ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Complaint and petition by Lee County Electric Cooperative, Inc. for an investigation of the rate structure of Seminole Electric Cooperative, Inc.
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Docket No. 981827

Filed: May 30, 2000

DIRECT TESTIMONY

of

WILLIAM STEVEN SEELYE

on behalf of

LEE COUNTY ELECTRIC COOPERATIVE, INC.

INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6711 Fallen Leaf, Louisville, Kentucky, 40241.

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Louisville, Kentucky. The Prime Group provides consulting and educational services in the areas of utility rate design, cost of service, regulatory analysis, marketing, and fuel and power procurement.

QUALIFICATIONS AND EXPERIENCE

Q. Please describe your educational background.

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 at the University of Louisville.

Q. Please describe your work experience prior to forming The Prime Group.

A. 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.

Q. What does your work for the Prime Group entail?

A. Since forming the Prime Group, I have provided consulting services to investor-owned electric utilities, rural electric cooperatives, and municipal electric utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs. I have prepared cost of service studies and developed rates for electric utilities. I have filed transmission rates as a part of Order No. 888 compliance filings with the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities. I have also filed Order No. 889 compliance filings or waiver requests with FERC on behalf of clients. I have prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates. I have assisted utilities with their market-based rate filings, and with developing and implementing strategic marketing plans. I have advised utility clients regarding: regulatory policy and strategy, state and federal regulatory filing development, cost of service development and support, the development of innovative rates to achieve strategic objectives, the unbundling of rates and the development of menus of rate alternatives for use with customers, performance-based rate development, and energy marketing and brokering capability development. I have provided training to account executives in sales and customer negotiation, as well as training in ratemaking and utility finance regarding basic utility marketing. I have provided marketing, market research and marketing support services for utility clients and have assisted them in assessing their marketing capabilities and processes.

Q. Have you ever testified before a state public utility regulatory commission?

A. Yes. I have testified before the Kentucky Public Service Commission in the following cases: Case No. 244 on behalf of LG&E regarding rates for cogenerators and small power producers; Case No. 8924 on behalf of LG&E regarding marginal cost service; Case No. 96-161 and Case No. 96-362 regarding complaints involving Prestonsburg City's Utilities Commission; Case No. 99-046 regarding an alternative regulation plan filed by Delta Natural Gas Company; Case No. 99-176 regarding cost of service, rate design and expense adjustments in connection with a rate case filed by Delta Natural Gas Company; and most recently, Case No. 2000-080 on behalf of LG&E concerning cost of service, rate design, and revenue adjustments. I have also testified in several fuel adjustment clause proceedings on behalf of LG&E.

Q. Have you ever designed rates for electric cooperatives?

A. Yes. I have designed rates for both Generation and Transmission Cooperatives and Distribution Cooperatives. In addition, I have prepared cost of service studies for both Generation and Transmission Cooperatives and Distribution Cooperatives. I have also developed transmission tariffs for Generation and Transmission Cooperatives to meet the "safe harbor" requirements of FERC Order 888.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony describes Rate Schedule SECI-7b, the current wholesale rate schedule for Seminole Electric Cooperative Inc. ("Seminole"), and addresses whether SECI-7b is designed in accordance with cost of service principles. I also recommend rate alternatives that more properly reflect the cost of providing service.

Q. Please summarize your testimony.

A. SECI-7b does not reflect fundamental cost of service principles, and is not supported by an appropriate cost-of-service analysis. Therefore, SECI-7b is not fair, just and reasonable.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit ___ (WSS-1) Burns & McDonnell Cost of Service Study and Wholesale Rate Design (December 1999).

Exhibit ___ (WSS-2) LCEC Cost of Service Analysis.

Exhibit ___ (WSS-3) Cost Recovery Under SECI-7b Compared To Actual Cost From Cost of Service Study.

Exhibit ____ (WSS-4) Revenues Produced by LCEC's Proposed Rate Alternatives Compared to SECI-7b (Based on Estimated 2001 Billing Units).

