CRAIG-BOTETOURT ELECTRIC COOPERATIVE

Case No. PUE-2009-00065

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

November 2, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky, 40014.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm providing consulting and educational services in the areas of cost of service, rate design, utility marketing, and regulatory analysis.

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

A. The purpose of my testimony is to support the application of Craig-Botetourt Electric Cooperative's ("C-BEC" or "the Cooperative") requesting a change in its rates for providing electric service. In my testimony I analyze C-BEC's revenue requirements for the 12 months ended December 31, 2008, and I am sponsoring exhibits to support a number of revenue and expense adjustments. I am also sponsoring a fully allocated, jurisdictionally assigned, class cost of service study ("cost of service study") based on C-BEC's embedded costs for the 12 months ended December 31, 2008. I also developed unit cost information from the cost of service study for use in developing C-BEC's proposed service rates, and I am sponsoring C-BEC's proposed Excess Facilities schedule, Schedule EF.

Q. PLEASE IDENTIFY THE SCHEDULES AND EXHIBITS YOU ARE SPONSORING IN THIS PROCEEDING

A. I am sponsoring the following Schedules in support of C-BEC application, pursuant to Appendix A of the Virginia State Corporation Commission's regulations, Rule 20 VAC 5-200-21:

Schedule 3 – Financial Status Statement

Schedule 7 – Class Cost of Service

Schedule 8 – Capital Structure and Cost of Debt Statement

Schedule 10 – Rate Base

Schedule 13 – Jurisdictional Separation

Schedule 14B – Revenue Adjustments and Witness to Support

Schedule 14C – Analysis Supporting Excess Facilities Charge

In addition, I am co-sponsoring the following schedules with Shawn Hildebrand, General Manager at C-BEC:

Schedule 4A & 4B – Detail of Ratemaking Adjustments

Schedule 11 – Ratemaking Adjustments

I am also sponsoring the following attachment to my testimony:

Attachment WSS-1 – Qualifications of William Steven Seelye

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Prime Group performed an analysis of C-BEC's revenue requirements for the 12 months ended December 31, 2008. Based on this analysis, C-BEC is proposing an increase in test-year revenues of $1,470,000. C-BEC's revenue requirement is designed to yield a rate of return on rate base of 8.01 percent, a rate of return on margins and equities of 10.87 percent, a times interest earned ratio ("TIER") of 2.63, and a debt service coverage ("DSC") of 1.98. I regard these rates of return and coverage ratios as conservative in the sense that C-BEC could have reasonably supported a larger rate increase. One of C-BEC's objectives was to limit the rate increase to approximately 14.9 percent. If C-BEC had not desired to limit the magnitude of the increase, it could have reasonably supported a higher return on rate base, return on margins and equities, TIER, and DSC than what is proposed in this proceeding.

The Prime Group prepared a jurisdictionally-assigned cost of service study for C-BEC's test-year operations using standard methodologies. The purpose of the cost of service study is to determine the contribution that each customer class is making towards C-BEC's overall rate of return. Rates of return are computed for each rate class. C-BEC was guided by the embedded cost of service study in allocating the proposed revenue increase to the classes of service and in developing the proposed rates. Specifically, unit costs from the cost of service study were used to develop the Customer Delivery Charge and other components of the proposed rates.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is divided into the following sections: (I) Qualifications, (II) Revenue Requirement, (III) Ratemaking Adjustments, (IV) Jurisdictionally-Assigned Cost of Service Study, (V) Allocation of the Rate Increase and Rate Design, and (VI) Excess Facilities.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PRIOR WORK EXPERIENCE.

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. Since leaving LG&E, I have performed cost of service and rate studies for over 130 investor-owned utilities, rural electric distribution cooperatives, generation and transmission cooperatives, and municipal utilities. A more detailed description of my qualifications is included in Attachment WSS-1.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY STATE OR FEDERAL REGULATORY COMMISSIONS?

