BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates

Docket No. EL14-026

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

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

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe your education.

A. I graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the

State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. ("Ebasco"), as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost of service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity, I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing, as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of Electrical World. My article on "Standby Electric Rates" was published in the November 8, 1984, issue of Public Utilities Fortnightly. In February 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the

Federal Energy Regulatory Commission ("FERC"), and in the United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit___(SJB-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Black Hills Industrial Intervenors ("BHII"), a group of General Service, Large and Industrial Contract customers of Black Hills Power, Inc. ("BHP" or the "Company").

Q. What is the purpose of your Direct Testimony?

A. I am presenting testimony on issues pertaining to BHP's class cost of service study and its apportionment of the overall revenue increase to rate classes. The South Dakota Public Utilities Commission (the "Commission") has not had the opportunity to consider the proposed Settlement Stipulation between BHP and the Commission Staff ("Staff") of December 8, 2014 (the "Proposed Settlement"). Therefore, my testimony addresses the revenue increases to each rate class under both the Company's originally filed case, in which it requested an overall revenue increase of $14,634,238, and the Proposed Settlement, under which it would receive an overall revenue increase of $6,890,746.

With respect to these increases, I present testimony on the Company's originally filed class cost of service study and rate class revenue apportionment, as well as the reasonableness of the Proposed Settlement rate class revenue increases shown in Exhibit No. 2 of the Proposed Settlement.

As part of this testimony, I discuss a number of errors in the Company's study. I present an alternative analysis that corrects these errors and provides a reasonable basis to evaluate the reasonableness of BHP's rates relative to cost of service and the appropriate apportionment of any approved increase in the Company's overall revenues.

Q. Would you please summarize your recommendations in this case?

A. Yes, my summary is as follows:

- **The Company's class cost of service study should be rejected because it has a number of errors – both actual numerical errors and conceptual errors – that result in an inaccurate measure of the cost of providing service to each of the its rate classes. These errors, when corrected, show that the Company is earning a rate of return higher than the system average rate of return from the Combined General Service Large/Industrial Contract rate class. This is in contrast to the results shown in the Company's filed class cost of service study.**

- **Notwithstanding the problems with the Company's class cost of service study, the Company's proposed apportionment of the overall approved revenue increase to each rate class appears to be reasonable and should be accepted. The Company's originally-filed rate class revenue increases reflect a level of mitigation to each rate class that produces results that are reasonably consistent with the results of the BHII corrected class cost of service study that I present in this testimony. The Proposed Settlement rate class revenue increases that are designed to recover the overall increase of $6.89 million in**

the Proposed Settlement are also reasonable. Effectively, the Proposed Settlement rate class increases shown in Exhibit No. 2 are consistent with the results of my corrected class cost of service study. If the Commission approves the overall base rate increase of $6,890,746, in the Proposed Settlement, then the rate class increases shown in Exhibit No. 2 should be accepted. However, if the Commission approves an overall base rate increase that is lower than $6,890,746, as BHII witness Lane Kollen recommends, then the increases shown in Exhibit No. 2 should be reduced proportionately.

- **Going forward, the Commission should require the Company to file a class cost of service study in its next base rate case reflecting the corrections that I recommend in my testimony. At a minimum, the Company should file an alternative study that incorporates my corrections in its next case.**

II. CLASS COST OF SERVICE ISSUES

A. Overview of the Company's Results

Q. Please provide an overview of the purpose of a class cost of service study.

A. In general terms, a class cost of service study is an analysis used to determine each class's responsibility for a utility's total costs by separating the utility's total costs into amounts that are associated with each of the various customer classes. This analysis consists of the following three steps: (1) a *functionalization* of costs, (2) a *classification* of those costs' primary causative factors, and (3) an *allocation* of those costs among the various customer classes. A utility's investments and expenses are first functionalized into production, transmission, distribution, and other functions. The next step is to determine the primary factors that cause the costs to be incurred (*i.e.*, determination of whether the investments and expenses are demand/capacity-related, energy-related, or customer-related). An appropriate allocator is then used to allocate the various classified costs to customer classes. There are various types of methods that can be employed to perform a class cost of service analysis. The analyst is charged with identifying the economic theory that is most representative to measure cost-causation.

