Law Offices HOLLAND & KNIGHT LLP

315 South Calhoun Street Suite 600 P.O. Drawer 810 (ZIP 32302-0810) Tallahassee, Florida 32301

850-224-7000 FAX 850-224-8832 www.hklaw.com

June 27, 2000

VIA HAND DELIVERY

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Blanca S. Bayo Director, Division of Records & Reporting Florida Public Service Commission Capital Circle Office Center 2540 Shumard Oak Boulevard Tallahassee, Florida 32399-0850

Re: <u>In Re: Complaint and petition by Lee County Electric Cooperative, Inc. For</u> <u>an investigation of the rate structure of Seminole Electric Cooperative,</u> <u>Inc.</u>, Docket No. 981827-EC

Dear Ms. Bayo:

On May 30, 2000, Lee County Electric Cooperative, Inc. ("LCEC") filed, under a Notice of Intent to Request Confidential Classification, exhibits to the Direct Testimony of William Steven Seelye identified as WSS-1, WSS-2, WSS-3, WSS-3, WSS-4 and WSS-5. LCEC filed that notice upon the request of counsel for Seminole who advised the undersigned that the exhibits may contain proprietary, confidential business information from the perspective of Seminole. On June 26, 2000, counsel for Seminole advised that the information contained in Mr. Seelye's exhibits is not confidential and can be made available publicly. Accordingly, enclosed for filing on behalf of LCEC are fifteen (15) copies of the exhibits to the Direct Testimony of William Steven Seelye.

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DOCUMENT NUMBER-DATE 07827 JUN 278 FPSC-RECORDS/REPORTING Blanca Bayo June 27, 2000 Page 2

For our records, please acknowledge your receipt of this filing on the enclosed copy of this letter. Thank you for your consideration.

Sincerely,

HOLLAND & KNIGHT LLP

Bruce May

DBM:kjg Enclosures

cc: William Cochran Keating David Wheeler Parties of Record

Exhibit _ - (WSS – 1) BURNS & McDONNELL COST OF SERVICE ANALYSIS

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Cost of Service Study and Wholesale Rate Design

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December 1999

Prepared for





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Seminole Electric Cooperative, Inc. Cost of Service & Rate Design Study

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EXECUTIVE SUMMARY

Exhibit_- (WSS-1)

INTRODUCTION

Seminole Electric Cooperative, Inc. (Seminole) has entered into an agreement with Burns & McDonnell to prepare a cost-of-service study and to recommend an appropriate rate structure for Seminole. As part of this agreement, dated September 21, 1999, Burns & McDonnell has completed an electric cost-of-service analysis and wholesale rate design for Seminole, a generation and transmission cooperative located in Tampa, Florida.

At Seminole's request, this is an independent, cost-based study in which Seminole staff has limited their involvement. Seminole or its member systems' strategic plans and long- and short-term objectives were not considered in the study. To further ensure an independent analysis, Seminole staff did not provide guidance or direction during the study, and they did not provide existing or prior wholesale rate schedules.

The primary objectives of this study are to perform an independent cost-of-service study for the Seminole system, where individual member cooperatives are considered as one customer class, and to recommend an appropriate wholesale rate structure for Seminole. This report contains a description of the results of the electric cost-of-service analysis and proposed wholesale rate for application to all Seminole members.

As the electric utility industry deregulates across the nation, Seminole should begin preparing itself for a more competitive business environment. While the effects that competition will have on the state of Florida are still not known, Seminole and its members systems should move to position themselves for an uncertain and competitive future.

COST-OF-SERVICE ANALYSIS

This analysis consisted of two primary steps: 1) development of the revenue requirement consistent with Seminole's year 2000 budget and 2) assignment of the various costs which make up the revenue requirement to unbundled functions.

Revenue Requirements

A cost-of-service study analyzes and identifies the revenue requirement for the fiscal year in which any revised rates would be implemented. The first step is to select a test year to be used in the development of revenue requirements. Since operating revenues and expenses of a utility generally vary on a seasonal basis, a 12-month period was used to capture the seasonal impacts on Seminole's financial results. Seminole has requested that Burns & McDonnell develop rates based on its budget for the year 2000. Given the advantages of using a future test year and the relationship of trust and accountability one would expect in a cooperative organization, this approach seems reasonable. Therefore, Seminole's budget for 2000 was used as the basis for identifying costs for this cost-of-service study.

Seminole provided budget information for the year that is summarized as Table ES-1. From this budget it can be seen that Utility Member Service Revenues are expected to be \$553,789,741. This amount represents the revenue requirements that must be recovered from the proposed wholesale rates and thus the cost of service for the member distribution cooperatives. Revenues from other sources result in a total Operating Revenue and Patronage Capital of \$568,221,117.

Rate Base

In addition to identifying all the costs for the test year, it is also necessary to define the rate base. The rate base represents the total investment required by Seminole to provide service to its member systems. It includes utility net of depreciation and an additional amount to recognize Seminole's investment in working capital to operate the system. The rate base is not truly a cost and is not added to the cost of service. Rather, it represents the investment needed to provide service and is used later to assign capitalrelated costs included in the year 2000 budget.

Cost Assignments

Having identified the costs to be included in the analysis, Burns & McDonnell turned to the next phase of the cost-of-service study, assigning costs to the appropriate utility functions. This phase is also known as the unbundling phase, in that total utility costs are broken out or unbundled by function. In this phase costs are assigned to the various functions or service that the utility provides. Breaking costs down into functions allows them to be used in rate design. Rates can then be designed to reflect how each customer or customer class uses the various functions or unbundled services of the utility. The unbundled costs for Seminole were summarized into the following major areas: 1) power supply – demand; 2) power supply – energy; 3) transmission; 4) consumer services; and 5) general.

The generation investment costs, i.e. depreciation, interest, patronage capital, etc., are a significant portion of the cost of service. How these costs are assigned can significantly impact the rate design process. Three different approaches were considered in the assignment of investment costs.

Executive Summary

Exhibit_- (WSS-1)

Table ES-1

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YEAR 2000 BUDGET

Seminole Electric Cooperative, Inc.

Item	Year 2000 Budget
Utility Member Service Revenues	\$ 553,789,741
Non-member Sales	8,006,085
Interruptible Sales	5,137 ,708
Martel Sales	62,80 6
Other Operating Revenues	1,224,777
Total Operating Revenue and Patronage Capital	\$ 568,221,117
Production Expense	\$243,299,011
Cost of Purchased Power	218,516,713
Transmission Expense - Operation	35,526,936
Transmission Expense - Maintenance	1,200,514
Administrative and General Expense	15,336,534
Total Operation & Maintenance Expense	\$513,879,708
Depreciation and Amortization Expense	\$25,581,072
Taxes	164,817
interest on Long-Term Debt	30,145,557
Other Deductions	3,818,880
Total Expenses	\$573,590,034
Patronage Capital or Operating Margins	(\$5,368,917)
Non Operating Margins - Interest	\$7,010,135
Gain on Disposition of Clean Air Allowances	100,000
Non Operating Margins - Other	493,662
Other Capital Credits and Patronage Dividends	100,000
Patronage Capital or Margins	\$2,334,880

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

An alternative approach to assigning power production costs, the "Energy" method, is to assign all baseload generation investment cost to power supply - energy. The reasoning behind this assignment method is that baseload units are developed to produce kilowatt-hours. Therefore the investment costs as well as the fuel and variable O&M cost should be recovered through an energy charge (investment costs of peaking units under this methodology are normally assigned to the power supply - demand function).

The recommended approach, the "Equivalent Peaker" method of assigning investment costs, is based on the type of generation resource and not whether the costs are fixed or variable. Peaking units are installed to provide capacity and the investment costs associated with this type of generation are assigned to the power supply - demand function. On the other hand, a baseload resource is installed to provide capacity, but also low-cost energy. Therefore, the investment cost for these units should be assigned to both the power supply - energy and power supply - demand function. Only that portion of the investment cost that would have been incurred with the peaking unit is assigned to the power supply - demand function, thus the term equivalent peaker method. The remaining investment costs are more appropriately assigned to the power supply - energy function.