A. Yes. I have testified on over 50 regulatory proceedings in 11 different jurisdictions regarding revenue requirements, cost of service and rate design. A listing of my prior testimony also is included in Attachment WSS-1. As indicated in Attachment WSS-1, I have previously testified before the Virginia State Corporation Commission.

II. REVENUE REQUIREMENT

Q. DID YOU PERFORM THE ANALYSIS COMPUTING C-BEC'S REVENUE REQUIREMENTS?

A. Yes. Schedule 3 – Financial Statement was prepared under my direct supervision. This schedule shows C-BEC's financial results for the 12 months ended December 31, 2008. Column 1 shows the actual financial and operating results per books for the test year. Column 5 shows actual financial and operating results for the Virginia Jurisdiction. Column 7 shows pro-forma financial and operating results for the Virginia Jurisdiction after reflecting the ratemaking adjustments described in Schedules 4A and 4B and supported in Schedule 11.

Q. HOW WERE C-BEC'S REVENUE REQUIREMENTS DETERMINED?

A. The proposed increase in revenue requirements shown in Column 8 of Schedule 3 was determined by calculating the increase in C-BEC's revenues that was necessary to produce a fair, just, and reasonable return on rate base, return on margins and equities, TIER, and DSC based on pro-forma test-year financial and operating results. Return on rate base is calculated by dividing operating margins by rate base. Rate base includes net plant (utility plant less accumulated depreciation) plus working capital, consisting of materials and supplies, cash working capital, and other working capital less customer deposits. Return on margins and equities is calculated by dividing total margins by the total margins and equity capitalization as of the end of the test year. TIER is calculated by dividing total margins plus interest on long-term debt by interest on long-term debt. DSC is the ratio calculated by dividing (i) total margins, interest on long-term debt, and depreciation and amortization expenses by (ii) interest on long-term debt and principal payments for the year.

C-BEC is proposing to increase jurisdictional revenue requirements by $1,470,000. Based on pro-forma test-year results, this increase results in a rate of return on rate base of 8.01 percent, a rate of return on margins and equities of 10.87 percent, a TIER of 2.63, and a DSC of 1.98.

Q. BASED ON YOUR EXPERIENCE, ARE THESE PROPOSED RATES OF RETURN AND COVERAGE RATIOS REASONABLE?

A. Yes. In fact, these financial indicators are conservative. They are certainly lower than what is now common for investor-owned utilities and are on the low end of what we are normally seeing for member-owned cooperative utilities. C-BEC could have reasonably supported a larger increase. C-BEC's proposed rates, which were approved by its member-elected board of directors, are designed to produce an increase in test-year revenues of approximately 14.9 percent. Although a higher increase could have been supported, C-BEC and its board of directors wanted to limit the increase to approximately 14.9 percent.

Q. ARE THERE ANY OTHER REASONS THAT THE PROPOSED FINANCIAL INDICATORS ARE CONSERVATIVE?

A. Yes. In efforts to keep the rate request to a minimum and to simplify the rate filing, C-BEC is proposing very few ratemaking adjustments for purposes of determining revenue requirements in this proceeding. Two significant adjustments that could have been included in the determination of revenue requirements were an adjustment to reflect a $3.4 million loan that C-BEC has secured from Rural Utilities Service

("RUS") and an adjustment to reflect the difference between actual depreciation accruals and annual depreciation expenses computed by applying C-BEC's depreciation rates to year-end plant in service. In April 2009, C-BEC made its first draw of $1.0 million on this loan. Because all interest charges on this $3.4 million loan and much of additional depreciation expenses will have occurred after the end of the test year, the decision was made not to include a ratemaking adjustment to reflect these additional interest expenses even though such adjustments would be reasonable.