Exhibit ____ (WSS-5) Individual Member Billings Under Proposed Rate Alternatives Compared to SECI-7b (Based on Estimated 2001 Billing Units).

GENERAL DESCRIPTION OF RATE SCHEDULE SECI-7B

Q. Please describe the basic design of SECI-7b.

A. SECI-7b is designed around six basic rate components: (1) a Production Demand Charge, (2) a Production Fixed Energy Charge, (3) a Transmission Demand Charge, (4) a Distribution Demand Surcharge, (5) a Non-Fuel Energy Charge, and (6) a Fuel Charge.

Q. Is this a typical rate design for a Generation and Transmission Cooperative?

A. No. The rate design for a Generation and Transmission Cooperative will typically consist of a demand charge, energy charge, and a substation charge. The substation charge is analogous to a customer charge for an investor-owned utility. The demand charge will typically recover fixed generation and transmission costs. The energy charge will generally recover variable expenses such as fuel and certain operation and maintenance expenses. The substation charge will typically recover the direct customer costs associated with transmission or distribution substations and related facilities. SECI-7b differs from traditional rate design because of the Production Fixed Energy Charge, which allocates a significant portion of Seminole's fixed production costs on the basis of historical three-year energy (kWhs), unadjusted for known and measurable changes in usage patterns, rather than on the basis of current demand (kWs).

Q. Please explain the Production Demand Charge Component.

A. The Production Demand Charge is a demand charge designed to recover a portion of Seminole's fixed production costs. The charge is applied on the basis of customer demands determined at the time of Seminole's monthly peak, which is referred to as the "coincident peak" demand. The Production Demand Charge is only applicable during Seminole's eight peak months – the four summer months of June through September and the four winter months of December through March, and is not applied during the four "shoulder" months of April, May, October and November.

Q. Please explain the Production Fixed Energy Charge.

A. The Production Fixed Energy Charge is designed to recover all fixed production costs not recovered through the Production Demand Charge. The Production Fixed Energy Charge is *allocated* to Seminole's customers on the basis of each customer's total kWhs purchased from Seminole during a three-year period prior to the current year and is apportioned equally across each month of the year. There is a one-year lag between the end of the three-year period used to determine the allocation of the Production Fixed Energy Charge and the current year. For example, during the year 2000, the Production Fixed Energy Charge is allocated on the basis of each distribution member's kWh purchases determined during the three-year period 1996 through 1998, *unadjusted for actual known changes in usage patterns*. The Production Fixed Energy Charge therefore is based on energy purchases that occurred up to 59 months (almost five years) earlier. For example, in December 2000, the Production Fixed Energy Charge will be determined on the basis of energy usage going back to January 1996.

COST OF SERVICE ANALYSIS

Q. Why do you assert that SECI-7b is not supported by an appropriate cost-of-service analysis?

A. Based on the information I have reviewed, Seminole failed to prepare a cost-of-service study prior to the implementation of SECI-7, which was the predecessor rate schedule that formed the basis for SECI-7b. A cost of service was performed by Seminole's consulting company, Burns & McDonnell, in December 1999, but that was done almost one year after implementation of SECI-7.

Q. What is the relationship between SECI-7 and SECI-7b?

A. SECI-7 and SECI-7b are structurally very similar. The primary difference is that SECI-7 provided for ramping of the Production Demand Charge and the Production Fixed Energy Charge. SECI-7b eliminates that ramping function.

Q. Please explain ramping.

A. SECI-7 provided that the Production Demand Charge would ramp down over a three year period from $8.50/kw/Month for the year 1999 to $7.50/kw/Month for the year 2000 to $6.50/kw/Month for the year 2001. Under SECI-7 there was to be a corresponding increase in the Production Fixed Energy Charge over this same period. Thus, SECI-7 shifted the recovery of a large portion of fixed production costs from the Production Demand Charge to the Production Fixed Energy Charge over a three-year period.