The budget costs identified in Table ES-1 were assigned to the utility functions and sub-functions. Results of all three methods are compared on Table ES-2. In addition to the rate base assignments discussed above, several assignment methodologies were used for other costs. These included the use of a cost-of-service ratio, payroll ratio and total utility plant ratio. These ratios were developed by adding the costs assigned to each of the functional categories and then dividing by the total cost. In other cases, costs were directly assigned to specific functions.

Unbundling the costs of providing electricity to the distribution cooperatives will give Seminole a clearer picture of the source of their costs. It is important for Seminole to remain aware of the opportunities and consequences of deregulation in other states and in Florida as they relate to its electric system. Examining and understanding the detailed costs of delivering power through its transmission system will aid Seminole in its management of competition. With the nationwide movement toward deregulation, and the challenges undertaken by Seminole to b' the future provider of choice, it will be important for

COMPARISON OF YEAR 2000 BUDGET ASSIGNMENT

Seminole Electric Cooperative, Inc.

Assignment Method	Year 2000 Budget	kW	КМН	ACC	T-KW	CONS	GENL
TRADITIONAL	\$553,789,741	\$211,041,972	\$290,308,500	\$33,596,446	\$13,330,013	\$1,476,741	\$4,036,067
EQUIVALENT PEAKER	\$553,789,741	\$171,056,692	\$330,293,781	\$33,596,446	\$13,330,013	\$1,476,741	\$4,036,067
ENERGY	\$553,789,741	\$136,967,004	\$364,383,468	\$33,596,446	\$13,330,013	\$1,476,741	\$4,036,067

Executive Summary

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Seminole to know the unbundled cost of service in order to realize its efficiency in each separate unbundled category. In preparation for changes in the industry, the proprietary cost-of-service model developed by Burns & McDonnell was designed to support the development of unbundled service rates.

Cost Allocation

Generally, the next step in a cost-of-service study is to allocate the unbundled costs to the appropriate customer classes. In this part of a study, costs are allocated based on various classes use of different services, i.e., kWh, kW, meters, etc. For this study, Seminole requested that all member distribution systems be considered as one class. To the extent that all member cooperatives receive the same level of service, this is an appropriate approach. Actual allocation between the various member systems then becomes covered in the actual rate design.

The unbundled costs listed on Table ES-2 (for the "Equivalent Peaker" method) were subsequently summarized into the following major areas:

- Power supply energy Power supply energy costs are expected to vary directly with the production or purchase of energy measured in kilowatt-hours (kWh). The power supply energy portion of Seminole's budgeted costs totaled \$330,293,781. Power supply energy costs included Seminole's expenditures associated with electricity generation and purchases. Power supply energy costs were defined as the costs incurred to meet the energy needs of the consumers and consisted primarily of fuel costs and variable generation operation and maintenance (O&M) costs.
- Power supply demand Power supply demand costs are expected to vary directly with the capacity installed or purchased to meet the demand requirements of Seminole's system measured in kilowatts (kW). The power supply - demand portion of Seminole's budgeted costs totaled \$171,056,692. Power supply - demand costs were defined as the costs incurred to meet the peak demand needs of the customers and included Seminole's expenditures associated with electricity generation and purchases. These costs consisted primarily of the equivalent peaker portion of investment costs for Seminole's generation resources, fixed generation O&M costs, and demand-related purchased power costs.
- Transmission Transmission costs are expected to vary directly with the transmission capacity installed or purchased to meet the transmission cemand requirements of Seminole's

system measured in kilowatts (kW). The transmission demand portion of Seminole's budgeted costs totaled \$46,926,459. Transmission demand costs were defined as the costs incurred to transmit the peak demands of Seminole's customers and consisted primarily of transmission facilities and operating expenses.

- Consumer Consumer costs for the Seminole system totaled \$1,476,741. Consumer service costs included expenditures that are directly related to providing member services to Seminole's ten distribution cooperatives.
- General General costs totaled \$4,036,067. These general costs are necessary to support all
 of the above functions of the utility. For this reason, the general costs wre broken down into
 sub-functions in proportion of the subtotal of the costs for power supply energy, power
 supply demand, transmission, and consumer costs.

RATE DESIGN

Burns & McDonnell used the cost-of-service study results that were based on the equivalent peaker method of assigning costs to design the proposed wholesale rates. The costs were combined into three major categories: commodity, capacity, and customer costs. These costs are summarized on Table ES-3. Commodity costs included the power supply – energy costs. Capacity costs included the power supply – demand and transmission costs. Customer costs included the consumer costs. General costs were included in each category based on the sub-function breakdown. The three major categories of costs provided the basis for developing three separate charges to recover revenues from the member distribution cooperatives on a cost basis.

Having determined the costs to be collected, the next task in designing wholesale rates was to identify the billing units that would be applied to the resulting rates. Table ES-4 summarizes the billing units that were selected for recovering each of the three cost categories.

Proposed Rates

Having defined the costs and the billing units, developing the proposed rates basically became a matter of dividing costs by billing units. The proposed cost-based rates for Seminole's member systems are summarized in Table ES-5. The commodity charge of 2.73 cents per kilowatt-hour is applied to all energy sales. The capacity charge is applied to the members' contribution to Seminole's monthly peak. The actual rate was developed by dividing the sum of monthly capacity costs by the sum of Seminole's

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Table ES-3

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COST TO BE RECOVERED THROUGH WHOLESALE RATES Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Category	Cost
Commodity	\$332,718,663
Capacity	219,583,495
Customer	1,487,583
Total Cost of Service	\$553,789,741

Seminole Electric Cooperative, Inc. Cost-of-Service & Rate Design Study

ES-9

Table ES-4

BILLING UNITS Seminole Electric Cooperative, Inc.

Units	Florida	Clay	Glades	Lee County	Peace River	Sumter
kWh Purchased	401,047,636	2,522,169,887	325,643,638	2,671,165,760	387,811,955	1,658,790,641
Sum of Monthly Coincident Peaks (kW)	973 .9 41	5,908,709	657,585	5,966,874	880,499	4,304,641
Customer	1	1	1	1	· 1	1
			· .			

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Total
kWh Purchased	302,701,398	856,509,058	185,508,871	2,882,7 94 ,637	12,1 94,143,4 81
Sum of Monthly Coincident Peaks (kW)	74,856	231,021	42,104	838,935	19,879,165
Customer	1	1	1	· 1	10

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Executive Summary

Table ES-5

PROPOSED WHOLESALE RATES

Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Commodity

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2.73 cents per kWh

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Capacity \$7.43 kW per month Monthly member contribution to SECI peak.

Customer Charge

\$12,397 per member

monthly peak demand and then dividing this result by 12. Since the billing units used to determine this rate were the sum of the 12 months' demands, no ratchet is included in this rate. Finally, the customer charge is a monthly charge assessed to each member system.

Exhibit (S-1)

Rates Under Alternate Assignment Methodologies

To provide an indication of how assigning the investment costs of baseload generation would affect the rates, rates were also calculated using the traditional and energy methods. Table ES-6 was included to compare the effect of using different assignment methods on each of the member systems. The average cost of service, expressed in cents per kilowatt-hour, was calculated for each member cooperative using each of the three assignment methods.

CONCLUSIONS AND RECOMMENDATIONS

This study was based on information provided by Seminole, including the 2000 budget numbers, and other sources. The information was also used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. These assumptions provided the basis for this cost-of-service and rate design study.

Important assumptions made in performing the cost-of-service study and rate design are that:

- 1. energy and demand will be as forecast for Seminole and its members;
- 2. costs will be as budgeted by Seminole; and
- 3. all member cooperatives will be considered as one customer class.

Conclusions

Based on the cost-of-service study and rate design, Burns & McDonnell concludes that:

- 1. Seminole will need to meet a load of 37,907 MW and produce 12,194,143,000 kWh for its members in 2000.
- 2. The total cost of service for Seminole to provide service to its ten member distribution systems in the year 2000, will be \$553,789,741;

Table ES-6

COMPARISON OF COST TO MEMBER SYSTEMS WITH DIFFERENT ASSIGNMENT METHODS Seminole Electric Cooperative, Inc.