Q. What are the results of the Company's cost of service study?

A. Table 1 below summarizes the earned rate of return and relative rate of return at present rates for each customer class, based on the Company's study.

Table 1
Summary of Cost of Service Results

Customer Class	Rate of Return As Filed	Relative ROR Index
Residential	5.11%	0.76
General Service	9.85%	1.46
Combined Gen Svc Lg - Ind Contract	5.70%	0.85
Lighting Service	12.14%	1.80
Water Pumping/Irrigation	7.78%	1.16
Total South Dakota Retail	6.73%	1.00

The analysis underlying the Company's results in Table 1 suggests that the Residential class and the Combined General Service Large/Industrial Contract class are earning below the system average return (relative rates of return below 1.0). However, the Company's analysis is flawed. As discussed below, the Combined General Service Large/Industrial Contract class is earning a rate of return higher than the system average rate of return.

Q. Have you identified specific problems with the Company's class cost of service study?

A. Yes. I have found a number of problems with the Company's study. As I will discuss, correcting these errors results in a significant revision to each rate class's earned rate of return and the corresponding rate increase for each class that can be justified based on its rate of return. I will present a revised cost of service study reflecting all of these corrections in a subsequent portion of my testimony.

Specifically, I have identified errors in three broad areas: (1) the allocation of production demand-related costs, (2) the classification and allocation of distribution-related costs and (3) the energy-related costs associated with voltage loss factors.

B. The Company Erroneously Allocates Production Demand-related Costs

Q. Have you reviewed the Company's class cost of service study filed in this case?

A. Yes. As discussed by Company witness Charles Gray, the Company utilized an Average and Excess Demand ("A&E") methodology to allocate fixed production demand-related costs to rate classes.

Q. What is the A&E Methodology?

A. According to the National Association of Regulatory Utility Commissions ("NARUC") Electric Utility Cost Allocation Manual (the "NARUC Cost Allocation Manual"), the A&E methodology is an energy-weighting method. Generally speaking, all production plant costs are classified as demand-related and the methodology allocates those production plant costs to rate classes using factors that incorporate the classes' average demands and non-coincident peak demands.

Q. Do you have any objections to the Company's use of the A&E Methodology?

A. No. It is a reasonable methodology that is consistent with traditional production demand allocation methodologies discussed in the NARUC Cost Allocation Manual. The A&E Methodology has also been adopted by a number of electric utilities and approved by state regulatory commissions throughout the country. For example, Public Service Company of Colorado has utilized the A&E method and it has been approved in a number of Colorado cases by the Public Utilities Commission of the State of Colorado. It has also been approved by the Virginia State Corporation Commission in a number of Virginia Electric Power Company rate cases, as well as the Texas Public Utility Commission in electric utility rate cases in that state.

Q. How does BHP apply the A&E Methodology?

A. Specifically, BHP used a 3 coincident peak ("CP") A&E method in which the A&E demand costs are allocated based on each class's contribution to the three BHP South Dakota summer coincident peaks, which are the average hourly demands during BHP's highest peaks in the months of July, August and September.

With respect to distribution costs, the Company assigned all costs in distribution account 362 through 368 on the basis of class non-coincident peak ("NCP") demands. For account 369, services, the Company used a weighted NCP demand allocation method.

Q. Would you please discuss the problems that you have identified with the Company's allocation of production demand-related costs?

A. Notwithstanding my support for the use of the A&E method in this case, I have identified two errors in the Company's method. First, there is an error in its A&E calculation for two rate classes (Residential – Total Electric Demand and General Service – Total Electric). While each of these two classes has "excess demand," no excess demand assignment was made to these classes.[1]

The second error is a conceptual error associated with the Company's calculation of the 3 CP A&E factor. The traditional A&E method separates demand-related costs into two categories, average demand-related and excess demand-related, based on the annual system load factor. This load factor is calculated as the ratio of average demand to the annual system peak (1 CP). Average demand costs are determined by multiplying the load factor times total demand costs; excess demand costs are determined by multiplying (1 minus the load factor) times total demand costs. In the Company's analysis in this case, it used a 3 CP load factor to perform this initial allocation. My experience has been that the initial separation of the demand-related costs into average and excess categories is based on a 1 CP annual system load factor, even if a multiple coincident peak is used to allocate the "excess" costs to classes. The annual system load factor is the correct measure of average demand and excess demand because the system is planned to meet the annual peak. While use of a 3 CP allocator to assign excess costs to rate classes is

[1] Excess demand is the rate class's 3 CP demand less its average demand.

reasonable and is consistent with the 4 CP A&E method used in Colorado, the 3 CP load factor is not consistent with the requirement that BHP has to meet its annual system peak.