Q. PLEASE EXPLAIN WHY A RATE OF RETURN OF 8.01 PERCENT REPRESENTS A REASONABLE RETURN FOR C-BEC.

A. C-BEC is a customer-owned cooperative utility. To continue to operate successfully and provide safe and reliable service to its customers, C-BEC must be able to earn a fair, just, and reasonable margin. Like any other business, cooperative utilities attempt operate their organizations as solid business enterprises. Cooperative utilities will typically set their rates at a level that will provide for an overall rate of return on rate base in the range of 100 to 400 basis points above the cost of long-term debt. Therefore, if the cost of long-term debt is 5.0 percent, then the cooperative might establish rates that will provide an opportunity to earn a rate of return on rate base of between 6.0 and 9.0 percent. A rate of return on rate base in the range of 6 to 9 percent is typical for cooperative utilities for purposes of setting rates. During the test year, C-BEC's average cost of long-term debt was 5.80 percent. Therefore, C-BEC's proposed rate of return on rate base of 8.01 percent is only 221 basis points above the average cost of debt.

Q. IS THERE A BASIS FOR ESTABLISHING A RATE OF RETURN THAT IS 100 TO 400 BASIS POINTS ABOVE THE COST OF DEBT?

A. There are no "equity shares" of municipal and cooperative utilities traded on stock exchanges to provide a basis for comparison. We therefore can rely only on experience and judgment, and on comparisons with other utilities, including our experience with both not-for-profit utilities and investor-owned utilities. As indicated earlier, many cooperative utilities are establishing utility rates designed to produce a rate of return on rate base that is 100 to 400 basis points above their cost of debt. Likewise, investor-owned utilities are currently being awarded overall rates of return (weighted cost of capital) in the range of 100 to 400 basis points above the cost of long-term debt.

Q. IS C-BEC CURRENTLY EARNING MARGINS SUFFICIENT FOR IT GROW AND THRIVE?

A. During the past two years C-BEC has seen its financial performance deteriorate significantly. For example, C-BEC's TIER has decreased from 2.07 in 2006 to 1.42 in 2008. C-BEC's interest coverage is currently not sufficient for it to continue operate successfully.

Q. WILL THE RATE OF RETURN YOU RECOMMEDND HELP C-BEC AGAIN ACHIEVE ITS EQUITY TARGETS?

A. There are no guarantees, but we are hopeful that the recommended rate of return will offer C-BEC the opportunity to return to a healthier equity ratio and achieve increased financial stability.

III. RATEMAKING ADJUSTMENTS

Q. PLEASE DESCRIBE THE RATEMAKING ADJUSTMENTS PROPOSED BY CRAIG-BOTETOURT.

A. The impact of the proposed ratemaking adjustments on test-year financial and operating results is summarized on column 6 of Schedule 3 of the Application. The individual adjustments are identified on Schedules 4A and 4B of the Application. The ratemaking adjustments reflecting pro-forma revenue and expense adjustments during the test-year are labeled 6-1 through 6-7 and are shown in columns 1 through 7 of Schedule 4A. The schedules used to develop these ratemaking adjustments are included in Schedule 11 of the Application. The ratemaking adjustment reflecting the increase in revenues resulting from the proposed change in base rates is labeled 8-1 and shown on column 1 of page 2 of Schedule 4A. A list of the ratemaking adjustments proposed by C-BEC and the witness who will testify in support of each adjustment are presented in Schedule 14B.

Q. HAVE THE RATEMAKING ADJUSTMENTS BEEN JURISDICTIONALLY ASSIGNED?

A. Yes. Each ratemaking adjustment was either (i) calculated on a jurisdictional basis or (ii) a jurisdictional factor from the jurisdictionally-assigned cost of service study was applied to the adjustment. The working capital adjustment (Adjustment 6-7) and the increase in base rate revenues (Adjustment 8-1) were calculated on a jurisdictional basis. Jurisdictional factors from the cost of service study were applied to all of the other adjustments. These factors, which are referred to as "allocation vectors" in the cost of service study, are identified on pages 1-8 and pages 12-14 of Schedule 7, Attachment B.

Q. DID THE COOPERATIVE INCLUDE PROJECTIONS OF RATE CASE EXPENSES INCURRED WITH THIS RATE APPLICATION?

A. C-BEC anticipates total consultant and attorney expenses of approximately $265,000. The projected jurisdictional amount to be amortized over three (3) years is $84,869. This is reflected as Adjustment No. 6-6.