(cents/kWh)

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter	
TRADITIONAL	4.57	4.47	4.22	4.37	4.43	4.69	
EQUIVALENT PEAKER	4.57	4.48	4.28	4.39	4.45	4.67	
ENERGY	4.57	4.49	4.32	4.42	4.47	4.65	

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Average
TRADITIONAL	4.55	4.60	4.44	4.72	\$4.54
EQUIVALENT PEAKER	4.56	4.59	4.47	4.69	\$4.54
ENERGY	4.56	4.58	4.49	4.67	\$4.54

Burns & McDonnell

Executive Summary

- 3. This total cost of service can be assigned to the major utility functions using the equivalent peaker method to:
 - Commodity costs \$332,718,663;
 - Capacity costs \$219,583,495; and
 - Consumer cost \$1,487,583.
- 4. Using the traditional method of assigning costs transfers \$40,278,836 from power supply energy to power supply demand. The total cost of service can be assigned to the major utility functions using the traditional method to:
 - Commodity costs \$292,439,827;
 - Capacity costs \$259,862,331; and
 - Consumer cost \$1,487,583.
- 5. Using the energy method of assigning costs transfers \$34,339,960 from power supply demand to power supply energy. The total cost of service for Seminole in the year 2000 using the energy method consists of:
 - Commodity costs \$367,058,623;
 - Capacity costs \$185,243,535; and
 - Consumer cost \$1,487,583.
- 6. The following rates (based on the equivalent peaker method of assigning costs) are cost-based and can provide the basis for designing wholesale rates for Seminole's ten members systems:
 - Commodity 2.73 cents per kWh
 - Capacity \$7.43 kW per month.
 - Customer \$12,397 per member

Recommendations

Based on conclusions as stated above, it is recommended that:

- 1. The equivalent peaker method be used for the assignment of costs;
- 2. Assignments based on the equivalent peaker method be the basis for developing final rates;
- 3. Seminole compare the cost-based rates with Seminole's existing rates to consider rate stability;
- 4. Seminole compare the cost-based rates with its strategic plans and other long- and short-term goals;
- 5. Seminole modify the rates, if necessary, after making comparisons with existing rates and Seminole and member goals;
- 6. Seminole implement the rate among its member systems;
- 7. Seminole's cost of service be re-evaluated regularly to ensure full cost recovery;
- 8. Seminole continue to review the effectiveness of its rates, especially if changes in member status or the electric utility occur;
- 9. Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry; and
- 10. Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry and consider investigating the appropriateness of rate concepts in the future including time-of-use rates, performance-based rates and accelerated recovery of investments.

PART I - INTRODUCTION

Exhibit_- (WSS-1)

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Exhibit_- (WSS-1)

PART I

Seminole Electric Cooperative, Inc. (Seminole) has entered into an agreement with Burns & McDonnell to prepare a wholesale cost-of-service study for the Seminole system and to develop a wholesale rate for application to all Seminole members. As part of this agreement, dated September 21, 1999, Burns & McDonnell has completed an electric cost-of-service analysis and wholesale rate design for Seminole Electric Cooperative, Inc., a generation and transmission cooperative located in Tampa, Florida.

At Seminole's request, this is an independent, cost-based study in which Seminole staff has limited their involvement. Seminole's or its members' strategic plans and long- and short-term objectives were not considered in this study. To further ensure an independent analysis, Seminole staff did not provide guidance or direction to Burns & McDonnell, nor did they provide existing or prior wholesale rate schedules.

This report contains a description of the results of the electric cost-of-service analysis and rate design performed for Seminole. The primary objectives of this study were:

- to determine the revenue required to meet all operating and capital costs consistent with Seminole's 2000 budget;
- to perform a cost-of-service study for the Seminole system where individual member systems are considered one customer class; and
- to develop a wholesale rate for application to all Seminole members.

The electric utility industry has undergone substantial changes in moving toward a more competitive business environment. The potential impacts of the impending deregulation of the electric industry are becoming clearer. While the effects that competition will have on Seminole are still not completely known, Seminole and its members should move to position itself for an uncertain and competitive future.

As the electric utility industry deregulates, utilities and suppliers must have competitive rates. In response to this changing environment, Seminole should have a clear understanding of its current cost structure. This cost-of-service analysis will provide Seminole with information to continue addressing this changing environment. The knowledge gained from the cost-of-service analysis will result in a rate

Part I

design that will allow Seminole to effectively recover its costs based on the assumptions made, including the projections in Seminole's 2000 budget.

SEMINOLE ELECTRIC COOPERATIVE, INC.

Seminole is a generation and transmission cooperative system with headquarters located in Tampa, Florida. Seminole provides wholesale electric service to ten member distribution cooperatives:

- Central Florida Electric Cooperative
- Clay Electric Cooperative
- Glades Electric Cooperative
- Lee County Electric Cooperative
- Peace River Electric Cooperative
- Sumter Electric Cooperative
- Suwannee Valley Electric Cooperative
- Talquin Electric Cooperative
- Tri-County Electric Cooperative
- Withlacoochee River Electric Cooperative

Seminole's primary generating facility, the Palatka generating station, is located on the St. Johns River in Putman County and consists of two 625 megawatt coal-fired units. Seminole also owns 14.4 megawatts of Florida Power Corporation's Crystal River 3 nuclear plant and approximately 345 miles of transmission line. While Seminole's primary source of electric power purchases is provided through a long-term agreement with an independent power producer, Seminole also has contracts with other Florida utilities.

METHOD OF ANALYSIS

The cost-of-service analysis performed by Burns & McDonnell first consisted of the determination of Seminole's revenue requirement for the year 2000. This determination was made by use of Burns & McDonnell's "Unbundle" model using data from Seminole's 2000 operating budget. Then the various costs that make up the revenue requirement were assigned to electric utility functions (i.e., power production, transmission, and consumer). The functionalized costs were classified as being either demand-related, energy-related, transmission-related, consumer-related or some combination of these

four. The ten member cooperatives in the Seminole system were treated as one customer class for the purposes of this study. The resulting cost of service provided the basis for the design of the proposed wholesale rate that resulted in a cost-based wholesale rate for all members.

Seminole's financial and accounting data, provided as input for the analysis, closely followed the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts for electric utilities. The FERC USOA captures expense data on a functional cost basis as unique accounts are categorized as production, transmission, or administration expenses. This organization of accounting data is important in a cost-of-service analysis for functionalizing costs, as well as assigning these costs to power supply - demand, power supply - energy, transmission or consumer services.

Part II of this report discusses the cost-of-service study including the determination of the revenue required from the distribution cooperatives. Results are shown at various stages in the analysis and are explained in detail in this section. The assignment of costs in the cost-of-service study performed for Seminole is based on an "equivalent peaker" methodology. Results are also shown for two other methods so that the reader can compare the equivalent peaker method to other alternative methodologies.

Part III discusses the rate design for Seminole developed with their member systems treated as one customer class. Results for two other methodologies are also shown here for comparison to alternative methodologies.

Part IV summarizes this report and provides conclusions and recommendations regarding the cost of service and recommended rate structure.

SOURCES OF DATA

Seminole's staff and management provided data for the cost-of-service study. This data included computer-generated reports, financial and statistical information, financial reports, and other documents such as power bills, debt service schedules, trial balances, and RUS Form 12 data. The data for the year 2000 provided by Seminole reflected the projected levels of expenses, sales, and revenues from the 2000 operating budget.

Burns & McDonnell used the information provided by Seminole and other sources to make certain assumptions with respect to conditions that may exist in the future. While we believe the assumptions made are reasonable for the purposes of this report, we make no representation that the conditions assumed will, in fact, occur. In addition, while we have no reason to believe that the information provided to us by Seminole and other parties is inaccurate in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to us, the actual results will vary from those projected.

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PART II – COST-OF

PART II - COST-OF-SERVICE STUDY



Exhibit_- (WSS-1)

PART II COST-OF-SERVICE ANALYSIS

OVERVIEW

This part of the report describes the data, methodology, and results of the wholesale cost-of-service analysis performed by Burns & McDonnell for Seminole Electric Cooperative Inc. Seminole has requested that Burns & McDonnell develop rates that were based solely on the cost of service. To complete this assignment, a cost-of-service study needed to be completed. In an electric utility there are many costs that are shared or common to more than one consumer. For this reason, a detailed study is necessary to determine the cost of providing service to each of Seminole's ten member distribution cooperatives.

