ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT AND REBUTTAL TESTIMONY OF TIMOTHY S. WOODBURY

ON BEHALF OF SEMINOLE ELECTRIC COOPERATIVE, INC.

DOCKET NO. 981827-EC

June 26, 2000

Q. Please state your name and business address.

A. My name is Timothy S. Woodbury; my business address is 16313 North Dale Mabry Highway, Tampa, Florida 33618.

I. QUALIFICATIONS

Q. What is your current position?

A. I am Vice President of Strategic Services at Seminole Electric Cooperative, Inc. ("Seminole"). I have held the title of vice president at Seminole since December 14, 1995. My responsibilities include, among other things, managerial oversight for activities related to rate design and development, strategic planning, power marketing, and purchased power and transmission service acquisition and contract administration. I have been responsible for the ratemaking function at Seminole since I began my employment with the Cooperative in 1979.

Q. Please briefly describe your professional and academic background.

A. I have over twenty-three years of experience in the electric utility business. Prior to my employment at Seminole in August 1979, I was employed as an economist by Duke Power Company working in areas of both rates and load forecasting. I have a Bachelor of Science in Financial Management and a Master of Arts in Economics from Clemson University.

Q. Have you previously testified on behalf of Seminole before regulatory agencies?

A. Yes. I have provided written testimony and testified on behalf of Seminole before the Federal Energy Regulatory Commission ("FERC") and the Florida Public Service Commission ("FPSC") in a number of different regulatory proceedings concerning a variety of issues relating to my areas of responsibility.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony has several purposes. First, I will provide an overview of Seminole. Second, I will discuss the rationale underlying Seminole's decision to revise its wholesale rate structure. I will also describe the process used by Seminole to establish this new rate structure. Finally, I will respond to the direct testimony of the Lee County Electric Cooperative's ("LCEC") witnesses in this case.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I have attached to my testimony Exhibits ___ (TSW-1) through ____(TSW-20).

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. My testimony, in conjunction with that of Seminole's other witnesses, will show that Seminole's wholesale rate structure (i) was developed in accordance with Seminole's Wholesale Power Contract, (ii) is consistent with Seminole's Board-approved Strategic Plan, and (iii) is fair, just and reasonable.

IV. BACKGROUND

Q. Please provide a brief overview of Seminole and its Members.

A. Seminole was incorporated in 1948 to provide unified representation for its Members in wholesale purchased power negotiations. Seminole is a non-profit Generation and Transmission Cooperative organized under Chapter 425 of the Florida Statutes. Each of Seminole's members is a distribution cooperative serving retail end users in Florida.

Seminole's activities were limited until 1974 when, following the 1973 oil embargo, its Board of Trustees determined that it should develop independent power supplies for the Members. In 1975, each Member entered into a long term contract with Seminole for the purchase of wholesale power ("Wholesale Power Contract" or "Contract"). The Wholesale Power Contracts require each Member to purchase from Seminole all of its power requirements for distribution within the State of Florida not otherwise supplied under pre-existing contracts.

Q Are there currently any applicable pre-existing contracts?

A. Yes. Four of Seminole's Members have pre-existing contracts with the Southeastern Power Administration ("SEPA") for a combined 26 MW of capacity. The energy supplied from SEPA to these Members represents less than 2% of Seminole's Members' total energy requirements.

Q. What is the term of the Wholesale Power Contracts?

A. The Wholesale Power Contracts have an initial term of forty-five (45) years, until 2020. Thereafter, each Contract may be terminated upon three years' written notice by the party desiring termination.

Q. Have these Wholesale Power Contracts ever been amended?

Yes. In June 1984, Seminole and its Members executed amendments to the Wholesale Power Contracts (Amendment One) in order to more clearly provide for a new uniform rate structure that was adopted at that time. The Wholesale Power Contracts, as amended, provide that the Seminole Board of Trustees shall establish rates that will produce revenues which will be sufficient, but only sufficient, with the revenues from all other sources, to meet (1) the cost of operating and maintaining generating plants, transmission system and related facilities, (2) the cost of purchased power and transmission services, (3) payments on the principal and interest on Seminole's indebtedness, and (4) the need to provide for establishment and maintenance of reasonable reserves. The Wholesale Power Contracts state that such rates shall also be sufficient to enable Seminole to comply with any mortgage requirements existing from time to time, including the Rural Utilities Service ("RUS") Mortgage.

Thereafter, Seminole and its Members again executed amendments to the Contracts (Amendment Two). Amendment Two made no changes to the Contract provisions relating to rates or rate structure.

Q. Which distribution cooperatives in Florida are Members of Seminole?

A. Seminole's members are Central Florida Electric Cooperative ("Central"), Clay Electric Cooperative ("Clay"), Glades Electric Cooperative ("Glades"), Lee County Electric Cooperative ("LCEC"), Peace River Electric Cooperative ("Peace River"), Sumter Electric Cooperative ("Sumter"), Suwannee Valley Electric Cooperative ("Suwannee"), Talquin Electric Cooperative ("Talquin"), Tri-County Electric Cooperative ("Tri-County"), and Withlacoochee River Electric Cooperative ("Withlacoochee"). These members serve over 640,000 retail consumers in 45 counties throughout the state. The map appended hereto as Exhibit ___ (TSW-1) shows the location of Seminole's Member systems throughout the State.

Q. How does Seminole meet the full requirements power supply and transmission needs of its Members?

A. In the early 1980s Seminole constructed two nominally rated 650 MW coal-fired generating units (the "Seminole Plant"), in Putnam County, Florida, supplying nearly 75% of the Members' energy requirements. The two units began commercial operation in 1984. Seminole also owns a 1.6994% (15 MW) undivided interest in Crystal River Unit No. 3, an 890 MW nuclear power plant operated by Florida Power Corporation ("FPC"). Seminole has numerous short and intermediate term purchased power contracts with other entities in the State, which provide for the Members' intermediate and peaking needs as well as reserves. Seminole is also in the process of constructing a new 500 MW class combined cycle facility in Hardee County with a scheduled commercial operation date of January 1, 2002.

Seminole uses a combination of its own 230 kV transmission facilities as well as the transmission systems of FPC and Florida Power & Light Company ("FPL") to deliver its power supply resources to the Members, which have loads located throughout much of peninsular Florida. Transmission service purchases from FPC and FPL are made under long term transmission service agreements with each of these companies.

Q. Please describe how the Membership governs the Seminole organization.

A. Pursuant to the Bylaws of the organization, the Seminole Board of Trustees has the primary responsibility for providing policy direction. The Board consists of two voting trustees and one alternate from each of the ten Members. Seminole trustees are selected by each Member system Board to serve on the Seminole Board. The manager of each Member serves as one of its voting trustees. Decisions are made on a majority vote basis with each voting trustee casting one vote.

As established by Board Policy, there are five standing Board committees. Voting and "non-voting" trustees serve on these committees, and each Member has one representative. At the committee level all trustees (alternate or otherwise) have the right to vote, and decision-making is based on a majority vote. The standing committees are the Executive, Administrative, Finance, Engineering and Operations, and Rate Committees. From time to time, the Board may appoint ad hoc committees to address a specific issue. For example, an ad hoc Strategic Planning Advisory Committee was established in early 1997 to oversee the development of Seminole's current Strategic Plan. Ad hoc committees are generally composed of trustees representing only a subset of Member systems.

V. THE WHOLESALE RATE APPROVAL PROCESS

Q. In general terms, please describe how Seminole recovers its revenue requirements.

A. Pursuant to the Wholesale Power Contract, the rates and terms and conditions under which Seminole furnishes electric power and energy to its Members are fixed from time to time by a majority vote of Seminole's Board of Trustees, subject to written approval by the Administrator of the RUS. Such approval is required because Seminole has obtained financing for various generating and transmission facilities through the RUS.

Since commercial operation of Seminole Unit No. 1 on January 31, 1984, Seminole has recovered its revenue requirement through a uniform wholesale rate schedule to its Members that blends all power supply costs incurred by Seminole. These include the operation, maintenance, and ownership costs of the Seminole facilities, as well as purchased power costs, transmission costs, and administrative and general expenses.

Q. **Please elaborate on the actual administrative process by which the Board considers and approves changes to the Wholesale Rate to the Members.**

A. Under Seminole's Board Policies, the Rate Committee has oversight responsibility for changes to Seminole's Wholesale Rate to its members. The Rate Committee is comprised of each of the Member Systems' General Managers (who as noted earlier are voting trustees of Seminole). Seminole Staff works with the Committee to assist it in performing its functions. This assistance includes, among other things, developing options and recommendations and performing applicable cost-of-service and revenue analyses that will be used by the Committee during the course of its deliberations. The formal process for the Committee to acknowledge its majority support for a particular rate schedule is for it to pass a resolution (or motion) recommending adoption by the full Board of Trustees. The Board will then act on the recommendation. If the rate schedule is approved by the Board (again by a majority vote), it is then submitted to the RUS for approval.

Q. **Has the structure of the Seminole Wholesale Rate to its Members changed from time to time?**

A. Yes. Over the years, the Board has approved a number of changes to the wholesale rate structure that I would consider to be structural in nature.

Q. Have these changes always been approved unanimously by the Board?

A. No.

Q. To your knowledge, has any Member of Seminole ever requested that RUS reject a Board-approved rate schedule that has been submitted to it for approval?

A. No.

Q. Prior to this proceeding, has any Seminole Member who had voted against a particular rate structure ever sought to have any state or federal regulatory agency overturn the decision of the Board?

A. No.

Q. Prior to this proceeding, has any Member of Seminole ever suggested that a rate structure change needed to be submitted to the FPSC for approval?

A. No.

VI. <u>LCEC'S COMPLAINT</u>

Q. What is your understanding of the basis for LCEC's complaint in this proceeding?

A. On October 8, 1998, Seminole's Board of Trustees approved Rate Schedule SECI-7 and directed that effective January 1, 1999, it would supercede Rate Schedule SECI-6b. This Rate Schedule was submitted to RUS for approval on October 19, 1998, and it was approved by RUS on November 20, 1998. A copy of the Rate

Schedule SECI-7 and the corresponding RUS approval is attached as Exhibit ___ (TSW-2).

On December 9, 1998, LCEC filed its Complaint and Petition in which it asks the FPSC to (a) direct Seminole to file its Rate Schedule SECI-7 and supporting documentation with the Commission and (b) investigate the rate structure adopted in that Rate Schedule, which LCEC alleges is discriminatory, arbitrary, unfair and unreasonable. It appears that LCEC's primary rate structure concern relates to the inclusion of a Production Fixed Energy Charge which recovers a portion of Seminole's fixed production costs through a charge allocated on the basis of historical energy usage.

Q. Has there been a change to Rate Schedule SECI-7 since LCEC filed its complaint?

A. Yes. In October 1999, the Board approved Rate Schedule SECI-7a, which modified the Transmission Demand Charge to reflect a revenue requirement for the year 2000. Then in December 1999, prior to Rate Schedule SECI-7a taking effect, the Board approved Rate Schedule SECI-7b. This new rate schedule went into effect on January 1, 2000. The new rate eliminated the automatic annual reduction feature for the Production Demand Charge, which had been included in Rate Schedule SECI-7 (and retained in SECI-7a). Thus, had Rate Schedule SECI-7b not been adopted, the Production Demand Charge for the year 2000 would have automatically been lowered from $8.50/kW-mo. to $7.50/kW-mo. (and in 2001 to $6.50/kW-mo.) with a corresponding increase in the dollar amounts allocated to Members under the Production Fixed Energy Charge component of the rate. Instead, the Production Demand Charge under Rate Schedule SECI-7b was left as a stated rate at $8.50/ kW-mo., without any automatic future adjustments. A copy of Rate Schedule SECI-7b is attached as Exhibit ___ (TSW-3).

Q. At the time Rate Schedule SECI-7b was approved, did LCEC and the other Members reach an understanding relative to the application of the rate during the year 2000?

A. Yes. It was understood and agreed that LCEC would not contest Seminole's use of Rate Schedule SECI-7b for service rendered during the year 2000.

Q. What then is LCEC litigating in this proceeding?

A. Seminole's view is that in addition to its wanting the FPSC to assert jurisdiction over Seminole's Wholesale Rate Structure to its Members, LCEC is asking the Commission to examine the justness, reasonableness and fairness of the structure of Rate Schedule SECI-7b as to its application in the year 2001 and beyond.

VII. SEMINOLE'S STRATEGIC PLAN

Q. What precipitated the Seminole Board's decision to modify the structure of the Seminole Wholesale Rate effective January 1, 1999?

A. In September 1997, the Board of Trustees adopted a new Strategic Plan that called for Seminole to "establish a wholesale rate structure which provides an appropriate price signal that is more reflective of the incremental cost of new capacity." A copy of the Strategic Plan is attached as Exhibit ___ (TSW-4). At the time, this was deemed to be of strategic importance for a number of reasons, including the following:

- Members actively becoming involved in installing "behind the meter" generation to be used, in part, to reduce capacity purchases from Seminole under the Wholesale Rate Schedule;
- Members being approached by other power suppliers offering to sell capacity and energy to the Members at market-based rates;
- The desire on the part of the Members for Seminole to attempt to find consensus on modifications to Seminole's Wholesale Power Contract to provide the Member Systems with flexibility relating to the obligation to acquire future capacity resources only from Seminole ("Member Choice Program").

Q. Why would a Member's "behind the meter" generation program have any bearing on the Board's desire to change Seminole's Wholesale Rate structure?

A. Seminole was concerned that the then-current Rate Schedule SECI-6b was sending a demand price signal that encouraged the Members to inefficiently overinvest in "behind the meter" generation. The inefficiency arises from the fact that Seminole's marginal cost to serve the incremental loads being displaced by "behind the meter" generators is in the order of $4 - $6/ kW-mo., whereas the production cost component of the bundled demand charge in Rate Schedule SECI-6b was approximately $9/ kW-mo. The Seminole Board agreed that it would be economically inefficient for a Member to invest, lets say, $7/ kW-mo. for a diesel generator for the purpose of avoiding a $10/ kW-mo. charge on the Seminole rate when it only cost Seminole $4-$6/ kW-mo. to serve the incremental load being displaced.

Q. Please explain why the fact that certain Members were being approached by others offering alternative power supply resources would prompt the Board to reconsider its Wholesale Rate structure.

A. In recent years, the market for wholesale electric service has become increasingly competitive. One of the first indications of this came a few years ago when Seminole was made aware of the fact that Louisville Gas & Electric Company ("LG&E") had suggested to LCEC that it could meet LCEC's power supply needs at a lower cost than that offered by Seminole. Since that time, Seminole has been advised that Members are routinely contacted by other suppliers. In this environment, the Board decided that Seminole should try to price power in a way that more closely mirrored what the competition was likely to be -- that is, the cost of new peaking/combined cycle generation. The Board agreed that in a competitive market not only do Seminole's costs need to be competitive, but also the price signals that effect behavior should, to the maximum extent possible, be tied to marginal costs rather than embedded costs.

Q. Please elaborate on the Member Choice Program's bearing on the issue of Seminole's Wholesale Rate Structure.

A. Seminole, as part of its Strategic Plan, is actively engaged in an effort to provide the Members with the ability to shop for alternative (i.e., non-Seminole) power supply resources to meet a portion of their respective power supply needs if it is their inclination to do so. This is a measure of flexibility that is currently not afforded to the Members under the existing Wholesale Power Contract. A key tenant of this program is that Members who opt for any such alternatives must <u>not</u> be able to shift cost burdens onto the remaining Members. One of the best ways to ensure that this will not be the case is for the Members exercising choice to be able to avoid only the incremental cost of service. Allowing Member X to avoid a $9/ kW-mo. (average embedded production cost) capacity charge when it only costs Seminole $5/ kW-mo. incrementally to supply the capacity, means the other Members would have to absorb the remaining $4/ kW-mo. cost left stranded by Member X's action.

Q. **You mentioned earlier that the Board set up a Strategic Planning Advisory Committee of select Board Members to work on the formulation of the Strategic Plan. What systems were represented on this Advisory Committee?**

A. LCEC, Central, Clay, Sumter, Tri-County, and Withlacoochee.

Q. **How many times did the Advisory Committee meet while it was deliberating on the contents of the Strategic Plan?**

A. The Advisory Committee met on five different occasions between February 1997 and September 1997 to discuss what should be included in the Strategic Plan. The Committee also met once in December 1997 to review a draft of a Tactical Plan describing how Seminole Staff intended to achieve the objectives identified in the Strategic Plan.

Q. **Were the general concepts you described above relative to the need for changes to the Wholesale Rate Structure discussed during the course of the Advisory Committee's deliberations?**

A. Yes.

Q. More specifically, was it made clear during these discussions that what was being contemplated would result in proportionately less costs being recovered through demand charges?

A. Yes. The primary focus of the rate-related discussions was that what effectively amounted to a bundled system average demand charge was sending the wrong price signal and that the demand charge had to be lowered to more closely track Seminole's incremental cost of supplying capacity. It was also felt that the demand charge should be unbundled so that production and transmission pricing information was not screened from the Members' view.

Q. Did the LCEC representative on the Advisory Committee vote in favor of the recommendation for approval to the Board?

A. Yes.

Q. Did the LCEC representatives on the Seminole Board vote in favor of adoption of the Strategic Plan?

A. Yes.

Q. Why did Seminole wait until January 1999 to implement the change to its Rate Structure?

A. There were two basic reasons why January 1, 1999, was determined to be the most opportune time to make the change in rate structure. The first was that Seminole's partial requirements agreement with FPL was terminating on that date. The second was that forecasts showed that the 1999 test period revenue requirement was going to result in a significant decrease in rates effective January 1 of that year.

Q. Why did termination of the FPL Partial Requirements contract have an impact on the timing decision for the new rate structure?

A. Termination of the FPL partial requirements contract impacted the timing of the decision in two ways -- the first way relates to demand billing determinants under the rate, and the second relates to the impact of the termination of this contract on Seminole's short run incremental cost of supplying capacity.

With regard to the first point, one of the features of the pre-existing rate structure (i.e., Rate Schedule SECI-6b) was that the peak hour for billing demand charges was not tied to either the Member's or Seminole's peak demand, but instead was tied to the peak hour used by Seminole's partial requirements suppliers (i.e., FPC and FPL) within their respective control areas. Member load in the FPL area was billed based on the hour in which the Seminole load in the FPL control area was at its maximum level; Member Load in the FPC control area was billed based on the hour coincident with FPC's system peak. This "power supplier-based" billing determinant feature was incorporated into the Seminole rate structure in 1994 after several Members, including LCEC, expressed concerns that the prior structure (which used the hour of Seminole's coincident peak demand) was causing the Members to overuse load management. This occurred because Members were trying to "catch" not only the Seminole coincident peak to reduce purchase power costs from Seminole, but also trying to "catch" the partial requirements billing peak in order to reduce Seminole's purchased power costs. The termination of the partial requirements agreement with FPL, effective January 1, 1999, meant that something had to be done with regard to the structure of the Seminole rate, since one of its major billing determinants was tied to a contract that was no longer going to be in place.

As to the second point, the termination of the FPL partial requirements contract resulted in a significant decrease in the short run marginal cost to supply production capacity to the Members. The FPL contract contained average system production capacity charges in the range of $12/ kW-mo. for what amounted to a load-following, peaking service. Seminole terminated this contract because these prices were not indicative of what Seminole could obtain in the market either by building peaking generating capacity itself or by contracting with others for it. In point of fact, Seminole replaced a significant portion of the FPL capacity with a purchase of approximately 450 MW of intermediate/peaking capacity from FPC at a price of approximately $5.50/ kW-mo. With this change in the FPL area, coupled with the prices already being obtained by Seminole for partial requirements service from FPC for Member load in the FPC control area (i.e., on the order of $4.90/ kW-mo.), the price signal contained in the then-existing Rate Schedule SECI-6b of $9/ kW-mo. was clearly out of line with the market for incremental capacity.

Q. Please describe the relevance of the rate decrease that Seminole was to experience on January 1, 1999, to the decision to change the rate structure at that time.

A. Changes in rate structure inevitably have disparate impacts on Members since each has its own unique usage characteristics (e.g., load factor, seasonal usage patterns, delivery voltage, etc.). The Board has historically gravitated toward rate structures that are designed to limit the adverse impact on any single Member to 0.5 mills/kWh or less on an annual basis. Since Seminole's forecasts had shown that it would be able to pass on to the Members an expected 3 mill general rate decrease during calendar year 1999, it was felt that any Member experiencing an adverse effect from the rate change in structure would still experience a net decrease and thus could more easily absorb such a change during that calendar year.

Q. Please describe the process by which Seminole Staff sought to develop a new Wholesale Rate structure consistent with the Strategic Plan.

A. The first step was to translate the Strategic Plan into a Tactical Plan with milestone schedules and tasks to be completed. This was accomplished in January 1998, and submitted to the Board for comments before being finalized.

Q. When comments were solicited from the Members regarding the Tactical Plan, did any Member System voice concern about the provisions dealing with the wholesale rate structure?

A. No.

Q. What did Seminole Staff do next?

A. After finalizing the Tactical Plan, the next step was to discuss different rate options and concepts with the Rate Committee. The first meeting was on March 13, 1998, at which time Seminole staff made a presentation on the different rate parameters that should be addressed in considering how to restructure the Seminole Wholesale Rate. Staff also discussed possible rate structure alternatives for the Committee's consideration. A redacted copy of the minutes to this meeting and the corresponding overheads used in that presentation are attached as Exhibit ___ (TSW-5). As the minutes reflect, the Committee agreed that a workshop would be conducted in April 1998 to discuss the matter in more detail, and the Member Systems were encouraged to invite their respective consultants to the meeting.

Q. Why have you provided only a redacted copy of these materials?

A. At any meeting, our Committee members and Trustees discuss a variety of matters that may involve confidential business information. I have redacted the minutes and presentation materials attached to my testimony to leave only the portions of the materials involving rates and rate structure.

Q. Was a Rate Workshop conducted in April 1998 by the Rate Committee?

A. Yes. At the workshop we discussed the cost drivers on the Seminole system as well as Seminole's incremental cost to serve from both a generation and transmission perspective. Staff also discussed some suggested changes to the rate structure alternatives that had been presented in March and presented rate comparisons by Member for the alternatives shown.

Q. Did any of the Members bring any consultants to the workshop?

A. Yes. LCEC and Glades both brought their rate consultants to the workshop.

Q. Were there any minutes kept for the April 1998 Workshop?

A. No. Workshops are not considered to be official meetings of the Committee, and hence no minutes were kept. However, the overheads used by Staff in the presentation are attached as Exhibit ___ (TSW-6).

Q. What happened after the Workshop?

A. The next meeting of the Rate Committee was May 13, 1998. At that meeting, Staff reviewed a recommended rate structure that made further enhancements reflecting prior input from the Members. Staff reviewed the various features of the recommended rate and described the logic used to support each of the features in question. A redacted copy of the minutes to this meeting and the relevant overheads used by Staff are attached as Exhibit ___ (TSW-7).

Q. Was action taken at this Rate Committee meeting?

A. Yes. As the minutes show, the Committee passed a motion recommending Board approval of the components of a revised rate structure to be placed into effect on January 1, 1999. The motion passed on a 6 to 3 vote, with the representatives from LCEC, Clay, and Glades voting against the motion.

Q. Did the Board of Trustees act on the Rate Committee's recommendation at its meeting in May 1998?

A. Yes. The Board accepted the Committee's recommendation on an 11-7 vote. The votes against were cast by LCEC (2), Clay (1), Glades (2), and Suwannee (2). A redacted copy of the minutes to this Board meeting is attached as Exhibit ___ (TSW-8).