Q. PLEASE DESCRIBE THE WORKING CAPITAL ADJUSTMENT (ADJUSTMENT 6-7).

A. The items included as working capital in C-BEC's rate base are material and supplies, prepayments and cash working capital. Cash working capital is a component of rate base representing the cash required to meet the utility's current operating obligations. A standard methodology for calculating cash working capital is to apply a 12.5 percent factor to test-year operating expenses. This approach, which is used in numerous regulatory jurisdictions, provides a measurement of the cash that must be invested by the cooperative to operate the utility. It assumes that the working cash that the utility must invest into the business is equal to a month and a half of annual operation and maintenance expenses, which is equivalent to 12.5 percent or $1/8^{th}$ (1.5 months ÷ 12 months = 12.5%) of annual operation and maintenance expenses.

On an unadjusted basis, the cash working capital requirements included in rate base is $1,026,752, which consists of $641,191 of cash working capital related to test-year purchased power expenses and $385,561 of cash working capital related to other operation and maintenance expenses. These amounts were determined by applying 12.5 percent to unadjusted expenses during the test year. C-BEC is also proposing an adjustment to rate base of $57,691 that reflects the application of the 12.5 percent factor to the other O&M ratemaking adjustments proposed by the cooperative. The detailed calculations for this adjustment are shown on page 8 of Schedule 11.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO BASE RATE REVENUES (ADJUSTMENT 8-1).

A. This adjustment reflects the increase in base rate revenues for each jurisdictional rate class. This adjustment is summarized on page 9 of Schedule 11. This schedule shows the dollar increase and the percentage increase for each customer class from applying the proposed rates to test-year billing determinants. The proposed rates are discussed in the testimony of C-BEC Witness Dr. Martin Blake.

IV. <u>JURISDICTIONALLY ASSIGNED COST OF SERVICE STUDY</u>

Q. DID YOU PREPARE A COST OF SERVICE STUDY FOR C-BEC BASED ON FINANCIAL AND OPERATING RESULTS FOR THE 12 MONTHS ENDED DECEMBER 31, 2008?

A. Yes. I supervised the preparation of a fully-allocated, jurisdictionally-assigned, embedded cost of service study for C-BEC's electric operations for the 12 months ended December 31, 2008. The cost of service study, which is included in Schedule 7 of C-BEC's Application, corresponds to the pro-forma financial exhibit included in Schedule 3 of the Application. The objective in performing the electric cost of service study is to determine the rate of return on rate base that C-BEC is earning from each customer class, which provides an indication as to whether C-BEC's service rates reflect the cost of providing service to each customer class.

Q. DID YOU DEVELOP THE MODEL USED TO PERFORM C-BEC'S COST OF SERVICE STUDIES?

A. Yes. I developed the spreadsheet model used to perform the cost of service study being submitted in this proceeding.

Q. WHAT PROCEDURE WAS USED IN PERFORMING THE COST OF SERVICE STUDY?

A. The three traditional steps of an embedded cost of service study – functional assignment, classification, and allocation – were used to perform the cost of service study for C-BEC. The cost of service study was therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to C-BEC's rate classes. The following functional groups were identified in the cost of service study: (1) Purchased Power, (2) Transmission, (3) Station Equipment, (4) Primary and Secondary Distribution Plant, (5) Customers Services (6) Lighting Systems, (7) Customer Service and Information, and (8) Load Management.

Q. HOW WERE COSTS CLASSIFIED AS ENERGY-RELATED, DEMAND-RELATED, OR CUSTOMER-RELATED?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's needs. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, costs related to line transformers and underground conductors were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE RESULTS OF THE FUNCTIONAL ASSIGNMENT AND CLASSIFICATION STEPS OF THE ELECTRIC COST OF SERVICE STUDY?

A. Yes. Attachment A of Schedule 7 shows the results of the first two steps of the electric cost of service study – functional assignment and classification.