In determining the cost of service, it is necessary to make a number of subjective decisions as to how to account for various costs. Obviously, these are decisions that affect the results of the cost of service and the subsequent rate design. In this report we have laid out in detail not only the information from which the cost of service was calculated, but also the methodology and assumptions used in developing the unbundled cost of service. With a better understanding of the methodology and assumptions, the reader will better appreciate the results of this study.

Completing a cost-of-service study involves several phases. These include identifying the costs necessary to provide service, assigning or unbundling these utility costs to functions provided by Seminole and summarizing the results in a succinct and meaningful manner. This part of the report has been written to follow the methodology outlined above and describes in detail the procedure used to identify, define, assign, and summarize Seminole's costs of providing wholesale electric power to its member distribution systems.

In performing this study, Burns & McDonnell made use of Unbundle, its proprietary cost-of-service model, to assign costs. A complete copy of the output from the model is included as Appendix A to this report. Significant intermediary and final results have been extracted from the model and are included as tables in the body of this report.

In addition to providing the basis for wholesale rates, a thorough cost-of-service study will provide other benefits to Seminole. It will provide unbundled cost data that will be of value to Seminole as it prepares

Part II

for deregulation. Unbundled cost information will help Seminole evaluate its ability to provide specific unbundled utility services in a deregulated market. Detailed cost breakdowns will also provide additional information to Seminole to help manage and operate its system.

REVENUE REQUIREMENT

Identifying all of the costs necessary to operate Seminole's electric system provides the foundation for the cost-of-service study and ultimately the final wholesale rate design recommendation. Simply stated, rates must be designed to collect *all* of the costs of operating an electric utility. These costs include operating costs, depreciation, interest, taxes and margins. In addition, other costs and revenue sources such as sales to non-members, non-operating margins, capital credits, etc. must be accounted for. In defining costs, the costs of operating the system for a complete 12-month period are used. A full year of cost information is necessary to recognize the seasonal variation of costs in operating an electric utility. For this reason, the first step in defining costs is to define a test year.

Test Year

Although there are a variety of ways to develop a test year, generally speaking test years can be broken into historical test years and future test years. Most other forms of test years are basically combinations of actual and projected cost information. Both historical and future test years offer advantages and disadvantages.

An historical test year method uses data developed from historical accounting and operating records. The advantage to using an historical test year is that the cost actually did occur and the data in the cost-ofservice study can be verified by others such as regulators or intervenors. If an historical test year were to be used at this point, Burns & McDonnell would most likely need to look back to 1998, the most recent year for which audited financial information is available. This would result in developing rates that would be based on information that would be over two years old at the time that rates were actually implemented.

Using a future test year allows the analyst to design rates based on costs that are expected to be incurred during the period in which the rates are initially in effect. If reliable budgets are available, this approach produces rates that have a higher probability of producing the desired results. This approach is also useful when future conditions are expected to change or differ from actual historical year data.
Seminole has requested that Burns & McDonnell develop rates based on its budget for the year 2000. Given the advantages of using a future test year and the relationship of trust and accountability one would expect in a cooperative organization, this approach seems reasonable. In addition, Seminole's projected budgets have historically been very close to year-end actual costs. Therefore, Seminole's budget for 2000 was used as the basis for identifying costs for this cost-of-service study.

Year 2000 Budget

Seminole provided budget information for the year that is summarized as Table II-1. From this budget it can be seen that Utility Member Service Revenues are expected to be \$553,789,741. This amount represents the revenue requirements that must be recovered from the proposed wholesale rates and thus the cost of service for the member distribution cooperatives. Revenues from other sources result in a total Operating Revenue and Patronage Capital of \$568,221,117.

The cost of operating the Seminole system consists of operation & maintenance expense, depreciation & amortization expense, and other deductions. These costs total \$573,590,034. To account for all costs of serving member systems, margins and capital credits and interest on long-term debt must be added and non-operating margins and other revenues must be subtracted. The budget was restated on Table II-2 to show how this cost build-up produced the total cost of service (\$553,789,741) equal to the Utility Member Service Revenues. This table also shows a more detailed breakdown of the costs.

Production Expenses and Cost of Purchased Power were the two largest operating and maintenance expenses and together accounted for over \$461 million or nearly 90 percent of the \$514 million in Total Operation & Maintenance Expense. Transmission Operation & Maintenance Expenses accounted for approximately seven percent of the total Operations & Maintenance expenses with Administrative and General expenses accounting for approximately three percent. Depreciation was budgeted to exceed \$25 million and Interest on Long Term Debt to exceed \$30 million. Taxes and Other Deductions are expected to total less than \$4 million.

The most significant of other Non-Operating Margins is interest of slightly over \$7 million. Other Revenues are budgeted to exceed \$14 million. The total of Other Revenues and Non-Operating Margins is budgeted to be \$22 million.

Exhibit_- (WSS-1)

Table II-1

YEAR 2000 BUDGET Seminole Electric Cooperative, Inc.

Utility Member Service Revenues\$ 553,789,741Non-member Sales8,006,085Interruptible Sales5,137,708Martel Sales62,806Other Operating Revenues1,224,777Total Operating Revenue and Patronage Capital\$ 568,221,117Production Expense\$243,299,011Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense\$513,879,708Depreciation and Amortization Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	item	Year 2000 Budget
Non-member Sales8,006,085Interruptible Sales5,137,708Martel Sales62,806Other Operating Revenues1,224,777Total Operating Revenue and Patronage Capital\$568,221,117Production Expense\$243,299,011Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense\$513,879,708Depreciation and Amortization Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Utility Member Service Revenues	\$ 553,789,741
Interruptible Sales5,137,708Martel Sales62,806Other Operating Revenues1,224,777Total Operating Revenue and Patronage Capital\$568,221,117Production Expense\$243,299,011Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Non-member Sales	8,006,085
Martel Sales62,806Other Operating Revenues1,224,777Total Operating Revenue and Patronage Capital\$568,221,117Production Expense\$243,299,011Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Interruptible Sales	5,137,708
Other Operating Revenues1,224,777Total Operating Revenue and Patronage Capital\$568,221,117Production Expense\$243,299,011Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins\$7,010,135Gain on Disposition of Clean Air Allowances\$7,010,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends\$2,334,880	Martel Sales	62,806
Total Operating Revenue and Patronage Capital\$568,221,117Production Expense\$243,299,011Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends\$2,334,880	Other Operating Revenues	1,224,777
Production Expense\$243,299,011Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Total Operating Revenue and Patronage Capital	\$ 568,221,117
Cost of Purchased Power218,516,713Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Production Expense	\$243,299,011
Transmission Expense - Operation35,526,936Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Cost of Purchased Power	218,516,713
Transmission Expense - Maintenance1,200,514Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends\$2,334,880	Transmission Expense - Operation	35,526,936
Administrative and General Expense15,336,534Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends\$2,334,880Patronage Capital or Margins\$2,334,880	Transmission Expense - Maintenance	1,200,514
Total Operation & Maintenance Expense\$513,879,708Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Administrative and General Expense	15,336,534
Depreciation and Amortization Expense\$25,581,072Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Total Operation & Maintenance Expense	\$513,879,708
Taxes164,817Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Depreciation and Amortization Expense	\$25,581,072
Interest on Long-Term Debt30,145,557Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Taxes	164,817
Other Deductions3,818,880Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Interest on Long-Term Debt	30,145,557
Total Expenses\$573,590,034Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Other Deductions	3,818,880
Patronage Capital or Operating Margins(\$5,368,917)Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Total Expenses	\$573,590,034
Non Operating Margins - Interest\$7,010,135Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Patronage Capital or Operating Margins	(\$5,368,917)
Gain on Disposition of Clean Air Allowances100,000Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Non Operating Margins - Interest	\$7,010,135
Non Operating Margins - Other493,662Other Capital Credits and Patronage Dividends100,000Patronage Capital or Margins\$2,334,880	Gain on Disposition of Clean Air Allowances	100,000
Other Capital Credits and Patronage Dividends 100,000 Patronage Capital or Margins \$2,334,880	Non Operating Margins - Other	493,662
Patronage Capital or Margins \$2,334,880	Other Capital Credits and Patronage Dividends	100,000
	Patronage Capital or Margins	\$2,334,880