Q. When you say that the Board approved a new rate structure, do you mean to suggest that the Board was approving the actual unit charges and tariff sheets that would go into effect on January 1, 1999?

A. No. Since this decision was made so early in the year (1998), all rate alternatives reviewed during the process reflected estimated unit charges based on revenue requirements estimates that would be subsequently fine-tuned during the 1999 budget development process. The Board was approving the conceptual structure of the rate that would be developed after the budgeted revenue requirement had been established.

Q. When did the Rate Committee meet next?

A. The Committee met again on July 8, 1998, at which time Staff presented a draft of a tariff sheet (designated SECI-7) that translated the structure previously approved by the Board into words and preliminary unit charges. It was still recognized that final unit charges would be developed once the budgeted revenue requirement had been approved by the Board. No action was required at this time since Staff was making this presentation only to give the Members time to review the actual tariff sheet before formal approval was requested later in the year. A redacted copy of the minutes to the July 8 meeting are attached as Exhibit ___ (TSW-9).

Q. When did the Rate Committee and Board act on Rate Schedule SECI-7?

A. Formal approval of Rate Schedule SECI-7 took place at the October 1998 Board Meeting. The Rate Committee met on October 7 and reviewed the terms and final unit charges in the Rate Schedule. The Committee passed a resolution calling for Board approval of Rate Schedule SECI-7, with LCEC registering the only vote against. The minutes show that LCEC's representative objected to the new rate structure's recovering a greater proportion of fixed costs in the energy charge. The redacted minutes to the Rate Committee meeting are attached as Exhibit ___ (TSW-10). At the Board meeting the following day, the Board approved the new rate schedule with only two "no" votes, both cast by LCEC's representatives. The redacted minutes to the Board meeting are attached as Exhibit ___ (TSW-11), and a copy of the approved Rate Schedule SECI-7 is attached as Exhibit ___ (TSW-2).

Q. Earlier you mentioned that a general rate decrease was taking place coincident with the implementation of the new rate structure. Did the

projections at the time indicate that all of the Members would experience a net decrease in power costs during 1999?

A. Yes. The 1999 test period forecasts showed that annual decreases (i.e., between 1998 and then-projected 1999) ranged between 1.5 mills/ kWh and 3.39 mills/ kWh, even with the new rate structure. LCEC was projected to have a decrease of 2.82 mills/ kWh. Exhibit ___ (TSW-12) shows, by Member, a comparison of 1998 average power costs under Rate Schedule SECI-6b versus the then-projected 1999 test period average power costs under Rate Schedule SECI-7.

Q. What was the actual cost of power to the Members in 1999 and how did LCEC compare to the other Members?

A. Exhibit ___ (TSW-13) is a table showing the actual average cost of power and the average monthly load factor for the Members during 1999. The table ranks the Members by cost from lowest to highest. The table also shows the strong inverse relationship between load factor and average power cost that resulted from the application of Rate Schedule SECI-7 during 1999. The table shows that LCEC's average cost of power during this year was 44.8 mills/ kWh, which was the second lowest among the Members.

Q. Returning now to the chronology of rate structure-related activities, please describe what happened next.

A. Before the new rate actually took effect, LCEC filed its complaint before the Commission on December 8, 1998. In mid-1999, the parties attempted to mediate the dispute with the help of the FPSC staff but to no avail. Following the mediation, Seminole Staff continued to work to identify whether there were modifications to the rate that could resolve the situation to the satisfaction of all parties. At the September 8, 1999 meeting of the Rate Committee, the Glades Electric representative indicated that the Glades Board had passed a resolution recommending that the Seminole Board reexamine the viability of Rate Schedule SECI-7. At the request of Glades, the Rate Committee agreed that Seminole Staff would hire an outside consultant to provide an independent cost-of-service study and make rate recommendations for the Board's consideration. The input from this consultant would be taken into consideration as the Committee attempted to address the rate structure for the year 2000, and as such the results were needed with a quick turnaround. In order to keep the consultant completely independent, it was agreed that Staff would not provide the consultant with any information concerning Seminole's Strategic or Tactical Plan, staff's associated rate structure recommendations, or the related deliberations by the Board of Trustees.

Q. **Did the Rate Committee retain a hand in overseeing this consultant project?**

A. Yes. It was also agreed that the Committee Chair (Suwannee) and Vice Chair (Sumter) would oversee the effort.

Q. **When did the Rate Committee meet next and what was discussed?**

A. The Rate Committee met in October 1999 at which time Staff advised the Committee that the rate consulting project had been awarded to Burns & McDonnell. Staff also advised the Committee that if Rate Schedule SECI-7 were left in place during the year 2000, Seminole would over-collect the year 2000 revenue requirement by approximately $6.3 million, primarily due to the fact that the stated rate for transmission capacity was now too high relative to Seminole's projected transmission revenue requirement. Staff recommended that Seminole's Board approve a lowered transmission rate to eliminate the over-recovery. In a continued effort to provide an opportunity for the Members to resolve their outstanding differences on the rate structure, Seminole Staff developed several different alternatives for the Rate Committee's consideration, although Staff's recommendation was to retain the Rate Schedule SECI-7 structure, albeit with adjusted unit charges to eliminate any over-recovery. Staff's recommended new rate schedule was designated as Rate Schedule SECI-7a. After much deliberation, the Committee passed a motion on a 5 to 3 vote (with 1 abstention) to recommend Board approval of Rate Schedule SECI-7a, to become effective January 1, 2000. Voting against the motion were the representatives from Clay, Glades, and Suwannee. LCEC's representative abstained. A copy of Rate Schedule SECI-7a is attached as Exhibit ___ (TSW-14), and a copy of the redacted Rate Committee minutes is attached as Exhibit ___ (TSW-15). The minutes show that the Committee expressed a strong desire to try to resolve differences, and recognizing that there was no scheduled Board meeting in November, it unanimously passed a motion to request that the full Board delegate to the Rate Committee the authority to modify the rate structure prior to the next Board meeting if a new rate could achieve unanimous approval. The minutes show that Staff was directed to develop two other specific rate proposals for the Committee's consideration at a special meeting in November 1999.

At the October Board meeting, the motion to approve Rate Schedule SECI-7a passed on a vote of 9 to 8, with the representatives from Clay, Glades, LCEC and Suwannee voting against. The Board also voted unanimously to delegate authority to the Rate Committee to adopt an alternative rate structure to become effective January 1, 2000, prior to the next Board meeting if all Members of the Committee were in accord.

Q. What happened at the special Rate Committee meeting in November 1999?

A. At this meeting, the Committee once again examined alternatives and unanimously agreed that staff should modify Rate Schedule SECI-7a to remove the automatic reduction mechanism in the Production Demand Charge and to leave the charge at $8.50/ kW-mo. LCEC agreed that it would not contest the application of the new rate schedule (designated as Rate Schedule SECI-7b) for billing during the year 2000. A copy of the redacted minutes to the special Rate Committee meeting is attached as Exhibit ___ (TSW-16).

Q. Did the Rate Committee take any action regarding the Rate Structure in December 1999?

A. Yes. At its December meeting, the Rate Committee approved a motion recommending that the Board clarify that Rate Schedule SECI-7b, which had been approved by the Rate Committee in November, was intended to remain in effect until further action of the Board of Trustees without any predefined ending date. The motion was approved with only LCEC's representative voting against. A copy of the redacted Rate Committee minutes is attached as Exhibit ___ (TSW-17).

Q. Did the Board take any action regarding the Rate Structure in December 1999?

A. Yes. The Board of Trustees passed a motion clarifying that it was the intention of the Board to leave SECI-7b in effect "until further action is taken by the Board." That is, the Board was basically clarifying that the effective period for the new rate did not have a fixed ending date. A copy of the redacted Board minutes is attached as Exhibit ___ (TSW-18).

Q. How does Rate Schedule SECI-7b differ from Rate Schedule SECI-7a?

A. The new rate incorporated the feature agreed to at the November Rate Committee meeting that locked in the Production Demand Charge at $8.50/kW-mo. This results in somewhat fewer dollars being recovered through the Production Fixed Energy Charge portion of the rate in years 2000 and beyond.

Q. How did the LCEC's projected power costs under the new rate for the year 2000 compare to that of Seminole's other Members?

A. Exhibit ___ (TSW-19) shows the projected average cost of power and projected average monthly load factors among Members for the year 2000 under Rate Schedule SECI-7b. This table demonstrates that the new rate continued to result in a strong inverse correlation between power costs and load factors. The table also shows that LCEC's power costs were projected to be the third lowest, and load factor the third best, among Seminole Members.

VIII. <u>THE BURNS & McDONNELL STUDY</u>

Q. Did Burns & McDonnell conduct the cost-of-service study referred to earlier in your testimony?

A. Yes. The consultants' findings were documented in a report entitled "Cost of Service Study and Wholesale Rate Design" dated December 1999. The report is attached as Exhibit ___ (DEC-1) to Mr. Christianson's testimony.

Q. What were Burns & McDonnell's recommendations?

A. Burns & McDonnell recommended the use of the Equivalent Peaker Method for the purpose of establishing Seminole's wholesale rate to its Members. The methodology is described in detail in the report. I note that the methodology results in a larger percentage of fixed costs being recovered through energy charges than that reflected in Rate Schedule SECI-7b.

Q. **Was the Burns & McDonnell study available to the Rate Committee and Board prior to their approving Rate Schedule SECI-7b in December 1999?**

A. Yes.

Q. **Has Seminole subsequently retained Burns & McDonnell for any other purpose?**

A. Yes. Burns & McDonnell was subsequently retained by Seminole to review Rate Schedule SECI-7b and to render an opinion in this case on whether that rate schedule is just and reasonable and not unduly discriminatory. In contrast to the first engagement, Burns & McDonnell has now been provided with all of the background information that had been previously withheld from them.

IX. REBUTTAL TO LCEC WITNESSES

LCEC's Fundamental Argument - Rate Structure

Q. **Having reviewed the testimony of LCEC's three witnesses, what is the basic argument LCEC is making with regard to Seminole Rate Schedule SECI-7b?**

A. LCEC's argument boils down to a claim that (i) the rate was not adopted in accordance with the Wholesale Power Contract because it was not adopted in accordance with generally accepted ratemaking standards (May, p.6, line 10), and (ii) the rate is unjust, unreasonable, and unfair (Blake, p.9, lines 17-18).

Q. With regard to the first point, what is the nexus between the Wholesale Power Contract and the concept of generally accepted ratemaking principles?

A. The linkage between the two is found in the Wholesale Power Contract language that provides that rates "... shall recognize and provide for variations in the cost of providing service at differing voltages, load factors, and power factors, the provisions <u>therefore</u> to be made in accordance with generally accepted ratemaking standards." (Emphasis added.)

Q. On what basis does LCEC claim that the Rate Schedule SECI-7b is unjust, unreasonable, unfair and not developed in accordance with generally accepted ratemaking principles?

A. In an effort to support this claim, LCEC contends the following:

1. The Rate Schedule was not based on a cost of service study (May, p.9, lines 2-7; Seelye, p.8, lines 18-20).
2. The Rate Schedule contains "tilting" (Seelye, p.10, lines 20-23).
3. The Rate Schedule discourages conservation and load management (Blake p.9, lines 18-21).
4. The Rate Schedule is not "simple and stable" (Blake, p.37, lines 23-24).
5. The Rate Schedule places Seminole's member Distribution Cooperatives at a disadvantage by shifting the risk of competition to such members (Blake, p. 35, lines 15-17).
6. The Rate Schedule adversely impacts economic development (Blake, p. 35, lines 17-18).

Q. How do you respond to the allegation that Rate Schedule SECI-7b is not based on a cost-of-service study?

A. LCEC's witnesses are simply misinformed. Staff performed a detailed analysis and functionalization of its costs in developing the Rate Schedule. This study is described in Seminole witness Novak's testimony. I note that Mr. Seelye acknowledges that the work conducted by Burns & McDonnell constituted "a cost of service" (Seelye, p. 8, lines 20-21). As described by Ms. Novak, Seminole Staff performed a cost of service analysis similar to that conducted by Burns & McDonnell when the Staff designed its new rate. The associated workpapers and analysis have always been available for inspection by any of the Members wishing to see them. In fact, LCEC availed itself of this opportunity prior to filing its testimony.

Q. How do you respond to the argument that the Rate Schedule is unjust, unreasonable and unfair because it contains "tilting"?

A. Let me start by defining what is meant by the term "tilting." Tilting is a term used to describe the recovery of a portion of a company's fixed costs through an energy component of its rate. There are varying degrees of "tilt" that can be built into a particular rate design. I believe that Seminole and LCEC witnesses agree on this conceptual definition of the term based on my reading of LCEC's witnesses' testimony.

Q. Mr. Seelye suggests that tilting is inappropriate because it is not a traditional feature of rate design (Seelye, p.10, lines 20-22). Do you agree?

A. I am quite confident that both Seminole and LCEC could cite examples of large commercial and/or wholesale rate designs used across the country that either contain or do not contain an element of tilting. In fact, Seminole witness Christianson states in his testimony that an informal survey he conducted in preparation for his testimony has identified several examples of rates that contain tilting. Seminole is confident that the large demand metered industrial loads in the State of Florida do not recover 100% of allocated fixed costs in demand charges. I am also sure that both Seminole and LCEC could cite different jurisdictions that treat the issue differently. Whether untilted rates are more commonly or less commonly used in the utility industry at the present time is a question I cannot answer, since I have not undertaken a study, nor am I aware of any study, which seeks to answer this question. My view is that the issue is really academic, since I do not believe that whichever way it is answered should have any bearing on whether the rate at issue before the Commission in this proceeding is fair, just and reasonable.

I would, however, like to focus the Commission's attention on what I can speak to with some authority, and that is what has been the history at Seminole with regard to the question of rate tilt. I think this discussion is relevant to the matter at hand, since LCEC's witnesses have incorrectly characterized the level of tilting reflected in Rate Schedule SECI-7b as a radical departure from past practices at Seminole.

Q. **Please describe what the history has been at Seminole with regard to rate tilt.**

A. Exhibit ___ (TSW-20) contains a table showing the amount of tilt that has been reflected in the major rate structure changes that have been placed into effect at Seminole over the years. The table shows that going back to 1985, Seminole's wholesale rate to its Members was designed to recover 55% of its total fixed costs (including transmission) in demand charges. In 1987, with the adoption of Rate Schedule SECI-5 the figure increased to 85% (including transmission). It remained as the formally adopted ratemaking criteria by the Board in Rate Schedule SECI-6 which went into effect in 1989. The change to Rate Schedule SECI-6b in 1994 did not address the question of rate tilt, as it was a structural change designed to only modify the hour of the billing peak and not to modify the level of the demand charges contained in the prior-existing rate. Over the years that Rate Schedule SECI-6b remained in effect the amount of tilt gradually decreased since the demand rate remained unchanged while loads continued to grow and Seminole's fixed costs continued to decline. The next major rate structure change came with Rate Schedule SECI - 7, which was projected to recover 81% of total fixed costs (including transmission) in demand charges during 1999. Rate Schedule SECI-7b is projected to recover this same percentage of fixed costs in demand charges during 2000.

This history shows that not only has tilting been traditional at Seminole, but that the level of tilting in Rate Schedule SECI-7b is not materially different from that expressly approved by the Seminole Board the last time it expressed a formal view on how it wanted the rate to be developed.

Q. **Do you agree with Mr. Seelye that _if_ a feature of a rate is deemed to be non-traditional, it is logical to conclude that it is therefore unfair, unjust and unreasonable?**

A. No. In recent years, traditions in the electric utility business have been falling by the wayside. Certainly most observers would agree that competition in the electric utility industry is not "traditional." This does not make competition bad any more than it makes bad "non-traditional" solutions that firms develop to try to deal with the changing realities of an evolving marketplace. LCEC is itself promoting Seminole's offering non-traditional options for the Members to self-supply a portion of their needs with non-Seminole resources. Yet on the other hand, LCEC is seeking to preclude Seminole from incorporating changes to its rate structure that reflect the true cost impacts of Members exercising such self-supply options on the grounds that such changes are “non-traditional."

Q. **Does the fact that Rate Schedule SECI-7b contains rate tilting mean that it does not meet the Wholesale Power Contract requirement referred to by Ms. May (p. 6, line 5) that the rate reflect the varying costs of load factors among Members?**

A. Not at all. As I showed in Exhibit __ (TSW-19) there exists a very strong inverse relationship between load factor and average power costs under the new rate structure. That is, the better the load factor, the lower the rate. The new rate reflects the proper value of improving load factor on the Seminole system by incorporating demand charges that reflect Seminole's marginal cost of capacity. Including greater amounts of fixed costs in demand charges would over-value the benefits of improving load factor on the system and result in undue discrimination in favor of high load factor customers.

Q. **How does one determine the proper amount of tilt in the rate?**

A. I think the answer lies in Dr. Blake's statement that "... customers that <u>cause</u> a utility to incur costs should generally pay rates that reflect those costs" (Blake, p.20, lines 4-5). (Emphasis added.) The key word here is "cause." Seminole's Rate Schedule SECI-7b recognizes that the price signals given to Members should be reflective of the incremental cost effects on Seminole <u>caused</u> by changes in Member demand. When the marginal cost of capacity is less than the embedded cost of capacity (as is the case with Seminole), it is appropriate to recognize that fact in setting rates by incorporating an appropriate level of rate tilt in its wholesale rate design.

From a slightly different perspective, Bonbright provides another justification for rate tilting on a system such as Seminole when he states;

> "About the only other controversy regarding energy charges is whether there should be a rate tilt. A rate tilt occurs where energy costs are counted as demand costs or vice-versa. According to the FERC Handbook (1983, p. 153) while these rate tilts have been accepted for years for gas pipelines, the Commission has usually rejected them in the rate designs of electric companies as it violates their stressed credo that rate design should reflect cost incurrence. <u>However, caution is warranted here, since capital costs may be incurred for the purpose of, and having the effect of, lowering energy costs. When a company can so demonstrate, a regulatory commission should allow a tilt on grounds of cost incidence."</u> (Emphasis added) (Bonbright, Danielsen, and Kamerschen, <u>Principles of Public Utility Rates</u>, 1988, p. 493-494)

Seminole's significant reliance on relatively high fixed cost base-load units, which were constructed to reduce the Members' total costs through offsetting low coal-fired energy costs, meets Bonbright's standards for the recovery of some portion of fixed costs on the basis of energy allocators. As described by Ms. Novak, approximately 40% of Seminole's fixed costs are associated with Seminole base load generation, compared to approximately 19% of the fixed costs recovered through the Production Fixed Energy Charge.

Q. How do you respond to the charge that the SECI-7b rate does not encourage load management and conservation?

A. I will respond to this question by first dealing with load management. Rate Schedule SECI-7b has a demand charge of $8.50/kW-mo. for the eight peak months of the year. As described by Ms. Novak, this translates into a price signal that closely mirrors Seminole's incremental cost of adding combined cycle generation. Arguably, this pricing signal still gives too much of an incentive to install additional load management equipment since peaking capacity is all that is displaced by load management. As explained by Ms. Novak, the equivalent 8-month price for new combustion turbine capacity is approximately $6.27/ kW-mo. Expressed differently, setting demand charges at the marginal cost of peaking capacity would encourage the proper amount of load management on the system. Dr. Blake proposes that we send a signal to the Members that suggests that load management displaces not only peaking capacity resources, but base and intermediate as well.

Q. Dr. Blake complains that past load management investments made by LCEC will be rendered less valuable under the new rate. (Blake, p. 27, line 4-14). Do you wish to comment on this complaint?

A. This complaint ignores the appropriateness of sending proper price signals that promote economic efficiency. Dr. Blake's position also ignores the fact that Rate Schedule SECI-7b (i) bills for demand on the basis of Seminole's monthly system coincident peak, and (ii) only bills during the defined peak months. Both of these features should enhance the value of load management in the LCEC area. They do so by significantly reducing the number of hours of control required to catch the peak as compared to what was required under the "power supplier" billing demand feature that was reflected in Rate Schedule SECI-6b.

Q. Are there any other relevant factors that Dr. Blake's complaint ignores?

A. Yes. Dr. Blake ignores the non-rate schedule pricing incentives that Seminole has provided to the Members in the past relative to load management. LCEC was the recipient of $9.7 million in load management incentives between the years 1989 and 1994. LCEC actually received the highest amount of incentive payments on the Seminole system during the years such incentive payments were made. Between these payments and the savings LCEC derived over the years through reducing its demands, Seminole believes that much, if not all, of LCEC's existing load management system has already paid for itself.

In addition, Dr. Blake may not realize that, from an operational perspective, Seminole has reached a point where making full use of existing load control requires a frequency and duration of interruption that is meeting strong end-use customer resistance. Notwithstanding the economics, these operational constraints should be taken into consideration in evaluating the desirability of additional load management.

Q. Please explain why you disagree with Dr. Blake's point with regard to energy conservation.

A. With regard to energy conservation, Dr. Blake fails to demonstrate how any of the rates endorsed by LCEC promote cost-effective conservation to any greater degree than the Seminole rate that he is criticizing.

Q. How do you respond to the criticism that Rate Schedule SECI-7b is deficient because it is not "simple and stable"?

A. My only comment with regard to the "not simple" criticism is that I have not discerned in my dealings with the Members that any of them do not understand the rate. I believe it to be straightforward and in some respects less complicated than the previous Rate Schedule SECI-6b which based billing demands on the hour of Seminole's respective power supplier's billing peaks. Having said this, I think it is fair to say that "simple" is a concept that is in the eye of the beholder. I do submit, however, that the subject rate is not unnecessarily complicated and easily passes Dr. Blake's "simple" test.

With regard to the Dr. Blake's stability issue, I suggest that Exhibit ___ (TSW-20) supports the view that this change in rate structure is not a radical departure from past ratemaking practices at Seminole, particularly with regard to the threshold issue of rate tilt. Having said this, I do not believe that in a rapidly changing business environment, rate features designed to send proper price signals to the Members should be rejected on the grounds that they are different from what has been done in the past. If Seminole is going to be successful in an evolving marketplace, we must be prepared to deal with change. The other point to keep in mind is that these changes were not imposed on the Members by a third party supplier. The Members made the decision to make the changes that are reflected in Rate Schedule SECI-7b.

Q. **How do you respond to Dr. Blake's "risk shifting" argument?**

A. Dr. Blake does not believe that the Members should bear the risk of competition. Presumably he believes that the risk should instead be borne by Seminole. The problem with this analysis is that the customers and owners of Seminole are one and the same (i.e., the Members). The Members ultimately bear the risk of stranded Seminole investment in a competitive environment. Dr. Blake thinks it unfair (and unjust and unreasonable) to have a rate that prevents a non-competitive Member that loses load in a competitive market from forcing the other Members to immediately absorb costs left stranded by the loss of such load. Rate Schedule SECI-7b transitions the transfer of approximately 20% of these costs (i.e., the percent of production fixed costs recovered through the Production Fixed Energy Charge) from the Member losing the load (i.e., energy sales) to the other Members over a period of four years. It would seem logical that any Member believing itself to be more competitive than other Members (and thus less likely to lose load) would find such a feature attractive in a competitive market.

Q. How do you respond to Dr. Blake's claim that the rate structure does not promote economic development?

A. Apparently Dr. Blake believes that promoting economic development is one of the criteria for determining whether a rate structure is fair, just and reasonable. Seminole disagrees. While based on the circumstances of any given utility, economic development may be a reasonable goal of a particular rate design, the failure to explicitly factor such considerations in the development of any given wholesale rate is hardly grounds for concluding that a rate is unjust, unreasonable or otherwise unfair.

<u>LCEC's Fundamental Argument - Jurisdiction</u>

Q. Do you wish to address any of the points raised by LCEC's witnesses related to the jurisdictional issue being litigated in this proceeding?