Q. HOW WERE C-BEC'S PURCHASED POWER COSTS CLASSIFIED?

A. C-BEC purchases its power requirements from American Electric Power Company and Dominion Virginia Power. In the cost of service study, fixed costs, including purchased power costs billed on a demand basis, were classified as demand-related. Variable costs, including purchased power costs billed on an energy basis, were classified as energy-related. Attachment D shows the classification of purchased power costs between demand-related and energy-related costs.

Q. WHAT METHODOLOGIES ARE COMMONLY USED TO CLASSIFY DISTRIBUTION PLANT?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductors, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of these minimum size facilities. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

The zero-intercept methodology was used in C-BEC's cost of service study because it is less subjective than the minimum system approach and is strongly preferred over the minimum system methodology when the necessary data is available. With the zero-intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer component. In the zero-intercept methodology, a zero-size conductor or line transformer is the absolute minimum system.

Q. WHAT IS THE THEORY BEHIND THE ZERO-INTERCEPT METHODOLOGY?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost ($/ft or $/transformer) of conductors or line transformers and the load flow capability of the plant, which is proportionate to the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, b are the coefficients representing the intercept and slope, respectively;

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of conductor or transformers that is invariant to the size (and load carrying capability) of the plant.

Like most electric utilities, the number of line transformers on C-BEC's distribution system is not uniformly distributed over all transformer sizes. For example, C-BEC has over 1,067 conventional 10.0 kVA transformers, but only one conventional 150 kVA transformer. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted regression analysis both transformer sizes would have the same impact on the analysis, even though there are almost three thousand times more 15.0 kVA transformers than 1,500 kVA transformers.

Using a weighted regression analysis, the cost and size of each type of conductor or transformer is, in effect, weighted by the number of feet of installed conductor or the number of transformers. In a weighted regression analysis, the following weighted sum of squared differences:

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and $\hat{\mathbf{y}}$ is the predicted value of the dependent variable.

Q. HAVE YOU PREPARED EXHIBITS SHOWING THE RESULTS OF THE ZERO-INTERCEPT ANALYSIS?

A. Yes. The zero-intercept analysis for line transformers is included in Attachment G of Schedule 7. The regression model for line transformers produced an R-square of 0.8280. Vintage problems with overhead and underground conductor data prevented the cost records from being used to classify costs in the cost of service study. Therefore, we developed the customer and demand components using a panel of zero-intercept results from other utilities. This analysis is included in Schedule 7, Attachment I.

Q. PLEASE DESCRIBE THE ALLOCATION FACTORS USED IN THE ELECTRIC COST OF SERVICE STUDY.

A. The following allocation factors were used in the C-BEC cost of service study:

- **PPEA** – The energy components of purchased power costs, fuel, variable production expenses, and power sales to IMPA were allocated on the basis of the kWh sales to each class of customers during the test year.
- **PPBDA** – The demand components of purchased power expenses, production costs, and transmission costs were allocated on the basis of each class's contribution to C-BEC's 12-month average coincident peak demand.
- **DA1** – The demand cost components of distribution poles, distribution substations, and primary distribution lines are allocated on the basis of the maximum class demands for primary and secondary voltage customers.
- **CSA** – The demand cost components of secondary distribution lines and line transformers are allocated on the basis of the sum of individual customer demands for secondary voltage customers.

- **C02** – Customer services are allocated on the basis of the average number of customers for the test year weighted by the cost of services for each type of customer.
- **C03** – Meter costs are allocated on the basis of the average number of customers for the test year weighted by the cost of meters for each type of customer.
- **C04** – Costs associated with street lighting systems were specifically assigned to the street lighting classes of customers.

Q. ARE COSTS ALLOCATED USING THE SAME METHODOLOGY FOR BOTH JURISDICTIONAL AND NON-JURISDICTIONAL CUSTOMER CLASSES?

A. Yes.

Q. IN YOUR COST OF SERVICE MODEL, ONCE COSTS ARE FUNCTIONALLY ASSIGNED AND CLASSIFIED, HOW ARE THESE COSTS ALLOCATED TO THE CUSTOMER CLASSES?