Q. When and why was SECI-7b implemented?

A. Seminole's Board of Trustees approved SECI-7b on December 9, 1999. LCEC had serious concerns with Seminole recovering a large portion of its fixed production costs on an energy basis, especially through a component that is allocated on the basis of three-year historical kWh purchases. In response to concerns expressed by LCEC (and other members), SECI-7b was adopted so as not to reduce the Production Demand Charge and increase the Production Fixed Energy Charge in 2000. Instead, under SECI-7b, the Production Demand Charge remained at $8.50 and the Production Fixed

Energy Charge was not increased. SECI-7b is essentially the same as SECI-7, except that the Production Demand Charge is not ramped down in 2000 and 2001 and the Production Fixed Energy Charge is not ramped up as designed in SECI-7.

Q. Does the December 1999 Burns & McDonnell cost of service study support SECI-7 or SECI-7b?

A. No. The cost of service study does not support allocating a portion of Seminole's fixed production costs on the basis of unadjusted three-year historical kWh purchases, which continues to be a feature of SECI-7b. In the Burns & McDonnell cost of service study, none of Seminole's fixed production costs were allocated on the basis of three-year historical energy (kWhs). Additionally, the cost of service study does not support ramping down of the Production Demand Charge as was contemplated under SECI-7.

Q. Does SECI-7b reflect the cost of providing service?

A. No. This is evident in the very language that Seminole used to describe the development of SECI-7. When Seminole was developing SECI-7, it referred to the process of shifting fixed production costs from the demand charge to the energy charge as "Tilting." In this context, "Tilting" suggests that the rate was being "Tilted" away from a standard (or "Traditional") cost of service methodology to something altogether different. This fact is reinforced by statements in the cost of service study prepared by Burns & McDonnell. <u>See</u> page ES-4 of Exhibit __ – (WSS – 1). In describing a "Traditional" approach to performing a cost of service study, Burns & McDonnell stated that: "This type of assignment recognizes the cost-causation relationship for the utility as it exists today". Therefore, a rate design which is "Tilted" departs from a standard or "Traditional" approach which recognizes the cost-causation relationship for the utility as it exists today.

Q. **Have you performed an analysis of Seminole's cost of service?**

A. Yes. I have prepared an analysis based on the information contained in the December 1999 Burns & McDonnell Study. See Exhibit __ - (WSS- 2).

Q. **Please describe the methodology used in your analysis.**

A. I used the cost information contained in the study, but applied a standard cost-of-service methodology. All production plant cost was assigned to production-demand. Land and land rights were assigned based on total production and transmission plant. Transportation equipment was assigned to production-demand. Since depreciation reserve is created by depreciating and amortizing plant investment, depreciation reserve was functionally assigned based on plant.

Expense functional assignments were also modified from Burns & McDonnell's original study. Power production expenses were functionally assigned based on the predominance methodology utilized by FERC. Under the FERC's predominance methodology, Accounts 500, 502, 505, 506, 507, 511, 514, and 528 are assigned to production-demand. Accounts 501, 510, 512, 513, and 518 are assigned to production-energy. Accounts 920, 923, and 930 were assigned on the same basis as non-Administrative & General operation and maintenance expenses. Property insurance (Account 924) and property taxes (Account 408.1) were allocated on the basis of net plant. The following table attached hereto as Exhibit __ (WSS - 3) compares the percentage of the costs classified as demand, energy and customer related to the revenue recovery through the demand charge and energy charge under SECI-7b based on 2001 billing determinants.

Q. What does this table indicate?

A. It shows that Seminole, through SECI-7b, is recovering much more of the cost through an energy charge or energy allocator than can be supported by a standard cost of service methodology. This illustrates how demand-related costs have been "Tilted" into an energy component. The cost of service study indicates that 49.25% of Seminole's costs are energy related, while 58.46% of Seminole's cost recovery is collected in an energy charge or energy allocator in SECI-7b. This disparity between energy related cost of providing service and the amount of revenues collected through the energy charge cannot be justified.

