for Estimated 69 kV Surveying Costs	<u>(0.137)</u>	94.855%	<u>(0.130)</u>
		Acct 593	
Remove Unamortized Regulatory Asset for Estimated 69 kV Surveying Costs	<u>(0.548)</u>	91.67%	<u>(0.502)</u>
		SALWAG	

Note: There was no ADIT included in the test year related to the Reg Asset to remove. Company confirmed in response to BHII-20.

EXHIBIT __ (LK-12)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 28, 2014
RESPONSE DATE : July 7, 2014
REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 20: Reference Schedule H-20. The following questions relate to the costs for the 69kV LIDAR Surveying Project.

- a. Please provide a schedule by month and by FERC account showing (1) the actual costs incurred for the surveying project through the most recent month for which actual information is available and (2) the projected costs thereafter.
- b. Please provide copies of all source documentation pertaining to the actual costs incurred referenced in response to subpart (a) of this question. Include all electronic work papers with formulas intact.
- c. Please provide the details of the plan to perform the surveying project, including the estimated timeframe that the project would start and conclude, the types of costs to be incurred, and the timing of such costs.
- d. Please provide a copy of all internal planning documents describing the surveying project.
- e. Please explain why there is no pro forma adjustment for the ADIT related to this deferred asset.
- f. Please indicate whether the Company has requested an order from the Commission to defer these costs as a regulatory asset. If so, please cite all authorities or references to such authorization included in the Company's filing in this proceeding. If there are none, please explain why.
- g. Reference the testimony of Mr. Fredrich at page 10, lines 15-17, pertaining to the 69kV LIDAR Surveying Project. Please describe "the past experience of BHC" and how the estimated cost of \$800,000 for the 69kV system was determined. Please provide all supporting assumptions, data, and computations, including electronic spreadsheets with formulas intact.

Response to BHII Request No. 20:

- a. Black Hills Power is still in the process of finalizing the scope of project to obtain final RFQ's from the vendors.
- b. As noted above, the LiDar patrol work has not yet begun for 2014, so there are no actual costs to report to date.

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 28, 2014
RESPONSE DATE : July 7, 2014
REQUESTING PARTY: Black Hills Industrial Intervenors

- c. Details of the plan: Black Hills Power is still in the process of developing the final plans and specifications for the work to be completed in 2014. Attachment 20B is the RFQ specifications that were associated with the 2013 survey work for Black Hills /Colorado Electric and Black Hills Power. It is anticipated that the 2014 survey work will be similar in nature to the type of work outlined in the attached specifications.

Estimated timeframe: Black Hills Power anticipates getting the RFQ out to the vendors by the end of July 2014.

Type of costs to be incurred:

- New Lidar, Ortho & Oblique Imagery, Ground Control Survey and Weather Data
- Processing and Mapping all topographical DTM files and Plan and Profile data maps along the route
- Conductor Operating Temperature Assessments and report
- Delivery in a PLS CADD.bak file

Timing of such costs: Timing of the costs will be dependent on the availability of the vendor to meet proposed schedule. Targeted timeline would be by the end of 3Q 2014.

- d. Please see Attachments 20A and 20B.
- e. A pro forma adjustment for the ADIT related to this deferred asset should have been reflected on Schedule M-1 and inadvertently it was not. Such an adjustment is determined to be \$191,688 ($\$547,680 * 35\%$).
- f. The Company has requested to defer these costs as a regulatory asset as part of this rate filing. If the Commission does not issue its decision in this filing by the end of 2014, the Company will make a separate request to the Commission to defer the LiDar costs as a regulatory asset.
- g. The \$800,000 estimate for 2014 was based on the completion of 532 miles of 69kV line to be surveyed at \$1,500/mile. See Attachment 20A.

Attachments:

20A - Lidar Workpaper
20B - BHCLidarSpec

EXHIBIT __ (LK-13)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Alternative Adjustment to Extend Amortization of 69kV Surveying Project Costs to 10 Years
And to Reduce Rate Base for Related ADIT
(\$ Millions)

	<u>Total Company</u>	<u>South Dakota Retail %</u>	<u>South Dakota Retail</u>
Source: Schedule H-20			
Total Estimated BHP Portion of Costs	0.685		
Company's Proposed Amortization Period in Years	<u>5</u>		
Company's Proposed Annual Amortization Expense	<u>0.137</u>	94.855%	<u>0.130</u>
		Acct 593	
Company's Proposed Unamortized Regulatory Asset	<u>0.548</u>	91.67%	<u>0.502</u>
		SALWAG	
Amortization Expense over 10 Years	<u>0.068</u>	94.855%	<u>0.065</u>
		Acct 593	
Reduction in Amortization Expense - 10 Years	<u>(0.068)</u>	94.855%	<u>(0.065)</u>
		Acct 593	
Increase in Rate Base By Amortizing over 10 Years	<u>0.068</u>	91.67%	<u>0.063</u>
		SALWAG	
ADIT on Remaining Regulatory Asset Balance			
Unamortized Regulatory Asset - 10 Years	0.616		
Federal Income Tax Rate	<u>35.0%</u>		
ADIT on Unamortized Regulatory Asset Balance	<u>(0.216)</u>	91.67%	<u>(0.198)</u>
		SALWAG	
Total Reduction to Rate Base			<u>(0.135)</u>
As Filed Grossed Up ROR			<u>11.43%</u>
Reduction in Return on Rate Base			<u>(0.015)</u>
Reduction in Revenue Requirement			<u>(0.080)</u>

EXHIBIT __ (LK-14)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 28, 2014
RESPONSE DATE : July 7, 2014
REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 18: Reference Schedule H-1, line 5, identified as “Employee Additions\Eliminations.”

- a. Please provide a detailed description of these costs. In the description, please detail the costs included for each open vacancy and additional employee.
- b. Please provide the calculation of this amount, including all assumptions, data, and electronic spreadsheets with formulas intact.
- c. Please explain how these additional costs differ from the requested FutureTrack Workforce costs.
- d. Please explain how these additional costs are incremental to the costs for those employees being transferred from the retired generating plants.

Response to BHII Request No. 18:

- a. See Attachment 18, “Positions by Dept” tab. The position descriptions and detail of the costs are shown in rows 30 through 54.
- b. See Attachment 18.
- c. The FutureTrack WorkForce Development Program is a recruitment and training program to address pending retirements. The additional costs on Schedule H-1 are for current open positions to be filled as soon as possible. They do not include any positions related to FutureTrack.
- d. The additional costs for Employee Additions are for current open positions. The only adjustment made for the employees being transferred from the retired generating plants is for labor costs associated with Neil Simpson I employees that will be charged to power plants not owned by Black Hills Power at the Neil Simpson Complex. These costs have been removed on line 3 of Schedule H-1.

Attachments: 18 – BHP SD Payroll Adjustment Workpaper

Position Summary by Dept

Department	Already filled before Jan 28th	Additions	Terminations	Transfers	Total	
5123			3			3 captured in GDPM adjustment
8600			1	-1	1	1 replacement/soon to retire
8606	0		3		-2	1
8610					3	3
8612			1			1
8616				-1		-1 retirement 2014
8617			1			1
8619			1			1
8621			1			1
8623			3			3
8626					-1	-1
8628			1			1
8638	1		2		2	5
8639			1			1
8640			2			2
8650	1				-1	0
8652			5	-6	-2	-3 Customer Service Remodel adjustment
		2	25	-8	0	19
less other adjustments			-6	6		
			19	-2	17	

Salaries for Additions by Dept				Salaries for Terminations by Dept			
	BHP portion	Fully Loaded (65%)		BHP portion	Fully Loaded (65%)		
8600	52,150	52,150	86,048	8600	32,635	32,635	53,848
8606	105,200	39,976	65,960	8616	70,762	70,762	116,757
	76,523	29,079	47,980				
	76,523	29,079	47,980				
8612	74,500	74,500	122,925	Total Terminations	103,397	103,397	170,605
8617	41,800	41,800	68,970				
8619	74,500	74,500	122,925				
8621	48,450	48,450	79,943				
8623	74,500	74,500	122,925				
	62,850	62,850	103,703				
	74,500	74,500	122,925				
8628	85,634	85,634	141,295				
8638	81,350	30,913	51,006				
	81,350	30,913	51,006				
8639	57,800	21,964	36,241				
8640	52,150	19,817	32,698				
	68,350	25,973	42,855				
8652	41,800	41,800	68,970				
	81,350	81,350	134,228				
Total Additions	1,311,280	939,747	1,550,583				
			Net Additions		1,379,978		
			2015 wage increase (union)		6,575		
			2015 wage increase (non-union)		23,987		
			Adjusted Total		1,410,540	BHP Fully Loaded	

Additions

8612 System Protection Engineer
8619 Reliability Engineer
8623 Energy Services Engineer
8623 Energy Services Rep
8638 Instrument Tech II
8638 Instrument Tech II
8639 Process Chemistry Tech
8600 Lead Customer Service Rep
8606 Generation Operations Trainer
8606 Plant Maintenance Operator
8606 Plant Maintenance Operator
8617 Mobile Communicatinos Tech
8621 Business Analyst
8623 Energy Services Key Acct Rep
8628 Lead Line Mechanic
8640 Drafting/Document Control Tech
8640 Electrical Control Engineer
8652 Admin Asst
8652 Construction Rep

Retirements pending

8600 Cashier/Switchboard Operator
8616 Electrician Thereafter

EXHIBIT __ (LK-15)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Extend Amortization Period for Remaining NBV on Retired Plants to 10 Years
And to Include ADIT in Rate Base
(\$ Millions)

	Total Company	South Dakota Retail %	South Dakota Retail
Source: Schedule J-2			
Amount of Remaining Plant Costs to be Amortized			
Ben French	(0.535)		
Osage Units 1-3	(0.688)		
Neil Simpson	4.833		
Total Remaining Plant Costs (NBV) to be Amortized	3.610		
Total Obsolete Inventory From All Above Units	2.867		
Total Costs Set Up as Regulatory Asset	6.477		
Company's Proposed Amortization Period in Years	5		
Company's Proposed Annual Amortization Expense	1.295		
Company's Proposed Unamortized Regulatory Asset	5.181		
Adjusted Amortization Period in Years	10		
Adjusted Annual Amortization	0.648		
Adjusted Unamortized Regulatory Asset	5.829		
Decrease in Annual Amortization Expense	(0.648)	89.83%	(0.582)
Increase in Unamortized Regulatory Asset	0.648	PRODPLT 89.83%	0.582
Increase in ADIT on Regulatory Asset Balance		PRODPLT	
Increase in Unamortized Regulatory Asset			0.582
Federal Income Tax Rate			35.0%
ADIT on Regulatory Asset Balance			(0.204)
Net Increase in Rate Base			0.378
As Filed Grossed Up ROR			11.43%
Increase in Return on Rate Base			0.043
Reduction in Revenue Requirement			(0.539)

EXHIBIT __ (LK-16)

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Reduce Depreciation Expense by Extending Service Life Span of CPGS
And to Include ADIT in Rate Base
(\$ Millions)

	<u>Total Company</u>	<u>South Dakota Retail %</u>	<u>South Dakota Retail</u>
Source: Statements E and J			
As Filed CPGS Plant in Service	92.251		
As Filed CPGS Average Depreciation Rate	<u>3.29%</u>	Based on 35 Year Life Span	
As Filed CPGS Depreciation Expense	<u>3.035</u>		
As Adjusted CPGS Average Depreciation Rate	2.88%	Based on 40 Year Life Span	
As Adjusted CPGS Depreciation Expense	<u>2.659</u>		
Reduce Depreciation Expense to Extend Life Span of CPGS	<u>(0.376)</u>	89.831% PRODPLT	<u>(0.338)</u>
Accumulated Depreciation One Half of Depreciation Expense Reduction (See Statement E Note 3)	(0.188)		
Decrease Accumulated Depreciation for Expense Reduction The Effect Increases Rate Base	<u>0.188</u>	89.831% PRODPLT	<u>0.169</u>
Accumulated Deferred Income Taxes (See Schedule M-2) Book Depreciation Expense Reduction	(0.376)	100% of Expense Reduction x Tax Rate	
Federal Income Tax Rate	<u>0.35</u>		
Increase ADIT for Expense Reduction The Effect Decreases Rate Base	<u>(0.132)</u>	89.831% PRODPLT	<u>(0.118)</u>

Docket No. EL14-026
Black Hills Power, Inc.
BHII Adjustment to Reduce Depreciation Expense by Extending Service Life Span of CPGS
And to Include ADIT in Rate Base
(\$ Millions)

Computation of Adjusted Depreciation Rate

See BHII 15 Attach b for Computed Rates

	Original Cost	Future Book Accruals	Rem Life at 35 Year Span	Rem Life at 40 Year Span	Annual Accrual	Rate
Acct 341	7,028,693	7,309,841	33.75	38.57	189,521	2.70%
Acct 342	10,543,040	10,964,761	31.5	36	304,577	2.89%
Acct 344	38,657,812	40,204,125	31.61	36.13	1,112,763	2.88%
Acct 345	10,543,040	10,964,761	31.78	36.32	301,893	2.86%
Acct 346	3,514,347	3,654,920	27.37	31.28	116,845	3.32%
	<u>70,286,931</u>				<u>2,025,600</u>	<u>2.88%</u>

EXHIBIT __ (LK-17)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 28, 2014
RESPONSE DATE : July 7, 2014
REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 11: If not previously provided in response to discovery, please provide a copy of all workpapers and source documents relied on by Mr. Spanos to perform the depreciation study for the depreciation rates proposed in this proceeding, including a copy of all notes, correspondence with the Company and/or its affiliates, and electronic spreadsheets with formulas intact.

Response to BHII Request No. 11:

Attachment 11 provides the workpapers and source documents relied on by Mr. Spanos to perform the depreciation study. These documents include notes and correspondence related to the depreciation study.

Attachments: 11 - Spanos Workpapers

Forecasted Plant Retirement Dates			
Coal Plants - BHP			
	ORIGINAL	REVISED	
Osage	2014		ok
Ben French	2014		ok
NSI	2014		ok
Wyodak	2030		want to sync with Pacificorp's depr study (John to look at)
NS2	2045		ok
Wygen III (52% ownership)	2060		ok
CT's - BHP			
Diesel Generators	2020		ok
Frame 5 Gas turbines	2030		ok
CT 1	2050		John, we want to see what the rates would look like using both a 40 year and 45 year life
Lange	2050		John, we want to see what the rates would look like using both a 40 year and 45 year life
CC Unit 1 @ CPGS	2054		ok, 40 years
Coal Plants - CLFP			
Wygen I (76.5% ownership)	2053	2048	we want to use a 45 year life to match what was approved in rate cases
Wygen II	2058	2053	we want to use a 45 year life to match what was approved in rate cases
CT's - CLFP			
CC Unit 1 @ CPGS	2054	2049	we are more comfortable with a 35 year life instead of 40
SC Unit 2 @ CPGS	2054		ok, 40 years

EXHIBIT __ (LK-18)

BLACK HILLS POWER
Rapid City, South Dakota

DEPRECIATION STUDY
CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2012

GANNETT FLEMING, INC. - VALUATION AND RATE DIVISION
Harrisburg, Pennsylvania

BLACK HILLS POWER

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2012

ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	ACCURUAL RATE	COMPOSITE REMAINING LIFE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
STEAM PRODUCTION PLANT								
BEN FRENCH STATION								
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5 *	2,251,067.03	2,470,217	411,149	225,045	10.00	1.8
312.01	BOILER PLANT EQUIPMENT	55-S0.5 *	6,842,535.53	6,971,855	1,786,590	985,304	14.40	1.8
314.00	TURBOGENERATOR UNITS	55-S0.5 *	3,956,115.75	3,267,891	1,795,937	987,811	24.97	1.8
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5 *	756,487.01	817,196	151,107	83,050	10.98	1.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0 *	461,437.84	529,424	61,216	33,837	7.33	1.8
TOTAL BEN FRENCH STATION			14,267,643.16	14,056,583	4,205,999	2,315,047	16.23	1.8
NEIL SIMPSON I								
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5 *	2,263,790.00	2,055,490	502,593	275,250	12.16	1.8
312.01	BOILER PLANT EQUIPMENT	55-S0.5 *	14,327,824.99	10,348,851	5,841,591	3,210,557	22.41	1.8
314.00	TURBOGENERATOR UNITS	55-S0.5 *	3,916,967.11	2,797,900	1,628,273	896,130	22.88	1.8
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5 *	1,334,432.06	622,246	885,662	484,612	36.32	1.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0 *	424,995.16	434,602	45,643	25,339	5.96	1.8
TOTAL NEIL SIMPSON I			22,268,009.32	16,259,089	8,903,762	4,891,888	21.97	1.8
NEIL SIMPSON II								
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5 *	15,863,029.45	5,523,394	12,560,460	412,027	2.60	30.5
312.01	BOILER PLANT EQUIPMENT	55-S0.5 *	76,897,107.11	26,330,450	61,332,252	2,211,622	2.88	27.7
314.00	TURBOGENERATOR UNITS	55-S0.5 *	41,534,097.95	11,029,471	36,319,401	1,278,221	3.08	28.4
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5 *	8,429,093.00	2,511,631	7,097,535	230,583	2.74	30.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0 *	875,989.44	165,386	833,242	31,072	3.55	26.8
TOTAL NEIL SIMPSON II			143,599,316.95	45,560,332	118,142,890	4,163,525	2.90	28.4
OSAGE PLANT								
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5 *	4,233,377.67	4,422,755	741,966	406,009	9.59	1.8
312.01	BOILER PLANT EQUIPMENT	55-S0.5 *	7,454,702.13	7,272,558	1,822,179	1,005,395	13.49	1.8
314.00	TURBOGENERATOR UNITS	55-S0.5 *	4,780,167.64	4,641,657	1,190,148	656,960	13.74	1.8
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5 *	1,054,887.74	1,198,790	88,173	48,528	4.60	1.8
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0 *	455,950.73	459,478	96,782	53,529	11.74	1.8
TOTAL OSAGE PLANT			17,979,085.91	17,995,238	3,939,248	2,170,421	12.07	1.8
WY GEN 3								
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5 *	6,799,493.56	417,254	7,266,174	166,503	2.45	43.6
312.01	BOILER PLANT EQUIPMENT	55-S0.5 *	57,567,754.14	4,343,796	60,707,766	1,517,622	2.64	40.0
314.00	TURBOGENERATOR UNITS	55-S0.5 *	58,398,596.28	3,202,879	62,787,535	1,569,482	2.69	40.0
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5 *	6,737,220.28	377,879	7,235,180	163,953	2.43	44.1
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0 *	709,079.57	28,882	772,378	21,429	3.02	36.0
TOTAL WY GEN 3			130,212,143.83	8,370,690	138,769,033	3,438,989	2.64	40.4

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BLACK HILLS POWER

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES AS OF DECEMBER 31, 2012

ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
WYODAK PLANT								
311.00	STRUCTURES AND IMPROVEMENTS	80-R1.5 *	9,164,989.89	7,214,391	3,142,048	125,770	1.37	25.0
312.01	BOILER PLANT EQUIPMENT	55-S0.5 *	76,887,888.24	29,347,729	57,535,585	2,378,850	3.09	24.2
313.00	ENGINES AND GENERATORS	50-S1.5 *	341,748.14	216,828	169,347	6,793	1.99	24.9
314.00	TURBOGENERATOR UNITS	55-S0.5 *	15,192,790.87	5,557,047	11,610,807	482,632	3.18	24.1
315.00	ACCESSORY ELECTRIC EQUIPMENT	65-R2.5 *	8,616,782.96	5,008,048	2,468,917	99,004	1.50	24.9
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	45-S0 *	1,007,314.51	427,522	710,743	31,411	3.12	22.6
TOTAL WYODAK PLANT			109,211,514.61	47,771,565	75,637,447	3,124,460	2.86	24.2
TOTAL STEAM PRODUCTION PLANT			437,537,713.78	150,013,497	349,598,379	20,104,330	4.59	17.4
OTHER PRODUCTION PLANT								
BEN FRENCH CT								
341.00	STRUCTURES AND IMPROVEMENTS	55-R3 *	22,448.14	18,574	6,792	437	1.95	15.5
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5 *	1,375,821.53	903,454	651,224	40,929	2.97	15.9
344.10	GENERATORS	45-R2 *	16,549,367.07	12,793,447	5,907,338	415,401	2.51	14.2
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	672,968.54	427,262	333,192	29,853	4.44	11.2
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	30-S1.5 *	14,717.62	12,177	4,454	569	3.87	7.8
TOTAL BEN FRENCH CT			18,635,322.90	14,154,914	6,903,000	487,189	2.61	14.2
BEN FRENCH DIESEL								
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5 *	51,864.25	47,265	16,009	2,215	4.27	7.2
344.10	GENERATORS	45-R2 *	828,868.97	774,635	236,585	36,709	4.43	6.4
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	110,823.34	60,434	74,770	11,226	10.13	6.7
TOTAL BEN FRENCH DIESEL			991,556.56	882,334	327,364	50,150	5.06	6.5
LANGE CT								
341.00	STRUCTURES AND IMPROVEMENTS	55-R3 *	324,886.40	102,053	239,078	7,174	2.21	33.3
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5 *	1,722,516.16	526,052	1,282,590	43,258	2.51	29.6
344.10	GENERATORS	45-R2 *	26,182,995.19	9,824,794	17,667,351	593,903	2.27	29.7
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	2,095,868.47	792,608	1,408,054	50,943	2.43	27.6
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	30-S1.5 *	16,611.59	6,306	11,136	527	3.17	21.1
TOTAL LANGE CT			30,342,877.81	11,251,813	20,608,209	695,805	2.29	29.6
NEIL SIMPSON CT								
341.00	STRUCTURES AND IMPROVEMENTS	55-R3 *	176,358.69	78,850	106,327	3,405	1.93	31.2
342.00	FUEL HOLDERS AND ACCESSORIES	50-S0.5 *	2,116,073.40	616,956	1,604,921	56,038	2.65	28.6
344.10	GENERATORS	45-R2 *	25,644,954.15	8,133,641	18,793,561	660,704	2.58	28.4
345.00	ACCESSORY ELECTRIC EQUIPMENT	40-S2 *	1,987,599.72	927,847	1,159,133	45,006	2.26	25.8
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	30-S1.5 *	51,538.76	24,278	29,838	1,316	2.55	22.7
TOTAL NEIL SIMPSON CT			29,976,524.72	9,781,572	21,693,780	766,469	2.56	28.3
TOTAL OTHER PRODUCTION PLANT			79,946,281.99	36,070,633	49,532,353	1,999,613	2.50	24.8

III-5

EXHIBIT __ (LK-19)

BUILDING A WORLD OF DIFFERENCE®



BLACK HILLS POWER, INC.