Exhibit_- (WSS-1)

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DETAILED COST BREAKDOWN

Seminole Electric Cooperative, Inc.

		rear
		2000
Acct #	Account Name	Budget

	PRODUCTION EXPENSES	
500	Operations Supervision And Engineering	\$2,681,634
501	Fuel Expense	162,184,362
502	Steam Expenses	7,720,824
505	Electric Expenses	1,694,210
506	Misc Steam Power Expenses	10,557,901
507	Power Plant Rents	28,641,657
510	Maintenance Supervision and Engineering	5,428,515
511	Maintenance of Structures	349,878
512	Maintenance of Power Plant	14,443,520
513	Maintenance of Electric Plant	1,105,936
514	Maintenance of Misc. Steam Plant	5,554,701
518	Nuclear Fuel Expense	648,000
528	Maintenance Supervision and Engineering	2,287,873
	COST OF PURCHASED POWER	
555	Purchased Power	\$216,750,478
556	System Control and Load Dispatch	1,717,774
557	Other Power Supply Expenses	48,461
	TRANSMISSION EXPENSE - OPERATIONS	······
560	Operations Supervision And Engineering	\$177,341
562	Station Expenses	9,604
565	Transmission of Electricity by Others	34,051,675
566	Miscellaneous Transmission Expense	1,285,816
567	Rents	2,500
	TRANSMISSION EXPENSE - MAINTENANCE	
570	Maintenance of Station Equipment	\$1,195,105
571	Maintenance of Overhead Lines	5,409
	ADMINISTRATIVE AND GENERAL EXPENSE	
920	Administrative & General Salaries	\$10,805,074
921	Office Supplies And Expense	2.276.213
922	Administrative Expenses Transferred - Credit	(1.007.800)
923	Outside Services Employed	1.666.460
924	Property Insurance	35,944
925	Injuries And Damages	39.607
926	Employee Pensions and Benefits	58.306
930	General Advertising and Miscellaneous General Expenses	1,342.030
932	Maintenance Of General Plant	120,700
	TOTAL OPERATION AND MAINTENANCE EXPENSE	\$513,879,708

Exhibit_- (WSS-1)

DETAILED COST BREAKDOWN Seminole Electric Cooperative, Inc.

Year 2000 Budget Account Name Acct # DEPRECIATION AND AMORTIZATION EXPENSE \$18,223,995 Steam Production Plant 403.1 1.061.449 403.2 Nuclear Production Plant 403.5 Transmission Plant 3,854,282 General Plant 953,646 403.7 **Depreciation Transferred** (23, 785)990 404 Amortization Leasehold Improvements 1,205,605 405 Miscellaneous Depreciation/Amortization 288.624 406 Amortization Electric Plant Acquisition 17,256 TAXES \$8,618,067 408.1 **Property Taxes** 24,186 408.2 **Payroll Taxes** 408.3 Payroll Taxes 1,731,795 15,116 408.4 **Payroll Taxes** 408.7 Taxes, Other (12, 282)(10,212,065) 990.0 Overhead Allocation and Taxes Transferred OTHER DEDUCTIONS 425 Miscellaneous Depreciation/Amortization \$72 426 Donations 38,120 Amortization of Debt Discount and Expense 428 3,780,688 TOTAL OPERATING EXPENSE \$543,444,477 **REQUIRED MARGINS & PATRONAGE CAPITAL REQUIRED MARGINS & PATRONAGE CAPITAL** \$2,334,880 NON-OPERATING MARGINS 419 Non-Operating Margins - Interest (\$7,010,135) 411 Gain on Disposition of Clean Air Allowances (100.000)421 Non-Operating Margins - Other (493.662)424 Other Capital Credits and Patronage Dividends (100.000)INTEREST ON LONG-TERM DEBT 427.0 Interest on Long-Term Debt \$30,145,557 OTHER REVENUES Interruptible Sales (\$5,137,708) Non-Member Sales (8,006,085) Martel Sales (62, 806)456 Other Electric Revenues (1,224,777)TOTAL COST OF SERVICE \$553,789,741

Rate Base

Exhibit_- (WSS-1)

In addition to identifying all the costs for the test year, it is also necessary to define the rate base. The rate base represents the total investment required by Seminole to provide service to its member systems. It includes utility net of depreciation and an additional amount to recognize Seminole's investment in working capital to operate the system. Table II-3 summarizes the rate base for Seminole. The actual rate base numbers shown are not truly cost of service and are not added to the cost of service. Rather, they represent the investment needed to provide service and are used later to assign capital-related costs included in the year 2000 budget.

As shown on Table II-3, total utility plant net of depreciation is \$489 million. This amount is based on a projected balance sheet for December 31, 2000, the end of the test year. Although this information is "projected" it provides a good indication of the relative investment and plant equipment. Since these dollars will not be directly recovered, but rather used as the basis for assigning patronage capital cost, they are appropriate for use in this study. Working capital is expected to be \$56 million. This represents 15 days of power production and purchase power expense, 45 days of other operating expenses, and approximately \$30 million in materials, supplies, and prepayments.

COST ASSIGNMENT

Having identified the costs to be included in the analysis, Burns & McDonnell turned to the next phase of the cost-of-service study, assigning costs to the appropriate utility functions. This phase is also known as the unbundling phase, in that total utility costs are broken out or unbundled by function. In this phase costs are assigned to the various functions or services that the utility provides. Breaking costs down into functions allows them to be used in rate design. Rates can then be designed to reflect how each customer or customer class uses the various functions or unbundled services of the utility.

Table II-4 lists the four major functions and associated sub-functions used in the cost-of-service study for Seminole. Also listed are the codes shown for each of the sub-functions. These codes are shown on a variety of tables and are provided to assist the reader in understanding how costs were tracked. The specific major functions were:

- Power Supply
- Transmission
- Consumer
- General

Exhibit_- (WSS-1)

Table II-3

RATE BASE SUMMARY

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Seminole Electric Cooperative, Inc.

Accour	lt i i i i i i i i i i i i i i i i i i i	` Year 2000
Numbe	r Hem	Budget
301-303	Total Intancible Blent	RE 770 220
310-316	Total Production Plant - Steam	873 348 020
320-325	Total Production Plant - Nuclear	22 208 484
42.4 .423	Total Production Plant	5701 434 633
		4
350	Land and Land Rights	\$16,406,249
352	Structures and Improvements	-
353	Station Equipment	
354-359	Other Transmission Plant	140,203,133
	Total Transmission Plant	\$156,609,382
389	Land and Land Rights	\$798,157
391	Office Furniture & Equipment	1.597.554
392	Transportation Equipment	748.182
397	Communication Equipment	5.649.731
398	Miscellaneous Equipment	15.591.733
	Total General Plant	\$24,385,357
	All Other Utility Plant	-
107	Construction Work in Progress	Ø
	-	
	Total Utility Plant	\$882,429,372
	Depreciation Reserve:	
108.1	Steam Plant	(\$281,169,188)
108.2	Nuclear Plant	(\$8,413,949)
108.5	Transmission Plant	(49,002,883)
108.7	General Plant	(12,791,254)
108.9	Cost of Removal - Nuclear	(94,379)
111.1	Transportation Lease	(23,444,300)
111.1	Intangible Plant (HPS-Acuera)	(2,311,850)
111. 1	Leasehold Improvements - U2	(8,850,311)
115.1	Acquisition Adjustment	(429,202)
120.5	Nuclear Fuel	(6,504,475)
	Total Depreciation	(\$392,811,791)
	Net Plant	\$489,517,581
	Working Capital:	
	Power Production	\$9,998 589
	Purchase Power Expense	8,980,139
	Transmission	4.528.042
	Administrative & General	1,890,806
	Payrol & Property Taxes	1,279,342
	Working Funds	4 289
154	Plant Materials and Operating Supplies	17.545.183
165	Prepayments	12.021.018
	Working Capital	\$56,247,408
	Deductions:	
235 (Consumer Deposits	(3,981)
-	TOTAL RATE BASE	\$545,861,008

Cost-of-Service Study

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Exhibit_- (WSS-1)

Table II-4

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UTILITY SERVICES

Seminole Electric Cooperative, Inc.