Q. Does your cost of service analysis support recovering a portion of Seminole's fixed production costs on the basis of a historical three-year energy allocator as prescribed in SECI-7b?

A. No, it does not. There is no basis whatsoever for allocating Seminole's fixed production costs on the basis of three-year kWh energy requirements. In fact, there is no basis for allocating fixed production costs on the basis of energy, much less on the basis of three-year historical energy unadjusted for known and measurable changes. There is no causal relationship between the amount of energy that Seminole's members use during a historical three-year period and fixed production costs. Consequently, recovering a portion of Seminole's fixed production costs on the basis of a three-year energy allocator is arbitrary.

Q. Please describe Burns and McDonnell's cost-of-service study.

A. The Burns and McDonnell study examines three cost of service methodologies -- Traditional, Energy, and Equivalent Peaker. The report explains that with the "Traditional" approach, production plant and fixed O&M are recovered through the demand charge, and fuel and variable O & M are recovered through the energy charge. The Burns and McDonnell report describes the "Traditional" approach as follows:

> Using a traditional approach, the investment cost (and fixed O&M cost) of a plant are recovered through the demand charge and the commodity cost of fuel and variable O&M are recovered through an energy charge. This type of assignment recognizes the cost causation relationship for a utility as it exists today.

Page ES-4 of Exhibit ___ (WSS-1).

Although I disagree that Burns & McDonnell's methodology can be fully characterized as a "Traditional" cost of service approach, based on the results described in their report it appears that this methodology, to some extent, follows the methodology I used in calculating cost of service. However, since only the results of this methodology were supplied, and not the details, it is not possible to determine exactly how costs were assigned and allocated.

The "Energy" approach assigns all base-load plant investment to production-energy, with only peaking capacity plant assigned to production-demand. As with the "Traditional" approach, only the results of this methodology were supplied; therefore, it is not possible to determine exactly how costs were assigned and allocated. Burns & McDonnell does not recommend this approach.

The methodology recommended by Burns and McDonnell is the "Equivalent Peaker" methodology. This methodology assigns fixed production costs to production-demand *as if* all of the production facilities had been installed as peaking capacity. The excess of actual plant investment over the estimate of a hypothetical investment in peaking plant is assigned to production-energy. The argument given by Burns & McDonnell for this assignment scheme is that base-load units are installed as much for their low-cost energy as they are for their capacity.

Q. Do you agree with Burns & McDonnell's recommendation?

A. No. I believe that there are at minimum seven serious flaws in this type of cost allocation. First, the "Equivalent Peaker" methodology uses hypothetical costs instead of Seminole's actual costs to determine the cost of providing service. In Burns & McDonnell's study, Seminole's base-load generation capacity cost has been restated on the basis of the hypothetical cost of combustion turbine capacity. In this study, demand-related costs were determined on the basis of the cost of combustion turbines that have been installed around the country by other utilities adjusted to current year dollars. This approach is based on the fiction that Seminole's costs are somehow related to the cost incurred by other utilities to install combustion turbine capacity. Seminole has base-load capacity on its system, and any kind of cost allocation should reflect this fact.

Second, with the "Equivalent Peaker" methodology, the cost of combustion turbine capacity has been imputed, but the fuel and other operating expenses associated with combustion turbine capacity has not been similarly imputed. In other words, Burns & McDonnell calculated demand-related costs on the basis of hypothetical gas- or oil-fired generation capacity, which has a lower capacity cost but a much higher fuel cost than base-load generation capacity. With the "Equivalent Peaker" methodology, the cost assigned to meeting the peak demand is understated because the fuel cost of gas- or oil-fired combustion turbines, which is much higher than the fuel cost for base-load generation, has not been assigned to the peak demand. During off-peak periods, combustion turbines would not be operated because there would be plenty of low-cost energy available in the marketplace; therefore, the operating costs of combustion turbines should be assigned to the peak rather than to off-peak kWh usage. The assignment of the higher cost of fuel for gas- or oil-fired combustion turbines to the peak is as supportable as the assignment of the capacity cost of combustion turbines to the peak. However, in Burns & McDonnell's study, the operating costs of combustion turbines have not been assigned to the peak in a manner consistent with the treatment of combustion turbine capacity. In fact, the higher operating cost of combustion turbine capacity has not been dealt with at all.