**Report on
Depreciation Accrual Rates**

**Electric Utility Property
Through December 31, 2008**

September 18, 2009



Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1953
 Retirement Date 2013
 Service Life, Yrs 60

2008

Historical and Forecast Plant Additions & Balances

Account: 311 Structures & Improvements Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year		Vintage Year Retirements	Year		Retirements			Adjustments	Per Books	Simulated
			Beg Balance	Additions		Additions	Retirements						
1	1953	60				2,046,367		2,046,367		2,046,367		2,046,367	
2	1954	59			107,853	26,060	6,246	26,060	6,246	2,066,181		2,066,181	
3	1955	58				26,313	6,307	26,313	6,307	2,086,187		2,086,187	
4	1956	57				26,568	6,368	26,568	6,368	2,106,387		2,106,387	
5	1957	56				26,825	6,429	26,825	6,429	2,126,783		2,126,783	
6	1958	55			1,823	27,085	6,492	27,085	6,492	2,147,375		2,147,375	
7	1959	54				27,347	6,555	27,347	6,555	2,168,168		2,168,168	
8	1960	53				27,612	6,618	27,612	6,618	2,189,161		2,189,161	
9	1961	52				27,879	6,682	27,879	6,682	2,210,358		2,210,358	
10	1962	51			432	28,149	6,747	28,149	6,747	2,231,760		2,231,760	
11	1963	50				28,421	6,812	28,421	6,812	2,253,369		2,253,369	
12	1964	49				28,697	6,878	28,697	6,878	2,275,188		2,275,188	
13	1965	48				28,974	6,945	28,974	6,945	2,297,217		2,297,217	
14	1966	47			1,657	29,255	7,012	29,255	7,012	2,319,461		2,319,461	
15	1967	46				29,538	7,080	29,538	7,080	2,341,919		2,341,919	
16	1968	45				29,824	7,148	29,824	7,148	2,364,595		2,364,595	
17	1969	44				30,113	7,218	30,113	7,218	2,387,490		2,387,490	
18	1970	43			2,521	30,405	7,287	30,405	7,287	2,410,608		2,410,608	
19	1971	42				30,699	7,358	30,699	7,358	2,433,948		2,433,948	
20	1972	41			5,973	30,996	7,429	30,996	7,429	2,457,515		2,457,515	
21	1973	40				31,296	7,501	31,296	7,501	2,481,311		2,481,311	
22	1974	39				31,599	7,574	31,599	7,574	2,505,336		2,505,336	
23	1975	38				31,905	7,647	31,905	7,647	2,529,594		2,529,594	
24	1976	37				32,214	7,721	32,214	7,721	2,554,088		2,554,088	
25	1977	36				32,526	7,796	32,526	7,796	2,578,818		2,578,818	
26	1978	35			1,313	32,841	7,871	32,841	7,871	2,603,787		2,603,787	
27	1979	34				33,159	7,948	33,159	7,948	2,628,999		2,628,999	
28	1980	33			459,599	33,480	8,025	33,480	8,025	2,654,455		2,654,455	
29	1981	32				33,804	8,102	33,804	8,102	2,680,157		2,680,157	
30	1982	31				34,132	8,181	34,132	8,181	2,706,107		2,706,107	
31	1983	30			6,667	34,462	8,260	34,462	8,260	2,732,310		2,732,310	
32	1984	29				34,796	8,340	34,796	8,340	2,758,766		2,758,766	
33	1985	28			79,664	35,133	8,421	35,133	8,421	2,785,478		2,785,478	
34	1986	27				35,473	8,502	35,473	8,502	2,812,448		2,812,448	
35	1987	26				35,816	8,585	35,816	8,585	2,839,680		2,839,680	
36	1988	25			87,422	36,163	8,668	36,163	8,668	2,867,176		2,867,176	
37	1989	24	2,867,176	46,652							2,913,828	2,913,828	
38	1990	23		103,313	2,194				(33,244)		2,981,703	2,981,703	
39	1991	22		37,851	12,666	18,717					3,006,888	3,006,888	
40	1992	21		147,740	39,067						3,115,561	3,115,561	
41	1993	20		501,546	22,370			501,546	22,370		3,594,737	3,594,737	
42	1994	19		1,337,983	29,747			1,337,983	29,747		4,902,973	4,902,973	
43	1995	18		73,372				73,372			4,976,345	4,976,345	
44	1996	17		7,898	9,057			7,898	9,057		4,975,185	4,975,185	
45	1997	16			521,670				521,670		4,453,515	4,453,515	
46	1998	15		4,369	136,832			4,369	136,832		4,321,052	4,321,052	
47	1999	14									4,321,052	4,321,052	
48	2000	13									4,321,052	4,321,052	
49	2001	12									4,321,052	4,321,052	
50	2002	11									4,321,052	4,321,052	
51	2003	10									4,321,052	4,321,052	
52	2004	9									4,321,052	4,321,052	
53	2005	8									4,321,052	4,321,052	
54	2006	7								(57,372)	4,263,680	4,263,680	
55	2007	6		128,368				128,368		104	4,392,152	4,392,152	
56	2008	5									4,392,152	4,392,152	
57	Total		\$ 2,867,176	\$ 2,389,091	\$ 773,603	\$ 773,642	\$ 5,125,928	\$ 258,753	\$ 5,179,464	\$ 978,429	\$ (90,512)	\$ 87,638,547	\$ 82,537,134

Major Additions/Retirements

1997		\$ 521,670
1994	\$ 1,337,983	
Routine Activity	\$ 1,051,108	\$ 251,933
Historical Interim Activity	1.27%	0.31%
Forecast Interim Activity	0.50%	0.31%

60	2009	4			21,961	13,406						4,400,706	
61	2010	3			22,004	13,433						4,409,277	
62	2011	2			22,046	13,459						4,417,865	
63	2012	1			22,089	13,485						4,426,469	
64	2013	0								(4,426,469)			
											\$ 5,267,564	\$ 1,032,211	\$ 187,829,999

Whole Life Depreciation Rate Calculation

Historical Additions	5,179,464
Forecast Additions	88,100
Total Additions	5,267,564
Gross Salvage Value	221,323
Less Cost of Removal	442,647
Net Salvage Value	(221,323)
Total to be Recovered	5,488,888
Forecast Plant Balances	187,829,999
Whole Life Accrual Rate	2.92%
Cost of Removal Accrual Rate	0.24%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.16%
Depreciable Service Life, years	34.2

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	4,392,152
Forecast Additions	88,100
Gross Salvage Value	221,323
Less Cost of Removal	442,647
Net Salvage Value	(221,323)
Forecast Plant Balances	17,654,318

Black Hills Power
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Osage Plant
 Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1953
 Retirement Date 2013
 Service Life, Yrs 60
 2008

Historical and Forecast Plant Additions & Balances
 Account: 314 Turbogenerator Equipment Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance			
			Transaction Year			Year		Year			Adjustments	Per Books	Simulated	
			Begin Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions					Retirements
1	1953	60						2,661,025	-		2,661,025	2,661,025		
2	1954	59				66,690	18,400	4,552	18,400	4,552	2,674,872	2,674,872		
3	1955	58					18,495	4,576	18,495	4,576	2,688,791	2,688,791		
4	1956	57					18,592	4,600	18,592	4,600	2,702,783	2,702,783		
5	1957	56					18,688	4,624	18,688	4,624	2,716,848	2,716,848		
6	1958	55					18,786	4,648	18,786	4,648	2,730,985	2,730,985		
7	1959	54					18,883	4,672	18,883	4,672	2,745,197	2,745,197		
8	1960	53					18,982	4,696	18,982	4,696	2,759,482	2,759,482		
9	1961	52					19,080	4,721	19,080	4,721	2,773,841	2,773,841		
10	1962	51					19,180	4,745	19,180	4,745	2,788,276	2,788,276		
11	1963	50					19,280	4,770	19,280	4,770	2,802,785	2,802,785		
12	1964	49					19,380	4,795	19,380	4,795	2,817,370	2,817,370		
13	1965	48					19,481	4,820	19,481	4,820	2,832,031	2,832,031		
14	1966	47					19,582	4,845	19,582	4,845	2,846,768	2,846,768		
15	1967	46					19,684	4,870	19,684	4,870	2,861,582	2,861,582		
16	1968	45					19,786	4,896	19,786	4,896	2,876,473	2,876,473		
17	1969	44					19,889	4,921	19,889	4,921	2,891,441	2,891,441		
18	1970	43					19,993	4,947	19,993	4,947	2,906,487	2,906,487		
19	1971	42					20,097	4,972	20,097	4,972	2,921,612	2,921,612		
20	1972	41					20,202	4,998	20,202	4,998	2,936,815	2,936,815		
21	1973	40					20,307	5,024	20,307	5,024	2,952,098	2,952,098		
22	1974	39					20,412	5,050	20,412	5,050	2,967,460	2,967,460		
23	1975	38					20,519	5,077	20,519	5,077	2,982,901	2,982,901		
24	1976	37					20,625	5,103	20,625	5,103	2,998,424	2,998,424		
25	1977	36					20,733	5,130	20,733	5,130	3,014,027	3,014,027		
26	1978	35					20,841	5,156	20,841	5,156	3,029,711	3,029,711		
27	1979	34				43,235	20,949	5,183	20,949	5,183	3,045,477	3,045,477		
28	1980	33					21,058	5,210	21,058	5,210	3,061,324	3,061,324		
29	1981	32					21,168	5,237	21,168	5,237	3,077,255	3,077,255		
30	1982	31					21,278	5,265	21,278	5,265	3,093,268	3,093,268		
31	1983	30					21,388	5,292	21,388	5,292	3,109,364	3,109,364		
32	1984	29				3,758	21,500	5,319	21,500	5,319	3,125,545	3,125,545		
33	1985	28				4,843	21,612	5,347	21,612	5,347	3,141,809	3,141,809		
34	1986	27				707	21,724	5,375	21,724	5,375	3,158,158	3,158,158		
35	1987	26					21,837	5,403	21,837	5,403	3,174,593	3,174,593		
36	1988	25					21,951	5,431	21,951	5,431	3,191,112	3,191,112		
37	1989	24	3,191,112	112,899	21,617	500					33,244	3,282,394	3,282,394	
38	1990	23		211,355	21,617							3,505,375	3,505,375	
39	1991	22			26,799							3,478,576	3,478,576	
40	1992	21		195,001	45,891	5,500						3,627,686	3,627,686	
41	1993	20		747,773		1,701		747,773	-			4,375,458	4,375,458	
42	1994	19						-	-			4,375,458	4,375,458	
43	1995	18						-	-			4,375,458	4,375,458	
44	1996	17						-	-			4,375,458	4,375,458	
45	1997	16		32,618	7,929	17,285		32,618	7,929			4,400,147	4,400,147	
46	1998	15						-	-			4,400,147	4,400,147	
47	1999	14						-	-			4,400,147	4,400,147	
48	2000	13						-	-			4,400,147	4,400,147	
49	2001	12		11,637				11,637	-			4,411,785	4,411,785	
50	2002	11						-	-			4,411,785	4,411,785	
51	2003	10						-	-			4,411,785	4,411,785	
52	2004	9						-	-			4,411,785	4,411,785	
53	2005	8		8,524	3,081			8,524	3,081			4,417,227	4,417,227	
54	2006	7		10,627				10,627	-	(107,873)		4,319,981	4,319,981	
55	2007	6		237	17,285			237	17,285	20		4,302,953	4,302,953	
56	2008	5		313,906				313,906	-			4,616,858	4,616,858	
57	Total		\$ 3,191,112	\$ 1,644,575	\$ 144,220	\$ 144,219	\$ 3,365,384	\$ 174,272	\$ 4,490,705	\$ 202,567	\$ (74,610)	\$ 105,057,990	\$ 84,300,612	\$ 189,358,601

Major Additions/Retirements

1993	\$ 747,773	
2008	\$ 313,906	
Routine Activity	\$ 582,897	\$ 144,220
Historical Interim Activity	0.69%	0.17%
Forecast Interim Activity	0.69%	0.17%

60	2009	4						31,923	7,898					4,640,883
61	2010	3						32,089	7,940					4,665,033
62	2011	2						32,256	7,981					4,689,309
63	2012	1						32,424	8,022					4,713,711
64	2013	0									(4,713,711)			-
											\$ 4,619,398	\$ 234,408	\$ 208,067,537	

Whole Life Depreciation Rate Calculation

Historical Additions	4,490,705
Forecast Additions	128,693
Total Additions	4,619,398
Gross Salvage Value	235,686
Less Cost of Removal	471,371
Net Salvage Value	(235,686)
Total to be Recovered	4,855,084
Forecast Plant Balances	208,067,537
Whole Life Accrual Rate	2.33%
Cost of Removal Accrual Rate	0.23%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.56%
Depreciable Service Life, years	42.9

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	4,616,858
Forecast Additions	128,693
Gross Salvage Value	235,686
Less Cost of Removal	471,371
Net Salvage Value	(235,686)
Forecast Plant Balances	18,708,936

Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Unit Property Depreciation Rate Analysis
 Net Salvage -5%
 Install Date 1953
 Retirement Date 2013
 Service Life, Yrs 60

2008

Historical and Forecast Plant Additions & Balances
 Account: 315 Accessory Electric Equipment

Initial Plant Balance 0

Line	[A] Vintage Year	[B] Vintage Age	[C] Reported Per Books			[F] Vintage Year	[G] Adjustments to Transaction		[H] Adjusted Transaction Year		[K] Transfers and Adjustments	[L] EOY Plant Balance		
			[D] Transaction Year				[E] Year		[I] Retirements			[J] Adjustments	[M] Per Books	[N] Simulated
			Boq Balance	Additions	Retirements		Additions	Retirements	Additions	Retirements				
1	1953	60						348,629				348,629		348,629
2	1954	59				1,215	453	1,215	453			349,391		349,391
3	1955	58				1,218	454	1,218	454			350,155		350,155
4	1956	57				1,221	455	1,221	455			350,920		350,920
5	1957	56				1,223	456	1,223	456			351,687		351,687
6	1958	55				1,226	457	1,226	457			352,456		352,456
7	1959	54				1,229	458	1,229	458			353,226		353,226
8	1960	53				1,232	459	1,232	459			353,998		353,998
9	1961	52				1,234	460	1,234	460			354,772		354,772
10	1962	51				1,237	461	1,237	461			355,548		355,548
11	1963	50				1,240	462	1,240	462			356,325		356,325
12	1964	49				1,242	463	1,242	463			357,104		357,104
13	1965	48				1,245	464	1,245	464			357,884		357,884
14	1966	47				1,248	465	1,248	465			358,667		358,667
15	1967	46				1,250	466	1,250	466			359,450		359,450
16	1968	45				1,253	468	1,253	468			360,236		360,236
17	1969	44				1,256	469	1,256	469			361,024		361,024
18	1970	43				1,259	470	1,259	470			361,813		361,813
19	1971	42				1,261	471	1,261	471			362,604		362,604
20	1972	41				1,264	472	1,264	472			363,396		363,396
21	1973	40				1,267	473	1,267	473			364,191		364,191
22	1974	39				1,270	474	1,270	474			364,987		364,987
23	1975	38				1,273	475	1,273	475			365,784		365,784
24	1976	37				1,275	476	1,275	476			366,584		366,584
25	1977	36				1,278	477	1,278	477			367,385		367,385
26	1978	35				1,281	478	1,281	478			368,188		368,188
27	1979	34				1,284	479	1,284	479			368,993		368,993
28	1980	33				1,286	480	1,286	480			369,800		369,800
29	1981	32				1,289	481	1,289	481			370,608		370,608
30	1982	31				1,292	482	1,292	482			371,418		371,418
31	1983	30				1,295	483	1,295	483			372,230		372,230
32	1984	29				1,298	484	1,298	484			373,044		373,044
33	1985	28				1,301	485	1,301	485			373,859		373,859
34	1986	27				1,303	486	1,303	486			374,676		374,676
35	1987	26				1,306	487	1,306	487			375,495		375,495
36	1988	25				1,309	488	1,309	488			376,316		376,316
37	1989	24	376,316										376,316	376,316
38	1990	23											376,316	376,316
39	1991	22											376,316	376,316
40	1992	21		5,676				5,676					381,992	381,992
41	1993	20		108,772				108,772					490,763	490,763
42	1994	19											490,763	490,763
43	1995	18											490,763	490,763
44	1996	17		10,760				10,760					501,524	501,524
45	1997	16											501,524	501,524
46	1998	15		20,127	19,982			20,127		359,680		881,330	881,330	
47	1999	14								162,486		1,043,817	1,043,817	
48	2000	13										1,043,817	1,043,817	
49	2001	12										1,043,817	1,043,817	
50	2002	11		6,817				6,817		1,649		1,052,282	1,052,282	
51	2003	10										1,052,282	1,052,282	
52	2004	9										1,052,282	1,052,282	
53	2005	8		10,184	19,982			10,184	19,982	167		1,054,450	1,054,450	
54	2006	7										1,054,450	1,054,450	
55	2007	6								12,236		1,054,888	1,054,888	
56	2008	5										1,054,888	1,054,888	
57	Total		\$ 376,316	\$ 162,336	\$ 19,982	\$ 19,982	\$ 392,790	\$ 16,474	\$ 555,126	\$ 36,456	\$ 536,218	\$ 13,042,842	\$ 15,363,388	\$ 28,406,230
Major Additions/Retirements 1993				\$ 108,772										
Routine Activity				\$ 53,564	\$ 19,982									
58	Historical Interim Activity			0.35%	0.13%									
59	Forecast Interim Activity			0.35%	0.13%									
60	2009	4						3,678	1,372				1,057,194	1,057,194
61	2010	3						3,686	1,375				1,059,504	1,059,504
62	2011	2						3,694	1,378				1,061,820	1,061,820
63	2012	1						3,702	1,381				1,064,141	1,064,141
64	2013	0								(1,064,141)				
								\$ 569,886	\$ 41,962					\$ 32,648,890