Q. Are there any additional problems with the Company's allocation of production demand costs?

A. Yes. The Company has identified [redacted] of interruptible/curtailable load on its system. This includes [redacted] of curtailable load associated with the general service large rate class and [redacted] of interruptible load associated with the industrial contract rate class. Customers taking non-firm interruptible service receive a credit reflecting the lower quality of service they receive. Other customers benefit from this interruptible load because the Company does not need as much capacity as it otherwise would require – thus, saving all firm customers the cost of such additional generating capacity. In effect, interruptible load provides a demand response generation resource in a manner similar to supply-side capacity. In exchange for providing capacity to the system by curtailing their usage at the time of peak demand and in other critical periods, customers subscribing to non-firm interruptible service receive a rate credit on their power bills.

Q. Did the Company's cost of service study reflect this interruptible load arrangement in any manner?

A. No. Rate classes that have interruptible load receive a rate credit, or an implicit rate credit in the form of a lower overall demand charge, in the case of a contract rate. As such, rate classes that have customers with interruptible load produce lower test-year revenues than an equivalent firm power customer, all else being equal. The Company's cost of service analysis makes no adjustment to reflect the important distinction between equivalent customers that receive different service (*i.e.*, interruptible vs. firm), nor does it make any load adjustment to reflect the interruptible portion of rate class load.

Q. What is the impact of this failure to recognize and distinguish between firm and interruptible load in the Company's cost of service study?

A. Because the BHP cost of service study simply reports the reduced revenues paid by interruptible load without any recognition (in the form of an adjustment) to reflect the interruptible nature of the load, the reported rates of return for rate classes that have interruptible load are biased and understate the Company's actual rate of return from those rate classes. This is a very significant problem for the combined general service large/industrial contract rate class – a class that has a significant amount of interruptible load. Thus, any decision based on the Company's analysis is incorrect; including relying on the class cost of service study to assign the proposed revenue increase to this class.

Q. How should the Company's class cost of service study be revised to correct this problem?

A. Based on my experience, the best way to properly reflect interruptible load in a class cost of service study is to use an imputed avoided capacity cost approach. This methodology assumes that the value of interruptible load (per kW) is equivalent to the avoided cost of a new combustion turbine generating unit. Each rate class that has interruptible load is credited with the avoided capacity cost on a $/kW basis and the total cost of the interruptible-load credit is then allocated on a demand allocation factor basis to all rate classes (including the classes that have interruptible load). The net impact on a total company basis is $0 and therefore the adjustment has no effect on the overall rate of return or revenue requirement for the Company. This is the methodology that I have used to adjust BHP's class cost of service study in this case.

Q. How did you develop the avoided capacity cost?

A. I relied on a levelized cost analysis from the U.S. Energy Information Administration ("EIA").[2] Baron Exhibit__(SJB-2) contains a copy of the EIA analysis, which reflects the levelized fixed costs of a new-build 2019 simple cycle combustion turbine, expressed in 2012 dollars. As shown on page 6 of the exhibit, the levelized capital cost is $40.20/MWh and the levelized fixed O&M expense is $2.80/MWh (both in $2012). Because the EIA values are on a $/MWh, I converted them to an equivalent $/kW-year basis using the 30% annual capacity factor assumed in EIA's analysis. Finally, I escalated the 2012 cost to 2013 by applying a 1.5% inflation factor. The resulting 2013 levelized avoided capacity cost is $114.70/kW-year. This avoided capacity cost is credited to the combined general service large/industrial contract rate class for each of the [redacted] of interruptible load. The total cost of this credit is then allocated to all rate classes (including the combined general service large/industrial contract class) to reflect the resource cost provided by interruptible load.