A. Yes. Dr. Blake (p.33, line 7-14) states that "[C]ontracts between electric utilities and their <u>customers</u> are common in the industry. However, the execution of a contract between an electric utility and a customer does not insulate the electric utilities rate structure from regulation."

Dr. Blake uses the word "customer" and in a certain respect he is correct in doing so, since the Members do consume the product that is being produced (i.e., delivered wholesale power) by Seminole on their behalf. However, Dr. Blake ignores the basic reality that (i) these "customers" are also the owners of the organization, (ii) that each freely entered into the arrangements that define a non-regulatory process by which rate structures are established, and (iii) that each has a <u>direct vote</u> in the establishment of the rate structures adopted by the cooperative. Second bites at the apple through the regulatory process at the FPSC, as are being sought in this case by LCEC, were not part of the bargain and severely undermine the majority vote concept that goes to the heart of decision-making at Seminole. It is the nature of the relationship that Seminole has with its Members that is relevant to the jurisdictional question, not, as Dr. Blake suggests, simply the fact that a contractual relationship exists.

Q. If the FPSC does conclude that it has jurisdiction over Seminole's wholesale rate structure, what standard of review should apply?

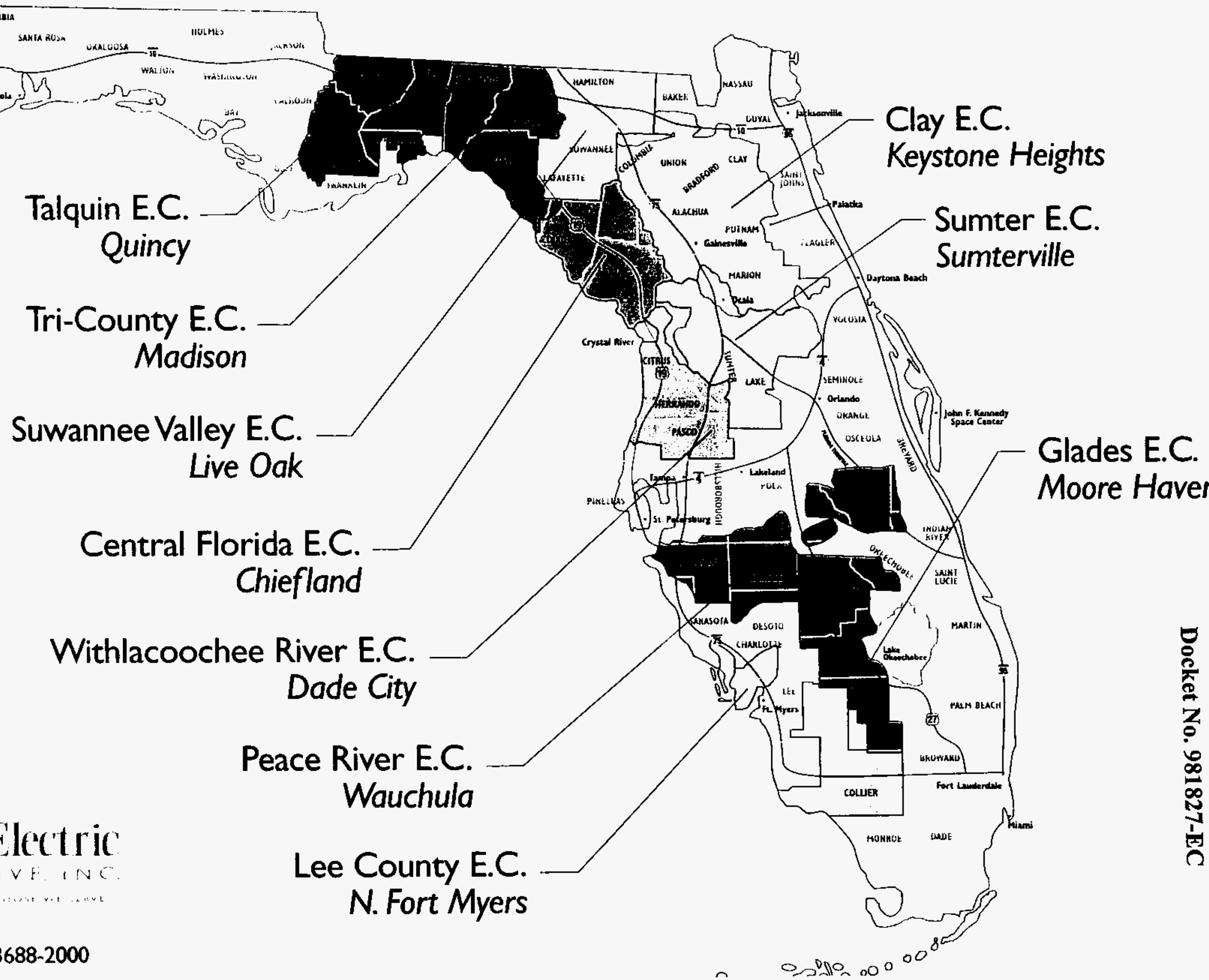
A. While Seminole trusts that the FPSC will not reach such a conclusion, it is Seminole's view that should it do so, its oversight over new Seminole rate structures should be limited to determining whether or not the rate structures were developed and approved in accordance Seminole's Wholesale Power Contract.

Q Does this conclude your testimony?

A. Yes.

Seminole's Member Distribution Cooperatives

FLORIDA



Seminole Electric
COOPERATIVE, INC.

P.O. Box 272000
Tampa, Florida 33688-2000
(813) 963-0994

Exhibit ___ (TSW-1)
Witness: Woodbury
Docket No. 981827-EC

Exhibit ___ (TSW-2)
Witness: Woodbury
Docket No. 981827-EC

SCHEDULE C
TO WHOLESALE POWER CONTRACT

Wholesale Service Rate to Members
Rate Schedule - SECI-7

I. AVAILABILITY

Available for electric service from the Seller to its Members.

II. APPLICABILITY

Wholesale service to Members for use, redistribution, and resale in accordance with the terms and conditions of the Wholesale Power Contract. This Rate Schedule shall apply to each Member. The Member's delivery points under this Rate Schedule are listed in Schedule B of the Wholesale Power Contract. The electric service at any such delivery point will be either the total requirements of the Member's electric system served from the delivery points under this Rate Schedule, or if applicable, partial requirements service which complements the Member's purchases of Interruptible Wholesale Service pursuant to the Seller's Rate Schedule INT under Schedule C of the Wholesale Power Contract and/or the Member's purchases from the Southeastern Power Administration.

III. CHARACTER OF SERVICE

The electric capacity and energy hereunder will be three-phase alternating current at a nominal frequency of sixty hertz.

IV. MONTHLY RATES AND CHARGES

The monthly charges to the Members shall be equal to the sum of the Base Charges, Power Factor Penalties and Transmission Facilities Use Charges.

(A) BASE CHARGES - Base Charges shall be equal to the sum of the Fixed Charges, the Non-Fuel Energy Charge, and the Fuel Charge.

FIXED CHARGES - Fixed Charges shall be equal to the sum of Production Charges and Transmission Charges.

Production - Production Charges shall be equal to the sum of the Production Demand Charge and the Production Fixed Energy Charge.

(1) Production Demand Charge (Applicable only during the months of January, February, March, June, July, August, September, and December):

1999 - $8.50 per kW
2000 - $7.50 per kW
2001 - $6.50 per kW

(2) Production Fixed Energy Charge shall be allocated to Members on an energy basis and calculated in accordance with the formula specified in Seller's Production Fixed Energy Charge Recovery Clause which is incorporated as part of this Rate Schedule as Appendix A.

Transmission - Transmission Charges which shall be applicable during all months, shall be equal to the sum of the Transmission Demand Charge and the Distribution Demand Surcharge.

(1) Transmission Demand Charge (applicable to all delivery points) - $1.83 per kW

(2) Distribution Demand Surcharge (applicable to delivery points below 69 kv) - $1.26 per kW

Issued by: Richard J. Midulla
Executive Vice President
and General Manager

Effective: January 1, 1999

NON-FUEL ENERGY CHARGE - $.00255 per kWh

FUEL CHARGE

The Fuel Charge shall be calculated in accordance with the formula specified in Seller's Fuel Charge Recovery Clause which is incorporated as a part of this Rate Schedule as Appendix B.

BILLING DETERMINANTS

(1) Monthly Billing Demand Determinants:

The Monthly Billing Demand Determinants is the Member's Aggregate Hourly Demand at the time of the Seller's peak demand during the calendar billing month, expressed in kW and rounded to the nearest kW. The Aggregate Hourly Demand for each clock hour of the calendar billing month is determined by the summation of the 60-minute kW demands, corresponding to each such clock hour, metered at each of the Member's delivery points. The Aggregate Hourly Demand for each clock hour shall, where applicable, be reduced by the amount of Southeastern Power Administration capacity, and/or the amount of Interruptible Wholesale Service under the Seller's Rate Schedule INT delivered to certain specified delivery points in each such clock hour during the calendar billing month.

(2) Monthly Energy Determinants:

The Monthly Energy Determinants, expressed in kWh and rounded to the nearest kWh, is determined by the summation of the energy associated with each hour's Aggregate Hourly Demand for all hours during the calendar billing month.

(3) Estimated Billing Determinants:

To the extent that any of the metering information required to determine the Monthly Billing Demand and Monthly Energy supplied during the billing month is not available at the time of billing, bills will be rendered using estimates of said billing determinants with such estimates being based upon all known pertinent facts. Differences between billings based on actual and estimated billing determinants shall be subsequently trued up, with interest accrued at the Seller's short term investment or cost of funds rate, whichever is applicable.

(B) POWER FACTOR

Power factor penalties incurred by the Seller under its contracts with other utilities as a result of a Member delivery point's failing to maintain a power factor at or above the applicable contractually required level, shall be billed to the Member receiving service at the delivery point on a direct pass-through basis as part of the bill for electric service provided hereunder. Seller shall be obligated to keep the Members apprised of the applicable contractual requirements which could affect power factor billings hereunder.

(C) TRANSMISSION FACILITIES USE CHARGE

A Transmission Facilities Use Charge as provided for in Seller's Transmission Policy No. 303 and Seller's Rate Policy No. 304 shall, if applicable be billed to the Member each month. In accordance with the terms and conditions described in said policies the charge shall be calculated in the manner prescribed in Appendix C which is incorporated as part of this Rate Schedule.

V. METERED READINGS AND BILLINGS

(A) PAYMENT OF BILLS

Bills for electric power and energy and for transmission facilities use services furnished hereunder shall be paid for at the office of the Seller within fifteen (15) days after the bill therefore is mailed to the Member. Bills not paid within such fifteen-day period shall be deemed delinquent and shall accrue interest at the Seller's monthly line of credit rate. The Board of Trustees of the Seller may, from time to time, establish terms and conditions under which (1) either Seller or Member makes payments of amounts owed hereunder in advance of the performance date provided for herein or (2) Seller offers the Member a premium on any billing credits owed hereunder from the Seller to the Member in consideration of such credits being applied by the Seller to billings subsequent to those provided for above. Said terms and conditions shall be specified in writing and provided to each of the Members of the Seller.

(B) METER READING AND TESTING

The Seller shall read meters monthly, or cause meters to be read monthly. In cases whereby the meter installation is made at a voltage different from the delivery point voltage designated in Schedule B of the Wholesale Power Contract, compensating devices, which automatically adjust meter readings to account for losses, shall be installed. The Seller shall test and calibrate meters, or shall cause such meters to be tested and calibrated, by comparison with accurate standards at intervals of twelve (12) months. The Seller shall also make or cause to be made special meter tests at any time at the Member's request. The costs of all tests shall be borne by the Seller: provided, however, that if any special meter test made at the Member's request shall disclose that the meters are recording accurately, the Member shall reimburse the Seller for the cost of such test. Meters registering not more than two percent (2%) above or below normal shall be deemed to be accurate. The readings of any meter which shall have been disclosed by test to be inaccurate shall be corrected for the thirty (30) days previous to such test in accordance with the percentage of inaccuracy found by such test. If any meter shall fail to register for any period, the Member and the Seller shall agree as to the amount of power and energy furnished during such period and the Seller shall render a bill therefore.

VI. TERMS AND CONDITIONS

Service hereunder is subject to all of the provisions of the Wholesale Power Contract between Seller and its Members, including all schedules, amendments, and supplemental agreements thereto in effect from time to time.

VII. SPECIAL PROVISIONS

In the event that the Member purchases power from a cogenerator or a small power producer (Qualifying Facility), the Seller may reallocate to the Member any costs that have not been avoided as a result of the Member's purchases from the Qualifying Facility. The criteria that a small power producer or a cogenerator must meet to achieve the status of a Qualifying Facility is defined by Section 201 of the Public Utility Regulatory Policies Act of 1978 and regulations adopted thereunder.

RATE SCHEDULE C

APPENDIX A

Production Fixed Energy Charge Recovery Clause

The monthly Production Fixed Energy Charge shall be rounded to the nearest whole dollar and determined by use of the following formula:

$$PFE = ((PFC-PBR) \times MEMALLOC) \div 12$$

where:

PFE = Member's monthly Production Fixed Energy Charge

PFC = Seller's production fixed costs projected for the applicable calendar year comprised of the following costs:

(i) Seller's total revenue requirements; less

(ii) Seller's transmission revenue requirements; less

(iii) Seller's Fuel costs; less

(iv) Seller's Non-fuel Energy costs.

PBR = Seller's Production Demand Charge revenues collected under this Rate Schedule projected for the applicable calendar year.

MEMALLOC = Portion of Production Fixed Energy Charge allocated to each Member based upon the Members' percentage share of actual Energy Determinants for the three calendar years ending with the year prior to the preceding calendar year. For example, for the year 1999 each Member's share of the total Production Fixed Energy Charge shall be based upon the total Energy Determinants for the years 1995 through 1997.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the Production Fixed Energy Charge in effect for the current calendar year.

RATE SCHEDULE C

APPENDIX B

Fuel Charge Recovery Clause

The Fuel Charge shall be equal to the Fuel Rate applied to the Monthly Energy Determinants (kWh), plus the Monthly Trueup, if applicable.

FUEL RATE The Fuel Rate shall be determined by the use of the following formula:

$$FR = \frac{F_m}{S_m}$$

where:

FR = Applicable Fuel Rate rounded to the nearest one thousandth of a cent.

F_m = Shall be comprised of the following costs projected for the applicable calendar year.

(i) Fossil and nuclear fuel consumed in Seller-owned plants and the Seller share of fossil and nuclear fuel consumed in jointly-owned or leased plants; plus

(ii) fossil and nuclear fuel costs associated with replacement power, reserve purchases and load following, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iii) the net energy cost of economy energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iv) allowable fuel and/or purchased economic power costs associated with Seller's purchases of full and partial requirements wholesale power; plus

(v) gains, losses, and associated costs related to fuel price hedging transactions; plus

(vi) the avoided energy payments to Qualifying Facilities; less

(vii) the cost of fossil and nuclear fuel recovered through inter-system sales.

S_m = Sum of the Projected Energy Determinants for all Members for the applicable calendar year.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the projected Fuel Rate in effect for the current calendar year.

MONTHLY TRUEUP In addition, each Member shall be charged or credited a Monthly Fuel Trueup during the last four months of each subsequent six-month period by a dollar amount equal to the sum of the following:

(A) The dollar amount equal to the difference between the Fuel Charges based on actual fuel costs during the preceding six-month period and the Fuel Charges collected based upon projected fuel costs during the same preceding six-month period.

(B) Interest compounded monthly on the amount computed each month pursuant to Item A above, up to the end of such six-month period, at the Seller's short term investment or cost of funds rate, whichever is applicable, and

(C) Interest compounded monthly for the two months following such six-month period on the total amount included in Items A and B above at the Seller's short term investment or cost of funds rate, whichever is applicable, for the month succeeding the end of the six-month period.

The distribution of the dollar amounts as determined by the sum of paragraphs A, B and C above shall be billed or credited in equal amounts on billings for the last four months of each six-month period.

RATE SCHEDULE C

APPENDIX C

Components of
Transmission Facilities Use Charge

The Seller's Transmission Policy No. 303 and Rate Policy No. 304 specify that the costs for transmission facilities owned by the Seller and provided for the exclusive use and benefit of a single Member shall be borne by that Member. Costs of operation and maintenance are to be borne directly by the Member, whereas costs of ownership will be recovered by Seller from the benefiting Member through a Transmission Facilities Use Charge. Outlined below are those components of the Transmission Facilities Use Charge and how they are to be computed.

DEPRECIATION

For facilities constructed by Seller, depreciation will be calculated monthly based on original installed cost (including cost of capitalized renewals and replacements) of depreciable property relating to the transmission facilities used exclusively by a Member system and the depreciation rate prescribed in REA Bulletin 183-1, or revisions thereto. The date at which depreciation cost commences will be the date that the transmission facility is placed in service for its intended use by Seller for the benefiting Member, regardless of the date of closing of the construction work order.

For facilities purchased from a Member by Seller to be used exclusively by that Member, depreciation will commence as of the effective date of the transfer thereof and calculated according to the method previously described.

PROPERTY TAXES

For facilities constructed by Seller, for the exclusive use of a Member, property tax costs will be included in the Transmission Facilities Use Charge at such time that the facility qualifies as taxable property and becomes taxable to Seller. The cost will be based on the ratio of the net book value of taxable property comprising the transmission facility used exclusively by the benefiting Member to the total net book value of all taxable property owned by Seller in the county in which the facility is located, as of January 1 of each year. This ratio will be applied to the estimated tax bill for the county in which the facility is located as the basis for determining the estimated monthly charge. When the actual tax bill is received, appropriate adjustments will be made.

For facilities purchased from a Member by Seller for exclusive use by that Member, property taxes will be prorated as of the effective date of transfer. Taxes associated with the facility will be based on the ratio of the net book value of taxable property comprising the facility to the total net book value of taxable property owned by the Member in the county in which the facility is located. The taxes will be calculated by the method described for Seller-built facilities.

PROPERTY INSURANCE

Seller will carry property insurance for transmission facilities in accordance with its standard insurance purchasing practices. For built facilities, the cost will be based on the ratio of insured value of the facility to the total insured value of all property covered in the policy. This ratio will be applied to the total premium for the policy to determine the cost applicable to the facility; however, if the premium for the facility is specifically identified in the policy, this amount will be used in the Transmission Facilities Use Charge.

For facilities purchased by Seller from a Member system, Seller will obtain appropriate property insurance as of the effective date of the transfer thereof and include this amount in the Transmission Facilities Use Charge.

COST OF MONEY

For facilities constructed by Seller, the cost of money component will be included in the Transmission Facilities Use Charge as of the date of in-service of the facility. This cost will be determined by applying the cost of permanent financing or interim financing, if permanent not in place, for the facility to the net book value of the facilities used exclusively by the Member at the end of each month.

For facilities purchased by Seller from a Member system for exclusive use by the Member system, the cost of money component will be determined by the cost of debt assumed or Seller's cost of permanent financing or interim financing, if permanent not in place, used to finance the purchase of the facility.

Rate Schedule C

Appendix D

Monthly Production Fixed Energy Charge and Projected Fuel Rate

MONTHLY PRODUCTION FIXED ENERGY CHARGE

Pursuant to Appendix A of this Rate Schedule, the amounts provided below represent the Monthly Production Fixed Energy Charge for each member to become effective January 1, 1999 through December 31, 1999.

Member	Monthly Fixed Energy Charge
Central Florida Electric Cooperative, Inc.	$ 135,056
Clay Electric Cooperative, Inc.	$ 881,634
Glades Electric Cooperative, Inc.	$ 111,117
Lee County Electric Cooperative, Inc.	$ 1,005,501
Peace River Electric Cooperative, Inc.	$ 131,880
Sumter Electric Cooperative, Inc.	$ 549,534
Suwannee Valley Electric Cooperative, Inc.	$ 105,049
Talquin Electric Cooperative, Inc.	$ 296,677
Tri-County Electric Cooperative, Inc.	$ 65,950
Withlacoochee River Electric Cooperative, Inc.	$ 1,025,231
Total	$ 4,307,629

PROJECTED FUEL RATE

Pursuant to Appendix B of this Rate Schedule the projected Fuel Rate to become effective January 1, 1999 shall be $0.02065 per kWh.

USDA

United States Department of Agriculture
Rural Development

Rural Business—Cooperative Service • Rural Housing Service • Rural Utilities Service
Washington, DC 20250

RECEIVED
NOV 20 1998
BY:

Mr. Richard J. Midulla
Executive Vice President
and General Manager
Seminole Electric Cooperative, Inc.
P. O. Box 272000
Tampa, Florida 33688-2000

Dear Mr. Midulla:

The Rural Utilities Service (RUS) is in receipt of your letter of October 19, 1998, submitting Seminole Electric Cooperative, Inc.'s (Seminole) proposed wholesale rate revision, designated as Rate Schedule SECI-7, under the terms of the Memorandum of Understanding between RUS and Seminole dated February 11, 1997. With an effective date of January 1, 1999, RUS has found the proposed rate revision to be acceptable and acknowledges your disclosure that Seminole is unable to achieve a Times Interest Earned Ratio (TIER) of at least 1.05 or a Debt Service Coverage (DSC) of at least 1.0 for each of the three calendar years immediately preceding this rate decrease as a result of declining revenues. RUS has determined that Seminole's inability to achieve TIER or DSC requirements as they pertain to the design of rates described in Section 4.15 of the Mortgage is not within itself detrimental to the government's loan security.

Sincerely,

THOMAS L. EDDY
Director
Power Supply Division

cc:
T. Woodbury

11-20-98
JMF

Exhibit ___ (TSW-3)
Witness: Woodbury
Docket No. 981827-EC

SCHEDULE C
TO WHOLESALE POWER CONTRACT

Wholesale Service Rate to Members
Rate Schedule - SECI-7b

I. AVAILABILITY

Available for electric service from the Seller to its Members.

II. APPLICABILITY

Wholesale service to Members for use, redistribution, and resale in accordance with the terms and conditions of the Wholesale Power Contract. This Rate Schedule shall apply to each Member. The Member's delivery points under this Rate Schedule are listed in Schedule B of the Wholesale Power Contract. The electric service at any such delivery point will be either the total requirements of the Member's electric system served from the delivery points under this Rate Schedule, or if applicable, partial requirements service which complements the Member's purchases of Interruptible Wholesale Service pursuant to the Seller's Rate Schedule INT under Schedule C of the Wholesale Power Contract and/or the Member's purchases from the Southeastern Power Administration.

III. CHARACTER OF SERVICE

The electric capacity and energy hereunder will be three-phase alternating current at a nominal frequency of sixty hertz.

IV. MONTHLY RATES AND CHARGES

The monthly charges to the Members shall be equal to the sum of the Base Charges, Power Factor Penalties and Transmission Facilities Use Charges.

(A) BASE CHARGES - Base Charges shall be equal to the sum of the Fixed Charges, the Non-Fuel Energy Charge, and the Fuel Charge.

FIXED CHARGES - Fixed Charges shall be equal to the sum of Production Charges and Transmission Charges.

Production - Production Charges shall be equal to the sum of the Production Demand Charge and the Production Fixed Energy Charge.

(1) Production Demand Charge (Applicable only during the months of January, February, March, June, July, August, September, and December) - $8.50 per kW

(2) Production Fixed Energy Charge shall be allocated to Members on an energy basis and calculated in accordance with the formula specified in Seller's Production Fixed Energy Charge Recovery Clause which is incorporated as part of this Rate Schedule as Appendix A.

Transmission - Transmission Charges which shall be applicable during all months, shall be equal to the sum of the Transmission Demand Charge and the Distribution Demand Surcharge.