Whole Life Depreciation Rate Calculation

Historical Additions	555,126
Forecast Additions	14,760
Total Additions	569,886
Gross Salvage Value	53,207
Less Cost of Removal	106,414
Net Salvage Value	(53,207)
Total to be Recovered	623,093
Forecast Plant Balances	32,648,890
Whole Life Accrual Rate	1.91%
Cost of Removal Accrual Rate	0.33%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.23%
Depreciable Service Life, years	52.4

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	1,054,888
Forecast Additions	14,760
Gross Salvage Value	53,207
Less Cost of Removal	106,414
Net Salvage Value	(53,207)
Forecast Plant Balances	4,242,660

Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1953
 Retirement Date 2013
 Service Life, Yrs 60

2008

Historical and Forecast Plant Additions & Balances
 Account: 316 Miscellaneous Power Equipment

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books				Adjustments to Transaction				Transfers and Adjustments	EOY Plant Balance			
			Transaction Year		Vintage Year Retirements	Year		Adjusted Transaction Year		Adjustments		Per Books	Simulated		
			Beg Balance	Additions		Retirements	Additions	Retirements	Additions					Retirements	
1	1953	60										132,992	-	132,992	132,992
2	1954	59			39,210	2,462	308	2,462	308		135,146			135,146	135,146
3	1955	58				2,502	313	2,502	313		137,335			137,335	137,335
4	1956	57				2,542	318	2,542	318		139,559			139,559	139,559
5	1957	56				2,583	323	2,583	323		141,819			141,819	141,819
6	1958	55				2,625	328	2,625	328		144,116			144,116	144,116
7	1959	54				2,668	334	2,668	334		146,449			146,449	146,449
8	1960	53				2,711	339	2,711	339		148,821			148,821	148,821
9	1961	52				2,755	345	2,755	345		151,231			151,231	151,231
10	1962	51				2,799	350	2,799	350		153,680			153,680	153,680
11	1963	50				2,845	356	2,845	356		156,169			156,169	156,169
12	1964	49				2,891	362	2,891	362		158,698			158,698	158,698
13	1965	48				2,937	367	2,937	367		161,268			161,268	161,268
14	1966	47				2,985	373	2,985	373		163,880			163,880	163,880
15	1967	46				3,033	379	3,033	379		166,534			166,534	166,534
16	1968	45				3,083	386	3,083	386		169,231			169,231	169,231
17	1969	44				3,132	392	3,132	392		171,972			171,972	171,972
18	1970	43				3,183	398	3,183	398		174,757			174,757	174,757
19	1971	42			438	3,235	405	3,235	405		177,587			177,587	177,587
20	1972	41				3,287	411	3,287	411		180,463			180,463	180,463
21	1973	40			300	3,340	418	3,340	418		183,385			183,385	183,385
22	1974	39				3,394	425	3,394	425		186,355			186,355	186,355
23	1975	38				3,449	431	3,449	431		189,373			189,373	189,373
24	1976	37				3,505	438	3,505	438		192,440			192,440	192,440
25	1977	36			133	3,562	446	3,562	446		195,556			195,556	195,556
26	1978	35			950	3,620	453	3,620	453		198,723			198,723	198,723
27	1979	34			1,850	3,678	460	3,678	460		201,942			201,942	201,942
28	1980	33			3,043	3,738	468	3,738	468		205,212			205,212	205,212
29	1981	32				3,798	475	3,798	475		208,535			208,535	208,535
30	1982	31				3,860	483	3,860	483		211,912			211,912	211,912
31	1983	30				3,922	491	3,922	491		215,344			215,344	215,344
32	1984	29				3,986	499	3,986	499		218,832			218,832	218,832
33	1985	28			511	4,051	507	4,051	507		222,376			222,376	222,376
34	1986	27				4,116	515	4,116	515		225,977			225,977	225,977
35	1987	26				4,183	523	4,183	523		229,637			229,637	229,637
36	1988	25			6,495	4,251	532	4,251	532		233,355			233,355	233,355
37	1989	24	233,355	16,456										249,811	249,811
38	1990	23		22,924	36,023									236,712	236,712
39	1991	22		10,097	3,058					96,488				340,239	340,239
40	1992	21		12,911										353,150	353,150
41	1993	20		14,373						14,373				367,523	367,523
42	1994	19		5,898										373,421	373,421
43	1995	18		4,964										378,386	378,386
44	1996	17												479,777	479,777
45	1997	16			7,352					7,352				472,425	472,425
46	1998	15		7,941		3,033								480,366	480,366
47	1999	14		947										481,313	481,313
48	2000	13		1,825										488,868	488,868
49	2001	12		3,738										492,605	492,605
50	2002	11		22,539										515,144	515,144
51	2003	10												515,144	515,144
52	2004	9		6,297	6,495					6,297	6,495			514,946	514,946
53	2005	8		2,502										517,449	517,449
54	2006	7		21,870						21,870				450,927	450,927
55	2007	6		4,128	3,033					4,128	3,033			452,022	452,022
56	2008	5												452,022	452,022
57	Total		\$ 233,355	\$ 159,411	\$ 55,961	\$ 55,961	\$ 247,703	\$ 14,347	\$ 344,726	\$ 31,227	\$ 115,217	\$ 6,430,662	\$ 8,612,253	\$ 15,042,915	

Major Additions/Retirements 1990

\$ 36,023

Routine Activity

\$ 159,411 \$ 19,938

Historical Interim Activity

1.85% 0.23%

Forecast Interim Activity

1.00% 0.23%

60	2009	4								4,520	1,046			455,496	455,496
61	2010	3								4,555	1,055			458,996	458,996
62	2011	2								4,590	1,063			462,524	462,524
63	2012	1								4,625	1,071			466,078	466,078
64	2013	0										(466,078)		-	-
										\$ 363,016	\$ 35,462			\$ 16,886,009	

Whole Life Depreciation Rate Calculation

Historical Additions	344,726
Forecast Additions	18,290
Total Additions	363,016
Gross Salvage Value	23,304
Less Cost of Removal	46,608
Net Salvage Value	(23,304)
Total to be Recovered	386,320
Forecast Plant Balances	16,886,009

Whole Life Accrual Rate 2.29%
 Cost of Removal Accrual Rate 0.28%

Whole Life Accrual Rate (Excluding Cost of Removal) 2.56%

Depreciable Service Life, years 43.7

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	452,022
Forecast Additions	18,290
Gross Salvage Value	23,304
Less Cost of Removal	46,608
Net Salvage Value	(23,304)
Forecast Plant Balances	1,843,094

Summary by Plant
 Black Hills Power
 Ben French Facility

Account	Description	Direct Investment 2008\$	Depreciation Rate
310	Land		
311	Structure & Improvements	2,119,670	2.68%
312	Boiler Plant Equipment	6,403,948	3.90%
313	Engines & Engine Driven Generators	0	0.00%
314	Turbo Generator Equipment	3,105,937	3.46%
315	Accessory Electric Equipment	747,759	2.24%
316	Misc Power Equipment	459,835	3.78%
Total		12,837,149	3.49% whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	13,360,210
Forecast Interim Additions	7,221,185
Forecast Gross Salvage Value	966,460
Forecast Less Cost of Removal	1,932,919
Forecast Net Salvage Value	(966,460)
Forecast Total to be Recovered with COR	21,547,854
Forecast Total to be Recovered w/o COR	19,614,935
Accumulated Depreciation (2008 EOY)	(13,050,958)
Forecast Remaining Life Balance with COR	8,496,897
Forecast Remaining Life Balance w/o COR	6,563,977
Forecast Plant Balances	234,568,689
Remaining Life Rate with COR	3.62%
Remaining Life Rate w/o COR	2.80%

Black Hills Power
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Ben French Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1960
 Retirement Date 2023
 Service Life, Yrs 63

Historical and Forecast Plant Additions & Balances
 Account: 311 Structures & Improvements

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction				Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year			Year		Year		Adjustments	Per Books		Simulated		
			Beq. Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions					Retirements	
1	1960	63								1,645,152	-		1,645,152	1,645,152	
2	1961	62								18,125	7,282		1,655,995	1,655,995	
3	1962	61				110,466				18,245	7,330		1,666,911	1,666,911	
4	1963	60								18,365	7,378		1,677,898	1,677,898	
5	1964	59								18,486	7,426		1,688,957	1,688,957	
6	1965	58								18,608	7,475		1,700,090	1,700,090	
7	1966	57								18,731	7,525		1,711,296	1,711,296	
8	1967	56								18,854	7,574		1,722,576	1,722,576	
9	1968	55								18,978	7,624		1,733,930	1,733,930	
10	1969	54								19,103	7,674		1,745,359	1,745,359	
11	1970	53								19,229	7,725		1,756,863	1,756,863	
12	1971	52				567				19,356	7,776		1,768,443	1,768,443	
13	1972	51								19,484	7,827		1,780,099	1,780,099	
14	1973	50								19,612	7,879		1,791,832	1,791,832	
15	1974	49								19,741	7,931		1,803,643	1,803,643	
16	1975	48								19,871	7,983		1,815,531	1,815,531	
17	1976	47								20,002	8,036		1,827,498	1,827,498	
18	1977	46								20,134	8,089		1,839,544	1,839,544	
19	1978	45								20,267	8,142		1,851,669	1,851,669	
20	1979	44								20,401	8,196		1,863,874	1,863,874	
21	1980	43				16,059				20,535	8,250		1,876,159	1,876,159	
22	1981	42				7,135				20,670	8,304		1,888,526	1,888,526	
23	1982	41				3,853				20,807	8,359		1,900,974	1,900,974	
24	1983	40								20,944	8,414		1,913,504	1,913,504	
25	1984	39								21,082	8,469		1,926,116	1,926,116	
26	1985	38								21,221	8,525		1,938,812	1,938,812	
27	1986	37							3,566	21,361	8,581		1,951,591	1,951,591	
28	1987	36								21,501	8,638		1,964,455	1,964,455	
29	1988	35							39,280	21,643	8,695		1,977,403	1,977,403	
30	1989	34	1,977,403	9,156	567					9,156	567		1,985,992	1,985,992	
31	1990	33		3,453	34,000					3,453	34,000		1,955,445	1,955,445	
32	1991	32		57,884	18,022					57,884	18,022		1,995,307	1,995,307	
33	1992	31		32,045	3,018					32,045	3,018		2,024,334	2,024,334	
34	1993	30		42,529	64,172					42,529	64,172		2,002,691	2,002,691	
35	1994	29		60,359	-					60,359	-		2,063,050	2,063,050	
36	1995	28		4,810	-					4,810	-		2,067,860	2,067,860	
37	1996	27		78,597	1,265					78,597	1,265		2,145,193	2,145,193	
38	1997	26		-	-					-	-	(135,790)	2,009,403	2,009,403	
39	1998	25		-	-					-	-	-	2,009,403	2,009,403	
40	1999	24		-	-					-	-	-	2,009,403	2,009,403	
41	2000	23		-	-					-	-	-	2,009,403	2,009,403	
42	2001	22		-	-					-	-	-	2,009,403	2,009,403	
43	2002	21		25,330	16,750					25,330	16,750		2,017,982	2,017,982	
44	2003	20		12,030	-					12,030	-		2,030,013	2,030,013	
45	2004	19		100,652	43,133					100,652	43,133		2,087,532	2,087,532	
46	2005	18		8,946	-					8,946	-		2,096,478	2,096,478	
47	2006	17		14,576	-					14,576	-	8,617	2,119,670	2,119,670	
48	2007	16		-	-					-	-	-	2,119,670	2,119,670	
49	2008	15		-	-					-	-	-	2,119,670	2,119,670	
50	Total		\$ 1,977,403	\$ 450,368	\$ 180,927	\$ 180,926	\$ 2,200,508	\$ 223,105	\$ 2,650,876	\$ 404,032	\$ (127,173)	\$ 52,384,699	\$ 40,877,900	\$ 93,262,599	

Major Additions/Retirements

Routine Activity \$ 450,368
 Historical Interim Activity 1.10% 0.44%
 Forecast Interim Activity 1.10% 0.44%

53	2009	14								23,353	9,382			2,133,642
54	2010	13								23,507	9,444			2,147,705
55	2011	12								23,662	9,506			2,161,862
56	2012	11								23,818	9,568			2,176,111
57	2013	10								23,975	9,632			2,190,455
58	2014	9								24,133	9,695			2,204,893
59	2015	8								24,292	9,759			2,219,426
60	2016	7								24,452	9,823			2,234,055
61	2017	6								24,613	9,888			2,248,780
62	2018	5								24,776	9,953			2,263,603
63	2019	4								24,939	10,019			2,278,523
64	2020	3								25,103	10,085			2,293,541
65	2021	2								25,269	10,151			2,308,659
66	2022	1								25,435	10,218			2,323,876
67	2023	0								-	-	(2,323,876)		
			\$ 1,977,403	\$ 450,368	\$ 180,927	\$ 180,926	\$ 2,200,508	\$ 223,105	\$ 2,992,205	\$ 541,155	\$ (2,451,049)		\$ 124,447,729	

Whole Life Depreciation Rate Calculation

Historical Additions	2,650,876
Forecast Additions	341,329
Total Additions	2,992,205
Gross Salvage Value	116,194
Less Cost of Removal	232,388
Net Salvage Value	(116,194)
Total to be Recovered	3,108,398

Forecast Plant Balances 124,447,729

Whole Life Accrual Rate 2.50%
 Cost of Removal Accrual Rate 0.19%
 Whole Life Accrual Rate (Excluding Cost of Removal) 2.68%

Depreciable Service Life, years 40.0

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	2,119,670
Forecast Additions	341,329
Gross Salvage Value	116,194
Less Cost of Removal	232,388
Net Salvage Value	(116,194)

Forecast Plant Balances 31,185,130

Black Hills Power
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Ben French Plant
 Historical and Forecast Plant Additions & Balances
 Account: 312 Boiler Plant Equipment

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1960
 Retirement Date 2023
 Service Life, Yrs 63

2008

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction			Adjusted Transaction Year			Transfers and Adjustments	BOY Plant Balance		
			Transaction Year		Vintage Year Retirements	Year		Additions	Retirements	Additions	Retirements		Adjustments	Per Books	Simulated
			Begin Balance	Additions		Retirements	Additions								
1	1960	63			2,500	52,984	12,641	52,984	12,641	3,820,187	-	3,820,187	3,820,187		
2	1961	62				53,544	12,774	53,544	12,774	3,860,530		3,860,530	3,860,530		
3	1962	61			39,889	54,109	13,046	54,109	13,046	3,901,299		3,901,299	3,901,299		
4	1963	60				54,681	13,046	54,681	13,046	3,942,499		3,942,499	3,942,499		
5	1964	59				55,258	13,183	55,258	13,183	3,984,134		3,984,134	3,984,134		
6	1965	58				55,842	13,323	55,842	13,323	4,026,209		4,026,209	4,026,209		
7	1966	57				56,431	13,463	56,431	13,463	4,068,728		4,068,728	4,068,728		
8	1967	56				57,027	13,605	57,027	13,605	4,111,696		4,111,696	4,111,696		
9	1968	55				57,630	13,749	57,630	13,749	4,155,118		4,155,118	4,155,118		
10	1969	54				58,238	13,894	58,238	13,894	4,198,999		4,198,999	4,198,999		
11	1970	53				58,853	14,041	58,853	14,041	4,243,343		4,243,343	4,243,343		
12	1971	52				59,475	14,189	59,475	14,189	4,288,155		4,288,155	4,288,155		
13	1972	51				60,105	14,339	60,105	14,339	4,333,440		4,333,440	4,333,440		
14	1973	50				60,738	14,491	60,738	14,491	4,379,204		4,379,204	4,379,204		
15	1974	49				61,379	14,644	61,379	14,644	4,425,451		4,425,451	4,425,451		
16	1975	48				62,027	14,798	62,027	14,798	4,472,186		4,472,186	4,472,186		
17	1976	47				62,682	14,955	62,682	14,955	4,519,415		4,519,415	4,519,415		
18	1977	46				63,344	15,113	63,344	15,113	4,567,142		4,567,142	4,567,142		
19	1978	45				64,013	15,272	64,013	15,272	4,615,374		4,615,374	4,615,374		
20	1979	44			6,000	64,689	15,433	64,689	15,433	4,664,115		4,664,115	4,664,115		
21	1980	43			98,487	65,372	15,596	65,372	15,596	4,713,371		4,713,371	4,713,371		
22	1981	42			32,549	66,063	15,761	66,063	15,761	4,763,147		4,763,147	4,763,147		
23	1982	41			12,941	66,760	15,928	66,760	15,928	4,813,448		4,813,448	4,813,448		
24	1983	40				67,465	16,096	67,465	16,096	4,864,281		4,864,281	4,864,281		
25	1984	39				68,178	16,266	68,178	16,266	4,915,651		4,915,651	4,915,651		
26	1985	38				68,898	16,437	68,898	16,437	4,967,563		4,967,563	4,967,563		
27	1986	37				69,625	16,611	69,625	16,611	5,020,023		5,020,023	5,020,023		
28	1987	36				70,361	16,787	70,361	16,787	5,073,037		5,073,037	5,073,037		
29	1988	35			72,919	71,134	16,965	71,134	16,965	5,126,612		5,126,612	5,126,612		
30	1989	34			29,189	71,888	17,145	71,888	17,145	5,181,204		5,181,204	5,181,204		
31	1990	33	5,126,612	37,022		72,650	17,328	72,650	17,328	5,236,811		5,236,811	5,236,811		
32	1991	32		52,835	9,353	73,425	17,517	73,425	17,517	5,293,499		5,293,499	5,293,499		
33	1992	31		15,092		74,217	17,710	74,217	17,710	5,351,291		5,351,291	5,351,291		
34	1993	30		148,634	133,732	41,778	75,015	17,908	75,015	5,410,204	4,701	5,414,905	5,414,905		
35	1994	29		21,689			75,826	18,111	75,826	5,470,329		5,470,329	5,470,329		
36	1995	28		35,582	2,092		76,648	18,319	76,648	5,531,977		5,531,977	5,531,977		
37	1996	27		129,310	7,100	35,265	77,483	18,532	77,483	5,595,209		5,595,209	5,595,209		
38	1997	26					78,323	18,750	78,323	5,660,529		5,660,529	5,660,529		
39	1998	25		11,134			79,177	18,923	79,177	5,727,653	74,036	5,801,689	5,801,689		
40	1999	24		57,570			80,050	19,101	80,050	5,796,703		5,796,703	5,796,703		
41	2000	23		26,381	8,000		80,941	19,284	80,941	5,867,644	8,000	5,875,644	5,875,644		
42	2001	22		271,830	28,500		81,851	19,471	81,851	5,940,495	(79,802)	5,860,693	5,860,693		
43	2002	21					82,784	19,663	82,784	5,974,848		5,974,848	5,974,848		
44	2003	20		19,484			83,743	19,860	83,743	5,763,332		5,763,332	5,763,332		
45	2004	19					84,726	20,062	84,726	5,763,332		5,763,332	5,763,332		
46	2005	18		89,039	41,778		85,734	20,269	85,734	5,810,593		5,810,593	5,810,593		
47	2006	17		22,792	3,588		86,767	20,481	86,767	5,829,796		5,829,796	5,829,796		
48	2007	16		230,602	72,919		87,825	20,698	87,825	6,080,183	92,704	6,172,887	6,080,183		
49	2008	15		205,698	29,189		88,908	20,920	88,908	6,256,691		6,256,691	6,256,691		
50	Total			182,522	35,265		182,522	35,265	182,522	6,403,948		6,403,948	6,403,948		
				\$ 5,126,612	\$ 1,557,214	\$ 371,517	\$ 371,517	\$ 5,535,956	\$ 409,345	\$ 7,093,171	\$ 780,861	\$ 91,639	\$ 128,834,355	\$ 112,275,853	\$ 241,110,208