A. In the cost of service model used in this study, C-BEC's accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Attachment B of Schedule 7, C-BEC's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 31 through 33. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors used in the study can be identified in the column labeled "Functional Vector." An example of this process is the use of payroll expenses ("LBSUB2") to allocate Account 926 - Employee Benefits. Because pension expenses are associated with employee payroll costs, it is appropriate (and a standard approach in the industry) to functionally assign and classify these costs on the same basis as payroll costs. (See Schedule 7, Attachment A, pages 16 through 18 for the functional assignment of employee benefits expenses on the basis of LBSUB2, shown on pages 22 through 24.) The functional vector used to allocate a specific cost is identified by the column in the model labeled "Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors." This process is illustrated in Figure 1 below.

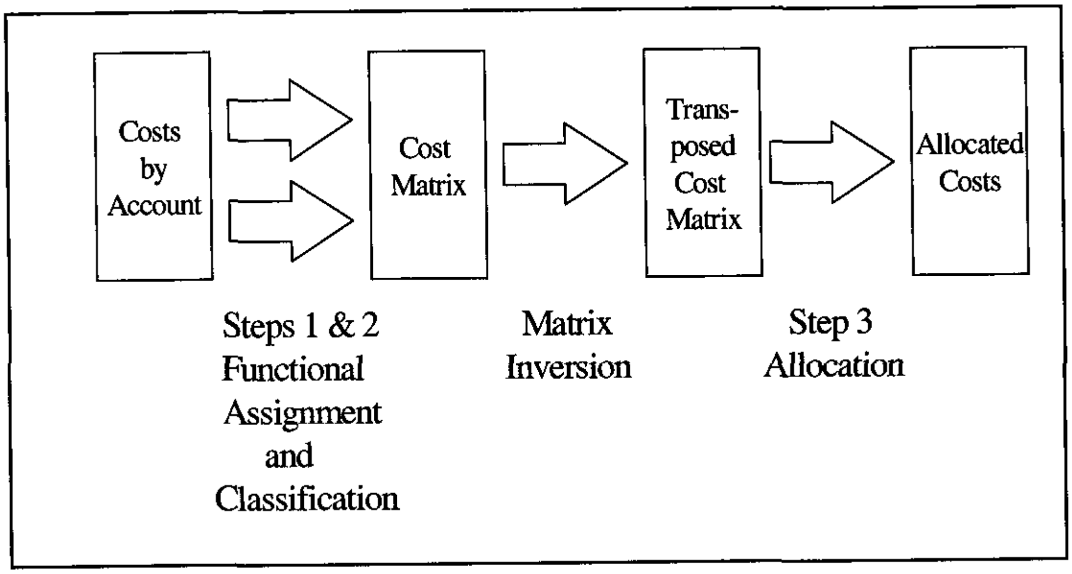

Figure 1

The results of the class allocation step of the cost of service study *on both and adjusted and unadjusted basis* are included in Attachment B of Schedule 7. The costs shown in the column labeled "Total System" in Attachment B were carried forward *from* the functionally assigned and classified costs shown in Schedule 7, Attachment A. The columns labeled "Ref" in Exhibits Attachment B provide a reference to the results included in Attachment A.

Q. HAVE YOU PREPARED AN EXHIBIT SHOWING THE DEVELOPMENT OF THE DEMAND ALLOCATORS USED IN THE COST OF SERVICE STUDY?

A. Yes. Attachment C of Schedule 7 shows the development of the demand allocation factors from load research data that was provided by RLW Analytics, Inc., a load research firm located in Clarklake, Michigan. RLW Analytics assisted us in developing the demand allocation factors used in the study. Having a load research results significantly improves the accuracy of the cost of service study.

Q. PLEASE DESCRIBE ATTACHMENTS E AND F TO SCHEDULE 7.

A. Attachment E of Schedule 7 shows the development of the allocation factors for meters, and Attachment F of Schedule 7 shows the development of the allocation factors for services. These allocation factors were developed based on the number of customers weighted by the cost of meters and services for each rate class.