		Unbundled Codes
1.	Power Supply	
	Demand	kW
	Energy	kVVh
2.	Transmission	
	Demand	T-kW
	Access	ACC
3.	Consumer	CONS
4.	General	GENL

Part II

Exhibit_- (WSS-1)

Assignment of Generation Investment Cost

As can be seen from a brief review of the costs identified in the previous section, the generation investment costs, i.e., depreciation, interest, patronage capital, etc., are a significant portion of the cost of service. How these costs are assigned can significantly impact the rate design process. To the extent that these costs are assigned to an energy- or demand-related function, they will impact the design of rates and its effect on high and low load factor consumers. Assigning investment-related costs for generation and transmission cooperatives is probably the single most controversial issue faced in most cost-of-service studies. For this reason, the following discussion of cost assignment is included before moving on to the discussion of the actual assignments used in the study. For this assignment, Burns & McDonnell evaluated a traditional form of investment cost assignment as well as an energy-based method and an equivalent peaker method.

Traditional Method. Traditionally, power supply costs are assigned either to power supply - energy or power supply - demand. Generally, there is little disagreement that fuel and variable operating cost should be assigned to the power supply - energy function. Traditionally, fixed costs including investment costs are assigned to the power supply - demand function. This approach helps ensure the fixed investment costs of generation resources (such as the depreciation) are recovered in the demand component of the resulting rates and are not subject to fluctuation and energy sales. Using this method, the investment cost (and fixed O&M cost) of a plant are recovered through the demand charge and the commodity cost of fuel and variable O&M are recovered through an energy charge. This type of assignment recognizes the cost-causation relationship for the utility as it exists today.

This approach protects the utility from changes in consumption patterns over what was expected. For example, if a baseload unit is installed and subsequently energy sales dropped off, the utility will still recover its fixed investment costs. Similarly, if peaking units are installed and energy growth exceeds demand growth, consumers will have paid for the increases in the cost of fuel. In a totally regulated environment this approach provides price signals to the consumer, i.e. use more energy and your bill will increase as fuel costs increase, increase your demand and your bill will increase as investment costs increase. Also, this approach minimizes the risk to the utility, and the utility in essence becomes a conduit for providing service with all cost changes being born by the consumer.

Energy Method. An alternative method to assigning power production costs is to assign all baseload generation investment costs to power supply - energy. The reasoning behind this assignment method is that baseload units are developed to produce kilowatt-hours. Therefore, the investment costs as well as

the fuel and variable O&M cost should be recovered through an energy charge (investment costs of peaking units under this methodology are normally assigned to the power supply - demand function).

As the electric utility industry moves toward deregulation, the energy method of assigning investment costs for baseload generation is taking on greater prominence. Many merchant power producers are pricing their baseload products on a cents per kilowatt-hour basis. Under this scenario, utilities no longer provide direct price signals and conduits, but rather producers bear the risk and reward of making the proper investment decision. A power producer that builds a baseload facility prices his product based on the market. To the extent that all costs of producing power (both investment and fuel) are lower than the market, he receives the reward in increased profits. Similarly, to the extent that he misgauges the market, he bears the loss.

Equivalent Peaker Method. The equivalent peaker method is based on the type of generation resource and not whether the costs are fixed or variable. Peaking units are installed to provide capacity and the investment costs associated with this type of generation are assigned to the power supply - demand function. On the other hand, a baseload resource is installed to provide capacity, but also low-cost energy. Therefore, the investment costs for these units should be assigned to both the power supply - energy and power supply - demand function. Only that portion of the investment cost that would have been incurred with the peaking unit is assigned to the power supply - demand function, thus the term equivalent peaker method. The remaining investment costs are more appropriately assigned to the power supply - energy function. The principals of the equivalent peaker method are (1) increases in peak demand require the addition of peaking capacity only, and (2) utilities incur the cost of more expensive baseload units because of the additional lower cost energy they provide. Thus, the cost of peaking capacity can be properly regarded as peak-demand related and classified as power supply - demand while all other investment costs can be regarded as energy-related and assigned to the power supply - energy function.

In applying the equivalent peaker method to the Seminole system, Burns & McDonnell determined the date and cost of the installed baseload units. The cost of these units, expressed in dollars per kilowatt, was adjusted to 1998 using the Handy-Whitman Index of Public Utility Construction Costs. Installed costs for combustion turbines, taken from Resource Data International's POWERdat database, were similarly adjusted to 1998 costs.

Cost-of-Service Study

The ratios of the investment cost of the equivalent peaker units (1998 dollars) to the investment cost of the baseload units (1998 dollars) were used to determine how much of the baseload investment cost should be allocated to the power supply - demand function. These ratios were:

	Percent of Investment Cost Assigned	Percent of Investment Cost
Plant	to Power Supply – Demand	Assigned to Power Supply - Energy
Coal	46.3%	53.1%
Nuclear	35.9%	64.1%

All three methods of assigning production investment costs were considered in developing cost-based rates for Seminole. For this project, Burns & McDonnell selected the equivalent peaker method to assign generation investment costs. As the utility industry moves from a regulated to a deregulated business, we anticipate that there will be a shift from the traditional approach to the energy approach. Using the equivalent peaker method will prepare Seminole for expected changes in the future while recognizing that many traditional techniques are still appropriate or must still be employed. In the remaining sections of this report the equivalent peaker method provided the basis for subsequent analyses and rate design; however, summary results from the other two assignment methodologies have been included for comparison.

Rate Base Assignment

Rate base was assigned using the equivalent peaker method discussed above and is summarized on Table II-5. (The resulting rate base assignments for all three methods are compared on Table II-6). The resulting assignment of rate base provided the basis for assigning investment-related costs in the year 2000 budget (see following section). More specifically, the following assignments were made:

- Production plant was assigned by the equivalent peaker method, one of the three methods discussed above.
- Total transmission plant accounts were assigned directly to the transmission-demand function.
- Intangible plant was assigned in proportion to the subtotals for production and transmission plant.
- Office furniture and equipment were assigned to the consumer function.
- Communication equipment was assigned based on the proportion of the estimated utilization by each function.
- Miscellaneous equipment was assigned in proportion to the subtotals for production and transmission plant.