Major Additions/Retirements

Line	Year	Age	Activity	Amount	Rate	
51	2009	14	Routine Activity	\$ 1,557,214		
51	2009	14	Historical Interim Activity	1.39%	0.33%	
52	2009	14	Forecast Interim Activity	1.39%	0.33%	
53	2010	13		88,820	21,190	
54	2010	13		89,758	21,414	
55	2011	12		1,990,706	21,640	
56	2012	11		118,016	28,156	
57	2013	10		119,262	28,453	
58	2014	9		120,522	28,754	
59	2015	8		121,794	29,057	
60	2016	7		2,272,757	29,364	
61	2017	6		154,195	36,788	
62	2018	5		155,824	37,176	
63	2019	4		157,469	37,569	
64	2020	3		159,132	37,965	
65	2021	2		160,813	38,366	
66	2022	1		162,511	38,772	
67	2023	0				
				\$ 12,964,749	\$ 1,215,527	
					(11,840,860)	\$ 377,907,055

Whole Life Depreciation Rate Calculation

Historical Additions	7,093,171
Forecast Additions	5,871,578
Total Additions	12,964,749
Gross Salvage Value	(592,043)
Less Cost of Removal	(1,184,086)
Net Salvage Value	(592,043)
Total to be Recovered	13,556,792
Forecast Plant Balances	377,907,055
Whole Life Accrual Rate	3.59%
Cost of Removal Accrual Rate	0.31%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.90%
Depreciable Service Life, years	27.9

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	6,403,948
Forecast Additions	5,871,578
Gross Salvage Value	(592,043)
Less Cost of Removal	(1,184,086)
Net Salvage Value	(592,043)
Forecast Plant Balances	136,796,847

Black Hills Power
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Ben French Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1960
 Retirement Date 2023
 Service Life, Yrs 63

2008

Historical and Forecast Plant Additions & Balances
 Account: 314 Turbogenerator Equipment

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance				
			Transaction Year		Vintage Year Retirements	Year		Additions	Retirements		Additions	Retirements	Adjustments	Per Books	Simulated
			Beq. Balance	Additions		Retirements	Additions								
1	1960	63						1,247,946	-		1,247,946	1,247,946			
2	1961	62				19,893	2,399	19,893	2,399		1,265,440	1,265,440			
3	1962	61			43,500	20,172	2,432	20,172	2,432		1,283,180	1,283,180			
4	1963	60				20,455	2,466	20,455	2,466		1,301,168	1,301,168			
5	1964	59				20,741	2,501	20,741	2,501		1,319,409	1,319,409			
6	1965	58				21,032	2,536	21,032	2,536		1,337,905	1,337,905			
7	1966	57				21,327	2,572	21,327	2,572		1,356,660	1,356,660			
8	1967	56				21,626	2,608	21,626	2,608		1,375,679	1,375,679			
9	1968	55				21,929	2,644	21,929	2,644		1,394,964	1,394,964			
10	1969	54				22,237	2,681	22,237	2,681		1,414,519	1,414,519			
11	1970	53				22,548	2,719	22,548	2,719		1,434,348	1,434,348			
12	1971	52				22,864	2,757	22,864	2,757		1,454,456	1,454,456			
13	1972	51				23,185	2,796	23,185	2,796		1,474,845	1,474,845			
14	1973	50				23,510	2,835	23,510	2,835		1,495,520	1,495,520			
15	1974	49				23,840	2,875	23,840	2,875		1,516,485	1,516,485			
16	1975	48				24,174	2,915	24,174	2,915		1,537,744	1,537,744			
17	1976	47				24,513	2,956	24,513	2,956		1,559,301	1,559,301			
18	1977	46				24,856	2,997	24,856	2,997		1,581,160	1,581,160			
19	1978	45				25,205	3,039	25,205	3,039		1,603,325	1,603,325			
20	1979	44				25,558	3,082	25,558	3,082		1,625,802	1,625,802			
21	1980	43				25,916	3,125	25,916	3,125		1,648,593	1,648,593			
22	1981	42				26,280	3,169	26,280	3,169		1,671,704	1,671,704			
23	1982	41				26,648	3,213	26,648	3,213		1,695,139	1,695,139			
24	1983	40				27,022	3,258	27,022	3,258		1,718,902	1,718,902			
25	1984	39				27,400	3,304	27,400	3,304		1,742,998	1,742,998			
26	1985	38				27,784	3,350	27,784	3,350		1,767,433	1,767,433			
27	1986	37				28,174	3,397	28,174	3,397		1,792,209	1,792,209			
28	1987	36				28,569	3,445	28,569	3,445		1,817,334	1,817,334			
29	1988	35				28,969	3,493	28,969	3,493		1,842,810	1,842,810			
30	1989	34	1,842,810		131,971	-	-	-	-		1,842,810	1,842,810			
31	1990	33		3,255				3,255	-		1,846,064	1,846,064			
32	1991	32		32,399	5,000			32,399	5,000		1,873,463	1,873,463			
33	1992	31		124,888	20,000			124,888	20,000		1,978,351	1,978,351			
34	1993	30		98,838	17,500			98,838	17,500		2,059,689	2,059,689			
35	1994	29		47,259	1,000			47,259	1,000		2,105,948	2,105,948			
36	1995	28		8,910				8,910	-		2,114,858	2,114,858			
37	1996	27						-	-		2,114,858	2,114,858			
38	1997	26						-	-		2,114,858	2,114,858			
39	1998	25						-	-		2,114,858	2,114,858			
40	1999	24						-	-		2,114,858	2,114,858			
41	2000	23						-	-		2,114,858	2,114,858			
42	2001	22						-	-		2,114,858	2,114,858			
43	2002	21		269,232				269,232	-		2,384,090	2,384,090			
44	2003	20						-	-		2,384,090	2,384,090			
45	2004	19						-	-		2,384,090	2,384,090			
46	2005	18						-	-		2,384,090	2,384,090			
47	2006	17						-	-		2,384,090	2,384,090			
48	2007	16		116,549	41,066	41,066		116,549	41,066		2,459,572	2,459,572			
49	2008	15		778,336	131,971			778,336	131,971		3,105,937	3,105,937			
50	Total		\$ 1,842,810	\$ 1,479,664	\$ 216,537	\$ 216,537	\$ 1,924,374	\$ 81,564	\$ 3,404,038	\$ 298,101	\$ -	\$ 44,276,978	\$ 43,996,286	\$ 86,273,263	

Major Additions/Retirements 2008

\$ 778,336 \$ 131,971

Routine Activity

\$ 701,329 \$ 84,566

51 Historical Interim Activity 1.59% 0.19%

52 Forecast Interim Activity 1.59% 0.19%

53	2009	14						49,511	5,970			3,149,477	3,149,477	
54	2010	13						50,205	6,054			3,193,628	3,193,628	
55	2011	12						50,908	6,139			3,238,398	3,238,398	
56	2012	11						51,622	6,225			3,283,796	3,283,796	
57	2013	10						52,346	6,312			3,329,830	3,329,830	
58	2014	9						53,080	6,400			3,376,509	3,376,509	
59	2015	8						53,824	6,490			3,423,843	3,423,843	
60	2016	7						54,578	6,581			3,471,840	3,471,840	
61	2017	6						55,343	6,673			3,520,510	3,520,510	
62	2018	5						56,119	6,767			3,569,862	3,569,862	
63	2019	4						56,906	6,862			3,619,906	3,619,906	
64	2020	3						57,704	6,958			3,670,652	3,670,652	
65	2021	2						58,513	7,055			3,722,109	3,722,109	
66	2022	1						59,333	7,154			3,774,287	3,774,287	
67	2023	0								(3,774,287)				
										\$ 4,164,028	\$ 389,741			\$ 136,617,911

Whole Life Depreciation Rate Calculation

Historical Additions	3,404,038
Forecast Additions	759,990
Total Additions	4,164,028
Gross Salvage Value	188,714
Less Cost of Removal	377,429
Net Salvage Value	(188,714)
Total to be Recovered	4,352,743

Forecast Plant Balances 136,617,911

Whole Life Accrual Rate 3.19%

Cost of Removal Accrual Rate 0.28%

Whole Life Accrual Rate (Excluding Cost of Removal) 3.46%

Depreciable Service Life, years 28.9

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	3,105,937
Forecast Additions	759,990
Gross Salvage Value	188,714
Less Cost of Removal	377,429
Net Salvage Value	(188,714)

Forecast Plant Balances 48,344,648

Black Hills Power
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Ben French Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1960
 Retirement Date 2023
 Service Life, Yrs 63

2008

Historical and Forecast Plant Additions & Balances
 Account: 315 Accessory Electric Equipment Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance			
			Transaction Year		Vintage Year Retirements	Year		Transaction Year			Adjustments	Per Books	Simulated	
			Beg. Balance	Additions		Retirements	Additions	Retirements	Additions					Retirements
1	1960	63			899	2,357,756	423,745	-		423,745		423,745		
2	1961	62				4,111	1,054	4,111	1,054		426,802	426,802		
3	1962	61			1,750	4,141	1,061	4,141	1,061		429,882	429,882		
4	1963	60				4,171	1,069	4,171	1,069		432,983	432,983		
5	1964	59				4,201	1,077	4,201	1,077		436,107	436,107		
6	1965	58				4,231	1,085	4,231	1,085		439,254	439,254		
7	1966	57			21,673	4,262	1,092	4,262	1,092		442,423	442,423		
8	1967	56				4,292	1,100	4,292	1,100		445,615	445,615		
9	1968	55				4,323	1,108	4,323	1,108		448,831	448,831		
10	1969	54				4,355	1,116	4,355	1,116		452,069	452,069		
11	1970	53				4,386	1,124	4,386	1,124		455,331	455,331		
12	1971	52				4,418	1,132	4,418	1,132		458,616	458,616		
13	1972	51				4,449	1,141	4,449	1,141		461,925	461,925		
14	1973	50				4,482	1,149	4,482	1,149		465,258	465,258		
15	1974	49				4,514	1,157	4,514	1,157		468,615	468,615		
16	1975	48				4,547	1,165	4,547	1,165		471,996	471,996		
17	1976	47				4,579	1,174	4,579	1,174		475,401	475,401		
18	1977	46				4,612	1,182	4,612	1,182		478,831	478,831		
19	1978	45				4,646	1,191	4,646	1,191		482,286	482,286		
20	1979	44				4,679	1,199	4,679	1,199		485,766	485,766		
21	1980	43				4,713	1,208	4,713	1,208		489,271	489,271		
22	1981	42				4,747	1,217	4,747	1,217		492,801	492,801		
23	1982	41				4,781	1,226	4,781	1,226		496,356	496,356		
24	1983	40				4,816	1,234	4,816	1,234		499,937	499,937		
25	1984	39			20,735	4,850	1,243	4,850	1,243		503,545	503,545		
26	1985	38				4,885	1,252	4,885	1,252		507,178	507,178		
27	1986	37				4,921	1,261	4,921	1,261		510,837	510,837		
28	1987	36				4,956	1,270	4,956	1,270		514,523	514,523		
29	1988	35				4,992	1,280	4,992	1,280		518,235	518,235		
30	1989	34	518,235	28,699				28,699	-		546,934	546,934		
31	1990	33						-	-		546,934	546,934		
32	1991	32		5,697				5,697	-		552,632	552,632		
33	1992	31		13,820	607			13,820	607		565,846	565,846		
34	1993	30		22,436	1,143			22,436	1,143		587,139	587,139		
35	1994	29						-	-		587,139	587,139		
36	1995	28						-	-		587,139	587,139		
37	1996	27			899			-	899		586,240	586,240		
38	1997	26		1,230				1,230	-		587,470	587,470		
39	1998	25						-	-	743,409	1,330,879	1,330,879		
40	1999	24						-	-		1,330,879	1,330,879		
41	2000	23						-	-		1,330,879	1,330,879		
42	2001	22						-	-		1,330,879	1,330,879		
43	2002	21						-	-		1,330,879	1,330,879		
44	2003	20						-	-		1,330,879	1,330,879		
45	2004	19		71,417	20,735			71,417	20,735		1,381,561	1,381,561		
46	2005	18						-	-		1,381,561	1,381,561		
47	2006	17						-	-	(644,605)	736,956	736,956		
48	2007	16						-	-		736,956	736,956		
49	2008	15		32,476	21,673			32,476	21,673		747,759	747,759		
50	Total		\$ 518,235	\$ 175,777	\$ 45,057	\$ 45,057	\$ 550,804	\$ 32,569	\$ 726,581	\$ 77,626	\$ 98,804	\$ 13,614,418	\$ 18,117,538	\$ 31,713,956

Major Additions/Retirements

Routine Activity	\$ 175,777	\$ 45,057
Historical Interim Activity	0.97%	0.25%
Forecast Interim Activity	0.97%	0.25%

53	2009	14						7,255	1,860			753,154		
54	2010	13						7,307	1,873			758,388		
55	2011	12						7,360	1,887			764,061		
56	2012	11						7,413	1,900			769,574		
57	2013	10						7,466	1,914			775,127		
58	2014	9						7,520	1,928			780,719		
59	2015	8						7,575	1,942			786,352		
60	2016	7						7,629	1,956			792,026		
61	2017	6						7,684	1,970			797,740		
62	2018	5						7,740	1,984			803,496		
63	2019	4						7,796	1,998			809,293		
64	2020	3						7,852	2,013			815,133		
65	2021	2						7,908	2,027			821,014		
66	2022	1						7,965	2,042			826,937		
67	2023	0								(826,937)				
									\$ 833,051	\$ 104,918				\$ 42,785,171

Whole Life Depreciation Rate Calculation

Historical Additions	726,581
Forecast Additions	106,470
Total Additions	833,051
Gross Salvage Value	41,347
Less Cost of Removal	82,694
Net Salvage Value	(41,347)
Total to be Recovered	874,398
Forecast Plant Balances	42,785,171
Whole Life Accrual Rate	2.04%
Cost of Removal Accrual Rate	0.19%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.24%
Depreciable Service Life, years	44.7

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	747,759
Forecast Additions	106,470
Gross Salvage Value	41,347
Less Cost of Removal	82,694
Net Salvage Value	(41,347)
Forecast Plant Balances	11,053,215

Black Hills Power
 Gross Salvage 5%
 Cost of Removal 10%
 Unit Property Depreciation Rate Analysis
 Net Salvage -5%
 Unit Property: Unit Property: Steam Production, Ben French Plant
 Install Date 1960
 Retirement Date 2023
 Service Life, Yrs 63
 2008

Historical and Forecast Plant Additions & Balances
 Account: 316 Miscellaneous Plant Equipment Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance			
			Transaction Year		Vintage Year Retirements	Year		Retirements			Adjustments	Per Books	Simulated	
			Beg. Balance	Additions		Retirements	Additions	Retirements						
1	1960	63			59	213,392		213,392		213,392		213,392		
2	1961	62				4,271	1,157	4,271	1,157	216,506		216,506		
3	1962	61			31,846	4,333	1,174	4,333	1,174	219,666		219,666		
4	1963	60				4,397	1,191	4,397	1,191	222,871		222,871		
5	1964	59				4,461	1,208	4,461	1,208	226,123		226,123		
6	1965	58				4,526	1,226	4,526	1,226	229,423		229,423		
7	1966	57			30,000	4,592	1,244	4,592	1,244	232,771		232,771		
8	1967	56				4,659	1,262	4,659	1,262	236,168		236,168		
9	1968	55				4,727	1,281	4,727	1,281	239,614		239,614		
10	1969	54				4,796	1,299	4,796	1,299	243,111		243,111		
11	1970	53				4,866	1,318	4,866	1,318	246,659		246,659		
12	1971	52				4,937	1,337	4,937	1,337	250,258		250,258		
13	1972	51				5,009	1,357	5,009	1,357	253,910		253,910		
14	1973	50			938	5,082	1,377	5,082	1,377	257,616		257,616		
15	1974	49				5,156	1,397	5,156	1,397	261,375		261,375		
16	1975	48				5,231	1,417	5,231	1,417	265,189		265,189		
17	1976	47				5,308	1,438	5,308	1,438	269,059		269,059		
18	1977	46			151,200	5,385	1,459	5,385	1,459	272,986		272,986		
19	1978	45			76,500	5,464	1,480	5,464	1,480	276,969		276,969		
20	1979	44			76,500	5,544	1,502	5,544	1,502	281,011		281,011		
21	1980	43				5,625	1,524	5,625	1,524	285,112		285,112		
22	1981	42			4,612	5,707	1,546	5,707	1,546	289,273		289,273		
23	1982	41				5,790	1,569	5,790	1,569	293,494		293,494		
24	1983	40				5,874	1,591	5,874	1,591	297,777		297,777		
25	1984	39				5,960	1,615	5,960	1,615	302,122		302,122		
26	1985	38				6,047	1,638	6,047	1,638	306,531		306,531		
27	1986	37			1,834	6,135	1,662	6,135	1,662	311,004		311,004		
28	1987	36				1,833	6,225	1,686	6,225	315,543		315,543		
29	1988	35				1,822	6,316	1,711	6,316	320,148		320,148		
30	1989	34	320,148	26,516	6,360	26,516	6,360	26,516	6,360	340,304	340,304	340,304		
31	1990	33		6,715	338,812	6,715	338,812	6,715	338,812	8,207	8,207	8,207		
32	1991	32		10,455	1,834	10,455	1,834	10,455	1,834	334,200	334,200	334,200		
33	1992	31		126,790		126,790		126,790			477,818	477,818		
34	1993	30		7,732		7,732		7,732			485,550	485,550		
35	1994	29		28,290	1,696	28,290	1,696	28,290	1,696		513,840	513,840		
36	1995	28		3,987	1,652	3,987	1,652	3,987	1,652		516,174	516,174		
37	1996	27		3,905	997	3,905	997	3,905	997	(101,391)	417,691	417,691		
38	1997	26		8,305		8,305		8,305			425,997	425,997		
39	1998	25		599		599		599			426,595	426,595		
40	1999	24		2,617		2,617		2,617			429,212	429,212		
41	2000	23		2,078		2,078		2,078		13,145	444,435	444,435		
42	2001	22		9,155		9,155		9,155			453,590	453,590		
43	2002	21		32,468	27,363	32,468	27,363	32,468	27,363		458,695	458,695		
44	2003	20		9,665		9,665		9,665			468,360	468,360		
45	2004	19		6,287		6,287		6,287			474,647	474,647		
46	2005	18			1,382						474,647	474,647		
47	2006	17		12,556		12,556		12,556		(19,159)	466,661	466,661		
48	2007	16									466,661	466,661		
49	2008	15			6,826						459,835	459,835		
50	Total		\$ 320,148	\$ 298,120	\$ 385,226	\$ 385,226	\$ 359,815	\$ 39,667	\$ 657,934	\$ 424,893	\$ 226,794	\$ 7,635,683	\$ 8,559,947	\$ 16,195,631

Major Additions/Retirements
 1990
 1992 \$ 126,790
 Routine Activity \$ 171,330 \$ 46,414
 Historical Interim Activity 2.00% 0.54%
 Forecast Interim Activity 2.00% 0.54%

51	2009	14					9,204	2,493				466,545
52	2010	13					9,338	2,530				473,354
53	2011	12					9,474	2,567				480,261
54	2012	11					9,613	2,604				487,270
55	2013	10					9,753	2,642				494,380
56	2014	9					9,895	2,681				501,595
57	2015	8					10,040	2,720				508,915
58	2016	7					10,186	2,759				516,341
59	2017	6					10,335	2,800				523,876
60	2018	5					10,486	2,841				531,521
61	2019	4					10,639	2,882				539,278
62	2020	3					10,794	2,924				547,147
63	2021	2					10,951	2,967				555,132
64	2022	1					11,111	3,010				563,233
65	2023	0								(563,233)		-
66	Total						\$ 799,751	\$ 463,313				\$ 23,384,480

Whole Life Depreciation Rate Calculation
 Historical Additions 657,934
 Forecast Additions 141,817
 Total Additions 799,751
 Gross Salvage Value 28,162
 Less Cost of Removal 56,323
 Net Salvage Value (28,162)
 Total to be Recovered 827,913
 Forecast Plant Balances 23,384,480
 Whole Life Accrual Rate 3.54%
 Cost of Removal Accrual Rate 0.24%
 Whole Life Accrual Rate (Excluding Cost of Removal) 3.78%
 Depreciable Service Life, years 28.2