Q. HOW ARE THE RATEMAKING ADJUSTMENTS ALLOCATED IN THE COST OF SERVICE STUDY?

A. Each ratemaking adjustment is allocated to the jurisdictional and non-jurisdictional rate classes using internally generated allocation factors representative of the costs being allocated. For example, the adjustment to reflect increased labor expenses are allocated to the jurisdictional and non-jurisdictional rate classes using an internally-generated allocation factor reflecting the assignment of actual labor costs in the study. Specifically, in the cost of service study the labor adjustment is allocated on the basis of the "LBT" allocation vector. See Schedule 7, Attachment B, at page 10.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COOPERATIVE'S COST OF SERVICE STUDY.

A. A "before and after" summary of the rates of return for each customer class, reflecting the rate adjustments proposed by C-BEC, is shown in Table 1, below. The Actual Adjusted Rate of Return was calculated by dividing the adjusted operating margins by the adjusted net cost rate base for each customer class. The adjusted operating margin and rate base reflect the pro-forma adjustments shown in Schedule 4 of the Application. The Proposed Rate of Return was calculated by dividing the net operating income adjusted for the proposed rate increase by the adjusted net cost rate base.

TABLE 1 Class Rates of Return		
Customer Class	**Actual Adjusted Rate of Return**	**Proposed Rate of Return**
Residential Service	(0.55)%	6.36%
Commercial and Small Power Service	3.08%	6.75%
Commercial and Large Power Service	38.88%	39.31%
Outdoor Lighting	13.37%	14.77%
Total System	1.70%	8.04%

V. UNIT COSTS

Q. DOES THE COST OF SERVICE STUDY PROVIDE INFORMATION CONCERNING THE UNIT COSTS INCURRED BY THE COOPERATIVE TO PROVIDE SERVICE UNDER EACH RATE SCHEDULE?

A. Yes. Customer-related, demand-related, and energy-related costs for each rate class are shown on page 15 of Attachment B of Schedule 7. Customer-related costs are stated as a cost per customer per month. Energy-related costs are stated as a cost per kWh. For customers metered predominantly on a per kWh basis, demand-related costs are stated as a cost per kWh. For demand-metered customer classes, such as Large Power, demand-related costs are stated as a cost per kW per month. The following table shows the customer-related costs for each rate class:

Table 2 Customer-Related Costs from the Cost of Service Study	
Customer Class	**Customer-Related Costs**
Residential Service	$31.63
Commercial and Small Power Service – Single-Phase	$34.95
Commercial and Small Power Service – Single-Phase	$38.95
Commercial and Large Power Service	$88.32

Q. WERE THESE COSTS USED TO DEVELOP THE ACCESS CHARGES IN C-BEC'S PROPOSED RATES?

A. Yes. C-BEC's proposed rate design is discussed in C-BEC Witness Blake's testimony. He used unit costs in developing the proposed access charges.

VI. EXCESS FACILITIES

Q. PLEASE DESCRIBE C-BEC'S EXCESS FACILITIES SCHEDULE.

A. C-BEC's Excess Facilities charge will apply whenever a customer requests a service arrangement requiring equipment and facilities in excess of those the Cooperative would normally install. Examples of excess facilities would include requests for non-standard facilities such as emergency backup feeds, automatic transfer switches, redundant transformer capacity, and duplicate (or check) meters. The customer would have the option of either (i) requesting that C-BEC incur the full cost of the equipment (including up-front equipment cost), in which event the monthly excess facilities charge would cover the expected carrying charges on the equipment, the estimated maintenance cost on the equipment, and the estimated cost of replacing the equipment if it fails prior to the service life of the facilities, or (ii) making an up-front payment to cover the cost of the facilities, in which event the monthly excess facilities charge would only cover C-BEC's estimated maintenance cost on the equipment and the estimated cost of replacing the facilities if they fail prior to the expected service life of the equipment. Because estimated failure costs would be included in the charge for either scenario, C-BEC would replace the equipment if it fails prior to the end of the specified service life under either option. The charge would differ depending on whether the equipment would be classified on the C-BEC's property records as 5-year, 10-year, or 30-year property.