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[2] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014, Energy Information Administration, April 2014.

C. The Company Misclassifies and Inaccurately Allocates Distribution-Related Costs

Q. Would you discuss the next category of adjustments that you made to the Company's cost of service study?

A. The next category of adjustments is associated with the classification and allocation of BHP distribution system costs. The largest of these adjustments is designed to correct the Company's study by reflecting a minimum distribution system methodology, as described in the NARUC Cost Allocation Manual. The Company's analysis assumed 100% of distribution costs in FERC accounts 364 to 369 are demand-related, with no amounts classified as customer-related. As I discuss below, this is not a reasonable cost classification/allocation methodology and is inconsistent with the methodologies discussed in the NARUC Cost Allocation Manual. While the NARUC Cost Allocation Manual does not require any specific methodology, the methodologies discussed in the NARUC Cost Allocation Manual for cost allocation are deemed to be reasonable and generally accepted.

Q. Would you explain the minimum distribution system methodology?

A. Yes. As described in the NARUC Cost Allocation Manual, the underlying argument in support of a customer component for distribution costs is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer. An excerpt from the NARUC manual that discusses the classification of distribution costs is contained in Baron Exhibit__(SJB-3).

The amount of distribution cost that is a function of the requirement to interconnect the customer, regardless of the customer's size, is appropriately assigned to rate classes on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs…[T]he number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.

Q. Has BHP offered evidence disputing that conclusion?

A. No. BHP witness Gray simply states on page 25 of his direct testimony that "Due to the potential misclassification or misallocation to customer classes from these shortcomings associated with employing these classification methods, the Company elected to classify these accounts as demand." Mr. Gray's testimony provides no justification for completely ignoring a customer component associated with poles, overhead conductors, underground conductors and transformers. Ironically, Mr. Gray relied completely on the analysis of distribution costs relied upon by BHP's affiliate in Colorado ("Black Hills Colorado" or "BHC") in 2012, for the purpose of developing the Company's primary/secondary distribution facility split, as I discuss below.[3] I say that Mr. Gray's reliance on the 2012 Black Hills Colorado case is ironic because the 2012 BHC case used distribution system analyses actually developed in a 2004 BHC case. Mr. Gray and I

[3] *See* Baron Exhibit__(SJB-4), which contains a copy of the Company's response BHII Request No. 36.

both participated in that case, a case in which the Company fully supported the use of the minimum distribution system methodology that I advocate here.[4]

Q. Would you briefly explain the conceptual basis for a minimum distribution cost methodology?

A. As discussed in the NARUC cost allocation manual, there are two approaches that are typically used to develop a customer component of distribution plant and expenses. Each of the two approaches ("zero-intercept" and "minimum size") is designed to measure a "zero load cost" associated with serving customers. Each methodology attempts to measure the customer component of various distribution plant accounts (e.g., poles, primary lines, secondary lines, line transformers). Each of the two methods is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. Though arithmetically the zero-intercept method does, for example, produce the cost of "line transformers" associated with "0" kW demand, the more appropriate interpretation of the zero-intercept is that it represents the portion of cost that does not vary with a change in size or kW demand and thus <u>should not</u> be allocated on NCP demand (as BHP has done). Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost, which is not related to customer usage levels, that is used in the zero-intercept method to identify the portion of distribution costs that

[4] The 2004 case involved BHC's predecessor company, Aquila , Inc.

should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. For example, new distribution investment in poles or underground conductors for a new subdivision may be associated with unsold, or unoccupied homes that have "0" kW demand – yet the cost for these facilities is still incurred. Similarly, distribution facilities must be installed to meet the needs of part time residents that may have little or no demand during a portion of the year – yet the cost of such distribution facilities still must be incurred and does not vary as a result of the fact that such facilities serve part-time residents. The minimum distribution system methodology recognizes this circumstance by assigning a portion of the cost of these facilities based on the existence of a "customer," and not just the level of the customer's kW demand. BHP's analysis, on the other hand, assumes that all distribution costs (except meters) vary directly with kW demand, without any fixed component that should be allocated on the basis of the number of customers in each class.