Remaining Life Depreciation Rate Calculation
 Account Balance - 12/31/08 459,835
 Forecast Additions 141,817
 Gross Salvage Value 28,162
 Less Cost of Removal 56,323
 Net Salvage Value (28,162)
 Forecast Plant Balances 7,188,849

Summary by Plant
 Black Hills Power
 Wyodak Facility

Account	Description	Direct Investment 2008\$	Depreciation Rate
310	Land		
311	Structure & Improvements	9,039,917	3.58%
312	Boiler Plant Equipment	51,154,925	3.22%
313	Engines & Engine Driven Generators	249,991	4.79%
314	Turbo Generator Equipment	11,199,149	3.42%
315	Accessory Electric Equipment	6,213,171	3.35%
316	Misc Power Equipment	892,134	7.21%
Total		78,749,286	3.35% whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	79,050,217
Forecast Interim Additions	23,744,384
Forecast Gross Salvage Value	4,987,227
Forecast Less Cost of Removal	10,469,954
Forecast Net Salvage Value	(5,482,728)
Forecast Total to be Recovered with COR	108,277,328
Forecast Total to be Recovered w/o COR	97,807,374
Accumulated Depreciation (2008 EOY)	(50,672,287)
Forecast Remaining Life Balance with COR	57,605,041
Forecast Remaining Life Balance w/o COR	47,135,087
Forecast Plant Balances	1,896,224,299
Remaining Life Rate with COR	3.04%
Remaining Life Rate w/o COR	2.49%

Black Hills Power

Gross Salvage 5%
 Cost of Removal 15%
 Net Salvage -10%
 Install Date 1978
 Retirement Date 2030
 Service Life, Yrs 52

2008

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

Historical and Forecast Plant Additions & Balances
 Account: 311 Structures & Improvements

Initial Plant Balance 9,057

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance			
			Transaction Year			Year		Year			Per Books	Simulated		
			Beg Balance	Additions	Retirements	Additions	Retirements	Additions	Retirements					
1	1978	52				8,669		8,669		8,669		8,669		
2	1979	51				48	10	48	10	8,707		8,707		
3	1980	50				48	10	48	10	8,745		8,745		
4	1981	49				48	10	48	10	8,783		8,783		
5	1982	48				48	10	48	10	8,822		8,822		
6	1983	47				49	10	49	10	8,861		8,861		
7	1984	46				49	10	49	10	8,899		8,899		
8	1985	45				49	10	49	10	8,938		8,938		
9	1986	44				49	10	49	10	8,978		8,978		
10	1987	43				50	10	50	10	9,017		9,017		
11	1988	42				50	10	50	10	9,057		9,057		
12	1989	41	9,057			-	-	-	-		9,057	9,057		
13	1990	40				-	-	-	-		9,057	9,057		
14	1991	39		8,346,974		156,948		8,346,974			8,356,031	8,356,031		
15	1992	38		135,082		22,339		135,082			8,491,113	8,491,113		
16	1993	37									8,491,113	8,491,113		
17	1994	36		111,144				111,144			8,602,257	8,602,257		
18	1995	35									8,602,257	8,602,257		
19	1996	34		178,075	22,339			178,075	22,339		8,757,992	8,757,992		
20	1997	33									8,757,992	8,757,992		
21	1998	32									8,757,992	8,757,992		
22	1999	31		211,509	74,467			211,509	74,467		8,895,035	8,895,035		
23	2000	30									8,895,035	8,895,035		
24	2001	29									8,895,035	8,895,035		
25	2002	28									8,895,035	8,895,035		
26	2003	27		31,636				31,636			8,926,670	8,926,670		
27	2004	26		41,920				41,920			8,968,590	8,968,590		
28	2005	25		26,267				26,267			8,994,857	8,994,857		
29	2006	24		138,834				138,834		(5,922)	9,127,769	9,127,769		
30	2007	23			82,482				82,482	(5,370)	9,039,917	9,039,917		
31	2008	22									9,039,917	9,039,917		
32	Total		\$ 9,057	\$ 9,221,440	\$ 179,288	\$ 179,287	\$ -	\$ -	\$ 9,221,440	\$ 179,288	\$ (11,292)	\$ -	\$ 158,512,720	\$ 158,512,720

Major Additions/Retirements

33	1991	\$ 8,346,974	
	Routine Activity	\$ 874,466	
	Historical Interim Activity	0.55%	0.11%
34	Forecast Interim Activity	0.55%	0.11%

35	2009	21		49,870	10,225							9,079,563
36	2010	20			50,089	10,270						9,119,382
37	2011	19			50,309	10,315						9,159,377
38	2012	18			50,529	10,360						9,199,546
39	2013	17			50,751	10,405						9,239,892
40	2014	16			50,974	10,451						9,280,415
41	2015	15			51,197	10,497						9,321,115
42	2016	14			51,422	10,543						9,361,994
43	2017	13			51,647	10,589						9,403,052
44	2018	12			51,874	10,635						9,444,291
45	2019	11			52,101	10,682						9,485,710
46	2020	10			52,330	10,729						9,527,311
47	2021	9			52,559	10,776						9,569,094
48	2022	8			52,790	10,823						9,611,061
49	2023	7			53,021	10,871						9,653,211
50	2024	6			53,254	10,918						9,695,547
51	2025	5			53,487	10,966						9,738,068
52	2026	4			53,722	11,014						9,780,775
53	2027	3			53,958	11,063						9,823,670
54	2028	2			54,194	11,111						9,866,753
55	2029	1			54,432	11,160						9,910,025
56	2030	0							(9,910,025)			-
					\$ 10,315,950	\$ 403,690						\$ 357,782,571

Whole Life Depreciation Rate Calculation

Historical Additions	9,221,440
Forecast Additions	1,094,510
Total Additions	10,315,950
Gross Salvage Value	495,501
Less Cost of Removal	1,486,504
Net Salvage Value	(991,003)
Total to be Recovered	11,306,953
Forecast Plant Balances	357,782,571
Whole Life Accrual Rate	3.16%
Cost of Removal Accrual Rate	0.42%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.58%
Depreciable Service Life, years	31.6

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	9,039,917
Forecast Additions	1,094,510
Gross Salvage Value	495,501
Less Cost of Removal	1,486,504
Net Salvage Value	(991,003)
Forecast Plant Balances	199,269,851

Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1978
 Retirement Date 2030
 Service Life, Yrs 52

Unit Property Depreciation Rate Analysis
Unit Property: Steam Production, Wyodak Plant

2008

Historical and Forecast Plant Additions & Balances

Account: 313 Engine and Engine Driven Generators Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year		Vintage Year	Year		Per Books	Simulated				
			Beg Balance	Additions		Retirements	Additions				Retirements		
1	1978	52											
2	1979	51											
3	1980	50											
4	1981	49											
5	1982	48											
6	1983	47											
7	1984	46											
8	1985	45											
9	1986	44											
10	1987	43											
11	1988	42											
12	1989	41	0										
13	1990	40											
14	1991	39											
15	1992	38											
16	1993	37											
17	1994	36											
18	1995	35											
19	1996	34											
20	1997	33											
21	1998	32											
22	1999	31											
23	2000	30											
24	2001	29											
25	2002	28		232,960				232,960				232,960	232,960
26	2003	27		7,427				7,427				240,387	240,387
27	2004	26		19,645				19,645				260,032	260,032
28	2005	25							(10,041)			249,991	249,991
29	2006	24										249,991	249,991
30	2007	23										249,991	249,991
31	2008	22										249,991	249,991
32	Total		\$	\$ 260,032	\$	\$	\$	\$ 260,032	\$	\$ (10,041)	\$	\$ 1,733,340	\$ 1,733,340

Major Additions/Retirements

	2002	\$ 232,960		
	Routine Activity	\$ 27,072		
33	Historical Interim Activity	1.56%	0.00%	
34	Forecast Interim Activity	1.00%	0.00%	

35	2009	21		2,500	-								252,490
36	2010	20		2,525	-								255,015
37	2011	19		2,550	-								257,565
38	2012	18		2,576	-								260,141
39	2013	17		2,601	-								262,743
40	2014	16		2,627	-								265,370
41	2015	15		2,654	-								268,024
42	2016	14		2,680	-								270,704
43	2017	13		2,707	-								273,411
44	2018	12		2,734	-								276,145
45	2019	11		2,761	-								278,906
46	2020	10		2,789	-								281,696
47	2021	9		2,817	-								284,513
48	2022	8		2,845	-								287,358
49	2023	7		2,874	-								290,231
50	2024	6		2,902	-								293,134
51	2025	5		2,931	-								296,065
52	2026	4		2,961	-								299,026
53	2027	3		2,990	-								302,016
54	2028	2		3,020	-								305,036
55	2029	1		3,050	-								308,086
56	2030	0							(308,086)				-
				\$ 318,127	\$ -								\$ 7,601,014

Whole Life Depreciation Rate Calculation

Historical Additions	260,032
Forecast Additions	58,096
Total Additions	318,127
Gross Salvage Value	15,404
Less Cost of Removal	30,809
Net Salvage Value	(15,404)
Total to be Recovered	333,532
Forecast Plant Balances	7,601,014
Whole Life Accrual Rate	4.39%
Cost of Removal Accrual Rate	0.41%
Whole Life Accrual Rate (Excluding Cost of Removal)	4.79%
Depreciable Service Life, years	22.8

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	249,991
Forecast Additions	58,096
Gross Salvage Value	15,404
Less Cost of Removal	30,809
Net Salvage Value	(15,404)
Forecast Plant Balances	5,867,674

Black Hills Power
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Wyodak Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1978
 Retirement Date 2030
 Service Life, Yrs 52

Historical and Forecast Plant Additions & Balances
 Account: 314 Turbogenerator Equipment Initial Plant Balance 7,179

2008

Line	Vintage Year	Vintage Age	Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year		Vintage Year		Year		Year			Per Books	Simulated	
			Beg. Balance	Additions	Retirements	Retirements	Additions	Retirements	Additions	Retirements				
1	1971					1,828								
2	1978	52						7,061	-			7,061		7,061
3	1979	51						7,073	3			7,073		7,073
4	1980	50						7,084	3			7,084		7,084
5	1981	49						7,096	3			7,096		7,096
6	1982	48						7,108	3			7,108		7,108
7	1983	47						7,120	3			7,120		7,120
8	1984	46						7,132	3			7,132		7,132
9	1985	45						7,143	3			7,143		7,143
10	1986	44						7,155	3			7,155		7,155
11	1987	43						7,167	3			7,167		7,167
12	1988	42						7,179	3			7,179		7,179
13	1989	41	7,179	7,179				7,179	-			14,358		14,358
14	1990	40						-	-			14,358		14,358
15	1991	39		9,214,295		711,034		9,214,295	-			9,228,654	9,228,654	9,228,654
16	1992	38		299,654				299,654	-			9,528,308	9,528,308	9,528,308
17	1993	37						-	-			9,528,308	9,528,308	9,528,308
18	1994	36			2,103	2,103		-	2,103			9,526,205	9,526,205	9,526,205
19	1995	35		6,610	1,828	2,963		6,610	1,828			9,530,987	9,530,987	9,530,987
20	1996	34		543,893	204,140			543,893	204,140			9,870,739	9,870,739	9,870,739
21	1997	33						-	-			9,870,739	9,870,739	9,870,739
22	1998	32						-	-			9,870,739	9,870,739	9,870,739
23	1999	31			73,635			-	73,635	(10,606)		9,786,199	9,786,199	9,786,199
24	2000	30						-	-			9,786,199	9,786,199	9,786,199
25	2001	29						-	-			9,786,199	9,786,199	9,786,199
26	2002	28						-	-			9,786,199	9,786,199	9,786,199
27	2003	27		56,390				56,390	-			9,842,588	9,842,588	9,842,588
28	2004	26		5,883				5,883	-			9,848,472	9,848,472	9,848,472
29	2005	25		1,127				1,127	-			9,849,598	9,849,598	9,849,598
30	2006	24		1,975,529				1,975,529	-	(98,843)		11,728,285	11,728,285	11,728,285
31	2007	23			436,222			-	436,222	(92,914)		11,199,149	11,199,149	11,199,149
32	2008	22						-	-			11,199,149	11,199,149	11,199,149
	Total		\$ 7,179	\$ 12,110,560	\$ 717,928	\$ 717,928	\$ -	\$ -	\$ 12,110,560	\$ 717,928	\$ (200,663)	\$ -	\$ 179,795,433	\$ 179,795,433

Major Additions/Retirements

1991	\$ 9,214,295	
1996	\$ 543,893	\$ 204,140
2006	\$ 1,975,529	\$ 436,222
Routine Activity	\$ 376,843	\$ 77,566
Historical Interim Activity	0.21%	0.04%
Forecast Interim Activity	0.21%	0.04%

33	2009	21						23,473	4,831					11,217,790
34	2010	20						23,512	4,839					11,236,463
35	2011	19						23,551	4,848					11,255,166
36	2012	18						23,590	4,856					11,273,901
37	2013	17						23,630	4,864					11,292,667
38	2014	16						23,669	4,872					11,311,464
39	2015	15						23,708	4,880					11,330,292
40	2016	14						23,748	4,888					11,349,152
41	2017	13						23,787	4,896					11,368,043
42	2018	12						23,827	4,904					11,386,966
43	2019	11						23,867	4,912					11,405,920
44	2020	10						23,906	4,921					11,424,905
45	2021	9						23,946	4,929					11,443,923
46	2022	8						23,986	4,937					11,462,972
47	2023	7						24,026	4,945					11,482,052
48	2024	6						24,066	4,953					11,501,164
49	2025	5						24,106	4,962					11,520,309
50	2026	4						24,146	4,970					11,539,485
51	2027	3						24,186	4,978					11,558,693
52	2028	2						24,226	4,987					11,577,933
53	2029	1						24,267	4,995					11,597,205
54	2030	0								(11,597,205)				-
								\$ 12,611,783	\$ 821,095					\$ 419,331,895

Whole Life Depreciation Rate Calculation

Historical Additions	12,110,560
Forecast Additions	501,223
Total Additions	12,611,783
Gross Salvage Value	579,860
Less Cost of Removal	1,159,720
Net Salvage Value	(579,860)
Total to be Recovered	13,191,643
Forecast Plant Balances	419,331,895
Whole Life Accrual Rate	3.15%
Cost of Removal Accrual Rate	0.28%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.42%
Depreciable Service Life, years	31.8

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	11,199,149
Forecast Additions	501,223
Gross Salvage Value	579,860
Less Cost of Removal	1,159,720
Net Salvage Value	(579,860)
Forecast Plant Balances	239,536,462

Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1978
 Retirement Date 2030
 Service Life, Yrs 52

Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Wyodak Plant

2008

Historical and Forecast Plant Additions & Balances
 Account: 315 Accessory Electric Equipment

Initial Plant Balance 0

Line	[A] Vintage Year	[B] Vintage Age	[C] Reported Per Books			[D] Vintage Year Retirements	[E] Adjustments to Transaction		[F] Adjusted Transaction Year		[G] Transfers and Adjustments	[H] EOY Plant Balance			
			[I] Transaction Year		[J] Retirements		[K] Year		[L] Additions	[M] Retirements		[N] Adjustments	[O] Per Books	[P] Simulated	
			[Q] Beg. Balance	[R] Additions			[S] Retirements	[T] Additions							[U] Retirements
1	1978	52													
2	1979	51													
3	1980	50													
4	1981	49													
5	1982	48													
6	1983	47													
7	1984	46													
8	1985	45													
9	1986	44													
10	1987	43													
11	1988	42													
12	1989	41	0												
13	1990	40													
14	1991	39		5,733,052		249,639			5,733,052				5,733,052	5,733,052	
15	1992	38											5,733,052	5,733,052	
16	1993	37											5,733,052	5,733,052	
17	1994	36		8,595		5,988			8,595				5,741,647	5,741,647	
18	1995	35											5,741,647	5,741,647	
19	1996	34		296,346		208,756			296,346	208,756			5,829,237	5,829,237	
20	1997	33											5,829,237	5,829,237	
21	1998	32									99,024		5,928,261	5,928,261	
22	1999	31		288,579		1,649			288,579	1,649			6,215,192	6,215,192	
23	2000	30											6,215,192	6,215,192	
24	2001	29											6,215,192	6,215,192	
25	2002	28											6,215,192	6,215,192	
26	2003	27		6,803					6,803				6,221,995	6,221,995	
27	2004	26											6,221,995	6,221,995	
28	2005	25											6,221,995	6,221,995	
29	2006	24											6,221,995	6,221,995	
30	2007	23		36,398		45,222			36,398	45,222			6,213,171	6,213,171	
31	2008	22											6,213,171	6,213,171	
32	Total			\$ 6,369,774	\$ 255,627	\$ 255,627	\$ -	\$ -	\$ 6,369,774	\$ 255,627	\$ 99,024	\$ -	\$ 108,444,277	\$ 108,444,277	

Major Additions/Retirements
 1991

\$ 5,733,052

Routine Activity

\$ 636,722 \$ 255,627

33 Historical Interim Activity
 34 Forecast Interim Activity

0.59% 0.24%
 0.59% 0.24%

35	2009	21							36,480	14,646					6,235,006
36	2010	20							36,608	14,697					6,256,917
37	2011	19							36,737	14,749					6,278,905
38	2012	18							36,866	14,801					6,300,970
39	2013	17							36,996	14,853					6,323,113
40	2014	16							37,126	14,905					6,345,334
41	2015	15							37,256	14,957					6,367,632
42	2016	14							37,387	15,010					6,390,010
43	2017	13							37,518	15,063					6,412,465
44	2018	12							37,650	15,116					6,435,000
45	2019	11							37,783	15,169					6,457,614
46	2020	10							37,915	15,222					6,480,307
47	2021	9							38,049	15,275					6,503,080
48	2022	8							38,182	15,329					6,525,933
49	2023	7							38,316	15,383					6,548,867
50	2024	6							38,451	15,437					6,571,881
51	2025	5							38,586	15,491					6,594,976
52	2026	4							38,722	15,546					6,618,152
53	2027	3							38,858	15,600					6,641,409
54	2028	2							38,994	15,655					6,664,749
55	2029	1							39,132	15,710					6,688,170
56	2030	0									(6,688,170)				-
										\$ 7,163,387	\$ 574,241				\$ 244,084,766

Whole Life Depreciation Rate Calculation

Historical Additions	6,369,774
Forecast Additions	793,613
Total Additions	7,163,387
Gross Salvage Value	334,408
Less Cost of Removal	668,817
Net Salvage Value	(334,408)
Total to be Recovered	7,497,795

Forecast Plant Balances 244,084,766

Whole Life Accrual Rate 3.07%

Cost of Removal Accrual Rate 0.27%

Whole Life Accrual Rate (Excluding Cost of Removal) 3.35%

Depreciable Service Life, years 32.6

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	6,213,171
Forecast Additions	793,613
Gross Salvage Value	334,408
Less Cost of Removal	668,817
Net Salvage Value	(334,408)

Forecast Plant Balances 135,640,489

Black Hills Power
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Wyojak Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1978
 Retirement Date 2030
 Service Life, Yrs 52

2008

Historical and Forecast Plant Additions & Balances
 Account: 316 Miscellaneous Plant Equipment