(1) Transmission Demand Charge (applicable to all delivery points) - $1.59 per kW

(2) Distribution Demand Surcharge (applicable to delivery points below 69 kV) - $1.27 per kW

Issued by: Richard J. Midulla
Executive Vice President
and General Manager

Effective: January 1, 2000

NON-FUEL ENERGY CHARGE - $.00263 per kWh

FUEL CHARGE

The Fuel Charge shall be calculated in accordance with the formula specified in Seller's Fuel Charge Recovery Clause which is incorporated as a part of this Rate Schedule as Appendix B.

BILLING DETERMINANTS

(1) Monthly Billing Demand Determinants:

The Monthly Billing Demand Determinants is the Member's Aggregate Hourly Demand at the time of the Seller's peak demand during the calendar billing month, expressed in kW and rounded to the nearest kW. The Aggregate Hourly Demand for each clock hour of the calendar billing month is determined by the summation of the 60-minute kW demands, corresponding to each such clock hour, metered at each of the Member's delivery points. The Aggregate Hourly Demand for each clock hour shall, where applicable, be reduced by the amount of Southeastern Power Administration capacity, and/or the amount of Interruptible Wholesale Service under the Seller's Rate Schedule INT delivered to certain specified delivery points in each such clock hour during the calendar billing month.

(2) Monthly Energy Determinants:

The Monthly Energy Determinants, expressed in kWh and rounded to the nearest kWh, is determined by the summation of the energy associated with each hour's Aggregate Hourly Demand for all hours during the calendar billing month.

(3) Estimated Billing Determinants:

To the extent that any of the metering information required to determine the Monthly Billing Demand and Monthly Energy supplied during the billing month is not available at the time of billing, bills will be rendered using estimates of said billing determinants with such estimates being based upon all known pertinent facts. Differences between billings based on actual and estimated billing determinants shall be subsequently trued up, with interest accrued at the Seller's short term investment or cost of funds rate, whichever is applicable.

(B) POWER FACTOR

Power factor penalties incurred by the Seller under its contracts with other utilities as a result of a Member delivery point's failing to maintain a power factor at or above the applicable contractually required level, shall be billed to the Member receiving service at the delivery point on a direct pass-through basis as part of the bill for electric service provided hereunder. Seller shall be obligated to keep the Members apprised of the applicable contractual requirements which could affect power factor billings hereunder.

(C) TRANSMISSION FACILITIES USE CHARGE

A Transmission Facilities Use Charge as provided for in Seller's Transmission Policy No. 303 and Seller's Rate Policy No. 304 shall, if applicable be billed to the Member each month. In accordance with the terms and conditions described in said policies the charge shall be calculated in the manner prescribed in Appendix C which is incorporated as part of this Rate Schedule.

V. METERED READINGS AND BILLINGS

(A) PAYMENT OF BILLS

Bills for electric power and energy and for transmission facilities use services furnished hereunder shall be paid for at the office of the Seller within fifteen (15) days after the bill therefore is mailed to the Member. Bills not paid within such fifteen-day period shall be deemed delinquent and shall accrue interest at the Seller's monthly line of credit rate. The Board of Trustees of the Seller may, from time to time, establish terms and conditions under which (1) either Seller or Member makes payments of amounts owed hereunder in advance of the performance date provided for herein or (2) Seller offers the Member a premium on any billing credits owed hereunder from the Seller to the Member in consideration of such credits being applied by the Seller to billings subsequent to those provided for above. Said terms and conditions shall be specified in writing and provided to each of the Members of the Seller.

(B) METER READING AND TESTING

The Seller shall read meters monthly, or cause meters to be read monthly. In cases whereby the meter installation is made at a voltage different from the delivery point voltage designated in Schedule B of the Wholesale Power Contract, compensating devices, which automatically adjust meter readings to account for losses, shall be installed. The Seller shall test and calibrate meters, or shall cause such meters to be tested and calibrated, by comparison with accurate standards at intervals of twelve (12) months. The Seller shall also make or cause to be made special meter tests at any time at the Member's request. The costs of all tests shall be borne by the Seller; provided, however, that if any special meter test made at the Member's request shall disclose that the meters are recording accurately, the Member shall reimburse the Seller for the cost of such test. Meters registering not more than two percent (2%) above or below normal shall be deemed to be accurate. The readings of any meter which shall have been disclosed by test to be inaccurate shall be corrected for the thirty (30) days previous to such test in accordance with the percentage of inaccuracy found by such test. If any meter shall fail to register for any period, the Member and the Seller shall agree as to the amount of power and energy furnished during such period and the Seller shall render a bill therefore.

VI. TERMS AND CONDITIONS

Service hereunder is subject to all of the provisions of the Wholesale Power Contract between Seller and its Members, including all schedules, amendments, and supplemental agreements thereto in effect from time to time.

VII. SPECIAL PROVISIONS

In the event that the Member purchases power from a cogenerator or a small power producer (Qualifying Facility), the Seller may reallocate to the Member any costs that have not been avoided as a result of the Member's purchases from the Qualifying Facility. The criteria that a small power producer or a cogenerator must meet to achieve the status of a Qualifying Facility is defined by Section 201 of the Public Utility Regulatory Policies Act of 1978 and regulations adopted thereunder.

RATE SCHEDULE C

APPENDIX A

Production Fixed Energy Charge Recovery Clause

The monthly Production Fixed Energy Charge shall be rounded to the nearest whole dollar and determined by use of the following formula:

$$PFE = ((PFC - PBR) \times MEMALLOC) \div 12$$

where:

PFE = Member's monthly Production Fixed Energy Charge

PFC = Seller's production fixed costs projected for the applicable calendar year comprised of the following costs:

(i) Seller's total revenue requirements; less

(ii) Seller's transmission revenue requirements; less

(iii) Seller's Fuel costs; less

(iv) Seller's Non-fuel Energy costs.

PBR = Seller's Production Demand Charge revenues collected under this Rate Schedule projected for the applicable calendar year.

MEMALLOC = Portion of Production Fixed Energy Charge allocated to each Member based upon the Members' percentage share of actual Energy Determinants for the three calendar years ending with the year prior to the preceding calendar year. For example, for the year 1999 each Member's share of the total Production Fixed Energy Charge shall be based upon the total Energy Determinants for the years 1995 through 1997.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the Production Fixed Energy Charge in effect for the current calendar year.

RATE SCHEDULE C

APPENDIX B

Fuel Charge Recovery Clause

The Fuel Charge shall be equal to the Fuel Rate applied to the Monthly Energy Determinants (kWh), plus the Monthly Trueup, if applicable.

FUEL RATE The Fuel Rate shall be determined by the use of the following formula:

$$FR = \frac{F_m}{S_m}$$

where:

FR = Applicable Fuel Rate rounded to the nearest one thousandth of a cent.

F_m = Shall be comprised of the following costs projected for the applicable calendar year.

(i) Fossil and nuclear fuel consumed in Seller-owned plants and the Seller share of fossil and nuclear fuel consumed in jointly-owned or leased plants; plus

(ii) fossil and nuclear fuel costs associated with replacement power, reserve purchases and load following, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iii) the net energy cost of economy energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iv) allowable fuel and/or purchased economic power costs associated with Seller's purchases of full and partial requirements wholesale power; plus

(v) gains, losses, and associated costs related to fuel price hedging transactions; plus

(vi) the avoided energy payments to Qualifying Facilities; less

(vii) the cost of fossil and nuclear fuel recovered through inter-system sales.

S_m = Sum of the Projected Energy Determinants for all Members for the applicable calendar year.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the projected Fuel Rate in effect for the current calendar year.

MONTHLY TRUEUP In addition, each Member shall be charged or credited a Monthly Fuel Trueup during the last four months of each subsequent six-month period by a dollar amount equal to the sum of the following:

(A) The dollar amount equal to the difference between the Fuel Charges based on actual fuel costs during the preceding six-month period and the Fuel Charges collected based upon projected fuel costs during the same preceding six-month period.

(B) Interest compounded monthly on the amount computed each month pursuant to Item A above, up to the end of such six-month period, at the Seller's short term investment or cost of funds rate, whichever is applicable, and

(C) Interest compounded monthly for the two months following such six-month period on the total amount included in Items A and B above at the Seller's short term investment or cost of funds rate, whichever is applicable, for the month succeeding the end of the six-month period.

The distribution of the dollar amounts as determined by the sum of paragraphs A, B and C above shall be billed or credited in equal amounts on billings for the last four months of each six-month period.

RATE SCHEDULE C

APPENDIX C

Components of
Transmission Facilities Use Charge

The Seller's Transmission Policy No. 303 and Rate Policy No. 304 specify that the costs for transmission facilities owned by the Seller and provided for the exclusive use and benefit of a single Member shall be borne by that Member. Costs of operation and maintenance are to be borne directly by the Member, whereas costs of ownership will be recovered by Seller from the benefiting Member through a Transmission Facilities Use Charge. Outlined below are those components of the Transmission Facilities Use Charge and how they are to be computed.

DEPRECIATION

For facilities constructed by Seller, depreciation will be calculated monthly based on original installed cost (including cost of capitalized renewals and replacements) of depreciable property relating to the transmission facilities used exclusively by a Member system and the depreciation rate prescribed in REA Bulletin 183-1, or revisions thereto. The date at which depreciation cost commences will be the date that the transmission facility is placed in service for its intended use by Seller for the benefiting Member, regardless of the date of closing of the construction work order.

For facilities purchased from a Member by Seller to be used exclusively by that Member, depreciation will commence as of the effective date of the transfer thereof and calculated according to the method previously described.

PROPERTY TAXES

For facilities constructed by Seller, for the exclusive use of a Member, property tax costs will be included in the Transmission Facilities Use Charge at such time that the facility qualifies as taxable property and becomes taxable to Seller. The cost will be based on the ratio of the net book value of taxable property comprising the transmission facility used exclusively by the benefiting Member to the total net book value of all taxable property owned by Seller in the county in which the facility is located, as of January 1 of each year. This ratio will be applied to the estimated tax bill for the county in which the facility is located as the basis for determining the estimated monthly charge. When the actual tax bill is received, appropriate adjustments will be made.

For facilities purchased from a Member by Seller for exclusive use by that Member, property taxes will be prorated as of the effective date of transfer. Taxes associated with the facility will be based on the ratio of the net book value of taxable property comprising the facility to the total net book value of taxable property owned by the Member in the county in which the facility is located. The taxes will be calculated by the method described for Seller-built facilities.

PROPERTY INSURANCE

Seller will carry property insurance for transmission facilities in accordance with its standard insurance purchasing practices. For built facilities, the cost will be based on the ratio of insured value of the facility to the total insured value of all property covered in the policy. This ratio will be applied to the total premium for the policy to determine the cost applicable to the facility; however, if the premium for the facility is specifically identified in the policy, this amount will be used in the Transmission Facilities Use Charge.

For facilities purchased by Seller from a Member system, Seller will obtain appropriate property insurance as of the effective date of the transfer thereof and include this amount in the Transmission Facilities Use Charge.

COST OF MONEY

For facilities constructed by Seller, the cost of money component will be included in the Transmission Facilities Use Charge as of the date of in-service of the facility. This cost will be determined by applying the cost of permanent financing or interim financing, if permanent not in place, for the facility to the net book value of the facilities used exclusively by the Member at the end of each month.

For facilities purchased by Seller from a Member system for exclusive use by the Member system, the cost of money component will be determined by the cost of debt assumed or Seller's cost of permanent financing or interim financing, if permanent not in place, used to finance the purchase of the facility.

Rate Schedule C

Appendix D

Monthly Production Fixed Energy Charge and Projected Fuel Rate

MONTHLY PRODUCTION FIXED ENERGY CHARGE

Pursuant to Appendix A of this Rate Schedule, the amounts provided below represent the Monthly Production Fixed Energy Charge for each member to become effective January 1, 2000 through December 31, 2000.

Member	Monthly Fixed Energy Charge
Central Florida Electric Cooperative, Inc.	$143,548
Clay Electric Cooperative, Inc.	$928,090
Glades Electric Cooperative, Inc.	$116,727
Lee County Electric Cooperative, Inc.	$1,044,149
Peace River Electric Cooperative, Inc.	$141,306
Sumter Electric Cooperative, Inc.	$590,459
Suwannee Valley Electric Cooperative, Inc.	$111,874
Talquin Electric Cooperative, Inc.	$309,768
Tri-County Electric Cooperative, Inc.	$69,876
Withlacoochee River Electric Cooperative, Inc.	$1,065,710
Total	$4,521,507

PROJECTED FUEL RATE

Pursuant to Appendix B of this Rate Schedule the projected Fuel Rate to become effective January 1, 2000 shall be $.01961 per kWh.

OUR MISSION

To be the preferred provider of wholesale energy services for our Member Systems.

OUR VISION

We will be a leading competitor in the emerging energy market, trusted and respected by our Members, employees, and business partners alike.

Through devotion to customer satisfaction and continually striving to exceed expectations, we will provide the best value in wholesale energy service. We will provide our employees a challenging and rewarding work environment, where pride and commitment will be the hallmark of our operations.

OUR VALUES

We uphold the highest ethical and professional standards.

We believe that Cooperative ownership and principles are the cornerstone of our success.

We affirm that quality, innovation, and teamwork are essential ingredients of customer satisfaction.

We improve the quality of life in our communities.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

CELEBRATING 50 YEARS 1948-1998

This information is prepared for employees of Seminole Electric Cooperative.
Please direct comments to:
CORPORATE PLANNING, TAMPA

9/97

STRATEGIC PLAN

Exhibit ___ (TSW-4)
Witness: Woodbury
Docket No. 981827-EC

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

CELEBRATING 50 YEARS 1948-1998

STRATEGIC GOALS

CUSTOMER SERVICE:

Achieve excellence in the eyes of our customers.

- MEMBER SERVICE
  Identify and implement a new approach to providing quality service and achieving excellence in customer satisfaction.

- MEETING CUSTOMER NEEDS
  Be proactive in finding ways to better serve the collective and individual needs of Seminole's Member Systems.

REDUCE COSTS:

Reduce Seminole's wholesale rate for bulk power to the market price for similar services; achieve an average wholesale rate of 42 mills/kWh by the year 2002.

- PURCHASED POWER AND FUEL
  Aggressively pursue cost reductions for purchased power and delivered fuel where such costs are in excess of a market-based standard.

- ADMINISTRATIVE EFFICIENCY
  Continue to prudently seek efficiency enhancements to ensure that all corporate functions are conducted at a competitive price.

- MARKETING
  Aggressively market Seminole's wholesale energy services to Members and non-Members alike in order to maximize revenue, reduce the wholesale rate, and reduce the risk of stranded investment.

- POWER SUPPLY INFRASTRUCTURE
  Reassess Seminole's overall power supply infrastructure in order to optimize to the maximum extent possible; and seek to achieve a portfolio of generating resources which prudently balances the objectives of cost minimization, flexibility, and reliability.

- ENHANCE EXISTING ASSET VALUE
  Seek new ways to maintain, maximize and improve the value of the existing assets of Seminole and its Member Systems.

MEMBER CHOICE:

Establish an organizational and contractual framework that accommodates member flexibility.

- RATE STRUCTURE
  Establish a wholesale rate structure which provides an appropriate price signal that is more reflective of the incremental cost of new capacity.

- MEMBER FLEXIBILITY
  Seek consensus on modifications to Seminole's wholesale power contract to provide the Member Systems with flexibility relating to commitments to future capacity resources, while protecting the recovery of costs associated with existing obligations and commitments.

- MENU OF SERVICES
  Seek to provide a menu of services (e.g., full requirements, partial requirements, interruptible, etc.) under a rate structure which ensures that one service does not subsidize another.

EMPLOYEES:

Improve processes by which Seminole management and staff interact internally and in conjunction with external business partners.

- ORGANIZATIONAL STRENGTH
  Strengthen Seminole's organizational capability and efficiency by improving our training, teamwork and internal communications.

- EMPOWERMENT
  Maximize the empowerment of individuals and work groups to meet corporate objectives.

RESTRUCTURING:

Ensure that industry restructuring efforts which evolve in Florida to deal with retail competition issues do not disadvantage rural cooperative consumers.

- POLITICAL INVOLVEMENT
  Seminole and its Members will be proactive in identifying and addressing issues relating to retail competition in Florida.

- STRATEGIC ALLIANCES
  Form strategic alliances which are consistent with Seminole's strategic goals and add value to the services provided by Seminole and its Members.

- COMPETITIVE INTELLIGENCE
  Increase efforts to gain valuable insight into the strategies of competitors in order to better prepare Seminole and its Members to compete in the future.

RATE COMMITTEE MEETING MINUTES
SEMINOLE ELECTRIC COOPERATIVE, INC.
TAMPA, FLORIDA
FRIDAY, MARCH 13, 1998

Chairman Martin called on T. Woodbury to discuss the establishment of a new wholesale rate structure which, as described in Seminole's Strategic Plan, would provide appropriate price signal that are more reflective of the incremental cost of new capacity.

Mr. Woodbury discussed the various features that can be included in the design of a wholesale rate, and reviewed the pros and cons of incorporating such features into a new structure for Seminole. The discussion included a review of the appropriateness of the use of features such as a two-part structure, seasonal price differentials, rate tilt, demand ratchets, stratified rates, bundled rates, voltage discounts, time-of-use rate pricing, and formula rates.

Mr. Woodbury discussed a possible new rate structure that staff believes would give appropriate price signals for full requirements service in the years ahead. Under this structure, the recovery of generation-related fixed costs would be accomplished in two separate sets of charges. The first, a seasonally differentiated $/kW charge, would be applied to member monthly demands at the time of Seminole's system peak during the months of December-March and June-September. The months of April, May, October and November would have no generation-related $/kW charge applied. The second generation related-cost recovery mechanism would be a $/month charge calculated separately for each member by (i) taking the difference between Seminole's total generation-related fixed dollar revenue requirement and the total revenues projected to be recovered for the applicable budget year under the earlier described seasonal $/kW month charges, (ii) multiplying this difference by each member's percentage share of Seminole's total metered kWh sales to members under the blended rate for the preceding three calendar years, and (iii) dividing this dollar quantity for each member by 12 in order to spread it evenly over the succeeding calendar year. Mr. Woodbury noted that each year the three-year allocation would be based on the three most recent calendar years (i.e., for a 1999 rate, kWh for 1995-1997 would be used; for a 2000 rate, kWh for 1996-1998 would be used, etc..)

The transmission-related fixed cost revenue requirement would be recovered by applying a $/kW month charge each month to each members' monthly demand at the time of Seminole's system peak. Staff is proposing that the transmission $/kW month charge be different for loads served below 69 kV versus those served at voltages 69 kV and above in order to track the transmission pricing signals given to Seminole from its transmission service providers.

The energy cost recovery charges would include a levelized fuel charge with a true-up, similar to that contained in the existing Seminole rate, and would also include a relatively small $/MWH charge to recover non-fuel variable O&M costs. The rate would not include a separate delivery point charge as is currently the case under the existing rate.

Mr. Woodbury also discussed the proposed phase-in plan for generation-related $/kW charges under the proposed seasonal rate structure. Staff suggests that in order to smooth the impact to the members, the targeted winter season $/kW charge for the year 2001 should be phased in over the three-year period as follows: 1999 - $8.50, 2000 - $6.50, and 2001 - $4.50. The proposed phase-in of the targeted summer season $/kW charge is 1999 - $6.50, 2000- $4.50, and 2001-$2.50. Mr. Woodbury explained that the targeted 2001 winter and summer charges approximate Seminole's incremental cost of combined cycle and peaking capacity, respectively. He explained that because of Seminole's severe needle peak in the winter, staff felt it was appropriate to have a higher charge in that season in order to encourage further improvements to annual load factor, while still sending a cost-based pricing signal.

Mr. Woodbury then reviewed the comparison of projected member average rates under existing Rate Schedule SECI-6b versus the proposed Seasonal Rate for 1999. He also showed member average cost comparisons between 1998 (under Rate Schedule SECI-6b) and 1999 (under the proposed Seasonal Rate Structure).

Mr. Woodbury indicated that the average cost impact by member associated with a change to the proposed seasonal rate structure generally fell within a tight cluster of +/- 0.5 mills for the year 1999. He noted that the only noteworthy exception was Peace River. He stated that, at the present time, Peace River has a relatively high percentage of its load metered at distribution voltage. He stated that he needed to confirm whether Peace River's new Crawley transmission voltage delivery point was reflected in the billing determinants used for the comparisons shown. Under the assumption that this delivery point was reflected in the data used, staff proposed to make an adjustment to the voltage differential as a means of reducing the initial adverse impact on Peace River. If it is determined that the new Crawley transmission voltage delivery point is not reflected in the data, staff's view on the size or need for such an adjustment could be affected since the impact of the proposed seasonal rate on Peace River would have been overstated.

He reviewed with the Committee the different parameters that drive the average cost differentials among members. Specifically, he showed each member's contribution to Seminole's peak, its relative proportion of 3-year energy consumption, its ratio of winter to summer peak demands, and its percentage of service taken at transmission versus distribution voltages.

It was agreed that a workshop would be held in April to discuss this new rate in more detail. The Committee was encouraged to have other member staff and/or consultants attend. Staff hopes to use the workshop as a way to generate a good exchange of ideas concerning how best to modify the existing wholesale rate structure consistent with the goals stated in Seminole's Strategic Plan.

STRATEGIC GOALS

- ## RATE STRUCTURE

  ESTABLISH A WHOLESALE RATE STRUCTURE WHICH PROVIDES AN APPROPRIATE PRICE SIGNAL THAT IS MORE REFLECTIVE OF THE INCREMENTAL COST OF NEW CAPACITY.

- ## MENU OF SERVICES

  SEEK TO PROVIDE A MENU OF SERVICES (E.G., FULL REQUIREMENTS, PARTIAL REQUIREMENTS, INTERRUPTIBLE, ETC.) UNDER A RATE STRUCTURE WHICH ENSURES THAT ONE SERVICE DOES NOT SUBSIDIZE ANOTHER.