Under the first option, in which C-BEC makes the up-front investment, the monthly charges stated as a percentage of the original cost of the facilities would be as follows:

Type of Excess Facility	
Standard Utility Plant (30-year estimated service life)	1.72%
Non-Standard Utility Plant (10-year estimated service life)	2.50%
Non-Standard Utility Plant (5-year estimated service life)	3.73%

Under the second option, in which the customer makes the initial up-front investment, the monthly charges stated as a percentage of the original cost of the facilities would be as follows:

Type of Excess Facility	
Standard Utility Plant (30-year estimated service life)	1.05%
Non-Standard Utility Plant (10-year estimated service life)	1.34%
Non-Standard Utility Plant (5-year estimated service life)	1.75%

Q. HOW ARE THE EXCESS FACILITIES CHARGES CALCULATED?

A. The calculations supporting C-BEC's proposed excess facilities charges are shown in Schedule 14C. For the first option, in which C-BEC makes the up-front investment, the charge includes (i) the levelized carrying charges associated with both the original cost facilities and the present value of the expected replacement cost of the facilities, plus (ii) operation and maintenance expenses as a percentage of the original cost plant. The levelized carrying charge rate is calculated based on a capital recovery factor using a 7.0 percent discount rate for the applicable recovery period (30, 10, or 5 years). The present value of the expected replacement costs is determined using an actuarial approach based on Iowa-type survivor curves, which are the survival frequency distributions developed by Iowa State University that are used in depreciation studies for electric and gas utilities throughout the U.S. Specifically, the present value replacement cost is determined by calculating the replacement cost for each year based on the failure percentage given by a specified survivor curve, adjusted to reflect a 3 percent inflation factor and present valued using a 7 percent discount rate. For 30-year facilities, a 30-year R-2 Iowa curve is used to determine the annual replacement percentages. This curve is typical of an Iowa curve that might be used for transformers and other distribution facilities. A 10-year S2 Iowa curve is used for the 10-year excess facility charge, and a 5-year S2 curve is used for the 5-year excess facility charge. These curves are typical of the distributions that might be used for industrial electronic equipment, although O-type or curves are also commonly used for industrial electronic equipment.

For the second option, in which the customer makes the initial up-front investment, the charge includes (i) the levelized carrying charges associated with the present value of the expected replacement cost of the facilities, plus (ii) operation and maintenance expenses as a percentage of the original cost plant. Therefore, under this option, the charge would not include the carrying charges associated with the initial cost of the facilities, but would include carrying charges on the present value of the replacement cost.

For both options, the operation and maintenance component is determined by dividing (i) actual operation and maintenance expenses less purchased power expenses during the test year by (ii) electric plant in service as of the end of the test year.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

Provides consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs; and develops revenue requirements for utilities in general rate cases, including the preparation of analyses supporting pro-forma adjustments and the development of rate base.

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

Assists utilities with developing strategic marketing plans and implementation of those plans. Provides utility clients assistance regarding regulatory policy and strategy; project management support for utilities involved in complex regulatory proceedings; process audits; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; unbundling of rates and the development of menus of rate alternatives for use with customers; performance-based rate development.

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 130 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Associations

Member of the Society for Industrial and Applied Mathematics

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Submitted direct testimony in Cause No. 43773 on behalf of Crawfordsville Electric Light & Power regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Submitted testimony in Case No. 2009-00040 on behalf of Big Rivers Electric Corporation regarding revenue requirements and rate design.

Submitted testimony on behalf of Columbia Gas Company of Kentucky in Case No. 2009-00141 regarding the demand side management program costs and cost recovery mechanism.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Submitted testimony in NSUARB – NSPI – P-884 (2) on behalf of Nova Scotia Power Company's regarding a demand-side management cost recovery mechanism.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Submitted testimony in Case No. PUE-2009-00029 on behalf of Old Dominion Power Company regarding class cost of service, jurisdictional separation, allocation of the revenue increase, general rate design, time of use rates, and excess facilities charge rider.