Initial Plant Balance 21,473

Line	Vintage Year	Vintage Age	Reported Per Books				Adjustments to Transaction		Adjusted Transaction Year		Transfers and Adjustments	EQY Plant Balance		
			Transaction Year			Vintage Year	Year		Year			Adjustments	Per Books	Simulated
			Beg. Balance	Additions	Retirements		Additions	Retirements	Additions	Retirements				
1	1978	52						12,423	-		12,423		12,423	
2	1979	51					724	724	25		13,122		13,122	
3	1980	50					765	765	26		13,860		13,860	
4	1981	49					808	808	28		14,639		14,639	
5	1982	48					853	853	30		15,463		15,463	
6	1983	47					901	901	31		16,333		16,333	
7	1984	46					952	952	33		17,251		17,251	
8	1985	45					1,005	1,005	35		18,222		18,222	
9	1986	44					1,062	1,062	37		19,247		19,247	
10	1987	43					1,121	1,121	39		20,329		20,329	
11	1988	42					1,184	1,184	41		21,473		21,473	
12	1989	41	21,473				-	-	-			21,473	21,473	
13	1990	40					-	-	-			21,473	21,473	
14	1991	39		344,033		118,037		344,033	-		365,506		365,506	
15	1992	38		29,448				29,448	-		394,954		394,954	
16	1993	37						-	-		394,954		394,954	
17	1994	36		120,135				120,135	-		515,089		515,089	
18	1995	35		9,686				9,686	-		524,776		524,776	
19	1996	34		136,897	22,551			136,897	22,551		639,121		639,121	
20	1997	33						-	-		639,121		639,121	
21	1998	32						-	-		639,121		639,121	
22	1999	31		1,231				1,231	-	(16,820)	623,532		623,532	
23	2000	30						-	-		623,532		623,532	
24	2001	29						-	-		623,532		623,532	
25	2002	28						-	-		623,532		623,532	
26	2003	27		12,656				12,656	-		636,188		636,188	
27	2004	26		2,079				2,079	-		638,267		638,267	
28	2005	25		16,471				16,471	-	10,041	664,779		664,779	
29	2006	24		142,622				142,622	-		807,402		807,402	
30	2007	23		180,218	95,486			180,218	95,486		892,134		892,134	
31	2008	22						-	-		892,134		892,134	
32	Total		\$ 21,473	\$ 995,477	\$ 118,037	\$ 118,037	\$ -	\$ 995,477	\$ 118,037	\$ (6,779)	\$ -	\$ 11,180,620	\$ 11,180,620	

Major Additions/Retirements

2007		\$ 95,486
1991	\$ 344,033	
Routine Activity	\$ 651,444	\$ 22,551
Historical Interim Activity	5.83%	0.20%
Forecast Interim Activity	5.83%	0.20%

35	2009	21					51,981	1,799			942,315		942,315
36	2010	20					54,904	1,901			995,319		995,319
37	2011	19					57,993	2,008			1,051,304		1,051,304
38	2012	18					61,255	2,120			1,110,438		1,110,438
39	2013	17					64,700	2,240			1,172,898		1,172,898
40	2014	16					68,339	2,366			1,238,872		1,238,872
41	2015	15					72,183	2,499			1,308,557		1,308,557
42	2016	14					76,244	2,639			1,382,161		1,382,161
43	2017	13					80,532	2,788			1,459,906		1,459,906
44	2018	12					85,062	2,945			1,542,023		1,542,023
45	2019	11					89,847	3,110			1,628,760		1,628,760
46	2020	10					94,900	3,285			1,720,375		1,720,375
47	2021	9					100,238	3,470			1,817,144		1,817,144
48	2022	8					105,877	3,665			1,919,355		1,919,355
49	2023	7					111,832	3,871			2,027,316		2,027,316
50	2024	6					118,123	4,089			2,141,349		2,141,349
51	2025	5					124,767	4,319			2,261,797		2,261,797
52	2026	4					131,785	4,562			2,389,020		2,389,020
53	2027	3					139,197	4,819			2,523,399		2,523,399
54	2028	2					147,027	5,090			2,665,336		2,665,336
55	2029	1					155,297	5,376			2,815,257		2,815,257
56	2030	0								(2,815,257)			
							\$ 2,987,561	\$ 186,998				\$ 47,293,520	\$ 47,293,520

Whole Life Depreciation Rate Calculation

Historical Additions	995,477
Forecast Additions	1,992,084
Total Additions	2,987,561
Gross Salvage Value	140,763
Less Cost of Removal	281,526
Net Salvage Value	(140,763)
Total to be Recovered	3,128,324
Forecast Plant Balances	47,293,520
Whole Life Accrual Rate	6.61%
Cost of Removal Accrual Rate	0.60%
Whole Life Accrual Rate (Excluding Cost of Removal)	7.21%
Depreciable Service Life, years	15.1

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	892,134
Forecast Additions	1,992,084
Gross Salvage Value	140,763
Less Cost of Removal	281,526
Net Salvage Value	(140,763)
Forecast Plant Balances	36,112,900

Summary by Plant
 Black Hills Power
 Neil Simpson I Facility

Account	Description	Direct Investment 2008\$	Depreciation Rate
310	Land	0	0.00%
311	Structure & Improvements	2,139,727	3.23%
312	Boiler Plant Equipment	12,718,813	3.92%
313	Engines & Engine Driven Generators		
314	Turbo Generator Equipment	2,866,457	2.42%
315	Accessory Electric Equipment	744,885	2.87%
316	Misc Power Equipment	429,468	2.83%
Total		18,899,349	3.55% whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	18,913,575
Forecast Interim Additions	7,260,936
Forecast Gross Salvage Value	1,278,309
Forecast Less Cost of Removal	2,556,618
Forecast Net Salvage Value	(1,278,309)
Forecast Total to be Recovered with COR	27,452,820
Forecast Total to be Recovered w/o COR	24,896,202
Accumulated Depreciation (2008 EOY)	(16,151,840)
Forecast Remaining Life Balance with COR	11,300,980
Forecast Remaining Life Balance w/o COR	8,744,362
Forecast Plant Balances	323,756,007
Remaining Life Rate with COR	3.49%
Remaining Life Rate w/o COR	2.70%

Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1969
 Retirement Date 2023
 Service Life, Yrs 54

2008

Unit Property Depreciation Rate Analysis

Unit Property: Steam Production, Neil Simpson 1 Plant

Historical and Forecast Plant Additions & Balances

Account: 312 Boiler Plant Equipment

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books				Adjustments to Transaction Year				Transfers and Adjustments	EOY Plant Balance				
			Transaction Year		Vintage Year Retirements	Year		Adjusted Transaction Year		Adjustments		Per Books	Simulated			
			BoR Balance	Additions		Retirements	Additions	Retirements	Additions					Retirements		
1	1954	69														
2	1955	68														
3	1956	67														
4	1957	66														
5	1958	65														
6	1959	64														
7	1960	63														
8	1961	62														
9	1962	61														
10	1963	60														
11	1964	59														
12	1965	58														
13	1966	57														
14	1967	56														
15	1968	55														
16	1969	54														
17	1970	53				361,655	49,227	12,069	6,188,859	-		6,188,859		6,188,859		
18	1971	52				39,933	49,523	12,142	49,523	12,142		6,226,018		6,226,018		
19	1972	51					49,820	12,214	49,820	12,214		6,263,399		6,263,399		
20	1973	50					50,119	12,288	50,119	12,288		6,301,005		6,301,005		
21	1974	49				10,678	50,420	12,362	50,420	12,362		6,338,837		6,338,837		
22	1975	48					50,723	12,436	50,723	12,436		6,376,805		6,376,805		
23	1976	47					51,028	12,510	51,028	12,510		6,415,183		6,415,183		
24	1977	46					51,334	12,586	51,334	12,586		6,453,700		6,453,700		
25	1978	45					51,642	12,661	51,642	12,661		6,492,448		6,492,448		
26	1979	44					51,952	12,737	51,952	12,737		6,531,429		6,531,429		
27	1980	43					52,264	12,814	52,264	12,814		6,570,644		6,570,644		
28	1981	42				50,000	52,578	12,891	52,578	12,891		6,610,095		6,610,095		
29	1982	41				3,000	52,894	12,968	52,894	12,968		6,649,782		6,649,782		
30	1983	40					53,211	13,046	53,211	13,046		6,689,708		6,689,708		
31	1984	39					53,531	13,124	53,531	13,124		6,729,873		6,729,873		
32	1985	38				8,207	53,852	13,203	53,852	13,203		6,770,280		6,770,280		
33	1986	37				23,675	54,175	13,282	54,175	13,282		6,810,929		6,810,929		
34	1987	36				5,610	54,501	13,362	54,501	13,362		6,851,822		6,851,822		
35	1988	35				31,963	54,828	13,442	54,828	13,442		6,892,961		6,892,961		
36	1989	34	6,934,347	289,654	10,000	59,541	289,654	10,000	59,541	10,000		6,934,347	7,214,000	7,214,000		
37	1990	33		36,670		192,406	36,670		192,406			7,250,671	7,250,671	7,250,671		
38	1991	32		11,235	40,260		11,235	40,260				7,221,646	7,221,646	7,221,646		
39	1992	31		5,042,694	357,921	13,700	5,042,694	357,921			(4,701)	11,901,718	11,901,718	11,901,718		
40	1993	30		50,000	28,548		50,000	28,548				11,923,171	11,923,171	11,923,171		
41	1994	29										11,923,171	11,923,171	11,923,171		
42	1995	28		6,691	2,500		6,691	2,500				11,927,362	11,927,362	11,927,362		
43	1996	27		7,142			7,142					11,934,504	11,934,504	11,934,504		
44	1997	26										11,934,504	11,934,504	11,934,504		
45	1998	25		327,253	48,781		327,253	48,781				12,212,977	12,212,977	12,212,977		
46	1999	24		28,250	20,000		28,250	20,000				12,221,227	12,221,227	12,221,227		
47	2000	23		296,577	46,139	7,499	296,577	46,139				12,471,665	12,471,665	12,471,665		
48	2001	22		11,755			11,755					12,483,420	12,483,420	12,483,420		
49	2002	21		11,477	8,824		11,477	8,824				12,486,074	12,486,074	12,486,074		
50	2003	20		60,439	16,789		60,439	16,789				12,529,723	12,529,723	12,529,723		
51	2004	19		177,055	56,758		177,055	56,758				12,650,020	12,650,020	12,650,020		
52	2005	18		7,608			7,608					12,657,628	12,657,628	12,657,628		
53	2006	17		7,608			7,608					12,657,628	12,657,628	12,657,628		
54	2007	16		104,038	83,697		104,038	83,697			(282,577)	12,395,393	12,395,393	12,395,393		
55	2008	15		409,796	87,750		409,796	87,750			1,375	12,718,813	12,718,813	12,718,813		
56	Total		\$ 6,934,347	\$ 6,878,335	\$ 807,965	\$ 807,965	\$ 7,176,483	\$ 242,136	\$ 14,054,817	\$ 1,050,101	\$ (285,903)	\$ 131,098,213	\$ 230,776,500	\$ 361,874,713		
Major Additions/Retirements																
1992				\$ 5,042,694	\$ 357,921											
Routine Activity				\$ 1,835,640	\$ 450,044											
Historical Interim Activity				0.80%	0.20%											
Forecast Interim Activity				0.80%	0.20%											
57	2009	14							2,201,168	24,803				14,895,178		
60	2010	13							118,479	29,048				14,984,609		
61	2011	12							119,190	29,222				15,074,578		
62	2012	11							119,906	29,397				15,165,086		
63	2013	10							120,626	29,574				15,256,139		
64	2014	9							121,350	29,751				15,347,737		
65	2015	8							122,079	29,930				15,439,886		
66	2016	7							122,812	30,110				15,532,588		
67	2017	6							2,682,195	30,291				18,184,493		
68	2018	5							144,643	35,462				18,299,673		
69	2019	4							145,511	35,675				18,403,510		
70	2020	3							146,385	35,889				18,514,006		
71	2021	2							147,264	36,105				18,625,165		
72	2022	1							148,148	36,322				18,736,991		
73	2023	0										(18,736,991)				
												\$ 20,514,574	\$ 1,491,680		\$ 594,328,352	

Whole Life Depreciation Rate Calculation

Historical Additions	14,054,817
Forecast Additions	6,459,757
Total Additions	20,514,574
Gross Salvage Value	936,850
Less Cost of Removal	1,873,699
Net Salvage Value	(936,850)
Total to be Recovered	21,451,424
Forecast Plant Balances	594,328,352
Whole Life Accrual Rate	3.61%
Cost of Removal Accrual Rate	0.32%
Whole Life Accrual Rate (Excluding Cost of Removal)	3.92%
Depreciable Service Life, years	27.7

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	12,718,813
Forecast Additions	6,459,757
Gross Salvage Value	936,850
Less Cost of Removal	1,873,699
Net Salvage Value	(936,850)
Forecast Plant Balances	232,453,639

Black Hills Power

Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Neil Simpson 1 Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1969
 Retirement Date 2023
 Service Life, Yrs 54

2008

Historical and Forecast Plant Additions & Balances
 Account: 314 Turbogenerator Equipment

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books				Adjustments to Transaction				Transfers and Adjustments	BOY Plant Balance			
			Transaction Year		Vintage Year	Year		Adjusted Transaction Year		Adjustments		Per Books	Simulated		
			Book Balance	Additions		Retirements	Additions	Retirements	Additions					Retirements	
1	1954	69													
2	1955	68													
3	1956	67													
4	1957	66													
5	1958	65													
6	1959	64													
7	1960	63													
8	1961	62													
9	1962	51													
10	1963	60													
11	1964	59													
12	1965	58													
13	1966	57													
14	1967	56													
15	1968	55													
16	1969	54													
17	1970	53				16,262	11,272	861	11,272	861			2,516,254		2,516,254
18	1971	52				3,000	11,319	864	11,319	864			2,537,120		2,537,120
19	1972	51					11,366	868	11,366	868			2,547,618		2,547,618
20	1973	50					11,413	871	11,413	871			2,558,159		2,558,159
21	1974	49					11,460	875	11,460	875			2,568,744		2,568,744
22	1975	48					11,507	879	11,507	879			2,579,373		2,579,373
23	1976	47					11,555	882	11,555	882			2,590,046		2,590,046
24	1977	46					11,603	886	11,603	886			2,600,762		2,600,762
25	1978	45					11,651	889	11,651	889			2,611,524		2,611,524
26	1979	44					11,699	893	11,699	893			2,622,329		2,622,329
27	1980	43					11,747	897	11,747	897			2,633,180		2,633,180
28	1981	42					11,796	901	11,796	901			2,644,075		2,644,075
29	1982	41					11,845	904	11,845	904			2,655,015		2,655,015
30	1983	40					11,894	908	11,894	908			2,666,001		2,666,001
31	1984	39					11,943	912	11,943	912			2,677,032		2,677,032
32	1985	38					11,992	916	11,992	916			2,688,109		2,688,109
33	1986	37					12,042	919	12,042	919			2,699,232		2,699,232
34	1987	36					12,092	923	12,092	923			2,710,400		2,710,400
35	1988	35				159,525	12,142	927	12,142	927			2,721,615		2,721,615
36	1989	34	2,721,615	19,946					19,946					2,741,561	2,741,561
37	1990	33												2,741,561	2,741,561
38	1991	32		86,929	14,289				86,929	14,289				2,814,201	2,814,201
39	1992	31												2,814,201	2,814,201
40	1993	30		21,734	3,000				21,734	3,000				2,832,935	2,832,935
41	1994	29												2,832,935	2,832,935
42	1995	28												2,832,935	2,832,935
43	1996	27												2,832,935	2,832,935
44	1997	26												2,832,935	2,832,935
45	1998	25												2,832,935	2,832,935
46	1999	24												2,832,935	2,832,935
47	2000	23												2,832,935	2,832,935
48	2001	22		4,100					4,100					2,837,035	2,837,035
49	2002	21		81,398	159,525				81,398	159,525				2,758,908	2,758,908
50	2003	20												2,758,908	2,758,908
51	2004	19												2,795,124	2,795,124
52	2005	18		38,189	1,973				38,189	1,973				2,795,124	2,795,124
53	2006	17										71,333		2,866,457	2,866,457
54	2007	16												2,866,457	2,866,457
55	2008	15												2,866,457	2,866,457
56	Total		\$ 2,721,615	\$ 252,295	\$ 178,787	\$ 178,787	\$ 2,738,590	\$ 16,975	\$ 2,990,885	\$ 195,761	\$ 71,333	\$ 52,353,254	\$ 56,319,477	\$ 108,672,731	\$ 108,672,731

Major Additions/Retirements

2002		\$ 159,525
Routine Activity	\$ 252,295	\$ 19,262
Historical Interim Activity	0.45%	0.03%
Forecast Interim Activity	0.45%	0.03%

59	2009	14							12,841	980				2,878,317	2,878,317
60	2010	13							12,894	984				2,890,227	2,890,227
61	2011	12							12,947	988				2,902,180	2,902,180
62	2012	11							13,001	993				2,914,194	2,914,194
63	2013	10							13,055	997				2,926,252	2,926,252
64	2014	9							13,109	1,001				2,938,360	2,938,360
65	2015	8							13,163	1,005				2,950,518	2,950,518
66	2016	7							13,217	1,009				2,962,727	2,962,727
67	2017	6							13,272	1,013				2,974,986	2,974,986
68	2018	5							13,327	1,017				2,987,295	2,987,295
69	2019	4							13,382	1,022				2,999,656	2,999,656
70	2020	3							13,438	1,026				3,012,067	3,012,067
71	2021	2							13,495	1,030				3,024,531	3,024,531
72	2022	1							13,549	1,034				3,037,045	3,037,045
73	2023	0										(3,037,045)		-	-
													\$ 3,175,574	\$ 209,862	\$ 150,071,092

Whole Life Depreciation Rate Calculation

Historical Additions	2,990,885
Forecast Additions	184,689
Total Additions	3,175,574
Gross Salvage Value	151,852
Less Cost of Removal	303,705
Net Salvage Value	(151,852)
Total to be Recovered	3,327,426
Forecast Plant Balances	150,071,092
Whole Life Accrual Rate	2.22%
Cost of Removal Accrual Rate	0.20%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.42%
Depreciable Service Life, years	41.3

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	2,866,457
Forecast Additions	184,689
Gross Salvage Value	151,852
Less Cost of Removal	303,705
Net Salvage Value	(151,852)
Forecast Plant Balances	41,398,361

Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1969
 Retirement Date 2023
 Service Life, Yrs 54

2008

Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Neil Stimpson 1 Plant

Historical and Forecast Plant Additions & Balances
 Account: 315 Accessory Electric Equipment

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books				Adjustments to Transaction				Transfers and Adjustments	BOY Plant Balance				
			Transaction Year			Vintage Year Retirements	Year		Adjusted Transaction Year			Adjustments	Per Books	Simulated		
			Begin Balance	Additions	Retirements		Additions	Retirements	Additions	Retirements						
1	1954	69				710										
2	1955	68														
3	1956	67														
4	1957	66														
5	1958	65														
6	1959	64														
7	1960	63														
8	1961	62														
9	1962	61														
10	1963	60														
11	1964	59														
12	1965	58														
13	1966	57				858										
14	1967	56														
15	1968	55														
16	1969	54								533,278			533,278			533,278
17	1970	53				39,960	5,402	2,451	5,402	2,451			536,229			536,229
18	1971	52					5,431	2,465	5,431	2,465			539,196			539,196
19	1972	51					5,462	2,478	5,462	2,478			542,179			542,179
20	1973	50					5,492	2,492	5,492	2,492			545,179			545,179
21	1974	49					5,522	2,506	5,522	2,506			548,195			548,195
22	1975	48					5,553	2,520	5,553	2,520			551,228			551,228
23	1976	47					5,583	2,534	5,583	2,534			554,278			554,278
24	1977	46					5,614	2,548	5,614	2,548			557,345			557,345
25	1978	45					5,645	2,562	5,645	2,562			560,428			560,428
26	1979	44					5,677	2,576	5,677	2,576			563,529			563,529
27	1980	43					5,708	2,590	5,708	2,590			566,647			566,647
28	1981	42					5,740	2,604	5,740	2,604			569,782			569,782
29	1982	41					5,771	2,619	5,771	2,619			572,935			572,935
30	1983	40				16,950	5,803	2,633	5,803	2,633			576,105			576,105
31	1984	39					5,835	2,648	5,835	2,648			579,292			579,292
32	1985	38					5,868	2,663	5,868	2,663			582,497			582,497
33	1986	37					5,900	2,677	5,900	2,677			585,720			585,720
34	1987	36					5,933	2,692	5,933	2,692			588,961			588,961
35	1988	35					5,966	2,707	5,966	2,707			592,219			592,219
36	1989	34	592,219	9,579				9,579						601,798		601,798
37	1990	33												601,798		601,798
38	1991	32		5,696	8,916		5,696	8,916		8,916				598,578		598,578
39	1992	31		1,892			1,892					(9,579)		590,891		590,891
40	1993	30												590,891		590,891
41	1994	29												590,891		590,891
42	1995	28												590,891		590,891
43	1996	27												590,891		590,891
44	1997	26												590,891		590,891
45	1998	25		72,341	31,044									632,188		632,188
46	1999	24												632,188		632,188
47	2000	23												632,188		632,188
48	2001	22												632,188		632,188
49	2002	21		39,365	18,518									653,035		653,035
50	2003	20												653,035		653,035
51	2004	19												653,035		653,035
52	2005	18												653,035		653,035
53	2006	17												653,035		653,035
54	2007	16											91,849	744,885		744,885
55	2008	15												744,885		744,885
56	Total		\$ 592,219	\$ 128,873	\$ 58,478	\$ 58,478	\$ 641,183	\$ 48,964	\$ 770,056	\$ 107,442	\$ 82,270	\$ 11,245,221	\$ 12,723,066	\$ 23,968,287		