Q. Do you believe that a minimum distribution system methodology is appropriate for BHP?

A. Yes. The conceptual basis for the minimum distribution system method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost-causation standpoint, the argument supporting this approach is that all of these minimal facilities are needed to interconnect a customer to the BHP system.

Q. Did BHP provide the necessary information to develop a BHP-specific minimum distribution system methodology?

A. No. However, as I noted previously, BHP's affiliate Black Hills Colorado developed, presented, and supported a minimum distribution analysis for its 2012 rate case. While BHP relies on BHC's primary/secondary split analysis from that case, the Company selectively ignores BHC's minimum distribution system analysis. In the interest of consistency, just as BHP is relying on the BHC primary/secondary classification analysis, I am relying on the BHC minimum distribution system classification analysis.

Q. Are you familiar with the methodology used by Black Hills Colorado to develop its minimum distribution system demand/energy classification?

A. Yes. The Company, which was Aquila, Inc. in 2004 at that time of the original distribution system analysis (both the primary/secondary split analysis used by BHP in this case and the minimum distribution system analysis that I am using), separately analyzed each distribution plant account to determine the amount of cost that is driven by the addition of customers to the BHC distribution system and the remaining amount of cost that is related to the level of NCP kW demand associated with these customers. BHC classified all of its distribution substation costs as demand-related, since these facilities provide service at the upstream portion of the distribution system and are designed and sized to meet the maximum diversified loads of customers imposed on the system downstream from these facilities. For other distribution facilities, such as primary conductors, secondary conductors and line transformers, BHC classified the facilities as both customer and demand-related using a statistical regression analysis of actual installed costs. The approach used by BHC is generally referred to as the "zero-intercept method" and is specifically identified in the NARUC Cost Allocation Manual as one of the two methods used to classify and allocate distribution costs in a cost of service study. As stated on page 90 of the manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

The manual goes on to state, also on page 90:

> Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

The manual clearly makes two important points on the issue of the classification of distribution costs into a customer component and a demand component. The manual states that (1) the utility must classify such costs, and (2) there are two methods to do so.

BHC performed a statistical analysis to identify the portion of a specific FERC distribution plant account (for example, Account No. 368, line transformers) that varies with changes in kW demand and the portion of the costs that do not. This latter portion, which has been statistically identified as invariant to the size of the facility and thus kW load changes, should reasonably be assigned to customer classes on the basis of the number of customers within the class.

Q. Does the Zero Intercept method provide a reasonable basis to classify distribution costs into both a customer and a demand component?

A. Yes. The methodology utilizes a statistical analysis to estimate the relationship between "size" and cost for each of the distribution plant accounts. As discussed in the NARUC Cost Allocation Manual, the purpose of the analysis is to identify the relationship between changes in the size of a particular distribution facility (such as line transformers, conductors, poles, etc.) and the cost of the facility. This statistical analysis then determines the portion of cost that varies with the level of customer load and the portion that is invariant with size or load. The cost-invariant portion is represented by the Y-intercept of the statistical regression equation.

The zero-intercept ("b" in the straight line equation "Y = A*X + b" used to estimate the customer component of each distribution account) represents the portion of cost that does not vary with a change in size or kW demand and thus <u>should not</u> be allocated on NCP demand as the Staff advocates. Essentially, the "zero-intercept" represents the cost that would be incurred, irrespective of differences in the kW demand of a distribution customer. It is this cost-invariant component that is used in the zero-intercept method to identify the portion of distribution costs that should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Q. Would you summarize the demand/customer classification for each FERC account that was developed by BHC and which you are relying on in this case?

A. Table 2 below shows the percentage demand/customer classification for each of the major distribution accounts. I used these classification percentages to classify BHP's distribution plant in the corresponding accounts in my corrected class cost of service study.

Table 2
Minimum Distribution Study Classification Factors*

Plant Account	Percent Demand	Percent Customer
364 - Poles, Towers & Fixtures	83.4%	16.6%
365 - Overhead Conductors & Devices	88.6%	11.4%
366 - Underground Conduit	19.3%	80.7%
367 - Underground Conductors & Devices	14.2%	85.8%
368 - Line Transformers	44.3%	55.8%

* Source: Black Hills Colorado Study

Q. Did you make any adjustments to the Company's allocation of FERC account 369 distribution services?

A. Yes. As stated in response to SDPUC Request No. 3-72, the Company allocated services on the following basis:

> Account 369 – Services were allocated on class NCP demand with additional customer weighting factors added to the NCPs of the residential class (2.41) and NCPs of the small general service class (1.53), consistent with the allocation method employed in Black Hills 2012 filing for Account 369.