ALTERNATE RATE STRUCTURE COMPONENTS*

UNIFORM RATE ❖	NON-UNIFORM RATE
TWO-PART RATE ❖	FLAT
COINCIDENT ❖	NON-COINCIDENT
ACTUAL DEMANDS ❖	RATCHETS
STRATIFIED ❖	AVERAGE
RATE TILT ❖	NO RATE TILT
BUNDLED ❖	UNBUNDLED
YEAR ROUND ❖	SEASONAL
TIME OF USE ❖	NON-TIME OF USE
STATED ❖	FORMULA
VOLTAGE DISCOUNT ❖	NON-DISCOUNTED

ALTERNATE RATE STRUCTURE COMPONENTS*

UNIFORM RATE	❖	NON-UNIFORM RATE
TWO-PART RATE	❖	FLAT
COINCIDENT	❖	NON-COINCIDENT
ACTUAL DEMANDS	❖	RATCHETS
STRATIFIED	❖	**AVERAGE**
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TIME OF USE	❖	**NON-TIME OF USE**
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VOLTAGE DISCOUNT	❖	NON-DISCOUNTED

* Highlighted shows components of existing rate schedule SECI - 6B

RATE COMMITTEE - MARCH 13, 1998

UNIFORM
V.S.
NON-UNIFORM RATE

- ☛ UNIFORM RATE - ALL MEMBERS TAKE POWER AND ENERGY UNDER SAME RATE SCHEDULE

- ☛ DIFFERENT RATES WOULD BE APPROPRIATE ONLY WHEN DIFFERENT SERVICES OFFERED - E.G., FULL AND PARTIAL REQUIREMENTS

TWO-PART
V.S.
FLAT RATE

- TWO-PART RATE - SEPARATE DEMAND AND ENERGY CHARGE - STANDARD TYPE RATE FOR LARGE LOADS

  FLAT RATE - ENERGY ONLY - USUALLY RESERVED FOR RESIDENTIAL AND SMALL COMMERCIAL

- TWO-PART RATE RESULTS IN DIFFERENT AVERAGE COST FOR CUSTOMERS WITH DIFFERING LOAD FACTORS

- TWO-PART RATE SHOULD CONTINUE TO BE USED BY SECI IN ORDER TO PROVIDE INCENTIVE TO CONTROL PEAK DEMANDS

COINCIDENT V.S. NON-COINCIDENT

- USE OF COINCIDENT BILLING RECOGNIZES THAT THE SYSTEM IS PLANNED AND COSTS INCURRED ON AGGREGATE, NOT INDIVIDUAL MEMBER, LOADS

- AT PRESENT, SECI USES COINCIDENT AT THE TIME OF SUPPLIER AREA BILLING DEMANDS

- WITH ELIMINATION OF FPL PR, SECI SHOULD CONSIDER;

  (i) BILLING COINCIDENT WITH THE SECI SYSTEM PEAK, OR

  (ii) BILLING COINCIDENT WITH FPC'S PR BILLING DEMAND

ACTUAL
V.S.
RATCHETED DEMANDS

- RATCHETS WORK AS FOLLOWS:

  (E.G., 100% 12 MONTH RATCHET)

  SYSTEM *X* SETS AN ANNUAL PEAK OF 150 MW IN JANUARY - SYSTEM *X* WOULD CONTINUE TO BE BILLED ON 150 MW DEMAND FOR 12 MONTHS REGARDLESS OF ACTUAL DEMANDS

  THE ABOVE EXAMPLE COULD BE ADJUSTED (1) BY MAKING THE RATCHET LESS THAN 100% OR (2) BY MAKING IT LESS THAN 12 MONTHS

- RATCHETS GIVE MUCH STRONGER INCENTIVE TO CONTROL ANNUAL PEAK (AS OPPOSED TO PEAKS EACH MONTH)

- RATCHETS DRIVE DOWN THE UNIT CHARGE ON THE DEMAND RATE BY INCREASING THE QUANTITY OF KW BILLING DETERMINANTS

i.e.,

$$(\Downarrow)\quad \text{UNIT CHARGE} = \frac{\text{FIXED COSTS}}{\text{KW BILLING DETERMINANTS } (\Uparrow)}$$

RATE COMMITTEE - MARCH 13, 1998

STRATIFIED
V.S.
AVERAGE SYSTEM

- STRATIFIED COSTING BREAKS DOWN THE LOAD CURVE INTO BASE, INTERMEDIATE AND PEAKING COMPONENTS

- STRATIFIED RATES PROVIDE MORE ACCURATE INCREMENTAL COST PRICE SIGNAL

- STRATIFIED RATES MAY NOT BE AS CRITICAL IN A FULL REQUIREMENTS ONLY STRUCTURE - CAN ACCOMPLISH SIMILAR OBJECTIVES WITH OTHER RATE FEATURES

- CURRENT SECI RATE IS BASED ON AVERAGE SYSTEM COST WITH SOME RATE TILT

- MAY WANT TO TRANSITION TO STRATIFIED RATES AS PART OF MEMBER CHOICE INITIATIVE

RATE TILT
V.S.
NO RATE TILT

- RATE TILT MEANS THE RECOVERY OF SOME FIXED RELATED COSTS IN ENERGY CHARGES

- AT PRESENT SECI RECOVERS APPROXIMATELY 10% OF ITS FIXED COSTS IN ENERGY CHARGES

- RATE TILT CAN BE USED TO GET DEMAND CHARGES TO A LEVEL THAT APPROXIMATES SECI'S INCREMENTAL COST OF PEAKING/ INTERMEDIATE CAPACITY

- TOO MUCH RATE TILT CAN RESULT IN ENERGY PRICES BEING OVERSTATED VIS-A-VIS ACTUAL INCREMENTAL COSTS

BUNDLED
V.S.
UNBUNDLED

- ☛ UNBUNDLING MEANS SEPARATING THE PRODUCTION AND TRANSMISSION FUNCTIONS FROM ONE ANOTHER FOR PURPOSES OF RATEMAKING

- ☛ INDUSTRY IS MOVING TOWARDS UNBUNDLING. SENDS BETTER PRICE SIGNALS - MAKES FOR BETTER DECISION MAKING

YEAR ROUND
V.S.
SEASONAL

- SEASONAL RATES - SEPARATE CHARGES DURING THE PEAK SEASON(S)

- ONE OPTION IS TO HAVE DEMAND CHARGES ONLY IN WINTER AND SUMMER SEASONS BUT TO HAVE ENERGY ONLY IN OFF PEAK MONTHS WHEN ADDITIONAL CAPACITY IS NOT NEEDED

- SEASONAL RATES MIGHT BE A GOOD SUBSTITUTE FOR DEMAND CHARGES WITH RATCHET

TIME OF USE
V.S.
NON-TIME OF USE

- TIME OF USE GENERALLY USED FOR PRICING ENERGY IN PEAK AND OFF PEAK PERIODS

- SECI HAS HISTORICALLY NOT SEEN A MATERIAL DIFFERENCE IN ITS SYSTEM AVERAGE ENERGY COSTS IN PEAK AND OFF-PEAK PERIODS

STATED
V.S.
FORMULA

- ☛ SECI PRESENTLY HAS A STATED RATE WITH AN AUTOMATIC RECOVERY CLAUSE FOR FUEL
- ☛ A STATED RATE MEANS THAT THE DEMAND AND OTHER NON-FUEL CHARGES CAN ONLY BE CHANGED BY BOARD ACTION
- ☛ A FORMULA RATE WOULD CONVERT ALL OF SECI'S COST RECOVERY INTO FORMULAE, AND RATES WOULD CHANGE AUTOMATICALLY
- ☛ BENEFITS OF FORMULA RATE FOR A COOPERATIVE ARE QUESTIONABLE. TEND TO INCREASE VOLATILITY OF RATES AND REDUCE ABILITY OF BOARD TO MANAGE RATE CHANGES

VOLTAGE DISCOUNT
V.S.
NON-DISCOUNTED

- ☛ SECI ONLY RECEIVES DISCOUNTS FOR TRANSMISSION LEVEL SERVICE (VERSUS DISTRIBUTION SERVICE) UNDER ITS TRANSMISSION ARRANGEMENTS WITH OTHERS

- ☛ DISCOUNTS FOR VARYING TRANSMISSION VOLTAGE LEVELS IS NOT COST BASED

ALTERNATE RATE STRUCTURE COMPONENTS*

UNIFORM RATE	❖	NON-UNIFORM RATE
TWO-PART RATE	❖	FLAT
COINCIDENT	❖	NON-COINCIDENT
ACTUAL DEMANDS	❖	RATCHETS
STRATIFIED	❖	**AVERAGE**
RATE TILT	❖	**NO RATE TILT**
BUNDLED	❖	**UNBUNDLED**
YEAR ROUND	❖	**SEASONAL**
TIME OF USE	❖	**NON-TIME OF USE**
STATED	❖	FORMULA
VOLTAGE DISCOUNT	❖	NON-DISCOUNTED

* Highlighted shows components of possible new rate structure

RATE COMMITTEE - MARCH 13, 1998

POSSIBLE RATE STRUCTURE
2001

- ➢ DELIVERY POINT CHARGE - NONE
- ➢ FIXED COST RECOVERY CHARGES
  - ♦ GENERATION
    - * $/KW/MO. CHARGES

DEC	-	MAR	-	$4.50/KW/MO.
JUNE	-	SEPT	-	$2.50/KW/MO
OTHER			-	NO CHARGE

    - * $/MONTH

      DIFFERENCE BETWEEN FIXED $ REV. REQ. AND $/KW/MO. DEMAND REVENUES ALLOCATED TO MEMBERS ON THE BASIS OF A 3-YEAR ROLLING AVERAGE OF ANNUAL METERED KWH PURCHASES
  - ♦ TRANSMISSION
    - * 69 KV AND ABOVE - $1.___/KW/MO.
    - * BELOW 69 KV - $2.___/KW/MO.
  - ♦ BILLING DETERMINANTS
    - * MONTHLY METERED KW DEMANDS COINCIDENT WITH SECI'S MONTHLY SYSTEM PEAK
- ➢ ENERGY COST RECOVERY CHARGES
  - ♦ FUEL - LEVELIZED CHARGE WITH TRUEUPS
  - ♦ NON-FUEL - $1.____ / MWH

POSSIBLE RATE STRUCTURE
1999

- ➢ DELIVERY POINT CHARGE - NONE
- ➢ FIXED COST RECOVERY CHARGES
  - ♦ GENERATION
    - * $/KW/MO. CHARGES

DEC -	MAR	-	$8.50/KW/MO.
JUNE -	SEPT	-	$6.50/KW/MO
OTHER		-	NO CHARGE

    - * $/MONTH
      DIFFERENCE BETWEEN FIXED $ REV. REQ. AND $/KW/MO. DEMAND REVENUES ALLOCATED TO MEMBERS ON THE BASIS OF A 3-YEAR ROLLING AVERAGE OF ANNUAL METERED KWH PURCHASES
  - ♦ TRANSMISSION
    - * 69 KV AND ABOVE - $1.624/KW/MO.
    - * BELOW 69 KV - $2.914/KW/MO.
  - ♦ BILLING DETERMINANTS
    - * MONTHLY METERED KW DEMANDS COINCIDENT WITH SECI'S MONTHLY SYSTEM PEAK
- ➢ ENERGY COST RECOVERY CHARGES
  - ♦ FUEL - LEVELIZED CHARGE WITH TRUEUPS
  - ♦ NON-FUEL - $2.05/ MWH

PROPOSED PHASE-IN PLAN FOR $/KW CHARGES UNDER NEW SEASONAL RATE STRUCTURE

		1999	2000	2001
WINTER	($/KW/MO)	8.50	6.50	4.50
SUMMER	($/KW/MO)	6.50	4.50	2.50

COMPARISON OF MEMBER AVERAGE RATES
SECI-6B versus SEASONAL RATE STRUCTURE

1999
MILLS PER KWH

Reflects $8.50 winter and $6.50 summer demand rates
With Voltage Discount Adjustment ($ .90 / kw-mo)

	SECI-6B*	SEASONAL RATE STRUCTURE**	DIFFERENCE
Central Florida	46.80	46.27	-0.53
Clay	45.87	46.05	0.18
Glades	46.11	46.40	0.29
Lee County	46.39	46.49	0.10
Okefenoke	46.53	45.90	-0.63
Peace River	47.38	47.85	0.47
Sumter	48.70	48.92	0.22
Suwannee	46.04	46.14	0.10
Talquin	47.25	47.13	-0.12
Tri-County	45.03	45.41	0.38
Withlacoochee	48.79	48.44	-0.35
Seminole	47.22	47.22	

* SECI - 6B is based on supplier area billing determinants.

** Seasonal Rate Structure Member demands are coincident with Seminole peaks and are billed at different rates for winter and summer months with no shoulder month demand charges.

COMPARISON OF MEMBER AVERAGE RATES
SECI-6B versus SEASONAL RATE STRUCTURE

MILLS PER KWH

	1998 SECI - 6B*	1999 SEASONAL RATE STRUCTURE**	DIFFERENCE
Central Florida	49.38	46.27	-3.11
Clay	48.33	46.05	-2.28
Glades	48.35	46.40	-1.95
Lee County	49.14	46.49	-2.65
Okefenoke	48.95	45.90	-3.05
Peace River	49.85	47.85	-2.00
Sumter	51.86	48.92	-2.94
Suwannee	48.40	46.14	-2.26
Talquin	49.80	47.13	-2.67
Tri-County	46.90	45.41	-1.49
Withlacoochee	51.94	48.44	-3.50
Seminole	50.00	47.22	-2.78

* Reflects 1998 Budget Revenue Requirement

** $ 8.50 / kW-mo. Winter Demand Rates December through March
$ 6.50 / kW-mo. Summer Demand Rates June through September
With Voltage Discount Adjustment

19-Mar-98
CP

WHERE DO WE GO FROM HERE?

APRIL 1998	☛ RATE COMMITTEE - DISCUSS PRELIMINARY RATE STRUCTURE CONCEPTS AND ALTERNATIVE MENU OF SERVICES
MAY 1998	☛ MEMBER RATE WORKSHOP
JULY 1998	☛ BOARD APPROVAL OF PHASE 1 OF NEW RATE STRUCTURE
OCTOBER 1998	☛ IMPLEMENTATION OF NEW RATE STRUCTURE IN 1999 BUDGET
JANUARY 1999	☛ PHASE 1 OF NEW RATE STRUCTURE EFFECTIVE

SEASONAL RATE STRUCTURE

ALLOCATION OF FIXED CHARGE AMOUNT TO MEMBERS BASED ON 3 YEAR HISTORICAL KWH USAGE

Central Florida	**3.1%**
Clay	**20.3%**
Glades	**2.6%**
Lee County	**23.1%**
Okefenoke	**1.0%**
Peace River	**3.0%**
Sumter	**12.6%**
Suwannee	**2.4%**
Talquin	**6.8%**
Tri-County	**1.5%**
Withlacoochee	**23.6%**
Seminole	**100.0%**

Based on 1995 - 1997 kWh energy usage.

COMPARISON OF DEMAND AND ENERGY FACTORS

1999

	SECI - 6B SUPPLIER AREA BILLING			SEASONAL RATE STRUCTURE WITH SEMINOLE COINCIDENT DEMANDS		
	KW-mo % of System	MWH % of System	Annual Load Factor	Winter/Summer Ratio	KW-mo % of System	Annual Load Factor
Central Florida	3.0%	3.1%	59%	1.0474	3.0%	57%
Clay	19.1%	20.3%	60%	1.0327	19.3%	59%
Glades	2.4%	2.5%	60%	1.3339	2.4%	59%
Lee County	21.7%	22.2%	58%	1.2176	20.9%	59%
Okefenoke	1.1%	1.1%	58%	0.8815	1.1%	55%
Peace River	2.7%	2.9%	61%	1.4346	2.8%	59%
Sumter	13.0%	12.2%	53%	1.3041	13.0%	52%
Suwannee	2.2%	2.4%	61%	0.8712	2.3%	59%
Talquin	6.8%	6.9%	57%	1.0436	6.9%	56%
Tri-County	1.3%	1.5%	65%	0.9510	1.3%	62%
Withlacoochee	26.7%	24.8%	53%	1.3357	26.9%	52%
Seminole	100.0%	100.0%	57%	1.1923	100.0%	56%

19-Mar-98

CP

MEMBER VOLTAGE LEVEL DEMAND PERCENTAGES

	TRANSMISSION LEVEL	DISTRIBUTION LEVEL
CENTRAL	100.0%	-
CLAY	99.6%	0.4%
GLADES	100.0%	-
LEE COUNTY	100.0%	-
OKEFENOKE	100.0%	-
PEACE RIVER	52.0%	48.0%
SUMTER	100.0%	-
SUWANEE	96.1%	3.9%
TALQUIN	100.0%	-
TRI-COUNTY	100.0%	-
WITHLACOOCHEE	100.0%	-
SEMINOLE	98.5%	1.5%

13 March 1998
CP

COMPARISON OF SEMINOLE RATES

	1998 SECI-6B	1999 SECI-6B	SEASONAL RATE STRUCTURE A	SEASONAL RATE STRUCTURE B
DEMAND RATES ($ / kW-mo):				
25 KV	$12.02	$9.80	-	-
69 KV	10.89	8.67	-	-
125 KV	10.76	8.54	-	-
230 KV	10.63	8.41	-	-
Winter	-	-	$8.50	$8.50
Summer	-	-	6.50	6.50
TRANSMISSION RATES ($ / kW-mo):				
Transmission	Included	Included	$1.624	$1.630
Distribution	Above	Above	2.914	2.530
ENERGY (MILLS/ kWh)				
Non-Fuel	3.20	5.18	2.05	2.05
Fuel in base	24.43	24.43	21.27	21.27
Fuel Adjustment	-3.83	-3.16	-	-
STATION CHARGE (per Delivery Point-mo)	$400	$400	-	-
FIXED CHARGE AMOUNT ($000) Allocated to Members based on 3 year historical kWh	-	-	$77,112	$77,111

CHANGES SINCE MARCH COMMITTEE MEETING

1. MADE MINOR CORRECTION TO REFLECT UPDATED DELIVERY POINT VOLTAGES

2. ADOPTED $0.90 VOLTAGE SURCHARGE FOR DISTRIBUTION

3. ELIMINATED DIFFERENTIAL BETWEEN SUMMER AND WINTER DEMAND CHARGES

4. CHANGED BILLING HOUR FROM COINCIDENT WITH SEMINOLE PEAK TO COINCIDENT WITH FPC PEAK

Exhibit ___ (TSW-6)
Witness: Woodbury
Docket No. 981827-EC

STRATEGIC GOALS

☛ **RATE STRUCTURE**

ESTABLISH A WHOLESALE RATE STRUCTURE WHICH PROVIDES AN APPROPRIATE PRICE SIGNAL THAT IS MORE REFLECTIVE OF THE INCREMENTAL COST OF NEW CAPACITY.

☛ **MENU OF SERVICES**

SEEK TO PROVIDE A MENU OF SERVICES (E.G., FULL REQUIREMENTS, PARTIAL REQUIREMENTS, INTERRUPTIBLE, ETC.) UNDER A RATE STRUCTURE WHICH ENSURES THAT ONE SERVICE DOES NOT SUBSIDIZE ANOTHER.

ALTERNATE RATE STRUCTURE COMPONENTS*

UNIFORM RATE	❖	NON-UNIFORM RATE
TWO-PART RATE	❖	FLAT
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* Highlighted shows components of existing rate schedule SECI - 6B

POSSIBLE RATE STRUCTURE
1999

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  - ♦ GENERATION
    - * $/KW/MO. CHARGES

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- ➢ ENERGY COST RECOVERY CHARGES
  - ♦ FUEL - LEVELIZED CHARGE WITH TRUEUPS
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PROPOSED PHASE-IN PLAN FOR $/KW CHARGES UNDER NEW SEASONAL RATE STRUCTURE

		1999	2000	2001
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COMPARISON OF MEMBER AVERAGE RATES
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$ 6.50 / kW-mo. Summer Demand Rates June through September
With Voltage Discount Adjustment

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19-Mar-98
CP

PEAK DEMAND/COST RELATIONSHIP

	COST DRIVER	INCREMENTAL COST TO SEMINOLE ($ / KW / MO)
GENERATION COSTS		
FPC CONTROL AREA	AGGREGATE MEMBER LOAD COINCIDENT WITH FPC SYSTEM	$4.95
ALL OTHER LOAD	MAXIMUM AGGREGATE MEMBER DEMAND FOR ALL LOAD OUTSIDE FPC CONTROL AREA	$2.10 - $4.50
TRANSMISSION COSTS		
FPC CONTROL	AGGREGATE MEMBER LOAD COINCIDENT WITH FPC SYSTEM PEAK	$1.11
FPL CONTROL AREA	AGGREGATE MEMBER LOAD COINCIDENT WITH FPL SYSTEM PEAK	$1.80
DIRECT SERVE AREA	AGGREGATE MEMBER LOAD IN DIRECT SERVE AREA	$1.00

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ALTERNATIVE SEASONAL RATE STRUCTURES CONSIDERED*

	SUMMER/ WINTER RATE DIFFERENTIAL	DISTRIBUTION VOLTAGE SURCHARGE $ / KW / MO	COINCIDENT BILLING DEMAND
ALT. 1	YES	1.29	SEMINOLE
ALT. 2	YES	.90	SEMINOLE
ALT. 3	NO	.90	SEMINOLE
ALT. 4	NO	.90	FPC

*ALL OTHER RATE STRUCTURE FEATURES REMAIN THE SAME

SUGGESTED CHANGES TO PRELIMINARY RATE STRUCTURE PROPOSED IN MARCH 2001

- DELIVERY POINT CHARGE - NONE
- FIXED COST RECOVERY CHARGES
  - GENERATION
    - $/KW/MO. CHARGES

DEC -	MAR	-	$4.50/KW/MO.
JUNE -	SEPT	- $4.50➡	$~~2.50~~/KW/MO.
OTHER		-	NO CHARGE

    - $/MONTH

      DIFFERENCE BETWEEN FIXED $ REV. REQ. AND $/KW/MO. DEMAND REVENUES ALLOCATED TO MEMBERS ON THE BASIS OF A 3-YEAR ROLLING AVERAGE OF ANNUAL METERED KWH PURCHASES
  - TRANSMISSION
    - 69 KV AND ABOVE - $1.75➡ $~~1.712~~/KW/MO.
    - BELOW 69 KV - $2.65➡ $~~2.612~~/KW/MO.
  - BILLING DETERMINANTS
    - MONTHLY METERED KW DEMANDS COINCIDENT WITH FPC'S ~~SECI'S~~ MONTHLY SYSTEM PEAK
- ENERGY COST RECOVERY CHARGES
  - FUEL - LEVELIZED CHARGE WITH TRUEUPS
  - NON-FUEL - $1.79 / MWH

SUGGESTED CHANGES TO PRELIMINARY RATE STRUCTURE PROPOSED IN MARCH 1999

➢ DELIVERY POINT CHARGE - NONE

➢ FIXED COST RECOVERY CHARGES

♦ GENERATION

* $/KW/MO. CHARGES

DEC -	MAR	-	$8.50/KW/MO.
JUNE -	SEPT	- $8.50 ➡	$~~6.50~~/KW/MO.
OTHER		-	NO CHARGE

* $/MONTH

DIFFERENCE BETWEEN FIXED $ REV. REQ. AND $/KW/MO. DEMAND REVENUES ALLOCATED TO MEMBERS ON THE BASIS OF A 3-YEAR ROLLING AVERAGE OF ANNUAL METERED KWH PURCHASES

♦ TRANSMISSION

* 69 KV AND ABOVE - $1.662 ➡ $~~1.628~~/KW/MO.

* BELOW 69 KV - $2.562 ➡ $~~2.528~~/KW/MO.