RATE BASE ASSIGNMENT Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Account		Year 2000							
Number	item	Budget	kW	KMH	ACC	T-KW	CONS	GENI.	Description of Assignment
301-303	Total Intengible Plant	\$5,779,220	\$2.044.878	2 672 372	<u> </u>	1.061 971	<u> </u>	<u> </u>	ProdXman Plant Ratio
310-316	Total Production Plant - Steam	673,348,929	293,551,261	379.797.666		.,,			KW. KAPI - 625 MW
320-325	Total Production Plant - Nuclear	22,308,484	8.008.028	14 298 458		-		-	KW. KWH - CR3
	Total Production Plant	\$701,434,633	\$303,604,167	\$396,768,496	\$0	\$1,061,971	\$0	\$0	
260	Londowd Lond Diable	B48 400 0.40							
330	Carlo and Links August	310,400,248	•	•	•	\$10,400,249	•	•	1-KW
-332	Several and improvements	•	-	•	•	•	•	•	1-644
333	Other Tennemission Direct	140 203 133	:	:	:	140 203 133			T-KW T-KW
334-339	Totel Totermission Plant	\$156 609 342				FILL 600 282			
		• • • • • • • • • • • • • • • • • • • •	~	•~	~	4100,000,001	~	••	
389	Land and Land Rights	\$790,157	\$262,414	\$369,076	\$0	\$146,667	\$0	\$0	ProdiXman Plant Ratio
391	Office Fumiliare & Equipment	1,597,554	•	-	•	• .	1,597,554	•	CONS
392	Transportation Equipment	748,182	•	745,182	•	•	-	•	KWH
397	Communication Equipment	5,649,731	225,989	335,964	•	2,259,892	2,259,892	564,973	Slandardi Judgmeni
396	Miscellaneous Equipment	15,591,733	5,516,867	7,209,780	-	2,865,086	•	-	ProdiXman Plant Ratio
	Total General Plant	\$24,385,357	\$6,025,271	\$8,686,022	\$0	\$5,271,645	\$3,857,446	\$564,973	
	AE Other Utility Plant	•	•	•			•	-	Prod/Xman Plant Ratio
107	Construction Mark in Browness	0	0	•	0		•	~	Brod Varue Diant Datio
197	Contraction of the second s					<u> </u>			
	Total Utility Plant	\$882,429,372	\$309,629,437	\$405,434,518	\$0	\$162,942,997	\$3,857,446	\$564,973	
	Depreciation Reserve:								
108.1	Steem Plant	(281,169,188)	(130,181,334)	(150,987,854)	0	0	0	0	KW. KWH - 625 MW Capac
108.2	Nuclear Plant	(8,413,949)	(3,020,606)	(5,393,341)	Ō	ō	ō	ō	KW, KWH - CR3
108.5	Transmission Plant	(49,002,883)	O O	0	0	(49,002,883)	ō	Ō	Total Utility Plant Ratio
108.7	General Plant	(12,791,254)	(4,485,233)	(5,876,976)	0	(2,361,940)	(55,916)	(8,190)	Total Utility Plant Ratio
108.9	Cost of Removal - Nuclear	(94,379)	(33,682)	(60,497)	0	0	0	0	KW, KWH - CR3
111.1	Transportation Lease	(23,444,300)	0	(23,444,300)	0	0	0	0	KW, KWH - CR3
111.1	Intangible Plant (HPS-Acuera)	(2,311,850)	(618,008)	(1,069,024)	0	(424,616)	0	0	KW, KWH - CR3
111.1	Leasehold Improvements - U2	(8,650,311)	(4,005,094)	(4,645,217)	0	0	0	0	KW, KWH - CR3
115.1	Acquisition Adjustment	(429,202)	(154,084)	(275,118)	0	0	0	0	KW, KMH - CR3
120.5	Nuclear Fuel	(6,504,475)	O	(6.504,475)	0	Ó	0	Ó	KW. KWH - CR3
	Total Depreciation	(\$392,811,791)	(\$142,701,243)	(\$198,256,802)	\$0	(\$51,789,641)	(\$55,916)	(\$8,190)	
	Net Plant	\$489,617,581	\$166,928,195	\$207,177,716	\$0	\$111,153,356	\$3,801,531	\$556,784	
	Working Capital:								
	Power Production	0 000 689	044 671	0.011.010	•	•	•	•	Operating Excessor
	Purchase Power Expense	58 980 139	A 944 374	4 004 310	0	0	21 605	0	Operating Expense
	Transmission	4 528 042	, 220, FFF, F	4,004,210	4 100 153	120 600	31,003		Charanti Exberre
	Administrative & General	1 890 806	770 173	483 760	-,	57 780	45 036	633.460	Admin & Concert Batte
	Pavrol & Property Taxes	1 279 342	914 809	128 612	0	31,108	00,835	333,109	
	Warking Funde	4 289	0.11,000	210,032			4 200	04,410	Tak Expense Rato
154	Plant Materials and Operating Supplies	17 545 183	6 156 306	8.061 181	Ň	1 210 744	78 607		Talal i Mito Olasti Galia
165	Propayments	12,021,016	4,217,970	5,623,089	ŏ	2,219,714	52,549	7,695	Total Utility Plant Rabo
	Working Capital	\$66,245,997	\$18,976,923	\$36,302,696	\$4,198,152	\$5,891,619	\$260,108	\$616,499	•
	Dechastana								
235	Consumer Deposits	(3.961)	0	0	٥	•	(3.061)		CONS
		10,0017				0	[3,801]	0	Cona
	TOTAL NATE BASE	\$545,861,008	\$184,918,447	\$234,468,495	\$4, 198, 152	\$117,044,975	\$4,057,656	\$1,173,282	
	Rate Base Relio	100.00%	33.86%	42 95%	0.77%	21.44%	0.74%	021%	

Seminole Electric Cooperative, Inc. Cost-of-Service & Rate Design Study

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Part II

Cost-of-Service Study

Exhibit_- (WSS-1)

COMPARISON OF RATE BASE ASSIGNMENT

Seminole Electric Cooperative, Inc.

Assignment Method	Year 2000 Budget	kW	KWH	ACC	T-KW	CONS	GENL
TRADITIONAL	\$545,861,008	\$394,437,055	\$24,949,888	\$4,198,152	\$117,044,975	\$4,057,656	\$1,173,282
EQUIVALENT PEAKER	\$545,861,008	\$184,918,447	\$234,468,495	\$4,198,152	\$117,044,975	\$4,057,656	\$1,173,282
ENERGY	\$545,861,008	\$7,343,297	\$412,043,646	\$4,198,152	\$117,044,975	\$4,057,656	\$1,173,282

Burns & McDonnell

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- Transportation equipment consists of fuel transportation equipment and was therefore assigned the power supply energy function..
- The depreciation reserves were assigned based on the corresponding plant.
- Working capital was assigned in the same ratio as the equivalent expense from the budget.
- Consumer deposits were assigned directly to the consumer function.

Year 2000 Budget Assignment

The budget costs identified in Table II-2 were assigned to the utility functions and sub-functions on Table II-7. Results of all three methods are compared on Table II-8. In addition to the rate base assignments discussed above, several assignment methodologies were used for other costs. These included the use of a cost-of-service ratio, payroll ratio and total utility plant ratio. These ratios were developed by adding the costs assigned to each of the functional categories and then dividing by the total cost. The actual ratios are shown at the end of Table II-7. In other cases, costs were directly assigned to specific functions.

Table II-7 summarizes the results from the Unbundle model that describe how the various costs in the year 2000 budget were assigned. More specifically, the costs were assigned as described below:

Power Production Expenses

- Operations supervision and engineering, and steam and nuclear maintenance supervision and engineering were assigned to power supply - demand. It was assumed that large portions of these costs were salaries and that the number of employees was dependent on the size of the plants.
- Steam, electric and miscellaneous steam power expenses depend on the amount of energy generated and were assigned to the power supply energy function. Maintenance related to these items is also an expense incurred to produce electricity and was assigned to energy.
- The costs of fossil and nuclear fuel are dependent on the amount of energy produced and were therefore assigned to the power supply energy function.
- The maintenance of structures is dependent on the size of the plants and was classified as a fixed expense assigned to the power supply demand function.
- Power plant rents apply only to Palatka 2 generating unit and were assigned to power supply demand and power supply energy based on the equivalent peaker method.

Exhibit__- (WSS-1)