Third, Burns & McDonnell's application of the "Equivalent Peaker" methodology does not recognize the historical development of Seminole's system. Their methodology looks at the system as if Seminole's generation capacity was installed all at once. As such, it ignores the historical fact that Seminole's system resources consist of a large amount of base-load capacity.

Fourth, the use of the "Equivalent Peaker" methodology in assigning fixed production cost is inconsistent with the assignment of fixed transmission costs. In Burns & McDonnell's study, fixed production costs are assigned on the basis of the "Equivalent Peaker" methodology, but fixed transmission costs are assigned entirely as demand-related. There is no justification for this inconsistency. Transmission facilities are primarily used to deliver power produced from the utility's generation resources to its customers. Therefore, the cost assignment for fixed transmission costs should follow the utility's production function. The Burns & McDonnell study recognizes that fixed transmission costs should not be allocated on the basis of energy; it should likewise recognize that fixed production costs should not be allocated on the basis of energy.

Fifth, the use of the "Equivalent Peaker" methodology is inconsistent with methodologies for allocating fixed production costs that have been endorsed by the FERC. In assigning fixed production costs, the FERC has endorsed the use of a 12-month coincident peak ("12-CP") methodology, which is essentially the same approach that I used to perform my cost of service study. For that reason, it is unlikely that FERC would allow the use of the "Equivalent Peaker" methodology for either allocating fixed production or transmission costs.

Sixth, although the "Equivalent Peaker" methodology is based on hypothetical costs, these costs do not reflect Seminole's marginal cost. Seminole's marginal cost must reflect the cost of combined-cycle generation which Seminole currently plans to install. Instead, the "Equivalent Peaker" methodology uses the hypothetical cost of combustion turbines that were installed by other utilities around the country, regardless of whether these units were combined-cycle units.

Seventh, there are several computational and methodological errors in Burns & McDonnell's study. For example, the billing units used in the study appear to be incorrect. On Table ES-4 of Burns & McDonnell's report (See Exhibit ___ (WSS- 1)), the kWh Purchased and the Sum of Monthly Coincident Peaks (kW) shown for Talquin, Tri-County, and Withlacoochee could not possibly be correct. For example, the Sum of Monthly Coincident Peaks (kW) for Withlacoochee is set out as 838,935, while the kWh Purchased is 12,194,143,481. This results in a load factor of approximately 471 percent, which does not appear to be within the realm of possibility. The demands shown for Withlacoochee appear to be significantly understated. Similar problems are evident in Talquin's and Tri-County's demands.

Q: Are there other problems with the study?

A: Yes. Several production operation and maintenance expenses have been improperly assigned as energy-related. Specifically, Accounts 502-Steam Expenses, 505-Electric Expenses, 506-Miscellaneous Steam Power Expenses, 512-Maintenance of Boiler Plant, 513-Maintenance of Electric Plant, and 514-Maintenance of Miscellaneous Steam Plant have all been assigned exclusively as energy-related. There is no basis for this assignment. The methodology is inconsistent with the "Predominance" methodology, which is utilized by the FERC in classifying operation and maintenance expenses for wholesale electric utilities, as described earlier in my testimony.

The impact of assigning production operation and maintenance expenses in the manner utilized by Burns & McDonnell is to assign a larger portion of Seminole's fixed production costs on the basis of energy.