Major Additions/Retirements

	Routine Activity	\$ 128,873	
57	Historical Interim Activity	1.01%	0.465%
58	Forecast Interim Activity	1.01%	0.465%

59	2009	14	7,545	3,424	749,006
60	2010	13	7,387	3,443	753,150
61	2011	12	7,629	3,462	757,317
62	2012	11	7,671	3,481	761,507
63	2013	10	7,713	3,500	765,720
64	2014	9	7,756	3,519	769,957
65	2015	8	7,799	3,539	774,217
66	2016	7	7,842	3,558	778,501
67	2017	6	7,885	3,578	782,808
68	2018	5	7,929	3,598	787,139
69	2019	4	7,973	3,618	791,494
70	2020	3	8,017	3,638	795,873
71	2021	2	8,061	3,658	800,277
72	2022	1	8,106	3,678	804,705
73	2023	0			
			\$ 879,570	\$ 157,135	\$ 34,839,958

Whole Life Depreciation Rate Calculation

Historical Additions	770,056
Forecast Additions	109,514
Total Additions	879,570
Gross Salvage Value	40,235
Less Cost of Removal	80,470
Net Salvage Value	(40,235)
Total to be Recovered	919,805
Forecast Plant Balances	34,839,958
Whole Life Accrual Rate	2.64%
Cost of Removal Accrual Rate	0.23%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.87%
Depreciable Service Life, years	34.8

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08	744,885
Forecast Additions	109,514
Gross Salvage Value	40,235
Less Cost of Removal	80,470
Net Salvage Value	(40,235)
Forecast Plant Balances	10,871,672

Black Hills Power

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1969
 Retirement Date 2023
 Service Life, Yrs 54

Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Neil Simpson 1 Plant

2008

Historical and Forecast Plant Additions & Balances
 Account: 316 Miscellaneous Plant Equipment

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction Year				Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year			Year		Year		Adjustments	Per Books		Simulated		
			Beg. Balance	Additions	Retirements	Additions	Retirements	Additions	Retirements						
1	1954	69													
2	1955	68													
3	1956	67													
4	1957	66													
5	1958	65													
6	1959	64													
7	1960	63													
8	1961	62													
9	1962	61													
10	1963	60													
11	1964	59													
12	1965	58													
13	1966	57													
14	1967	56													
15	1968	55													
16	1969	54							300,112			300,112		300,112	
17	1970	53				64,347	3,108		3,108			303,220		303,220	
18	1971	52					3,141		3,141			306,361		306,361	
19	1972	51					3,173		3,173			309,534		309,534	
20	1973	50					3,206		3,206			312,740		312,740	
21	1974	49					3,239		3,239			315,979		315,979	
22	1975	48					3,273		3,273			319,252		319,252	
23	1976	47					3,307		3,307			322,559		322,559	
24	1977	46					3,341		3,341			325,900		325,900	
25	1978	45					3,376		3,376			329,275		329,275	
26	1979	44					3,411		3,411			332,686		332,686	
27	1980	43					3,446		3,446			336,132		336,132	
28	1981	42					3,482		3,482			339,613		339,613	
29	1982	41					3,518		3,518			343,131		343,131	
30	1983	40					3,554		3,554			346,685		346,685	
31	1984	39					3,591		3,591			350,276		350,276	
32	1985	38					3,628		3,628			353,904		353,904	
33	1986	37					3,666		3,666			357,569		357,569	
34	1987	36					3,704		3,704			361,273		361,273	
35	1988	35					3,742		3,742			365,015		365,015	
36	1989	34	365,015	17,009			17,009		17,009			382,024	382,024	382,024	
37	1990	33		6,448	64,347		6,448		6,448	64,347		324,125	324,125	324,125	
38	1991	32		4,170			4,170		4,170			328,295	328,295	328,295	
39	1992	31		12,917			12,917		12,917			341,211	341,211	341,211	
40	1993	30										344,211	344,211	344,211	
41	1994	29		25,487			25,487		25,487			366,699	366,699	366,699	
42	1995	28										366,699	366,699	366,699	
43	1996	27		5,371			5,371		5,371			372,070	372,070	372,070	
44	1997	26		399			399		399			372,469	372,469	372,469	
45	1998	25		2,297			2,297		2,297			374,765	374,765	374,765	
46	1999	24										374,765	374,765	374,765	
47	2000	23										374,765	374,765	374,765	
48	2001	22										374,765	374,765	374,765	
49	2002	21										374,765	374,765	374,765	
50	2003	20		2,729			2,729		2,729			377,494	377,494	377,494	
51	2004	19		763			763		763			378,257	378,257	378,257	
52	2005	18										378,257	378,257	378,257	
53	2006	17									51,210	429,468	429,468	429,468	
54	2007	16										429,468	429,468	429,468	
55	2008	15										429,468	429,468	429,468	
56	Total		\$ 365,015	\$ 77,590	\$ 64,347	\$ 64,347	\$ 365,015	\$ -	\$ 442,604	\$ 64,347	\$ 51,210	\$ 6,631,213	\$ 7,491,039	\$ 14,122,252	

Major Additions/Retirements

1990

Routine Activity

Historical Interim Activity

Forecast Interim Activity

57

58

59

60

61

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64

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66

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72

73

2009 14

2010 13

2011 12

2012 11

2013 10

2014 9

2015 8

2016 7

2017 6

2018 5

2019 4

2020 3

2021 2

2022 1

2023 0

\$ 509,252 \$ 64,347

Whole Life Depreciation Rate Calculation

Historical Additions 442,604

Forecast Additions 66,647

Total Additions 509,252

Gross Salvage Value 24,806

Less Cost of Removal 49,612

Net Salvage Value (24,806)

Total to be Recovered 534,058

Forecast Plant Balances 20,623,499

Whole Life Accrual Rate 2.59%

Cost of Removal Accrual Rate 0.24%

Whole Life Accrual Rate (Excluding Cost of Removal) 2.83%

Depreciable Service Life, years 38.6

Remaining Life Depreciation Rate Calculation

Account Balance - 12/31/08 429,468

Forecast Additions 66,647

Gross Salvage Value 24,806

Less Cost of Removal 49,612

Net Salvage Value (24,806)

Forecast Plant Balances 6,501,247

Summary by Plant
 Black Hills Power
 Neil Simpson 2 Facility

Account	Description	Direct Investment 2008\$	Depreciation Rate
310	Land		
311	Structure & Improvements	13,248,871	2.73%
312	Boiler Plant Equipment	75,551,337	2.87%
313	Engines & Engine Driven Generators		
314	Turbo Generator Equipment	29,102,926	2.59%
315	Accessory Electric Equipment	6,272,379	2.58%
316	Misc Power Equipment	479,676	7.23%
Total		124,655,189	2.79% whole life weighted average rate

Remaining Life Depreciation Rate Calculation

Per Books Balance 12/31/08	125,534,971
Forecast Interim Additions	29,159,701
Forecast Gross Salvage Value	7,637,352
Forecast Less Cost of Removal	15,274,704
Forecast Net Salvage Value	(7,637,352)
Forecast Total to be Recovered with COR	162,332,024
Forecast Total to be Recovered w/o COR	147,057,320
Accumulated Depreciation (2008 EOY)	(38,724,257)
Forecast Remaining Life Balance with COR	123,607,767
Forecast Remaining Life Balance w/o COR	108,333,063
Forecast Plant Balances	4,957,526,249
Remaining Life Rate with COR	2.49%
Remaining Life Rate w/o COR	2.19%

Black Hills Power Company
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Neil Simpson 2 Plant
 Historical and Forecast Plant Additions & Balances
 Account: 311 Structures & Improvements

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1998
 Retirement Date 2045
 Service Life, Yrs 47
 Initial Plant Balance 0

2008

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance			
			Transaction Year		Vintage Year Retirements	Year		Year			Adjustments	Per Books	Simulated	
			Beg. Balance	Additions		Retirements	Additions	Retirements	Additions					Retirements
41	1998	47		11,540,435		17,822						11,540,435	11,540,435	
42	1999	46		322,184					624,511			12,487,130	12,487,130	
43	2000	45		87,340								12,574,470	12,574,470	
44	2001	44										12,574,470	12,574,470	
45	2002	43		5,484				5,484				12,579,954	12,579,954	
46	2003	42		22,835				22,835				12,602,789	12,602,789	
47	2004	41		338,036				338,036				12,940,825	12,940,825	
48	2005	40										12,940,825	12,940,825	
49	2006	39		84,446				84,446		165,739		13,191,009	13,191,009	
50	2007	38		76,060	17,822			76,060	17,822	(376)		13,248,871	13,248,871	
51	2008	37										13,248,871	13,248,871	
52	Total		\$ -	\$ 12,476,819	\$ 17,822	\$ 17,822	\$ -	\$ -	\$ 12,476,819	\$ 17,822	\$ 789,874	\$ -	\$ 139,929,647	\$ 139,929,647

Major Additions/Retirements
 1998

\$ 11,540,435

Routine Activity

\$ 936,383

53 Historical Interim Activity

0.67% 0.01%

54 Forecast Interim Activity

0.67% 0.01%

55	2009	36						88,659	1,687				13,335,842	
56	2010	35						89,241	1,699				13,423,385	
57	2011	34						89,827	1,710				13,511,502	
58	2012	33						90,416	1,721				13,600,197	
59	2013	32						91,010	1,732				13,689,475	
60	2014	31						91,607	1,744				13,779,339	
61	2015	30						92,209	1,755				13,869,793	
62	2016	29						92,814	1,767				13,960,840	
63	2017	28						93,423	1,778				14,052,486	
64	2018	27						94,037	1,790				14,144,732	
65	2019	26						94,654	1,802				14,237,585	
66	2020	25						95,275	1,813				14,331,047	
67	2021	24						95,901	1,825				14,425,122	
68	2022	23						96,530	1,837				14,519,815	
69	2023	22						97,164	1,849				14,615,130	
70	2024	21						97,802	1,861				14,711,070	
71	2025	20						98,444	1,874				14,807,640	
72	2026	19						99,090	1,886				14,904,844	
73	2027	18						99,740	1,898				15,002,686	
74	2028	17						100,395	1,911				15,101,171	
75	2029	16						101,054	1,923				15,200,302	
76	2030	15						101,718	1,936				15,300,083	
77	2031	14						102,385	1,949				15,400,520	
78	2032	13						103,057	1,962				15,501,616	
79	2033	12						103,734	1,974				15,603,375	
80	2034	11						104,415	1,987				15,705,803	
81	2035	10						105,100	2,000				15,808,903	
82	2036	9						105,790	2,014				15,912,680	
83	2037	8						106,485	2,027				16,017,137	
84	2038	7						107,184	2,040				16,122,281	
85	2039	6						107,887	2,053				16,228,115	
86	2040	5						108,596	2,067				16,334,644	
87	2041	4						109,308	2,080				16,441,872	
88	2042	3						110,026	2,094				16,549,803	
89	2043	2						110,748	2,108				16,658,444	
90	2044	1						111,475	2,122				16,767,797	
91	2045	0								(16,767,797)			-	
									\$ 16,064,021	\$ 86,098				\$ 679,506,724

Whole Life Depreciation Rate Calculation

Historical Additions	12,476,819
Forecast Additions	3,587,202
Total Additions	16,064,021
Gross Salvage Value	838,390
Less Cost of Removal	1,676,780
Net Salvage Value	(838,390)
Total to be Recovered	16,902,411

Forecast Plant Balances 679,506,724

Whole Life Accrual Rate 2.49%

Cost of Removal Accrual Rate 0.25%

Whole Life Accrual Rate (Excluding Cost of Removal) 2.73%

Depreciable Service Life, years 40.2

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	13,248,871
Forecast Additions	3,587,202
Gross Salvage Value	838,390
Less Cost of Removal	1,676,780
Net Salvage Value	(838,390)
Forecast Plant Balances	539,577,076

Black Hills Power Company
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Neil Simpson 2 Plant
 Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1998
 Retirement Date 2045
 Service Life, Yrs. 47
 2008

Historical and Forecast Plant Additions & Balances
 Account: 312 Boiler Plant Equipment
 Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Vintage Year	Adjustments to Transaction		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year				Year		Year			Per Books	Simulated	
			Beq Balance	Additions	Retirements		Additions	Retirements	Additions	Retirements				
13	1970	75				6,013	-	-	-	-	-	-	-	-
14	1971	74					-	-	-	-	-	-	-	-
15	1972	73					-	-	-	-	-	-	-	-
16	1973	72					-	-	-	-	-	-	-	-
17	1974	71					-	-	-	-	-	-	-	-
18	1975	70					-	-	-	-	-	-	-	-
19	1976	69					-	-	-	-	-	-	-	-
20	1977	68					-	-	-	-	-	-	-	-
21	1978	67					-	-	-	-	-	-	-	-
22	1979	66					-	-	-	-	-	-	-	-
23	1980	65					-	-	-	-	-	-	-	-
24	1981	64					-	-	-	-	-	-	-	-
25	1982	63					-	-	-	-	-	-	-	-
26	1983	62					-	-	-	-	-	-	-	-
27	1984	61					-	-	-	-	-	-	-	-
28	1985	60					-	-	-	-	-	-	-	-
29	1986	59					-	-	-	-	-	-	-	-
30	1987	58					-	-	-	-	-	-	-	-
31	1988	57					6,533	-	-	-	-	-	-	-
32	1989	56						-	-	-	-	-	-	-
33	1990	55						-	-	-	-	-	-	-
34	1991	54						-	-	-	-	-	-	-
35	1992	53						-	-	-	-	-	-	-
36	1993	52						-	-	-	-	-	-	-
37	1994	51						-	-	-	-	-	-	-
38	1995	50						-	-	-	-	-	-	-
39	1996	49						-	-	-	-	-	-	-
40	1997	48		28,341					28,341	-			28,341	28,341
41	1998	47		74,009,175	6,533	1,658,776			74,009,175	6,533			74,030,983	74,030,983
42	1999	46		869,214	30,316				869,214	30,316	(467,515)		74,402,366	74,402,366
43	2000	45		587,861	31,013				587,861	31,013			74,959,214	74,959,214
44	2001	44		105,595	112,000				105,595	112,000			74,952,809	74,952,809
45	2002	43		135,029	3,344				135,029	3,344			75,084,494	75,084,494
46	2003	42		77,435					77,435				75,161,928	75,161,928
47	2004	41		380,167	50,060				380,167	50,060			75,492,095	75,492,095
48	2005	40		16,469	8,484				16,469	8,484			75,500,080	75,500,080
49	2006	39									183,186		75,683,266	75,683,266
50	2007	38		1,293,706	1,429,632				1,293,706	1,429,632	3,997		75,551,337	75,551,337
51	2008	37											75,551,337	75,551,337
52	Total			\$ 77,502,991	\$ 1,671,322	\$ 1,671,322	\$ -	\$ -	\$ 77,502,991	\$ 1,671,322	\$ (280,332)	\$ -	\$ 826,398,249	\$ 826,398,249

Major Additions/Retirements

1998	\$ 74,037,516	
2007	\$ 1,293,706	\$ 1,429,632
Routine Activity	\$ 2,171,769	\$ 241,690
53 Historical Interim Activity	0.26%	0.03%
54 Forecast Interim Activity	0.26%	0.03%

55	2009	36						198,548	22,096					75,727,789
56	2010	35						199,012	22,148					75,904,654
57	2011	34						199,477	22,199					76,081,931
58	2012	33						1,775,881	22,251					77,835,561
59	2013	32						204,551	22,764					78,017,348
60	2014	31						205,029	22,817					78,199,560
61	2015	30						205,508	22,870					78,382,198
62	2016	29						205,988	22,924					78,565,262
63	2017	28						206,469	22,977					78,748,753
64	2018	27						206,951	23,031					78,932,673
65	2019	26						2,080,730	23,085					80,990,318
66	2020	25						212,842	23,687					81,179,473
67	2021	24						213,339	23,742					81,369,071
68	2022	23						213,837	23,797					81,559,111
69	2023	22						214,337	23,853					81,749,594
70	2024	21						214,837	23,909					81,940,523
71	2025	20						215,339	23,965					82,131,898
72	2026	19						2,442,601	24,020					84,550,478
73	2027	18						222,198	24,728					84,747,948
74	2028	17						222,717	24,786					84,945,880
75	2029	16						223,237	24,843					85,144,274
76	2030	15						223,759	24,901					85,343,131
77	2031	14						224,281	24,960					85,542,452
78	2032	13						224,805	25,018					85,742,239
79	2033	12						2,872,247	25,076					88,389,410
80	2034	11						235,312	25,909					88,790,313
81	2035	10						233,356	25,970					89,003,700
82	2036	9						233,901	26,030					89,211,570
83	2037	8						234,447	26,091					89,419,927
84	2038	7						234,993	26,152					89,628,770
85	2039	6						235,544	26,213					89,838,101
86	2040	5						3,382,446	26,274					93,194,272
87	2041	4						244,914	27,236					93,411,930
88	2042	3						245,486	27,319					93,630,097
89	2043	2						246,059	27,383					93,848,773
90	2044	1						246,634	27,447					94,067,559
91	2045	0									(94,067,559)			-
								\$ 90,902,106	\$ 2,553,814					\$ 3,862,371,189

Whole Life Depreciation Rate Calculation

Historical Additions	77,502,991
Forecast Additions	19,399,115
Total Additions	96,902,106
Gross Salvage Value	4,703,398
Less Cost of Removal	9,406,796
Net Salvage Value	(4,703,398)
Total to be Recovered	101,605,504

Forecast Plant Balances 3,862,371,189

Whole Life Accrual Rate 2.63%
 Cost of Removal Accrual Rate 0.24%
 Whole Life Accrual Rate (Excluding Cost of Removal) 2.87%

Depreciable Service Life, years 38.0

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	75,551,337
Forecast Additions	19,399,115
Gross Salvage Value	4,703,398
Less Cost of Removal	9,406,796
Net Salvage Value	(4,703,398)

Forecast Plant Balances 3,035,972,939

Black Hills Power Company
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Neil Simpson 2 Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1998
 Retirement Date 2045
 Service Life, Yrs 47

2008

Historical and Forecast Plant Additions & Balances
 Account: 314 Turbogenerator Equipment

Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books				Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance		
			Transaction Year			Vintage Year Retirements	Additions	Retirements	Additions	Retirements		Adjustments	Per Books	Simulated
			Beg Balance	Additions	Retirements									
41	1998	47		27,051,645		192,000			27,051,645	-		27,051,645	27,051,645	
42	1999	46								(77,928)		26,973,718	26,973,718	
43	2000	45		37,085				37,085				27,010,803	27,010,803	
44	2001	44		3,265				3,265				27,014,068	27,014,068	
45	2002	43		1,713,883				1,713,883				28,727,951	28,727,951	
46	2003	42		121,566				121,566				28,849,517	28,849,517	
47	2004	41		76,317				76,317				28,925,834	28,925,834	
48	2005	40										28,925,834	28,925,834	
49	2006	39		285,377	192,000			285,377	192,000	7,967		29,027,178	29,027,178	
50	2007	38		75,749				75,749				29,102,926	29,102,926	
51	2008	37										29,102,926	29,102,926	
52	Total		\$ -	\$ 29,364,887	\$ 192,000	\$ 192,000	\$ -	\$ -	\$ 29,364,887	\$ 192,000	\$ (69,961)	\$ -	\$ 310,712,400	\$ 310,712,400