♦ BILLING DETERMINANTS

* MONTHLY METERED KW DEMANDS COINCIDENT WITH FPC'S ~~SECI'S~~ MONTHLY SYSTEM PEAK

➢ ENERGY COST RECOVERY CHARGES

♦ FUEL - LEVELIZED CHARGE WITH TRUEUPS

♦ NON-FUEL - $2.05/ MWH

PHASE-IN PLAN FOR $/KW CHARGES UNDER SEASONAL RATE STRUCTURES

DIFFERENTIATED

		1999	2000	2001
WINTER	($/KW/MO)	8.50	6.50	4.50
SUMMER	($/KW/MO)	6.50	4.50	2.50

NON-DIFFERENTIATED

WINTER	($/KW/MO)	8.50	6.50	4.50
SUMMER	($/KW/MO)	8.50	6.50	4.50

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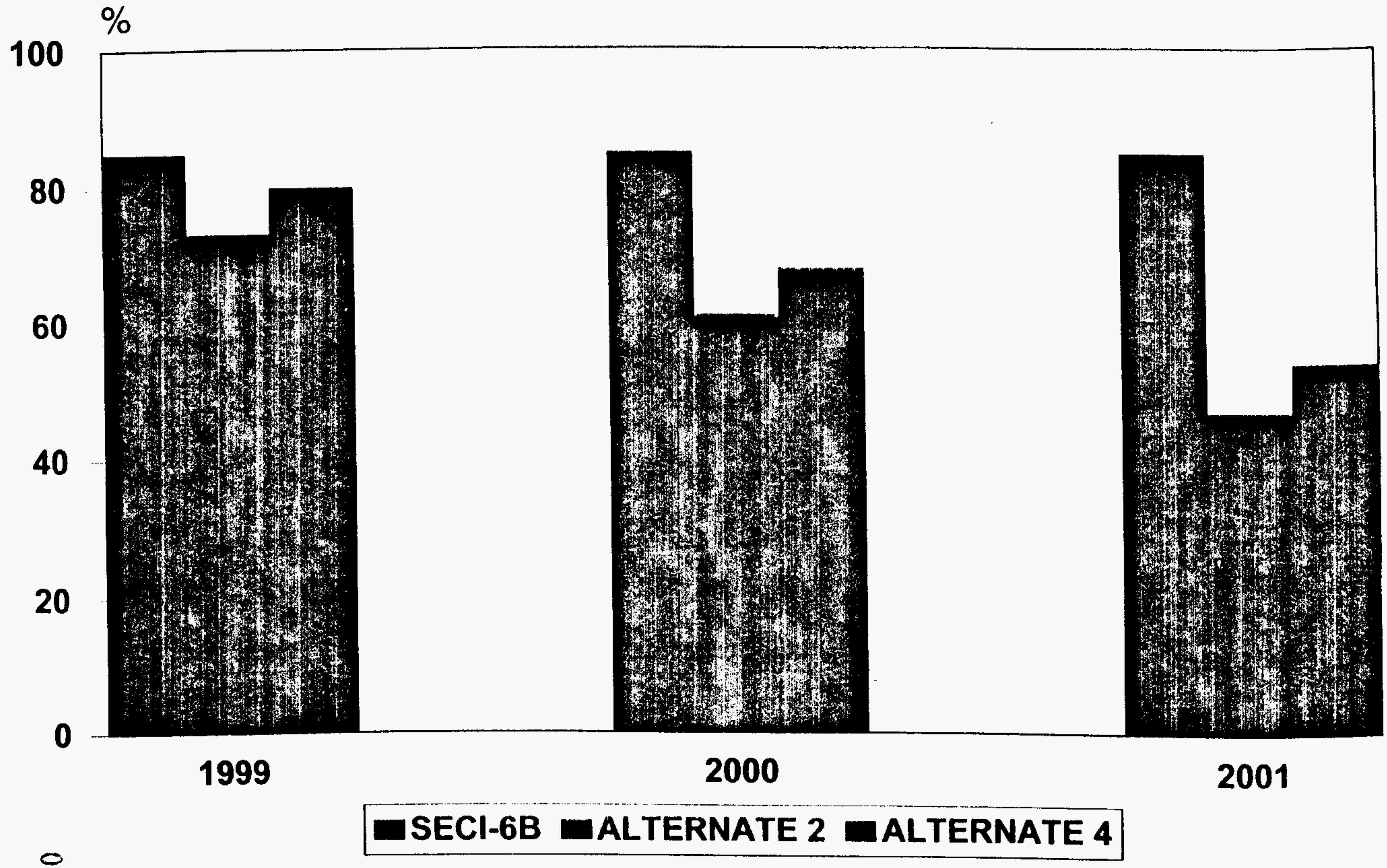
RATE COMMITTEE WORKSHOP - APRIL 9, 1998

A-IOH-409 RWS

FIXED COSTS IN DEMAND CHARGES

Comparison of SECI-6B and Seasonal Rates
Including Transmission



RATE COMMITTEE
4/9/98

00013

COMPARISON OF MEMBE AVERAGE RATES
SECI-6B vs ALTERNATE 4 SEASONAL RATE STRUCTURE
1999
MILLS PER KWH

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.37	46.80	-0.43
Clay	45.98	45.86	0.12
Glades	45.90	46.11	-0.21
Lee County	46.66	46.39	0.27
Okefenoke	45.47	46.53	-1.06
Peace River	46.78	46.94	-0.16
Sumter	49.02	48.85	0.17
Suwannee	45.96	46.04	-0.08
Talquin	47.05	47.25	-0.20
Tri-County	45.06	45.03	0.03
Withlacoochee	48.54	48.79	-0.25
Seminole	47.22	47.22	0.00

G0014

Reflects $8.50 winter and $8.50 summer demand rates with Voltage Discount Adjustment of $0.90 per kW-mo with FPC Coincident Billing

COMPARISON OF MEMBER AVERAGE RATES
SECI-6B vs ALTERNATE 4 SEASONAL RATE STRUCTURE
2000
MILLS PER KWH

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.15	46.48	-0.33
Clay	46.08	45.77	0.31
Glades	46.02	46.07	-0.05
Lee County	46.50	46.08	0.42
Okefenoke	45.51	46.28	-0.77
Peace River	47.60	47.58	0.02
Sumter	48.39	48.40	-0.01
Suwannee	46.11	46.00	0.11
Talquin	47.00	47.18	-0.18
Tri-County	45.60	45.22	0.38
Withlacoochee	47.87	48.42	-0.55
Seminole	47.00	47.00	0.00

Reflects $6.50 winter and $6.50 summer demand rates
with Voltage Discount Adjustment of $0.90 per kW-mo
with FPC Coincident

00015

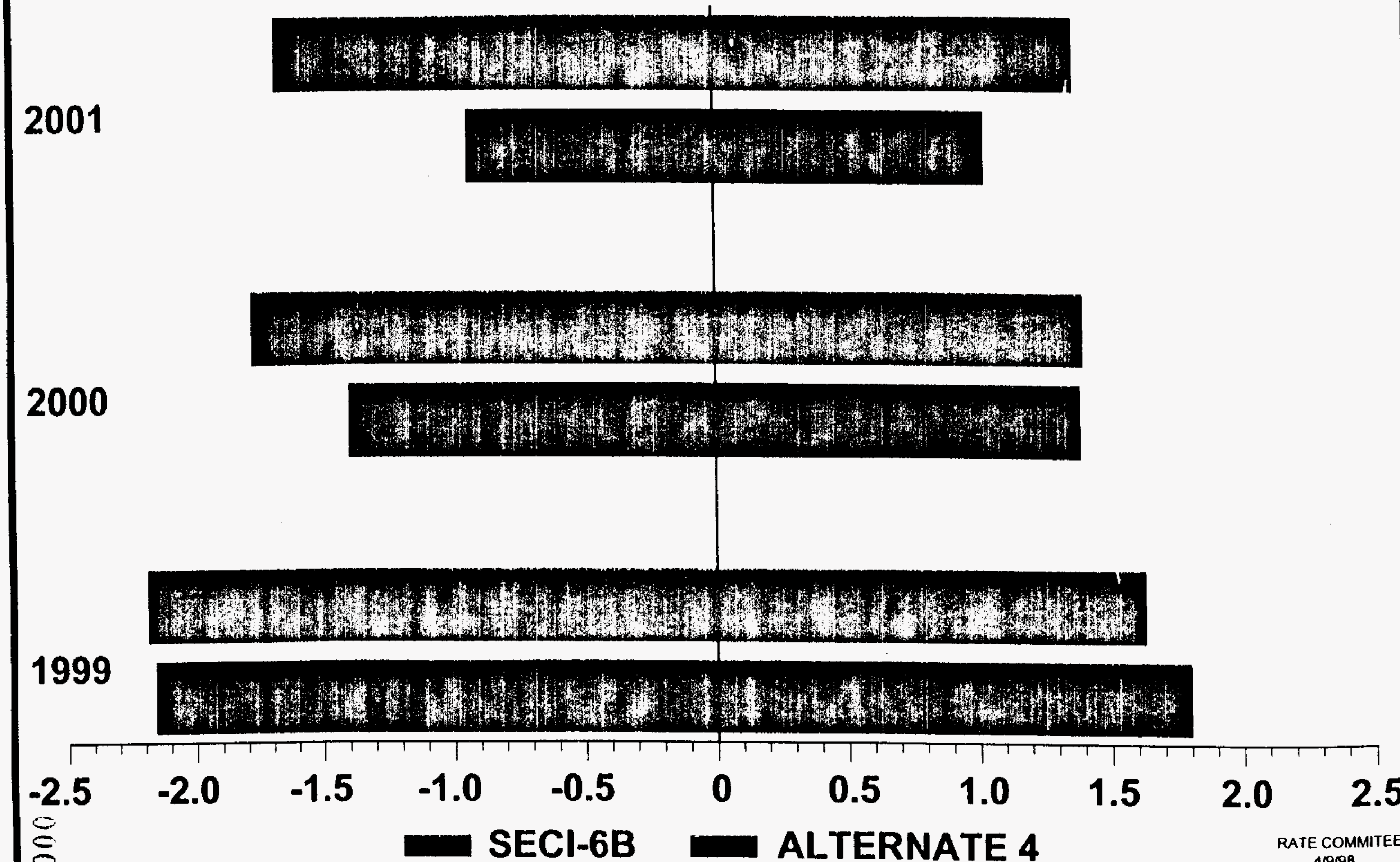
COMPARISON OF M[illegible]BER AVERAGE RATES
SECI-6B vs ALTERNATE 4 SEASONAL RATE STRUCTURE
2001
MILLS PER KWH

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.27	46.43	-0.16
Clay	46.37	45.81	0.56
Glades	46.27	46.15	0.12
Lee County	46.61	46.06	0.55
Okefenoke	46.10	46.30	-0.20
Peace River	47.86	47.63	0.23
Sumter	48.03	48.37	-0.34
Suwannee	46.29	46.04	0.25
Talquin	46.98	47.23	-0.25
Tri-County	46.06	45.32	0.74
Withlacoochee	47.58	48.36	-0.78
Seminole	47.00	47.00	0.00

00016

Reflects $4.50 winter and $4.50 summer demand rates
with Voltage Discount Adjustment of $0.90 per kW-mo
with FPC Coincident Billing

RANGE OF VARIA‿ON OF AVERAGE ANNUAL RATE FOR MEMBERS
ALTERNATE 4 VS. SECI-6B
(MILLS/KWH)



RATE COMMITEE
4/9/98

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B versus SEASONAL RATE STRUCTURE

MILLS PER KWH

	1998 SECI-6B *	1999 SEASONAL RATE STRUCTURE ALTERNATE 4	DIFFERENCE
Central Florida	49.38	46.37	-3.01
Clay	48.33	45.98	-2.35
Glades	48.35	45.90	-2.45
Lee County	49.14	46.66	-2.48
Okefenoke	48.95	45.47	-3.48
Peace River	49.85	46.78	-3.07
Sumter	51.86	49.02	-2.84
Suwannee	48.40	45.96	-2.44
Talquin	49.80	47.05	-2.75
Tri-County	46.90	45.06	-1.84
Withlacoochee	51.94	48.54	-3.40
Seminole	50.00	47.22	-2.78

* Reflects 1998 Budget Revenue Requirement

** $8.50 / kW-Mo Winter and Summer Demand Rates
With $0.90 / kW Distribution Surcharge

ADVANTAGES TO NEW PROPOSED RATE DESIGN

❶ MORE ACCURATELY REFLECTS THE INCREMENTAL COST OF NEW CAPACITY

❷ MORE ACCURATELY REFLECTS ALLOCATION OF BASE LOAD CAPACITY BASED UPON COST CAUSATION

❸ REDUCES INCENTIVE TO CONTROL LOADS IN OFF-PEAK MONTH

❹ REDUCES FREQUENCY OF LOAD MANAGEMENT IN FPL AREA

❺ REDUCES DISPARITY IN AVERAGE COST OF WHOLESALE POWER AMONG MEMBERS

	1998 SECI-6B	1999 SECI-6B	SEASONAL RATE STRUCTURE ALTERNATE 4
			-
DEMAND RATES ($ / kW-mo):			
25 KV	$12.02	$9.80	-
69 KV	10.89	8.67	-
125 KV	10.76	8.54	-
230 KV	10.63	8.41	-
Winter	-	-	$8.50
Summer	-	-	8.50
TRANSMISSION RATES ($ / kW-mo):			
Transmission	Included	Included	$1.662
Distribution Adder	Above	Above	0.90
ENERGY (MILLS/ kWh)			
Non-Fuel	3.20	5.18	2.05
Fuel	20.60	21.27	21.27
	23.80	26.45	23.32
STATION CHARGE (per Delivery Point-mo)	$400	$400	-
FIXED CHARGE AMOUNT ($000) Allocated to Members based on 1995-1997 actual kWh	-	-	$60,988

COMPARISON OF SEMINOLE RATES

	1998 SECI-6B	2000 SECI-6B	SEASONAL RATE STRUCTURE ALTERNATE 4
			-
DEMAND RATES ($ / kW-mo):			
25 KV	$12.02	$9.39	-
69 KV	10.89	8.25	-
125 KV	10.76	8.12	-
230 KV	10.63	7.99	-
Winter	-	-	$6.50
Summer	-	-	6.50
TRANSMISSION RATES ($ / kW-mo):			
Transmission	Included	Included	$1.770
Distribution Adder	Above	Above	0.90
ENERGY (MILLS/ kWh)			
Non-Fuel	3.20	5.24	1.76
Fuel	20.60	22.10	22.10
	23.80	27.34	23.86
STATION CHARGE (per Delivery Point-mo)	$400	$400	-
FIXED CHARGE AMOUNT ($000)	-	-	$96,681

Allocated to Members based on 1996-1998 actual kWh

00021

	1998 SECI-6B	2001 SECI-6B	SEASONAL RATE STRUCTURE ALTERNATE 4
			-
DEMAND RATES ($ / kW-mo):			
25 KV	$12.02	$9.17	-
69 KV	10.89	8.03	-
125 KV	10.76	7.90	-
230 KV	10.63	7.77	-
Winter	-	-	$4.50
Summer	-	-	4.50
TRANSMISSION RATES ($ / kW-mo):			
Transmission	Included	Included	$1.750
Distribution Adder	Above	Above	0.90
ENERGY (MILLS/ kWh)			
Non-Fuel	3.20	5.17	1.79
Fuel	20.60	22.66	22.66
	23.80	27.83	24.45
STATION CHARGE (per Delivery Point-mo)	$400	$400	-
FIXED CHARGE AMOUNT ($000) Allocated to Members based on 1997-1999 actual kWh	-	-	$139,235

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE ~~4~~ 6 SEASONAL RATE STRUCTURE

1999

MILLS PER KWH

Reflects $8.50 winter and $8.50 summer demand rates

with Voltage Discount Adjustment of $0.90 per kW-mo

Allocation of Fixed Charge Amount
Based Upon 3-Year Average of
Top 876 Hours of KW

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.39	46.80	-0.41
Clay	46.04	45.86	0.18
Glades	45.30	46.11	-0.81
Lee County	46.39	46.39	0.00
Okefenoke	45.81	46.53	-0.72
Peace River	46.41	46.94	-0.53
Sumter	49.15	48.85	0.30
Suwannee	46.24	46.04	0.20
Talquin	47.19	47.25	-0.06
Tri-County	44.95	45.03	-0.08
Withlacoochee	48.69	48.79	-0.10
Seminole	47.22	47.22	0.00

00023

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE ~~4~~ 6 SEASONAL RATE STRUCTURE

2000

MILLS PER KWH

Reflects $6.50 winter and $6.50 summer demand rates

with Voltage Discount Adjustment of $0.90 per kW-mo

Allocation of Fixed Charge Amount
Based Upon 3-Year Average
of Top 876 Hours of KW

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.16	46.48	-0.32
Clay	46.15	45.77	0.38
Glades	45.13	46.07	-0.94
Lee County	46.21	46.08	0.13
Okefenoke	45.77	46.28	-0.51
Peace River	47.04	47.58	-0.54
Sumter	48.65	48.40	0.25
Suwannee	46.50	46.00	0.50
Talquin	47.22	47.18	0.04
Tri-County	45.44	45.22	0.22
Withlacoochee	48.00	48.42	-0.42
Seminole	47.00	47.00	0.00

00024

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE ~~4~~ 6 SEASONAL RATE STRUCTURE

2001

MILLS PER KWH

Reflects $4.50 winter and $4.50 summer demand rates

with Voltage Discount Adjustment of $0.90 per kW-mo

Allocation of Fixed Charge Amount
Based Upon 3-Year Average of
Top 876 Hours of Use

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.28	46.43	-0.15
Clay	46.47	45.81	0.66
Glades	45.11	46.15	-1.04
Lee County	46.33	46.06	0.27
Okefenoke	45.88	46.30	-0.42
Peace River	47.22	47.63	-0.41
Sumter	48.52	48.37	0.15
Suwannee	46.85	46.04	0.81
Talquin	47.26	47.23	0.03
Tri-County	45.92	45.32	0.60
Withlacoochee	47.58	48.36	-0.78
Seminole	47.00	47.00	0.00

00025

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE 6 SEASONAL RATE STRUCTURE

1999

MILLS PER KWH

Reflects $8.50 winter and $6.50 summer demand rates

with Voltage Discount Adjustment of $0.90 per kW-mo

Allocation of Fixed Charge Amount Based Upon

3-Year Average of Top 876 Hours of kW

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.34	46.80	-0.46
Clay	46.02	45.86	0.16
Glades	45.36	46.11	-0.75
Lee County	46.49	46.39	0.10
Okefenoke	45.49	46.53	-1.04
Peace River	46.61	46.94	-0.33
Sumter	49.17	48.85	0.32
Suwannee	46.18	46.04	0.14
Talquin	47.13	47.25	-0.12
Tri-County	44.98	45.03	-0.05
Withlacoochee	48.62	48.79	-0.17
Seminole	47.22	47.22	0.00

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE 6 SEASONAL RATE STRUCTURE

2000

MILLS PER KWH

Reflects $6.50 winter and $4.50 summer demand rates

with Voltage Discount Adjustment of $0.90 per kW-mo

Allocation of Fixed Charge Amount Based Upon

3-Year Average of Top 876 Hours of kW

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.13	46.48	-0.35
Clay	46.13	45.77	0.36
Glades	45.17	46.07	-0.90
Lee County	46.32	46.08	0.24
Okefenoke	45.53	46.28	-0.75
Peace River	47.22	47.58	-0.36
Sumter	48.69	48.40	0.29
Suwannee	46.40	46.00	0.40
Talquin	47.10	47.18	-0.08
Tri-County	45.42	45.22	0.20
Withlacoochee	47.93	48.42	-0.49
Seminole	47.00	47.00	0.00

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE 6 SEASONAL RATE STRUCTURE

2001

MILLS PER KWH

Reflects $4.50 winter and $2.50 summer demand rates

with Voltage Discount Adjustment of $0.90 per kW-mo

Allocation of Fixed Charge Amount Based Upon

3-Year Average of Top 876 Hours of kW

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.25	46.43	-0.18
Clay	46.46	45.81	0.65
Glades	45.14	46.15	-1.01
Lee County	46.45	46.06	0.39
Okefenoke	45.63	46.30	-0.67
Peace River	47.40	47.63	-0.23
Sumter	48.56	48.37	0.19
Suwannee	46.76	46.04	0.72
Talquin	47.14	47.23	-0.09
Tri-County	45.91	45.32	0.59
Withlacoochee	47.50	48.36	-0.86
Seminole	47.00	47.00	0.00

COMPARISON OF MEMBER AVERAGE RATES
SECI-6B vs SEASONAL RATE STRUCTURE
1999
MILLS PER KWH

Reflects $8.50 winter and $6.50 summer demand rates with Voltage Discount Adjustment of $0.90 per kW-mo with FPC Coincident Billing

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.31	46.80	-0.49
Clay	45.95	45.86	0.09
Glades	46.14	46.11	0.03
Lee County	46.84	46.39	0.45
Okefenoke	45.04	46.53	-1.49
Peace River	47.10	46.94	0.16
Sumter	48.99	48.85	0.14
Suwannee	45.81	46.04	-0.23
Talquin	46.94	47.25	-0.31
Tri-County	45.13	45.03	0.10
Withlacoochee	48.42	48.79	-0.37
Seminole	47.22	47.22	0.00

COMPARISON OF MEMBER AVERAGE RATES
SECI-6B vs SEASONAL RATE STRUCTURE
2000
MILLS PER KWH

Reflects $6.50 winter and $4.50 summer demand rates with Voltage Discount Adjustment of $0.90 per kW-mo with FPC Coincident Billing

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.12	46.48	-0.36
Clay	46.05	45.77	0.28
Glades	46.23	46.07	0.16
Lee County	46.68	46.08	0.60
Okefenoke	45.22	46.28	-1.06
Peace River	47.89	47.58	0.31
Sumter	48.37	48.40	-0.03
Suwannee	45.93	46.00	-0.07
Talquin	46.84	47.18	-0.34
Tri-County	45.61	45.22	0.39
Withlacoochee	47.78	48.42	-0.64
Seminole	47.00	47.00	0.00

00030

COMPARISON OF MEMBER AVERAGE RATES
SECI-6B vs SEASONAL RATE STRUCTURE
2001
MILLS PER KWH

Reflects $4.50 winter and $2.50 summer demand rates with Voltage Discount Adjustment of $0.90 per kW-mo with FPC Coincident Billing

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.24	46.43	-0.19
Clay	46.34	45.81	0.53
Glades	46.48	46.15	0.33
Lee County	46.77	46.06	0.71
Okefenoke	45.88	46.30	-0.42
Peace River	48.13	47.63	0.50
Sumter	47.99	48.37	-0.38
Suwannee	46.11	46.04	0.07
Talquin	46.81	47.23	-0.42
Tri-County	46.07	45.32	0.75
Withlacoochee	47.50	48.36	-0.86
Seminole	47.00	47.00	0.00

00031

RATE COMMITTEE MEETING MINUTES
SEMINOLE ELECTRIC COOPERATIVE, INC.
TAMPA, FLORIDA
WEDNESDAY, MAY 13, 1998

Mr. Woodbury then discussed the proposed revisions to the wholesale rate design. He reviewed with the Committee the strategic plan which calls for the implementation of a wholesale rate to the members which is based upon the incremental price of new capacity. With the termination of Seminole's partial requirements purchased power agreement with FPL effective in 1999, and the resulting reduction in Seminole's revenue requirements, staff has proposed that the first phase of the revised rate be implemented January 1, 1999. Mr. Woodbury reviewed the discussions which took place in the March Rate Committee and the April Rate Workshop. He described that staff had received some feedback from the members to look at specific rate alternatives since the last meeting and staff had examined more than 25 alternatives.

Mr. Woodbury presented a recommended rate structure alternative which includes the following characteristics: 1) unbundled transmission and production charges; 2) billing demands at the time of the Seminole system peak; 3) phased in production demand charges applied only to the winter and summer months (the production demand rates will be $8.50/kW/month, $7.50/kW/month and $6.50/kW/month during 1999, 2000 and 2001, respectively); 4) the difference between the total fixed production costs and the fixed production costs recovered under the demand charges will be recovered on a fixed dollar payment per month allocated to each member based upon the prior 3-year rolling average of kWh purchases; and 5) cost based voltage discounts based upon the weighted average rate of the transmission suppliers surcharge for service at the distribution delivery points. There was some discussion of changing the distribution adder from a weighted average rate to a flow through of any distribution surcharges from the transmission suppliers directly to the members with the distribution delivery points.

A motion was made by B. Brown and seconded by J. Duncan recommending that the Seminole Board of Trustees approve the implementation of a revised wholesale rate structure effective January 1, 1999 as recommended by staff and subject to the details of the specific cost-based distribution adder to be worked out by the members with distribution delivery points. The motion passed with six affirmative votes, and with William Phillips, L. T. Todd and Pam May voting against the motion.

There being no further business, the Rate Committee meeting was adjourned at 2:45 p.m.