RATE DESIGN RECOMMENDATION

Q. What rate design do you recommend for Seminole?

A. There are several alternatives that would better reflect costs than SECI-7b. Under the first alternative (Rate Alternative 1), Seminole could implement a more traditional rate design consisting of: (i) a monthly demand charge that recovers fixed production and transmission costs, (ii) an energy charge that recovers variable operation and maintenance expenses, and (iii) a distribution delivery charge that recovers the cost of distribution facilities on Seminole's system. These charges can be derived from the results of my cost of service study. LCEC's proposed rate for this alternative is shown below:

Rate Alternative 1

Demand Charge (Applied to all 12 months)	\$9.13/kW/Mo
Energy Charge	\$0.0224/kWh
Distribution Delivery Charge	\$1.26/kW/Mo

Under the second alternative (Rate Alternative 2), Seminole could offer an unbundled rate with a seasonally differentiated production demand charge that recovers all fixed production costs during the eight peak months. This alternative would be similar to SECI-7b except that Seminole's fixed production costs would be recovered through the demand charge rather than the Production Fixed Energy Charge. LCEC does not object to either unbundling the rate or developing a demand charge that is higher during the eight peak months. What LCEC objects to is the allocation of the Production Fixed Energy Charge on the basis of energy. LCEC's proposed rate for this alternative is shown below:

Rate Alternative 2

Production Demand Charge (Applied to 8 peak months)	$10.59/kW/Mo
Transmission Demand Charge (Applied to all 12 months)	$1.49/kW/Mo
Distribution Delivery Charge (Applied to all 12 months)	$1.26/kW/Mo
Fuel Charge	$0.01989/kWh
Non-Fuel Energy Charge	$0.00254/kWh

Under the third alternative (Rate Alternative 3), Seminole could allocate the Production Fixed Energy Charge on the basis of demand rather than energy. The use of a demand allocator would be preferable to an energy allocator, although I would not recommend using three year historical data to allocate the charge. The proposed rate for this alternative is shown below:

Rate Alternative 3

Production Demand Charge (Applied to 8 peak months)	$8.50/kW/Mo
Production Fixed Demand Charge *	$46,046,418
Transmission Demand Charge (Applied to 12 months)	$1.49/kW/Mo

Distribution Delivery Charge	$1.26/kW/Mo
Fuel Charge	$0.01989/kWh
Non-Fuel Energy Charge	$0.00254/kW

* Allocated on the basis of the 12-month member system demands.

Q. Are these rate alternatives designed to recover the same revenue requirement as SECI-7b?

A. Yes. As shown in Exhibit ___ (WSS-4), all three of these rate alternatives will produce the same revenue as SECI-7b based on Seminole's estimated billing units for the year 2001. The impact on the individual member systems is shown in Exhibit ___ (WSS-5).

Q. Of these three alternatives, which is the most appropriate?

A. All three of these alternatives are preferable to SECI-7b. They are more consistent with the generally accepted ratemaking principles in that they all eliminate the Production Fixed Energy Charge. The elimination of the Production Fixed Energy Charge will result in costs being allocated in a manner that more properly reflects the cost of providing service. In addition, our three recommended alternatives will avoid the use of stale billing data based on three-year historical kWhs that are up to 59 months old and that have not even been adjusted for known and measurable changes in customer usage. This should remove impediments to conservation, load management, on-site generation, and competition, which my colleague, Martin Blake, discusses in his testimony. Elimination of the Production Fixed Energy Charge will also alleviate the unnecessary complexity of the current rate structure and will satisfy concerns regarding undue rate discrimination.

All three of these alternatives are therefore acceptable to LCEC. Rate Alternative 1 is the least complicated of the three alternatives and represents a more traditional rate structure for a Generation and Transmission Cooperative. However, because the charges under Rate Alternative 2 are (i) unbundled, (ii) seasonally differentiated, and (iii) do not contain any sort of ratchet, I believe that this alternative more properly reflects the cost of providing service and for that reason is preferred.

Q: Does this conclude your testimony?

A: Yes.