Q. Is this a reasonable allocation method for Account 369-Services costs?

A. No. I do not recall ever seeing a utility classifying Account 369 costs as anything other than 100% customer-related and then allocated to rate classes on the basis of the number of customers. The NARUC Cost Allocation Manual, at page 96 [page 14 of 17, Exhibit__(SJB-3)] states that these costs are "generally classified as customer-related." While the NARUC manual notes that some utilities recognize size differences through a demand component, this does not mean that it is appropriate to allocate these costs on NCP demand, with a weighting factor for the residential and small general service classes, as the Company has done in this case. I believe that a customer classification of these costs appropriately reflects cost causation.

Q. Would you discuss the next correction that you made to the Company's class cost of service study?

A. The Company's analysis of distribution facilities did not recognize any distinction between customers served at 69,000 volt ("69 kV") and other primary voltage customers. Based on a review of BHP data, these 69 kV customers should not be allocated substation and primary line costs that are associated with lower voltage primary service that cannot be used to serve 69 kV loads. To correct this problem, I functionalized Accounts 360 to 362, which are associated with substation plant costs, into two sub-functions: 69 kV subtransmission and other. Because the 69 kV customers are not served by lower voltage facilities, they should only be allocated an NCP demand share of the 69 kV facilities and none of the other lower voltage costs. This adjustment removes the NCP demand allocator for the 69 kV classes for accounts 361-362 and develops a blended allocator for account 360 that 1) allocates the land for 69 kV lines to all classes and 2) the land for substations only to rate classes taking service below 69 kV.

A similar adjustment has been made to distribution costs in Accounts 364 to 367 associated with poles, overhead lines and underground lines and conduit. To the extent that these distribution accounts contain costs for facilities that can only serve customers taking service at voltages below 69 kV, the 69 kV customers should not be allocated such costs. To sub-functionalize these costs, investment in Accounts 364-367 associated with the 69 kV system were separated based on the ratio of 69 kV related investment at September 2013. These 69 kV costs were then assigned to all rate classes in the manner used in the Company's study. The remaining investment is assigned only to rate classes served below 69 kV. For purposes of this adjustment, I relied on the primary/secondary functionalization developed by the Company and assumed that the 69 kV investment is completely in the primary amount.

D. The Company Failed to Take Into Account Loss Factors

Q. Would you discuss the final adjustment that you made to the Company's class cost of service study?

A. Based on the Commission's decision in Docket EL12-061, all costs collected through the Energy Cost Adjustment ("ECA") have been removed from base rates in this case. All of these costs will be collected through the ECA. The current ECA does not differentiate by rate class service voltage (i.e, secondary, primary, 69 kV). As a result customers that take service at primary and 69 kV are subsidizing customers taking service at secondary voltage – this occurs because all kWh are billed the identical ECA charge per kWh. When the ECA was determined as simply the incremental cost over (or under) the base amount of fuel and purchased power expense, this voltage issue was not significant since the base amount of fuel and purchased power expenses were allocated to rate classes in each base rate cost of service study on a loss adjusted kWh energy basis. Thus only the incremental (negative or positive) ECA adjustment was misaligned with cost causation.

As a result of the change to 100% of fuel and purchased power costs now being recovered in the ECA, ignoring this loss issue becomes more significant. Absent a change in the ECA to reflect loss differences among rate classes, it is reasonable to make a loss adjustment in the base rate class cost of service study.

Q. Would you describe how you performed this analysis?

A. Yes. I developed an adjustment to each rate class's O&M expenses based on the difference between: (1) an allocation of the test year amount of fuel and purchased energy expense ($33,519,802) based on metered kWh and (2) an allocation of the same expense using loss-adjusted rate class kWh. The resulting amounts for each rate class sum to $0 on a total BHP basis and therefore this adjustment has no impact on BHP's overall expenses or revenue requirements. The adjustment simply provides a cost of service recognition for differences in energy losses incurred by BHP to actually serve each rate class.