RECOMMENDED RATE STRUCTURE
1999

- ➢ DELIVERY POINT CHARGE - NONE
- ➢ FIXED COST RECOVERY CHARGES
  - ♦ GENERATION
    - * $/KW/MO. CHARGES

DEC -	MAR	-	$8.50/KW/MO.
JUNE -	SEPT	-	$8.50/KW/MO.
OTHER		-	NO CHARGE

    - * $/MONTH
      DIFFERENCE BETWEEN FIXED $ REV. REQ. AND $/KW/MO. DEMAND REVENUES ALLOCATED TO MEMBERS ON THE BASIS OF A 3-YEAR ROLLING AVERAGE OF ANNUAL METERED KWH PURCHASES
  - ♦ TRANSMISSION
    - * 69 KV AND ABOVE - $1.662/KW/MO. (estimate)
    - * DISTRUBUTION ADDER - FLOW THRU OR $1.29/KW/MO. (estimate)
  - ♦ BILLING DETERMINANTS
    - * MONTHLY METERED KW DEMANDS COINCIDENT WITH SEMINOLE'S MONTHLY SYSTEM PEAK
- ➢ ENERGY COST RECOVERY CHARGES

00003

- ♦ FUEL - LEVELIZED CHARGE WITH TRUEUPS
- ♦ NON-FUEL - $2.05/ MWH (estimate)

PHASE-IN PLAN FOR $/KW CHARGES UNDER RECOMMENDED SEASONAL RATE STRUCTURE

		1999	2000	2001
WINTER	($/KW/MO)	8.50	7.50	6.50
SUMMER	($/KW/MO)	8.50	7.50	6.50

ADDITIONAL OPTIONS DEVELOPED

- STAFF EXAMINED OVER 25 ALTERNATIVES
- FOCUS HAS REMAINED ON SEASONAL RATE FOR DEMAND
- HAVE EXAMINED A NUMBER OF COMBINATIONS USING A PHASED IN SEASONAL SUMMER/WINTER RATE OF $8.50/7.50/6.50 WITH VARYING BILLING DEMAND OPTIONS
- HAVE EXAMINED STRATIFIED RATES

CONCLUSIONS

- ADOPT SEASONAL SUMMER/WINTER RATE OF $8.50/7.50/6.50 WITH NO PRODUCTION DEMAND CHARGES FOR APRIL, MAY, OCTOBER AND NOVEMBER

LOGIC

A PHASE-IN WILL ALLOW A SMOOTHER TRANSITION.

THE FINAL YEAR CHARGE OF $6.50/KW/MONTH ON AN ANNUAL BASIS EQUATES TO $52/KW/YR WHICH IS VERY CLOSE TO SEMINOLE'S PROJECTED COST OF NEW COMBINED CYCLE TYPE CAPACITY, WHETHER PURCHASED OR CONSTRUCTED.

THE USE OF A SEASONAL RATE REFLECTS SEMINOLE'S NEEDS FOR INCREMENTAL CAPACITY ONLY DURING THE WINTER AND SUMMER MONTHS.

THIS SEASONAL RATE MEETS THE STRATEGIC GOAL TO ESTABLISH RATES REFLECTIVE OF INCREMENTAL COST OF NEW CAPACITY.

- CHARGE $1.29/KW/MO. SURCHARGE FOR SERVICE AT DISTRIBUTION VOLTAGES

LOGIC

THE PROPOSED CHARGE IS COST BASED.

THE CHARGE REPRESENTS A WEIGHTED AVERAGE OF THE DISTRIBUTION VOLTAGE SURCHARGES BILLED TO SEMINOLE FOR TRANSMISSION SERVICE FROM FPC AND FPL.

THE WEIGHTING IS BASED ON THE ACTUAL PROJECTED LOADS EXPECTED TO BE SERVED AT DISTRIBUTION VOLTAGE WITHIN BOTH THE FPC AND FPL CONTROL AREAS DURING THE TEST PERIOD.

- GENERATION FIXED COSTS NOT RECOVERED THROUGH DEMAND CHARGES SHOULD BE ALLOCATED TO MEMBERS ON AN ENERGY BASIS AND BILLED ON A FLAT $/MONTH BASIS.

LOGIC

STAFF BELIEVES THAT THERE IS A SOUND COST BASED LOGIC FOR ALLOCATING A SUBSTANTIAL PORTION OF THE FIXED COSTS OF BASE LOAD GENERATION ON AN ENERGY BASIS. BY THE YEAR 2001, THE PROPOSED METHODOLOGY ALLOCATES APPROXIMATELY 75% OF SEMINOLE PLANT FIXED COSTS ON AN ENERGY BASIS.

UNDER THE PROPOSED RATE, EXCLUSIVE OF THE $/MONTH FIXED CHARGE AMOUNT, THE DEMAND AND ENERGY CHARGES WOULD RECOVER, ON AVERAGE, 40.2 MILLS/ KWH WHICH IS IN THE RANGE OF WHAT SEMINOLE ESTIMATES THE MARKET PRICE OF POWER TO BE BY THE YEAR 2002

- THE HOUR OF BILLING DEMAND SHOULD BE SEMINOLE COINCIDENT PEAK DEMAND

LOGIC

SEMINOLE'S LONG RUN FIXED PRODUCTION COSTS WILL BE DETERMINED ON A SEMINOLE SYSTEM PEAK DEMAND BASIS.

THERE IS A HIGH LEVEL OF COINCIDENCE BETWEEN THE SEMINOLE COINCIDENT PEAK AND THE FPC COINCIDENT SYSTEM PEAK.

FPC PARTIAL REQUIREMENTS LOAD FOLLOWING SERVICE MAY BE TERMINATED OR SIGNIFICANTLY ALTERED IN THE NEAR FUTURE.

NOTE: BILLING ON THE BASIS OF SEMINOLE COINCIDENT PEAK DEMANDS WILL INCREASE THE FREQUENCY OF LOAD CONTROL BY THE MEMBERS IN ORDER TO ENSURE THAT WE "HIT THE PEAK".

CONCLUSIONS - (CONT')

- TRANSMISSION CHARGES SHOULD BE UNBUNDLED AND PRICED ON A SEPARATE $/KW DEMAND CHARGE TO BE BILLED EACH MONTH

LOGIC

SEPARATING OR UNBUNDLING TRANSMISSION COSTS FROM PRODUCTION COSTS SENDS A BETTER PRICE SIGNAL TO THE MEMBERS AS WE MOVE INTO A COMPETITIVE ENVIRONMENT

AT THE PRESENT TIME, COST ALLOCATION UNDER THE NETWORK TRANSMISSION TARIFFS IS BASED UPON COINCIDENT PEAK DEMANDS. DISTRIBUTED GENERATION MAY NOT BE ABLE TO BE USED TO AVOID TRANSMISSION CHARGES UNDER THE TARIFF.

SEMINOLE'S RATE SHOULD BE REVIEWED FROM TIME TO TIME TO ENSURE THAT ITS TREATMENT OF DISTRIBUTED GENERATION TRACKS SEMINOLE'S TRANSMISSION COSTS.

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	1998 SECI-6B	1999 SECI-6B	SEASONAL RATE STRUCTURE ALTERNATE 3(AT)
			-
DEMAND RATES ($ / kW-mo):			
25 KV	$12.02	$9.80	-
69 KV	10.89	8.67	-
125 KV	10.76	8.54	-
230 KV	10.63	8.41	-
Winter	-	-	$8.50
Summer	-	-	8.50
TRANSMISSION RATES ($ / kW-mo):			
Transmission	Included	Included	$1.624
Distribution Adder	Above	Above	1.29
ENERGY (MILLS/ kWh)			
Non-Fuel	3.20	5.18	2.05
Fuel	20.60	21.27	21.27
	23.80	26.45	23.32
STATION CHARGE (per Delivery Point-mo)	$400	$400	-
FIXED CHARGE AMOUNT ($000) Allocated to Members based on 1995-1997 actual kWh	-	-	$57,660

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	1998 SECI-6B	2000 SECI-6B	SEASONAL RATE STRUCTURE ALTERNATE 3(AT)
DEMAND RATES ($ / kW-mo):			
25 KV	$12.02	$9.39	-
69 KV	10.89	8.25	-
125 KV	10.76	8.12	-
230 KV	10.63	7.99	-
Winter	-	-	$7.50
Summer	-	-	7.50
TRANSMISSION RATES ($ / kW-mo):			
Transmission	Included	Included	$1.729
Distribution Adder	Above	Above	1.29
ENERGY (MILLS/ kWh)			
Non-Fuel	3.20	5.24	1.76
Fuel	20.60	22.10	22.10
	23.80	27.34	23.86
STATION CHARGE (per Delivery Point-mo)	$400	$400	-
FIXED CHARGE AMOUNT ($000) Allocated to Members based on 1996-1998 actual kWh	-	-	$71,424

00012

	1998 SECI-6B	2001 SECI-6B	SEASONAL RATE STRUCTURE ALTERNATE 3(AT) -
DEMAND RATES ($ / kW-mo):			
25 KV	$12.02	$9.17	-
69 KV	10.89	8.03	-
125 KV	10.76	7.90	-
230 KV	10.63	7.77	-
Winter	-	-	$6.50
Summer	-	-	6.50
TRANSMISSION RATES ($ / kW-mo):			
Transmission	Included	Included	$1.709
Distribution Adder	Above	Above	1.29
ENERGY (MILLS/ kWh)			
Non-Fuel	3.20	5.17	1.79
Fuel	20.60	22.66	22.66
	23.80	27.83	24.45
STATION CHARGE (per Delivery Point-mo)	$400	$400	-
FIXED CHARGE AMOUNT ($000) Allocated to Members based on 1997-1999 actual kWh	-	-	$90,245

00013

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B versus SEASONAL RATE STRUCTURE

MILLS PER KWH

	1998 SECI-6B *	NEW 1999 SEASONAL RATE STRUCTURE	DIFFERENCE AMOUNT	DIFFERENCE PERCENTAGE
Central Florida	49.38	46.30	-3.08	-6.2%
Clay	48.33	46.07	-2.26	-4.7%
Glades	48.35	46.18	-2.17	-4.5%
Lee County	49.14	46.32	-2.82	-5.7%
Okefenoke	48.95	46.37	-2.58	-5.3%
Peace River	49.85	47.57	-2.28	-4.6%
Sumter	51.86	48.91	-2.95	-5.7%
Suwannee	48.40	46.37	-2.03	-4.2%
Talquin	49.80	47.28	-2.52	-5.1%
Tri-County	46.90	45.40	-1.50	-3.2%
Withlacoochee	51.94	48.55	-3.39	-6.5%
Seminole	50.00	47.22	-2.78	-5.6%

* Reflects 1998 Budget Revenue Requirement

** Alternate 3(AT) - $8.50 / kW-Mo Winter Demand Rates December through March

$8.50 / kW-Mo Summer Demand Rates June through September

Based Upon Seminole Coincident Billing

00014

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE 3(AT) SEASONAL RATE STRUCTURE

1999

MILLS PER KWH

Reflects $8.50 winter and $8.50 summer demand rates

with Voltage Discount Adjustment of $1.29 per kW-mo

Allocation of Fixed Charge Amount Based Upon

3-Year Rolling Average of KWH

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
ntral Florida	46.30	46.80	-0.50
[illegible]	46.07	45.86	0.21
Glades	46.18	46.11	0.07
e County	46.32	46.39	-0.07
Okefenoke	46.37	46.53	-0.16
ace River	47.57	46.94	0.63
mter	48.91	48.85	0.06
Suwannee	46.37	46.04	0.33
lquin	47.28	47.25	0.03
i-County	45.40	45.03	0.37
Withlacoochee	48.55	48.79	-0.24
Seminole	47.22	47.22	0.00

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE 3(AT) SEASONAL RATE STRUCTURE

2000

MILLS PER KWH

Reflects $7.50 winter and $7.50 summer demand rates

with Voltage Discount Adjustment of $1.29 per kW-mo

Allocation of Fixed Charge Amount Based Upon

3-Year Rolling Average of KWH

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
Central Florida	46.12	46.48	-0.36
Clay	45.97	45.77	0.20
Glades	46.10	46.07	0.03
Lee County	46.11	46.08	0.03
Okefenoke	46.45	46.28	0.17
Peace River	47.94	47.58	0.36
Sumter	48.51	48.40	0.11
Suwannee	46.24	46.00	0.24
Talquin	47.09	47.18	-0.09
Tri-County	45.46	45.22	0.24
Withlacoochee	48.14	48.42	-0.28
Seminole	47.00	47.00	0.00

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B vs ALTERNATE 3(AT) SEASONAL RATE STRUCTURE

2001

MILLS PER KWH

Reflects $6.50 winter and $6.50 summer demand rates

with Voltage Discount Adjustment of $1.29 per kW-mo

Allocation of Fixed Charge Amount Based Upon

3-Year Rolling Average of KWH

	SEASONAL RATE STRUCTURE	SECI-6B	DIFFERENCE
[illegible]tral Florida	46.15	46.43	-0.28
[illegible]	46.10	45.81	0.29
Glades	46.23	46.15	0.08
[illegible] County	46.16	46.06	0.10
Okefenokee	46.76	46.30	0.46
Peace River	48.04	47.63	0.41
[illegible]nter	48.31	48.37	-0.06
Suwannee	46.32	46.04	0.28
[illegible]quin	47.10	47.23	-0.13
Tri-County	45.72	45.32	0.40
Withlacoochee	48.01	48.36	-0.35
Seminole	47.00	47.00	0.00

ANNUAL DIFFERENCES OF SEASONAL

RATE STRUCTURE COMPARED TO SECI-6B

1999 - 2001

MILLS PER KWH

SECI-6B vs ALTERNATE 3(AT) SEASONAL RATE STRUCTURE

Reflects Undifferentiated Winter and Summer Demand Rates

with Voltage Discount Adjustment of $1.29 per kW-mo

Allocation of Fixed Charge Amount Based Upon

3-Year Rolling Average of KWH

	1999	2000	2001
Central Florida	-0.50	-0.36	-0.28
Clay	0.21	0.20	0.29
Glades	0.07	0.03	0.08
Lee County	-0.07	0.03	0.10
Okefenoke	-0.16	0.17	0.46
Peace River	0.63	0.36	0.41
Sumter	0.06	0.11	-0.06
Suwannee	0.33	0.24	0.28
Talquin	0.03	-0.09	-0.13
Tri-County	0.37	0.24	0.40
Withlacoochee	-0.24	-0.28	-0.35
Seminole	0.00	0.00	0.00

ALTERNATE 3(AT)
PERCENTAGE OF FIXED COSTS
RECOVERED IN DEMAND CHARGES
AND PERCENTAGE OF BASE REVENUE REQUIREMENT
ALLOCATED BASED UPON ENERGY

	% FIXED COSTS IN DEMAND CHGS	% BASE REV. REQ. ALLOC. W/KWH	% SECI/CR3 REV. REQ. ALLOC. W/KWH
1999	80.1%	40.9%	47.6%
2000	75.8%	50.6%	59.0%
2001	69.8%	64.0%	74.6%

*Base Revenue Requirement = Seminole Plant, CR3 and HPS 1&2.

1999 Load Management

- Control 8 of 12 Months
- Seminole Coincident Control
  - 44 Days
  - 155 Hours
- FPC System Peak Coincident Control
  - 28 Days
  - 82 Hours
- Control Frequency and Duration Differs Due to:
  - Amount of Load Management Relative to Load
  - Location of Load Reduction Capability
  - Diversity in Loads
- Significant Improvement From Present Control
  - FPL Area: 79 days, 264 hours
  - FPC Area: 44 days, 114 hours

The Rate Committee received a presentation on several wholesale rate structure alternatives for 1999. Mr. Martin noted the committee has been reviewing several alternatives over the past few months. He called on T. Woodbury to present the recommended rate structure from the Rate

Committee. Mr. Woodbury advised the recommended rate structure alternative includes the following characteristics: 1) unbundled transmission and production charges; 2) billing demands at the time of the Seminole system peak; 3) phased in production demand charges applied only to the winter and summer months (the production demand rates will be $8.50 per kilowatt month, $7.50 per kilowatt month, and $6.50 per kilowatt month during 1999, 2000, and 2001, respectively); 4) the difference between the total fixed production costs and the fixed production costs recovered under the demand charges will be recovered on a fixed dollar payment per month allocated to each Member based upon the prior three-year rolling average of kilowatt hour purchases; and 5) cost based voltage discounts based upon the weighted average rate of the transmission suppliers surcharge for service at the distribution delivery points. Mr. Martin stated the Rate Committee recommended that the Seminole Board of Trustees approve the implementation of a revised wholesale rate structure effective January 1, 1999 as recommended by staff and subject to the details of the specific cost-based distribution adder to be worked out by the Members with distribution delivery points. There was a motion by Jerry Martin, seconded by A. Ward, to approve the recommended motion from the Rate Committee. The motion passed on a vote of 11-7, with the seven "no" votes being cast by T. Todd, J. Drake, P. May, D. Gomer, B. Phillips, J. Martin, and A. Ward.

RATE COMMITTEE MEETING MINUTES
SEMINOLE ELECTRIC COOPERATIVE, INC.
TAMPA, FLORIDA
WEDNESDAY, JULY 8, 1998

Chairman Martin called on T. Novak who reviewed with the Rate Committee, the draft proposed new Seminole Rate Schedule SECI-7 which will go into effect on January 1, 1999. The new rate schedule incorporates the revised rate structure methodology which was approved by the Board in May. Upon determination of the budgeted revenue requirement for 1999, the new Rate Schedule SECI-7 will be brought to the Board for approval.

Exhibit ___ (TSW-10)
Witness: Woodbury
Docket No. 981827-EC

RATE COMMITTEE MEETING MINUTES
SEMINOLE ELECTRIC COOPERATIVE, INC.
TAMPA, FLORIDA
WEDNESDAY, OCTOBER 7, 1998

Chairman Martin called on T. Novak who reviewed with the Rate Committee, that in May 1998, in accordance with Seminole's strategic plan, the Board of Trustees approved a revised rate structure to be implemented January 1, 1999. This rate structure includes 1) unbundled transmission and distribution charges, 2) billing demands based upon Seminole's system peak, 3) phased-in production demand charges applied only to the winter and summer months, 4) a monthly production fixed energy charge to recover production fixed cost not recovered in the demand charge, and 5) cost based voltage discounts. Consistent with the approved rate structure Seminole staff developed a new rate schedule, (Rate Schedule SECI-7). Ms. Novak reviewed the development of the final unit charges which are to be incorporated in this schedule to reflect the final budgeted revenue requirement for 1999. Ms. Novak pointed out that under the new schedule, there would no longer be the need for a levelized fuel adjustment charge since fuel and other variable energy charges are seperately priced. Mr. Woodbury disclosed that in contrast to what staff had told the Committee when the rate structure was being developed, it now looked like voluntary load management in May and November may be required to avoid the purchase of partial requirements power from FPC. He pointed out that this fact did not change staff's conclusion that seasonal demand charges are appropriate for Seminole. Ms. May stated that Lee County objected to the new rate structure's recovering a greater proportion of fixed costs in the energy charge. A motion was made by T. Todd and seconded by B. Brown recommending that the Seminole Board of Trustees approve Resolution R-9, for the Rate Schedule SECI-7 to become effective January 1, 1999. The motion passed with Pam May registering a no vote.

President Rivenbark called on Jerry Martin for the Rate Committee Report. Mr. Martin reported the committee considered and recommended a resolution approving Rate Schedule SECI-7, to supersede Rate Schedule SECI-6b effective January 1, 1999. There was a motion by

J. Martin, seconded by A. Ward, to approve this resolution. Mr. Bostick registered a negative voice on the resolution due to his view of the rate tilting factor, as well as the new rate structure's recovering a greater proportion of fixed costs in the energy charge. The resolution was adopted with two "no" votes cast by C. Bostick and P. May. *(A copy of this resolution is attached, R-9.)*

COMPARISON OF MEMBER AVERAGE RATES

SECI-6B versus SEASONAL RATE STRUCTURE

MILLS PER KWH

	1998 SECI-6B *	NEW 1999 SEASONAL RATE STRUCTURE	DIFFERENCE AMOUNT	DIFFERENCE PERCENTAGE
Central Florida	49.38	46.30	-3.08	-6.2%
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Glades	48.35	46.18	-2.17	-4.5%
Lee County	49.14	46.32	-2.82	-5.7%
Okefenoke	48.95	46.37	-2.58	-5.3%
Peace River	49.85	47.57	-2.28	-4.6%
Sumter	51.86	48.91	-2.95	-5.7%
Suwannee	48.40	46.37	-2.03	-4.2%
Talquin	49.80	47.28	-2.52	-5.1%
Tri-County	46.90	45.40	-1.50	-3.2%
Withlacoochee	51.94	48.55	-3.39	-6.5%
Seminole	50.00	47.22	-2.78	-5.6%

* Reflects 1998 Budget Revenue Requirement

** Alternate 3(AT) - $8.50 / kW-Mo Winter Demand Rates December through March

$8.50 / kW-Mo Summer Demand Rates June through September

Based Upon Seminole Coincident Billing

Exhibit ___ (TSW-13)
Witness: Woodbury
Docket No. 981827-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.

AVERAGE POWER COST VS. LOAD FACTOR

	Actual 1999	
	Average Power Cost (Mills/kWh)	Average Monthly Load Factor (%)
Glades	41.8	72.2
Lee County	44.8	63.7
Tri-County	45.2	61.6
Peace River	46.4	59.7
Clay	46.6	56.1
Sumter	46.8	55.0
Suwannee Valley	46.8	56.1
Central Florida	47.2	54.5
Withlacoochee	47.5	54.5
Talquin	47.5	55.2
Seminole	46.4	57.5

Exhibit ___ (TSW-14)
Witness: Woodbury
Docket No. 981827-EC

SCHEDULE C
TO WHOLESALE POWER CONTRACT

Wholesale Service Rate to Members
Rate Schedule - SECI-7a

I. AVAILABILITY

Available for electric service from the Seller to its Members.

II. APPLICABILITY

Wholesale service to Members for use, redistribution, and resale in accordance with the terms and conditions of the Wholesale Power Contract. This Rate Schedule shall apply to each Member. The Member's delivery points under this Rate Schedule are listed in Schedule B of the Wholesale Power Contract. The electric service at any such delivery point will be either the total requirements of the Member's electric system served from the delivery points under this Rate Schedule, or if applicable, partial requirements service which complements the Member's purchases of Interruptible Wholesale Service pursuant to the Seller's Rate Schedule INT under Schedule C of the Wholesale Power Contract and/or the Member's purchases from the Southeastern Power Administration.

III. CHARACTER OF SERVICE

The electric capacity and energy hereunder will be three-phase alternating current at a nominal frequency of sixty hertz.

IV. MONTHLY RATES AND CHARGES

The monthly charges to the Members shall be equal to the sum of the Base Charges, Power Factor Penalties and Transmission Facilities Use Charges.

(A) BASE CHARGES - Base Charges shall be equal to the sum of the Fixed Charges, the Non-Fuel Energy Charge, and the Fuel Charge.

FIXED CHARGES - Fixed Charges shall be equal to the sum of Production Charges and Transmission Charges.

Production - Production Charges shall be equal to the sum of the Production Demand Charge and the Production Fixed Energy Charge.

(1) Production Demand Charge (Applicable only during the months of January, February, March, June, July, August, September, and December):

1999 - $8.50 per kW
2000 - $7.50 per kW
2001 - $6.50 per kW

(2) Production Fixed Energy Charge shall be allocated to Members on an energy basis and calculated in accordance with the formula specified in Seller's Production Fixed Energy Charge Recovery Clause which is incorporated as part of this Rate Schedule as Appendix A.

Transmission - Transmission Charges which shall be applicable during all months, shall be equal to the sum of the Transmission Demand Charge and the Distribution Demand Surcharge.