Major Additions/Retirements

1998	\$ 27,051,645	
2002	\$ 1,713,883	
Routine Activity	\$ 599,359	\$ 192,000
53 Historical Interim Activity	0.19%	0.06%
54 Forecast Interim Activity	0.19%	0.00%

55	2009	36						56,139	-			29,159,066	29,159,066
56	2010	35						56,247	-			29,215,313	29,215,313
57	2011	34						56,356	-			29,271,669	29,271,669
58	2012	33						56,465	-			29,328,133	29,328,133
59	2013	32						56,574	-			29,384,707	29,384,707
60	2014	31						56,683	-			29,441,390	29,441,390
61	2015	30						56,792	-			29,498,181	29,498,181
62	2016	29						56,902	-			29,555,083	29,555,083
63	2017	28						57,011	-			29,612,094	29,612,094
64	2018	27						57,121	-			29,669,216	29,669,216
65	2019	26						57,231	-			29,726,447	29,726,447
66	2020	25						57,342	-			29,783,789	29,783,789
67	2021	24						57,452	-			29,841,241	29,841,241
68	2022	23						57,563	-			29,898,805	29,898,805
69	2023	22						57,674	-			29,956,479	29,956,479
70	2024	21						57,786	-			30,014,264	30,014,264
71	2025	20						57,897	-			30,072,162	30,072,162
72	2026	19						58,009	-			30,130,170	30,130,170
73	2027	18						58,121	-			30,188,291	30,188,291
74	2028	17						58,233	-			30,246,524	30,246,524
75	2029	16						58,345	-			30,304,869	30,304,869
76	2030	15						58,458	-			30,363,326	30,363,326
77	2031	14						58,570	-			30,421,897	30,421,897
78	2032	13						58,683	-			30,480,580	30,480,580
79	2033	12						58,797	-			30,539,377	30,539,377
80	2034	11						58,910	-			30,598,286	30,598,286
81	2035	10						59,024	-			30,657,310	30,657,310
82	2036	9						59,137	-			30,716,448	30,716,448
83	2037	8						59,252	-			30,775,699	30,775,699
84	2038	7						59,366	-			30,835,065	30,835,065
85	2039	6						59,480	-			30,894,545	30,894,545
86	2040	5						59,595	-			30,954,140	30,954,140
87	2041	4						59,710	-			31,013,850	31,013,850
88	2042	3						59,825	-			31,073,676	31,073,676
89	2043	2						59,941	-			31,133,616	31,133,616
90	2044	1						60,056	-			31,193,672	31,193,672
91	2045	0								(31,193,672)			
								\$ 31,455,633	\$ 192,000				\$ 1,396,661,779

Whole Life Depreciation Rate Calculation

Historical Additions	29,364,887
Forecast Additions	2,090,746
Total Additions	31,455,633
Gross Salvage Value	1,559,684
Less Cost of Removal	3,119,367
Net Salvage Value	(1,559,684)
Total to be Recovered	33,015,317

Forecast Plant Balances 1,396,661,779

Whole Life Accrual Rate	2.36%
Cost of Removal Accrual Rate	0.22%
Whole Life Accrual Rate (Excluding Cost of Removal)	2.59%

Depreciable Service Life, years 42.3

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	29,102,926
Forecast Additions	2,090,746
Gross Salvage Value	1,559,684
Less Cost of Removal	3,119,367
Net Salvage Value	(1,559,684)

Forecast Plant Balances 1,085,949,379

Black Hills Power Company
 Unit Property Depreciation Rate Analysis
 Unit Property: Steam Production, Neil Simpson 2 Plant

Gross Salvage 5%
 Cost of Removal 10%
 Net Salvage -5%
 Install Date 1998
 Retirement Date 2045
 Service Life, Yrs 47

2008

Historical and Forecast Plant Additions & Balances
 Account: 316 Miscellaneous Power Equipment Initial Plant Balance 0

Line	Vintage Year	Vintage Age	Reported Per Books			Adjustments to Transaction Year		Adjusted Transaction Year		Transfers and Adjustments	EOY Plant Balance			
			Transaction Year		Vintage Year Retirements	Year		Retirements			Adjustments	Per Books	Simulated	
			Beg. Balance	Additions		Additions	Retirements							
41	1998	47		279,045				279,045	-		279,045	279,045		
42	1999	46		6,941			6,941	-	(79,068)		206,917	206,917		
43	2000	45		13,614			13,614	-	38,764		259,296	259,296		
44	2001	44		43,205			43,205	-			302,500	302,500		
45	2002	43		7,852			7,852	-			310,352	310,352		
46	2003	42		35,386			35,386	-			345,739	345,739		
47	2004	41		21,531			21,531	-			367,270	367,270		
48	2005	40		69,107			69,107	-			436,377	436,377		
49	2006	39		25,198	7,978	7,978	25,198	7,978	5,965		459,562	459,562		
50	2007	38									459,562	459,562		
51	2008	37		20,114			20,114				479,676	479,676		
52	Total		\$ -	\$ 521,993	\$ 7,978	\$ 7,978	\$ -	\$ -	\$ 521,993	\$ 7,978	\$ (34,340)	\$ -	\$ 3,906,296	\$ 3,906,296

Major Additions/Retirements
 1998

Routine Activity \$ 242,948
 Historical Interim Activity 6.22% 0.20%
 Forecast Interim Activity 6.22% 0.20%

55	2009	36					29,833	980			508,529	
56	2010	35					31,627	1,039			539,118	
57	2011	34					33,530	1,101			571,547	
58	2012	33					35,547	1,167			605,927	
59	2013	32					37,685	1,237			642,374	
60	2014	31					39,952	1,312			681,014	
61	2015	30					42,355	1,391			721,978	
62	2016	29					44,903	1,474			765,407	
63	2017	28					47,604	1,563			811,447	
64	2018	27					50,467	1,657			860,257	
65	2019	26					53,503	1,757			912,003	
66	2020	25					56,721	1,863			966,862	
67	2021	24					60,133	1,975			1,025,020	
68	2022	23					63,750	2,093			1,086,677	
69	2023	22					67,585	2,219			1,152,043	
70	2024	21					71,650	2,353			1,221,340	
71	2025	20					75,960	2,494			1,294,806	
72	2026	19					80,529	2,644			1,372,691	
73	2027	18					85,373	2,803			1,455,261	
74	2028	17					90,508	2,972			1,542,797	
75	2029	16					95,953	3,151			1,635,599	
76	2030	15					101,724	3,340			1,733,983	
77	2031	14					107,843	3,541			1,838,285	
78	2032	13					114,330	3,754			1,948,862	
79	2033	12					121,207	3,980			2,066,089	
80	2034	11					128,498	4,219			2,190,368	
81	2035	10					136,228	4,473			2,322,122	
82	2036	9					144,422	4,742			2,461,802	
83	2037	8					153,109	5,028			2,609,884	
84	2038	7					162,319	5,330			2,766,873	
85	2039	6					172,083	5,651			2,933,306	
86	2040	5					182,434	5,990			3,109,749	
87	2041	4					193,408	6,351			3,296,806	
88	2042	3					205,042	6,733			3,495,115	
89	2043	2					217,375	7,138			3,705,352	
90	2044	1					230,451	7,567			3,928,236	
91	2045	0								(3,928,236)		
							\$ 4,087,636	\$ 125,060				\$ 64,685,826

Whole Life Depreciation Rate Calculation

Historical Additions	521,993
Forecast Additions	3,565,643
Total Additions	4,087,636
Gross Salvage Value	196,412
Less Cost of Removal	392,824
Net Salvage Value	(196,412)
Total to be Recovered	4,284,047

Forecast Plant Balances 64,685,826

Whole Life Accrual Rate	6.62%
Cost of Removal Accrual Rate	0.61%
Whole Life Accrual Rate (Excluding Cost of Removal)	7.23%
Depreciable Service Life, years	15.1

Remaining Life Depreciation Rate Calculation

Account Balance 12/31/08	479,676
Forecast Additions	3,565,643
Gross Salvage Value	196,412
Less Cost of Removal	392,824
Net Salvage Value	(196,412)
Forecast Plant Balances	60,779,529

EXHIBIT __ (LK-20)

Docket No. EL14-026
 Black Hills Power, Inc.
 BHII Adjustment to Depreciation Expense - Production
 (\$ Millions)

Description	As Filed Depreciable Plant In Service	As Filed Depreciation Rate	As Filed Depreciation Expense	BHII Adjusted Depreciation Rate	BHII Adjusted Depreciation Expense	BHII Adjustment Total Company	South Dakota Retail %	BHII Adjustment South Dakota
Steam Production- by Plant								
Ben French	-		-		-	-	89.831%	-
Neil Simpson	-		-		-	-	89.831%	-
Neil Simpson II	153,367,574	2.90%	4,447,660	2.58%	3,956,883	(490,776)	89.831%	(440,869)
Osage	-		-		-	-	89.831%	-
Wygen III	134,929,287	2.64%	3,562,133	2.44%	3,292,275	(269,859)	89.831%	(242,417)
Wyodak	111,009,656	2.86%	3,174,876	2.53%	2,808,544	(366,332)	89.831%	(329,080)
CPGS	92,250,624	3.29%	3,035,046	2.88%	Adjusted in Separate Adjustment		89.831%	-
Other Production	83,199,162	2.50%	2,079,979	2.34%	1,946,860	(133,119)	89.831%	(119,582)
Total Production Plant Sum	574,756,303		16,299,694		12,004,563	(1,260,085)		(1,131,947)
Transmission	109,287,969	2.26%	2,469,908	2.26%	2,469,908	-		-
Distribution	331,966,699	2.70%	8,963,101	2.70%	8,963,101	-		-
General	50,440,557	4.62%	1,635,464	4.62%	1,635,464	-		-
Other Utility Plant	27,796,131	7.65%	2,126,404	7.65%	2,126,404	-		-
Subtotal Plant in Service Sum	1,094,247,659		31,494,570		27,199,439	(1,260,085)		(1,131,947)
Plant Acquisition Adjustment	4,870,308	2.00%	97,406	2.00%	97,406	-		-
Total Depreciable Plant In Service	1,099,117,967		31,591,976		27,296,846	(1,260,085)		(1,131,947)
Accumulated Depreciation One Half of Depreciation Expense Reduction (See Statement E Note 3)						(630,043)		
Decrease Accumulated Depreciation for Expense Reduction The Effect Increases Rate Base						630,043	89.831%	565,974
Accumulated Deferred Income Taxes (See Schedule M-2) Book Depreciation Expense Reduction						(1,260,085)		
Federal Income Tax Rate						0.35		
Increase ADIT for Expense Reduction The Effect Decreases Rate Base		(100% of Expense Reduction x tax rate)				(441,030)	89.831%	(396,182)

BLACK HILLS POWER, INC.
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2012

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL		COMPOSITE REMAIN LIFE (IX)
						AMOUNT (X)	PERCENT (XI)	
STEAM PRODUCTION PLANT								
BEN FRENCH STATION								
311.00	Structures & Improvements	(28)	2,251,067	2,470,217	411,149	225,045	10.00%	1.8
312.01	Boiler Plant Equipment	(28)	6,842,536	6,971,855	1,786,590	985,304	14.40%	1.8
314.00	Turbogenerator Units	(28)	3,956,116	3,267,891	1,795,937	987,811	24.97%	1.8
315.00	Accessory Electrical Equipment	(28)	756,487	817,196	151,107	83,050	10.98%	1.8
316.00	Misc. Power Plant Equip.	(28)	461,438	529,424	61,216	33,837	7.33%	1.8
	Total		<u>14,267,643</u>	<u>14,056,583</u>	<u>4,205,999</u>	<u>2,315,047</u>	16.23%	1.8
NEIL SIMPSON I								
311.00	Structures & Improvements	(13)	2,263,790	2,055,490	502,593	275,250	12.16%	1.8
312.01	Boiler Plant Equipment	(13)	14,327,825	10,348,851	5,841,591	3,210,557	22.41%	1.8
314.00	Turbogenerator Units	(13)	3,916,967	2,797,900	1,628,273	896,130	22.88%	1.8
315.00	Accessory Electrical Equipment	(13)	1,334,432	622,246	885,662	484,612	36.32%	1.8
316.00	Misc. Power Plant Equip.	(13)	424,995	434,602	45,643	25,339	5.96%	1.8
	Total		<u>22,268,009</u>	<u>16,259,089</u>	<u>8,903,762</u>	<u>4,891,888</u>	21.97%	1.8
NEIL SIMPSON II								
311.00	Structures & Improvements	(5)	15,863,029	5,523,394	11,132,787	365,194	2.30%	30.5
312.01	Boiler Plant Equipment	(5)	76,897,107	26,330,450	54,411,512	1,962,062	2.55%	27.7
314.00	Turbogenerator Units	(5)	41,534,098	11,029,471	32,581,332	1,146,664	2.76%	28.4
315.00	Accessory Electrical Equipment	(5)	8,429,093	2,511,631	6,338,917	205,937	2.44%	30.8
316.00	Misc. Power Plant Equip.	(5)	875,989	165,386	754,403	28,132	3.21%	26.8
	Total		<u>143,599,317</u>	<u>45,560,332</u>	<u>105,218,951</u>	<u>3,707,989</u>	2.58%	28.4
OSAGE								
311.00	Structures & Improvements	(22)	4,233,378	4,422,755	741,966	406,009	9.59%	1.8
312.01	Boiler Plant Equipment	(22)	7,454,702	7,272,558	1,822,179	1,005,395	13.49%	1.8
314.00	Turbogenerator Units	(22)	4,780,168	4,641,657	1,190,148	656,960	13.74%	1.8
315.00	Accessory Electrical Equipment	(22)	1,054,888	1,198,790	88,173	48,528	4.60%	1.8
316.00	Misc. Power Plant Equip.	(22)	455,951	459,478	96,762	53,529	11.74%	1.8
	Total		<u>17,979,086</u>	<u>17,995,238</u>	<u>3,939,248</u>	<u>2,170,421</u>	12.07%	1.8
WY GEN 3								
311.00	Structures & Improvements	(5)	6,799,494	417,254	6,722,214	154,038	2.27%	43.6
312.01	Boiler Plant Equipment	(5)	57,567,754	4,343,796	56,102,346	1,402,492	2.44%	40.0
314.00	Turbogenerator Units	(5)	58,398,596	3,202,879	58,115,647	1,452,700	2.49%	40.0
315.00	Accessory Electrical Equipment	(5)	6,737,220	377,879	6,696,202	151,739	2.25%	44.1
316.00	Misc. Power Plant Equip.	(5)	709,060	28,882	715,652	19,855	2.80%	36.0
	Total		<u>130,212,144</u>	<u>8,370,690</u>	<u>128,352,061</u>	<u>3,180,824</u>	2.44%	40.4
WYODAK								
311.00	Structures & Improvements	(5)	9,164,990	7,214,391	2,408,848	96,421	1.05%	25.0

BLACK HILLS POWER, INC.
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2012

ACCT. (I)	TITLE (II)	NET SALVAGE PERCENT	ORIGINAL COST (III)	BOOK RESERVE	FUTURE ACCRUALS	ANNUAL ACCRUAL		COMPOSITE REMAIN LIFE (IX)
						AMOUNT (X)	PERCENT (XI)	
312.01	Boiler Plant Equipment	(5)	76,887,888	29,347,729	51,384,554	2,124,531	2.76%	24.2
313.00	Engines and Generators	(5)	341,748	216,828	142,008	5,696	1.67%	24.9
314.00	Turbogenerator Units	(5)	15,192,791	5,557,047	10,395,383	432,110	2.84%	24.1
315.00	Accessory Electrical Equipment	(5)	6,616,783	5,008,048	1,939,574	77,777	1.18%	24.9
316.00	Misc. Power Plant Equip.	(5)	1,007,315	427,522	630,158	27,850	2.76%	22.6
Total			<u>109,211,515</u>	<u>47,771,565</u>	<u>66,900,525</u>	<u>2,764,385</u>	2.53%	24.2
Total Steam Production			<u>437,537,714</u>	<u>150,013,497</u>	<u>317,520,546</u>	<u>19,030,554</u>	4.35%	16.7
Other Production Plant								
BEN FRENCH CT								
341.00	Structures & Improvements	(5)	22,448	18,574	4,997	322	1.43%	15.5
342.00	Fuel Holders and Accessories	(5)	1,375,822	903,454	541,159	34,011	2.47%	15.9
344.10	Generators	(5)	16,549,367	12,793,447	4,583,388	322,302	1.95%	14.2
345.00	Accessory Electrical Equip.	(5)	672,969	427,262	279,355	25,029	3.72%	11.2
346.00	Misc. Power Plant Equip.	(5)	14,718	12,177	3,277	419	2.85%	7.8
Total			<u>18,635,323</u>	<u>14,154,914</u>	<u>5,412,176</u>	<u>382,083</u>	2.05%	14.2
BEN FRENCH DIESEL								
342.00	Fuel Holders and Accessories	(5)	51,864	47,265	7,192	995	1.92%	7.2
344.10	Generators	(5)	828,869	774,635	95,677	14,845	1.79%	6.4
345.00	Accessory Electrical Equip.	(5)	110,823	60,434	55,931	8,398	7.58%	6.7
Total			<u>991,557</u>	<u>882,334</u>	<u>158,800</u>	<u>24,238</u>	2.44%	6.6
LANGE CT								
341.00	Structures & Improvements	(5)	324,886	102,053	239,078	7,174	2.21%	33.3
342.00	Fuel Holders and Accessories	(5)	1,722,516	526,052	1,282,590	43,258	2.51%	29.6
344.10	Generators	(5)	26,182,995	9,824,794	17,667,351	593,903	2.27%	29.7
345.00	Accessory Electrical Equip.	(5)	2,095,868	792,608	1,408,054	50,943	2.43%	27.6
346.00	Misc. Power Plant Equip.	(5)	16,612	6,306	11,136	527	3.17%	21.1
Total			<u>30,342,878</u>	<u>11,251,813</u>	<u>20,608,209</u>	<u>695,805</u>	2.29%	29.6
NEIL SIMPSON CT								
341.00	Structures & Improvements	(5)	176,359	78,850	106,327	3,405	1.93%	31.2
342.00	Fuel Holders and Accessories	(5)	2,116,073	616,956	1,604,921	56,038	2.65%	28.6
344.10	Generators	(5)	25,644,954	8,133,641	18,793,561	660,704	2.58%	28.4
345.00	Accessory Electrical Equip.	(5)	1,987,600	927,847	1,159,133	45,006	2.26%	25.8
346.00	Misc. Power Plant Equip.	(5)	51,539	24,278	29,838	1,316	2.55%	22.7
Total			<u>29,976,525</u>	<u>9,781,572</u>	<u>21,693,780</u>	<u>766,469</u>	2.56%	28.3
Total Other Production Plant			<u>79,946,282</u>	<u>36,070,633</u>	<u>47,872,965</u>	<u>1,868,595</u>	2.34%	25.6

EXHIBIT __ (LK-21)

BLACK HILLS POWER, INC.
SD PUC DOCKET: EL-14-026
RATE CASE

REQUEST DATE : April 25, 2014
RESPONSE DATE : July 7, 2014
REQUESTING PARTY: Black Hills Industrial Intervenors

BHII Request No. 5: Refer to Statement G, page 3 of 5. Please provide a copy of the source for the 5.79% interest rate assumed on the projected October 1, 2014 debt issuance.

Response to BHII Request No. 5:

The interest cost of 5.79% assumed on Statement G, page 3 of 5 was determined by using an estimate of the 30 year treasury rate plus a spread over the treasury rate applicable to Black Hills Power. These estimates were made just prior to the time the case was filed. On June 30, 2014, Black Hills Power entered into an agreement to issue \$85 million of 30 year First Mortgage Bonds with a coupon rate of 4.43. The bond offering will be closed and funded on October 1, 2014.

Attachments: None

EXHIBIT __ (LK-22)