E. Results from Corrected Class Cost of Service Study

Q. What are the overall results of your corrected class cost of service study?

A. Table 3 below summarizes the rates of return and relative rate of return indexes at present rates produced by the BHII corrected class cost of service study versus the Company's filed cost of service study. Baron Exhibit__(SJB-5) contains summary schedules from the corrected class cost of service study.

Table 3
Summary of Cost of Service Results
BHII Corrected Class Cost of Service Study

	BHII Corrected		BHP As-Filed	
Customer Class	Rate of Return	ROR Index	Rate of Return	ROR Index
Residential	4.23%	0.63	5.11%	0.76
General Service	9.98%	1.48	9.85%	1.46
Combined GSL-ICS	7.26%	1.08	5.70%	0.85
Lighting Service	12.37%	1.84	12.14%	1.80
Water Pumping/Irrigation	9.39%	1.40	7.78%	1.16
Total South Dakota Retail	6.73%	1.00	6.73%	1.00

III. APPORTIONMENT OF THE REVENUE INCREASE TO RATE CLASSES

Q. In its original filing in this case, how did the Company propose to apportion its requested $14,634,238 revenue increase to rate classes?

A. Table 4 below shows the increases proposed by BHP, assuming that it receives its originally filed requested overall revenue increase in this case. According to the testimony of Company witness Kyle White, the Company has utilized the results of its filed class cost of service study, subject to mitigation limits such that no rate class receives less than 75% of the average retail percentage increase of 9.3% and no class receives more than 120% of the average increase.[5] Also shown in Table 4 are the unmitigated increases that would otherwise be produced by the Company's as-filed class cost of service study.

Table 4
Summary of BHP Proposed Rate Increases

Customer Class	Increases Per BHP Cost of Service		BHP Proposed Increases	
	$	%	$	%
Residential	11,671,978	19.3%	6,536,767	10.8%
General Service	(3,259,960)	-6.4%	3,899,585	7.3%
Combined Gen Svc Lg - Ind Contract	6,465,811	15.4%	4,048,108	9.7%
Lighting Service	(319,005)	-15.7%	148,409	7.3%
Water Pumping/Irrigation	75,415	3.5%	7,290	6.1%
Total South Dakota Retail	14,634,238	9.3%	14,640,159	9.3%

Q. Have you developed the rate class increases that would be supported by your corrected class cost of service study?

[5] Direct Testimony of Kyle D. White at 9.

A. Yes. Table 5 shows these increases, again based on the Company's overall originally requested increase of $14.6 million. These increases are the increases that would be required at full cost of service rates, with no mitigation or limitations.

Table 5
Summary of BHII Corrected Cost of Service Results

Customer Class	Increases Per BHII Cost of Service		BHP Proposed Increases	
	$	%	$	%
Residential	16,070,797	26.5%	6,536,767	10.8%
General Service	(3,515,966)	-6.9%	3,899,585	7.3%
Combined Gen Svc Lg - Ind Contract	2,501,091	6.0%	4,048,108	9.7%
			-	
Lighting Service	(334,987)	-16.5%	148,409	7.3%
			-	
Water Pumping/Irrigation	(86,697)	-4.0%	7,290	6.1%
Total South Dakota Retail	14,634,238	9.3%	14,640,159	9.3%

As can be seen, based on the BHII corrected class cost of service study, the increase to the Combined General Service Large/Industrial Contract Class would be substantially less than the Company's proposed increase (6.0% versus 9.7%). However, the increases shown in Table 5 are based directly on the BHII class cost of service study and do not reflect any mitigation. As I will discuss below, I believe that it is appropriate to mitigate the increases to each rate class.

Q. What are the increases to each rate class proposed in the Proposed Settlement?

A. Table 6 below summarizes the increases to each rate class shown in Proposed Settlement Exhibit No. 2.

Table 6
Summary of BHP Proposed Rate Increases

Customer Class	Increases Per BHP Cost of Service	
	$	%
Residential	3,077,150	5.04%
General Service*	1,838,869	3.45%
Combined Gen Svc Lg - Ind Contract	1,904,657	4.55%
Lighting Service	69,858	3.45%
Total South Dakota Retail	6,890,534	4.35%

* Includes Water Pumping/Irrigation.