(1) Transmission Demand Charge (applicable to all delivery points) - $1.59 per kW

(2) Distribution Demand Surcharge (applicable to delivery points below 69 kv) - $1.27 per kW

Issued by: Richard J. Midulla
Executive Vice President
and General Manager

Effective: January 1, 20[illegible]

NON-FUEL ENERGY CHARGE - $.00263 per kWh

FUEL CHARGE

The Fuel Charge shall be calculated in accordance with the formula specified in Seller's Fuel Charge Recovery Clause which is incorporated as a part of this Rate Schedule as Appendix B.

BILLING DETERMINANTS

(1) Monthly Billing Demand Determinants:

The Monthly Billing Demand Determinants is the Member's Aggregate Hourly Demand at the time of the Seller's peak demand during the calendar billing month, expressed in kW and rounded to the nearest kW. The Aggregate Hourly Demand for each clock hour of the calendar billing month is determined by the summation of the 60-minute kW demands, corresponding to each such clock hour, metered at each of the Member's delivery points. The Aggregate Hourly Demand for each clock hour shall, where applicable, be reduced by the amount of Southeastern Power Administration capacity, and/or the amount of Interruptible Wholesale Service under the Seller's Rate Schedule INT delivered to certain specified delivery points in each such clock hour during the calendar billing month.

(2) Monthly Energy Determinants:

The Monthly Energy Determinants, expressed in kWh and rounded to the nearest kWh, is determined by the summation of the energy associated with each hour's Aggregate Hourly Demand for all hours during the calendar billing month.

(3) Estimated Billing Determinants:

To the extent that any of the metering information required to determine the Monthly Billing Demand and Monthly Energy supplied during the billing month is not available at the time of billing, bills will be rendered using estimates of said billing determinants with such estimates being based upon all known pertinent facts. Differences between billings based on actual and estimated billing determinants shall be subsequently trued up, with interest accrued at the Seller's short term investment or cost of funds rate, whichever is applicable.

(B) POWER FACTOR

Power factor penalties incurred by the Seller under its contracts with other utilities as a result of a Member delivery point's failing to maintain a power factor at or above the applicable contractually required level, shall be billed to the Member receiving service at the delivery point on a direct pass-through basis as part of the bill for electric service provided hereunder. Seller shall be obligated to keep the Members apprised of the applicable contractual requirements which could affect power factor billings hereunder.

(C) TRANSMISSION FACILITIES USE CHARGE

A Transmission Facilities Use Charge as provided for in Seller's Transmission Policy No. 303 and Seller's Rate Policy No. 304 shall, if applicable be billed to the Member each month. In accordance with the terms and conditions described in said policies the charge shall be calculated in the manner prescribed in Appendix C which is incorporated as part of this Rate Schedule.

V. METERED READINGS AND BILLINGS

(A) PAYMENT OF BILLS

Bills for electric power and energy and for transmission facilities use services furnished hereunder shall be paid for at the office of the Seller within fifteen (15) days after the bill therefore is mailed to the Member. Bills not paid within such fifteen-day period shall be deemed delinquent and shall accrue interest at the Seller's monthly line of credit rate. The Board of Trustees of the Seller may, from time to time, establish terms and conditions under which (1) either Seller or Member makes payments of amounts owed hereunder in advance of the performance date provided for herein or (2) Seller offers the Member a premium on any billing credits owed hereunder from the Seller to the Member in consideration of such credits being applied by the Seller to billings subsequent to those provided for above. Said terms and conditions shall be specified in writing and provided to each of the Members of the Seller.

(B) METER READING AND TESTING

The Seller shall read meters monthly, or cause meters to be read monthly. In cases whereby the meter installation is made at a voltage different from the delivery point voltage designated in Schedule B of the Wholesale Power Contract, compensating devices, which automatically adjust meter readings to account for losses, shall be installed. The Seller shall test and calibrate meters, or shall cause such meters to be tested and calibrated, by comparison with accurate standards at intervals of twelve (12) months. The Seller shall also make or cause to be made special meter tests at any time at the Member's request. The costs of all tests shall be borne by the Seller; provided, however, that if any special meter test made at the Member's request shall disclose that the meters are recording accurately, the Member shall reimburse the Seller for the cost of such test. Meters registering not more than two percent (2%) above or below normal shall be deemed to be accurate. The readings of any meter which shall have been disclosed by test to be inaccurate shall be corrected for the thirty (30) days previous to such test in accordance with the percentage of inaccuracy found by such test. If any meter shall fail to register for any period, the Member and the Seller shall agree as to the amount of power and energy furnished during such period and the Seller shall render a bill therefore.

VI. TERMS AND CONDITIONS

Service hereunder is subject to all of the provisions of the Wholesale Power Contract between Seller and its Members, including all schedules, amendments, and supplemental agreements thereto in effect from time to time.

VII. SPECIAL PROVISIONS

In the event that the Member purchases power from a cogenerator or a small power producer (Qualifying Facility), the Seller may reallocate to the Member any costs that have not been avoided as a result of the Member's purchases from the Qualifying Facility. The criteria that a small power producer or a cogenerator must meet to achieve the status of a Qualifying Facility is defined by Section 201 of the Public Utility Regulatory Policies Act of 1978 and regulations adopted thereunder.

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RATE SCHEDULE C

APPENDIX A

Production Fixed Energy Charge Recovery Clause

The monthly Production Fixed Energy Charge shall be rounded to the nearest whole dollar and determined by use of the following formula:

PFE = ((PFC-PBR) X MEMALLOC) ÷ 12

where:

PFE = Member's monthly Production Fixed Energy Charge

PFC = Seller's production fixed costs projected for the applicable calendar year comprised of the following costs:

(i) Seller's total revenue requirements: less

(ii) Seller's transmission revenue requirements: less

(iii) Seller's Fuel costs: less

(iv) Seller's Non-fuel Energy costs.

PBR = Seller's Production Demand Charge revenues collected under this Rate Schedule projected for the applicable calendar year.

MEMALLOC = Portion of Production Fixed Energy Charge allocated to each Member based upon the Members' percentage share of actual Energy Determinants for the three calendar years ending with the year prior to the preceding calendar year. For example, for the year 1999 each Member's share of the total Production Fixed Energy Charge shall be based upon the total Energy Determinants for the years 1995 through 1997.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the Production Fixed Energy Charge in effect for the current calendar year.

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RATE SCHEDULE C

APPENDIX B

Fuel Charge Recovery Clause

The Fuel Charge shall be equal to the Fuel Rate applied to the Monthly Energy Determinants (kWh), plus the Monthly Trueup, if applicable.

FUEL RATE The Fuel Rate shall be determined by the use of the following formula:

$$FR = \frac{F_m}{S_m}$$

where:

FR = Applicable Fuel Rate rounded to the nearest one thousandth of a cent.

F_m = Shall be comprised of the following costs projected for the applicable calendar year.

(i) Fossil and nuclear fuel consumed in Seller-owned plants and the Seller share of fossil and nuclear fuel consumed in jointly-owned or leased plants; plus

(ii) fossil and nuclear fuel costs associated with replacement power, reserve purchases and load following, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iii) the net energy cost of economy energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transactions); plus

(iv) allowable fuel and/or purchased economic power costs associated with Seller's purchases of full and partial requirements wholesale power; plus

(v) gains, losses, and associated costs related to fuel price hedging transactions; plus

(vi) the avoided energy payments to Qualifying Facilities; less

(vii) the cost of fossil and nuclear fuel recovered through inter-system sales.

S_m = Sum of the Projected Energy Determinants for all Members for the applicable calendar year.

Appendix D, which is incorporated as part of this Rate Schedule, shall specify the projected Fuel Rate in effect for the current calendar year.

MONTHLY TRUEUP In addition, each Member shall be charged or credited a Monthly Fuel Trueup during the last four months of each subsequent six-month period by a dollar amount equal to the sum of the following:

(A) The dollar amount equal to the difference between the Fuel Charges based on actual fuel costs during the preceding six-month period and the Fuel Charges collected based upon projected fuel costs during the same preceding six-month period.

(B) Interest compounded monthly on the amount computed each month pursuant to Item A above, up to the end of such six-month period, at the Seller's short term investment or cost of funds rate, whichever is applicable, and

(C) Interest compounded monthly for the two months following such six-month period on the total amount included in Items A and B above at the Seller's short term investment or cost of funds rate, whichever is applicable, for the month succeeding the end of the six-month period.

The distribution of the dollar amounts as determined by the sum of paragraphs A, B and C above shall be billed or credited in equal amounts on billings for the last four months of each six-month period.

RATE SCHEDULE C

APPENDIX C

Components of
Transmission Facilities Use Charge

The Seller's Transmission Policy No. 303 and Rate Policy No. 304 specify that the costs for transmission facilities owned by the Seller and provided for the exclusive use and benefit of a single Member shall be borne by that Member. Costs of operation and maintenance are to be borne directly by the Member, whereas costs of ownership will be recovered by Seller from the benefiting Member through a Transmission Facilities Use Charge. Outlined below are those components of the Transmission Facilities Use Charge and how they are to be computed.

DEPRECIATION

For facilities constructed by Seller, depreciation will be calculated monthly based on original installed cost (including cost of capitalized renewals and replacements) of depreciable property relating to the transmission facilities used exclusively by a Member system and the depreciation rate prescribed in REA Bulletin 183-1, or revisions thereto. The date at which depreciation cost commences will be the date that the transmission facility is placed in service for its intended use by Seller for the benefiting Member, regardless of the date of closing of the construction work order.

For facilities purchased from a Member by Seller to be used exclusively by that Member, depreciation will commence as of the effective date of the transfer thereof and calculated according to the method previously described.

PROPERTY TAXES

For facilities constructed by Seller, for the exclusive use of a Member, property tax costs will be included in the Transmission Facilities Use Charge at such time that the facility qualifies as taxable property and becomes taxable to Seller. The cost will be based on the ratio of the net book value of taxable property comprising the transmission facility used exclusively by the benefiting Member to the total net book value of all taxable property owned by Seller in the county in which the facility is located, as of January 1 of each year. This ratio will be applied to the estimated tax bill for the county in which the facility is located as the basis for determining the estimated monthly charge. When the actual tax bill is received, appropriate adjustments will be made.

For facilities purchased from a Member by Seller for exclusive use by that Member, property taxes will be prorated as of the effective date of transfer. Taxes associated with the facility will be based on the ratio of the net book value of taxable property comprising the facility to the total net book value of taxable property owned by the Member in the county in which the facility is located. The taxes will be calculated by the method described for Seller-built facilities.

PROPERTY INSURANCE

Seller will carry property insurance for transmission facilities in accordance with its standard insurance purchasing practices. For built facilities, the cost will be based on the ratio of insured value of the facility to the total insured value of all property covered in the policy. This ratio will be applied to the total premium for the policy to determine the cost applicable to the facility; however, if the premium for the facility is specifically identified in the policy, this amount will be used in the Transmission Facilities Use Charge.

For facilities purchased by Seller from a Member system, Seller will obtain appropriate property insurance as of the effective date of the transfer thereof and include this amount in the Transmission Facilities Use Charge.

COST OF MONEY

For facilities constructed by Seller. the cost of money component will be included in the Transmission Facilities Use Charge as of the date of in-service of the facility. This cost will be determined by applying the cost of permanent financing or interim financing. if permanent not in place. for the facility to the net book value of the facilities used exclusively by the Member at the end of each month.

For facilities purchased by Seller from a Member system for exclusive use by the Member system. the cost of money component will be determined by the cost of debt assumed or Seller's cost of permanent financing or interim financing. if permanent not in place. used to finance the purchase of the facility.

Rate Schedule C

Appendix D

Monthly Production Fixed Energy Charge and Projected Fuel Rate

MONTHLY PRODUCTION FIXED ENERGY CHARGE

Pursuant to Appendix A of this Rate Schedule, the amounts provided below represent the Monthly Production Fixed Energy Charge for each member to become effective January 1, 2000 through December 31, 2000.

Member	Monthly Fixed Energy Charge
Central Florida Electric Cooperative, Inc.	$199,944
Clay Electric Cooperative, Inc.	$1,292,713
Glades Electric Cooperative, Inc.	$162,586
Lee County Electric Cooperative, Inc.	$1,454,369
Peace River Electric Cooperative, Inc.	$196,822
Sumter Electric Cooperative, Inc.	$822,435
Suwannee Valley Electric Cooperative, Inc.	$155,826
Talquin Electric Cooperative, Inc.	$431,468
Tri-County Electric Cooperative, Inc.	$97,329
Withlacoochee River Electric Cooperative, Inc.	$1,484,400
Total	$6,297,892

PROJECTED FUEL RATE

Pursuant to Appendix B of this Rate Schedule the projected Fuel Rate to become effective January 1, 2000 shall be $.01961 per kWh.

00009

Issued by: Richard J. Midulla
Executive Vice President
and General Manager

Effective: January 1,2000

Chairman Martin called on T. Woodbury to inform the committee of the status of the Board directed RFP for rate consulting services and to review the status of the Lee County complaint before the FPSC regarding Rate Schedule SECI-7. On September 21, a Request for Proposals (RFP) for Rate Consulting Services was issued. Burns & McDonnell has been retained, as the low bidder, to conduct a cost of service study and recommend wholesale rates for a flat fee of $34,600. Seminole staff has provided responses to the consultant's data requests and a meeting is scheduled, for the consultant to review the preliminary results of the cost of service study with Seminole staff, and the chairman and vice chairman of Rate Committee. The consultant's schedule provides that a draft report of the cost of service and wholesale rates will be provided by October 26, and a final presentation will be made to the Rate Committee during the December board meeting.

Ms. Novak was called on to discuss the member wholesale rate for the year 2000. Ms. Novak pointed out that, the existing SECI-7 rate would, if left unchanged, collect approximately $6.3 million more than was needed to recover the proposed budgeted revenue requirement for the year 2000. She stated that staff was recommending that the Board approve a new rate in order to eliminate this over-recovery, and that the rate be structured using the SECI-7 rate design methodology. In addition to this rate, Ms. Novak reviewed several other alternative rate structures that had been previously sent to each of the managers for review. All of these alternative rates were structured to recover the proposed budgeted revenue requirement for the year 2000. Mills per kWh rate comparisons by member for each of the rate options were reviewed with the Committee. After much discussion, a motion was made by E. Ricketson and duly seconded by W. Mulcay recommending the Seminole Board of Trustees approve a new rate schedule SECI-7A to take effect on January 1, 2000. The approved rate was designed using the SECI-7 rate methodology as recommended by staff. The motion passed on a vote of 5 to 3 with 1 abstention. The three members voting against were W. Phillips, T. Todd, and J. Martin with P. May abstaining.

Prior to adjourning the Committee returned to the question of the Seminole wholesale rate for 2000. There was a strong desire expressed by members of the Committee to try to work towards developing a rate for 2000 that would be acceptable to all members and that would eliminate pending litigation before the Florida Public Service Commission. The Committee agreed to meet again in early November to discuss the matter further. Staff was asked to develop two other specific rate proposals for the Committee's consideration.

A motion was made by B. Brown and duly seconded by T. Todd recommending the Seminole Board of Trustees delegate the authority to the Rate Committee to adopt an alternative rate structure to become effective January 1, 2000 prior to the next Board meeting if all members of the Committee are in accord. The motion carried unanimously. The Committee agreed that the prior motion approving the SECI-7A rate would stand as it was necessary to have a rate structure set to go into effect on January 1, in the event further discussions are unable to achieve unanimous agreement on an alternative rate structure.

Exhibit ___ (TSW-16)
Witness: Woodbury
Docket No. 981827-EC

RATE COMMITTEE MEETING MINUTES
SEMINOLE ELECTRIC COOPERATIVE, INC.
TALLAHASSEE, FLORIDA
WEDNESDAY, NOVEMBER 3, 1999
- AMENDED -

Ms. Novak reviewed the status of the cost of service work being conducted by Burns & McDonnell (B&M) concerning Seminole's wholesale rate. She reviewed a chronology of events that have taken place since B&M was retained. Ms. Novak then reviewed B&M's preliminary findings which were summarized in a report that was distributed to each of the Member Managers on October 29. She pointed out that pursuant to the wishes of the Rate Committee to obtain an independent perspective, staff had not provided B&M any guidance or direction during its study work. Ms. Novak discussed the specific features of B&M's cost of service study and the resulting rate design that it was proposing. She stated that B&M was recommending the "Equivalent Peaker Method" which has the affect of, among other things, assigning a portion of the fixed costs of base load resources to energy charges. She pointed out that B&M was proposing (i) a power supply demand charge of $4.52/kW/month with a 100% ratchet for billing purposes; (ii) a $1.58/kW/month transmission charge applied to Members' monthly non-coincident peak demands; (iii) an energy charge of 26.3 mills/kWh; and (iv) a customer charge of $6,449/delivery point/month. Ms. Novak indicated that staff was still reviewing the cost of service work to make sure that B&M had correctly interpreted the information that staff had previously provided to them. Ms. Novak distributed applicable billing determinants under the B&M recommended rate to each Member Manager.

The discussion then turned to whether or not to replace Rate Schedule SECI-7a which was adopted in October by the Board to take effect January 1, 2000. Ms. Novak reminded the committee that the Board had given the Rate Committee the authority to adopt a new rate schedule to replace SECI-7a, so long as it was done with unanimous approval. She then reviewed with the committee an overhead showing mills/kWh rate comparisons for the six alternative rate design options which had previously been provided to the Rate Committee.

After much discussion, a motion was made by G. Laughlin, and seconded by W. Phillips to adopt the "Case 2" alternative which is similar to Rate Schedule SECI-7a with the exception that it has an $8.50 per kW Production Demand Charge (versus $7.50/kW/mo.) with approximately $54 million (versus $76 million) designed to be recovered in the Production Fixed Energy Charge for the two-year period January 1, 2000 through December 31, 2001.

Prior to voting on the motion, there was additional discussion on two points. The first point concerned the implications of the settlement on the current complaint proceeding before the FPSC. The second was the need for a specified two year time period for the effectiveness of the rate.

With regard to the former issue, P. May indicated that LCEC wanted assurances that Seminole would not use the compromise year 2000 rate as a means of prejudicing LCEC's petition that the FPSC assert jurisdiction over Seminole's rate structure. No member of the committee expressed any concerns with providing LCEC with such assurances, and it was suggested that a joint stipulation to this affect could be prepared by the attorneys for both parties. During the course of the discussion, Ms. May asked if the committee would consider deferring a decision until after the next FPSC agenda conference. Certain committee members responded that they wished to get this issue behind them right away and a further delay would not be desirable.

With regard to the latter issue, several members expressed concern that there was no need to agree on a rate for longer than one year, and that the committee would revisit the rate structure at some point in the future if it chose to do so. G. Laughlin made a motion to amend his previous motion by (i) eliminating any reference to the two year effective period, and (ii) to clarify that this action was being done with the understanding that Seminole would agree to not seek to use Lee County's agreement to the compromise year 2000 rate as a basis of prejudicing Lee County's continued efforts to seek FPSC jurisdiction over Seminole's rate structure. The amended motion was seconded by W. Phillips. The motion passed unanimously.

Exhibit ___ (TSW-17)
Witness: Woodbury
Docket No. 981827-EC

RATE COMMITTEE MEETING MINUTES
SEMINOLE ELECTRIC COOPERATIVE, INC.
TAMPA, FLORIDA
WEDNESDAY, DECEMBER 8, 1999

In October, the Board of Trustees approved a motion providing the Rate Committee the authority to adopt a new Seminole wholesale rate schedule to replace the previously approved Rate Schedule SECI-7a to become effective January 1, 2000 as long as a unanimous decision could be made on such a new rate schedule. On November 3, the Rate Committee met and unanimously agreed upon a new rate for 2000. The new rate schedule has been designated as Rate Schedule SECI-7b. A motion was made by J. Duncan and duly seconded by T. Todd, to recommend that the Seminole Board of Trustees clarify that Rate Schedule SECI-7b will remain in effect until further action is taken by the Board of Trustees. The motion was approved with P. May voting against.

Burns & McDonnell then made a presentation on the final results of the independent cost of service study and rate design project that Seminole had retained it to conduct. Burns & McDonnell recommended what it called an "Equivalent Peaker Method" for developing rates for Seminole. This method assigns only a portion of the fixed cost of base load units to demand charges. The remaining fixed costs are assigned to energy charges. The amount of fixed costs assigned to demand charges is based on an assessment of what the fixed costs would have been had peaking units been built rather than base load generation. The consultant explained its rationale for such an approach and contrasted it against a "traditional" method - which assigns all fixed costs to demand charges, and an "energy method" - which assigns all fixed costs to energy. The Committee asked several questions of Burns & McDonnell and there was some discussion regarding the study effort. This agenda item was for information only, and no action was taken by the Committee.

President Rivenbark called on Jerry Martin for the Rate Committee Report. Mr. Martin reported the committee was advised that in October, the Board of Trustees approved a motion providing the Rate Committee the authority to adopt a new Seminole wholesale rate schedule to replace the previously approved Rate Schedule SECI-7a to become effective January 1, 2000 as long as a unanimous decision could be made on such a new rate schedule. On November 3, the Rate Committee met and unanimously agreed upon a new rate for 2000. The new rate schedule has been designated as Rate Schedule SECI-7b. *A motion was recommended by the Rate Committee to clarify that Rate Schedule SECI-7b will remain in effect until further action is taken by the Board of Trustees.* Upon a motion by J. Martin, seconded by W. Phillips, this motion was adopted with two no votes cast by C. Bostick and P. May.

The Rate Committee received a presentation from Burns & McDonnell on the final results of the independent cost of service study and rate design project that Seminole had retained it to conduct. Burns & McDonnell is recommending what it calls an "Equivalent Peaker Method" for developing rates for Seminole. This method assigns only a portion of the fixed cost of base load units to demand charges. The remaining fixed costs are assigned to energy charges. The amount of fixed costs assigned to demand charges is based on an assessment of what the fixed costs would have been had peaking units been built rather than base load generation. The consultant explained their rationale for such an approach and contrasted it against a "traditional" method - which assigns all fixed costs to demand charges, and an "energy method" - which assigns all fixed costs to energy.

Exhibit ___ (TSW-19)
Witness: Woodbury
Docket No. 981827-EC

SEMINOLE ELECTRIC COOPERATIVE, INC.

AVERAGE POWER COST VS. LOAD FACTOR

	Budget 2000	
	Average Power Cost (Mills/kWh)	Average Monthly Load Factor (%)
Glades	41.3	67.7
Tri-County	44.2	61.2
Lee County	44.3	61.1
Clay	44.6	58.3
Peace River	44.9	60.2
Central Florida	45.0	56.2
Suwannee Valley	45.7	57.1
Talquin	45.9	55.2
Sumter	46.3	52.7
Withlacoochee	47.2	51.9
Seminole	45.4	56.4

Exhibit ___ (TSW-20)
Witness: Woodbury
Docket No. 981827-EC

SEMINOLE ELECTRIC COOPERATIVE, INC. RATE STRUCTURE HISTORY			
SCHEDULE DESIGNATION	**DATE APPROVED**	**EFFECTIVE DATES**	**% OF FIXED COSTS RECOVERED IN DEMAND**
SECI-2	APR. '83	1/1/84 - 12/31/84	45% Estimate
SECI-3B	MAY '85	1/1/85 - 12/31/85	54.5%
SECI-4	OCT. '85	1/1/86 - 9/31/87	70%
SECI-5	OCT. '87	10/1/87 - 12/31/88	85%
SECI-6	OCT. '88	1/1/89 - 8/31/98	85%
SECI-7	10/08/98	1/1/99-12/31/99	81%
SECI-7b	11/3/99	1/1/00	81%