Q. Have you developed an analysis of the increases to each rate class using the BHII corrected class cost of service study, adjusted to reflect the Proposed Settlement revenue increases agreed to by the Company and the Commission Staff?

A. Yes. Table 7 shows these increases, based on the Staff/BHP overall revenue increase of $6.89 million. Also shown in Table 7 are a set of corresponding increases with two levels of mitigation that I believe would be appropriate, if the BHII corrected class cost of service study were adopted by the Commission. The first level of mitigation would eliminate any revenue decreases (*i.e.*, a limitation that no rate class receives a rate decrease). The additional revenue produced by this "no rate decrease" limitation is spread as a credit to each of the other rate classes in proportion to the otherwise applicable increases. The second level of mitigation that I would recommend would limit the increase to each rate class to no more than 1.5 times the retail average increase (1.5 X 4.35 = 6.53%).

Table 7
Summary of BHII Class Cost of Service Results and Mitigated Increases
Using the Settlement Revenue Requirement

Customer Class	Increases Per BHII Cost of Service		Increases with Mitigation -1 (Eliminate decreases)		Increases With Additional Mitigation (Limit Increase to 1.5 X Avg,)		
	$	%	$	%	$ Mitigation	$	%
Residential	12,636,616	20.72%	6,633,869	10.88%	(2,650,215)	3,983,654	6.53%
General Service	(5,649,518)	-11.04%	-	0.00%	1,394,103	1,394,103	2.73%
Combined GS Lg - Ind Contr	489,315	1.17%	256,877	0.61%	1,141,373	1,398,249	3.34%
Lighting Service	(409,879)	-20.23%	-	0.00%	55,222	55,222	2.73%
Water Pumping/Irrigation	(175,787)	-8.05%	-	0.00%	59,517	59,517	2.73%
Total South Dakota Retail	6,890,746	4.35%	6,890,746	4.35%	(0)	6,890,746	4.35%

For this second mitigation adjustment, I have allocated the reduction to the residential class increase to each of the other rate classes based on a uniform percentage amount applied to present revenues.

Q. How do the mitigated increases shown in Table 7 compare to the increases shown in Exhibit No. 2 to the Proposed Settlement?

A. While the increases shown in Table 7 differ from the Proposed Settlement rate class increases, I am offering Table 7 as a means of reaching the Proposed Settlement increases. Thus, I am not advocating that the Commission accept the increases set forth in Table 7. I believe that the relative apportionment of the increases shown in Proposed Settlement Exhibit No. 2 (my Table 6) are reasonable, assuming the Commission approves the overall Proposed Settlement revenue increase of $6,890,746.

If, however, the Commission accepts the recommendation of BHII witness Kollen that the overall revenue increase in this case should be much lower than the Proposed Settlement amount, then I recommend that the overall approved BHP revenue increase be apportioned based on the increases shown in Proposed Settlement Exhibit No. 2, by scaling back the increases in Exhibit No. 2 proportionately. For example, if the Commission approves an overall BHP increase of $3.0 million, then the increases shown in Proposed Settlement Exhibit No. 2 should be reduced proportionately for each rate class by the ratio of [$3,000,000/$6,890,746] or 43.5367%. This would mean that the dollar increase to say, the residential class, would be $1,339,688 instead of the Proposed Settlement residential class increase of $3,077,150. Similar proportionate adjustments would be made to the increases for each rate class shown in Exhibit No. 2.

Q. Do you have any additional recommendations?

A. Yes. The Commission should require BHP to file a class cost of service study in its next base rate case reflecting the corrections that I have discussed in my testimony. At a minimum, the Company should be required to file an alternative class cost of service study (in addition to its preferred method) reflecting the corrections that I am recommending. The changes to the Company's study that I have presented provide a more appropriate basis to evaluate the reasonableness of the Company's rates.

Q. Does this conclude your Direct Testimony?

A. Yes.

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates

Docket No. EL14-026

EXHIBITS

OF

STEPHEN J. BARON

**ON BEHALF OF THE
BLACK HILLS INDUSTRIAL INTERVENORS**

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

December 2014

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