Pert II

Cost-of-Service Study

Year 2000 Budget Assignment Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

· · · · ·		EY 2000			<u> </u>				
		Burloet		.					
Acas		Totals	KW I	KMH I	ACC	T-KW	CONS	GENI	Description of Assignment
r								<u> </u>	
i	POWER PRODUCTION EXPENSES								
500	Operations Supervision And Engineering	2,681,634	2.681.634	0	0	0	a	6	XW
501	Fuel Expense	162,184,362	0	162,184,362	0	ō	0	0	10444
502	Sieam Expenses	7,720,824	ō	7,720,824	Ō	Ō	ŏ	0	I CARL
505	Electric Expenses	1,694,210	0	1.694.210	ō	n n		Ō	KIAB-I
508	Misc Sleam Power Expenses	10,557,901	o o	10.557.901	ō	ő			KOAH
507	Power Plant Rents	20,041,057	13,261,087	15.380.570	ō	ő	ů		IOA/ IOAA4
510	Maintenance Supervision and Engineering	5,428,515	5,428,515	0	ō	a	0	0	KW
511	Maintenance nf Siructures	349,878	349.878	a	Ő	ō	Ō		low
512	Mainlanance of Boller Plant	14,443,520	0	14,443,620	Ō	i a	Ō	i i	IGAA4
513	Maintenance of Electric Plant	1,105,936	Ō	1,105,935	Ó	i o	Ŏ	l ñ	NOAA.
514	Maintenance of Misc. Steam Plant	5,554,701	ō	5.554.701	ů.	ő	, o	i a	ICA44
518	Nuclear Fuel Expense	648,000	a	648,000	0	ő	Ō		IGAA4
526	Maintanance Supervision and Engineering	2,287,873	2,207,873	0	0	0	0	i õ	KW
	PURCHASED POWER						·	<u> </u>	
555	Purchased Power	216,750,478	118,545,653	97.435.770	0	6	769.055	} 0	KW KMH CONS - BY CONTRACT
556	System Control and Load Dispatch	1,717,774	1,717,774	0	Ō	ō	0		KW
557	Other Power Supply Expenses	48,461	48,461	Ō	a	l o	ō	0	IKW
	TRANSMISSION OPERATIONS EXPENSES								
580	Operations Supervision And Engineering	177,341	0	0	0	177.341	o		THOW
562	Station Expenses	9,604	0	a	a 🛛	9.604	Ō	í ő	T-KW
565	Transmission of Electricity by Others	34,051,675	0	0	34.051.675	0	Ō	i õ	ACC
566	Miscelleneous Transmission Expenses	1,285,816	0	0	Û	1,285,818	ň		IT-IOW
567	Rents	2,500	0	o i	Ö	2,500	ō	ì	T-KW
	TRANSMISSION MAINTENANCE EXPENSES							~	
570	Maintenance of Station Equipment	1,195,105	0	o	0	1,195,105	0	i o	T-KW
571	Maintenance Of Overhead Lines	5,409	0	0	0	5,409	Ō		T-KW
[ADMINISTRATIVE AND GENERAL OPERATIONS EX	PENSES				<u> </u>			
920	Administrative & General Salaries	10,805,074	4,890,317	3,787,480	0	565,680	485,177	1.076.420	Personnel Function
921	Office Supplies And Expense	2,276,213	1,627,634	403,224	0	79.104	51 653	114 500	PAYROLL BATIO
922	Administrative Expenses Transferred - Credit	(1,007,800)	(353,620)	(463,036)	ō	(186.093)	(4.405)	(845	TOTAL LITE ITY PLANT RATIO
923	Outside Services Employed	1,658,460	0	0	Ō	0	0	1 666 460	IGEN
924	Property Insurance	35,944	12,612	16,515	0	6.637	157	23	TOTAL UTILITY PLANT RATIO
925	Injuries And Damages	39,607	28,321	7.016	0	1.376	899	1,994	PAYROLL RATIO
926	Employee Penalons and Banefits	58,308	41,692	10,329	0	2,025	1,323	2,835	PAYROLL RATIO
930	General Advertising and Macellaneous General Expen	1,342,030	0	0	0	0	0	1.342.030	GENL
	ADMINISTRATIVE AND GENERAL MAINTENANCE E	EXPENSES				t		1	
932	Meintenence Of General Plant	120,700	0	0	0	} 0	0	120,700	GENL
1	DEPRECIATION AND AMORTIZATION EXPENSE							1	1
403.1	Steam Production Plant	18,223,995	8,437,710	9,786,285	0	0	0	a 1	KWKWH
403.2	Nuclear Production Plant	1,061,449	381,080	680,389	0	0	0		KWKWH
403.5	Transmission Plant	3,854,282	G	0	0	3,854,282	1 0		IT-KW
403.7	General Plant	953,646	0	0	0	0	0	953,646	GENL
990.0	Depreciation Transferred	(23,785)	(8,346)	(10,928)	0	(4,392)	100	(15	TOTAL UTILITY PLANT RATIO
404.0	Amortization Lessehold improvements	1,205,605	558,195	647,410	0	0	0		KWIGH
405.0	Miscellaneous Depreciation/Amortization	208,824	101,273	132,609	0	53,295	1,262	185	TOTAL UTILITY PLANT RATIO
1405.0	Amorization Electric Plant Acquisition	17,258	8,196	11,081	0	0	0		KWKWH

Bums & McDonnell

Part II

Year 2000 Budget Assignment Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

	······································	EV 2000	T	T				··	
1		Budget					1		
Acct		Totals	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
408.1	Denarty Taxas	8 8 18 067	1 023 033	3 050 504	ام	1 501 350	37 473	6 518	TOTAL LITH ITY PLANT RATIO
408.2	Parti Tenes	24 186	17 294	4 284		841	57,673	1 218	PAYRON RATIO
408.3	Parrol Taxes	1 731 795	1 238 341	508 782	, i	60 184	30 200	87 189	PAYROLI RATIO
408.4	Period Terres	15 118	10 809	2 678		575	343	741	
406 7	Tavas Other	(12 282)		2,010	ň			(12 283)	OFW
900.7	Comband Allocation and Taxas Transformed	(10 212 065)	(7 583 240	(4 601 060)		(1 895 686)	144 8415	(12,204)	TOTAL HER ITY DI ANT RATIO
426	Magnitude Percenting and Tables Transmisses	(10,212,000)	(3,003,240)	(4,081,000)	ž	(1,000,000)	(44,641)	(0,550)	TOTAL UTILITY PLANT DATIO
428	Dosaliana	38 120	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~					38 120	GEN#
428	Amortization of Debt Discount and Expense	3 780 688	1 128 570	1 737 047		608 114	18.577	30,120	TOTAL LITHITY PLANT RATIO
120	TOTAL OPERATING EXPENSE	543 444 477	162 077 661	333.052.605	34.051.675	7 513 032	1 354 746	6 304 737	
	ANNUAL INVESTMENT COST:			000,000,000			1,000,100	0,00-,101	
v	Target Harpin Dollar Amount								
ľ	Required Margins & Paironage Capital	2.334.840	818 270	1 072 747		431 142	10 207	1 404	TOTAL LITE ITY PLANT BATIO
	Required Mamine & Patronane Canital	2 334 880	Rta 370	1 073 747		431 143	10,207	1 404	
	Non-Constained Marries	2,007,000	019,270	1,072,707	v	431,142	10,207	1,400	
410	Non Operating Memory interest	(7.010.136)	(2 185 317)	/4 181 0101	1475 200	/168 738	(18 603)	151 000	COS PATIO - PREI
411	Gain on Disposition of Clean Air Allowences	(100 000)	(100,017)	(4, 101,010) A	(123,200)	(100,730)	(10,003)	(31,040)	KW
421	Non Operation Marries - Other	(493.652)	(162,660)	(204 432)	(20 040)	/11 003	/1 3101	(3.604)	
474	Other Capital Credits and Patronate Dividends	(100,000)	(102,007)	(207,732)	(20,070)	(11,003)	(1,316)	(3,000)	ACENI
[*]	Regulard Operating Margins	(5 368 917)	(1 608 532)	(1 402 682)	(455 220)	250 622	/0 mm	(153,103)	
427	internet on L-T Debt	30 145 667	10 577 501	13 660 484	(100,220)	5 644 444	191 774	10 100	TOTAL LITE ITY & ANT DATIO
	Total Internet & Op. Marring	24 776 640	8 979 031	10 447 775	(455 229)	5 818 081	121 876	/133 803	
<u> </u>	Total Operation Expense	543 444 477	162 077 644	131 052 604	34.051.074	7 513 033	1 364 744	6 104 717	·····
1	Less Other Boundage		102,017,001	333,032,005	34,001,075	7,513,032	1,334,700	5,304,737	
1	international Salas	(5 137 700)		15 137 704					Internet
	Non-Member Sales	(8,006,065)		(0,131,700)					INAL I
	Martal Salas	(0,000,000)	0	(0,000,085)					
458	Other Electric Revenues	(1,224,777)	0	(02,000)	0			(1 224 777	DIGEN!
	TOTAL COST OF SERVICE	553,769,741	171 056 692	330 293 241	33 596 444	13 330 013	1 478 741	4 034 047	
1	Cost-of-Service Ratio	1,000	0,300	0 504	6.041	0.674	0.001	4,0.00,007	1
	Non-Power Supply COS Ratio	1,000	0,000	0,000	8.000	0.747	0,074	0.214	1
					4,000				t
ŚI MAMA	RY OF COST OF SERVICE							{	
Power P	reduction	243,299,011	24,008,947	219,290 024	n				
Purchase	d Power	218.518.713	120.311.668	97.435.770	0		769.055		
Trenami	alon Operations Expenses	35,526,936	0	0	34.051.675	1.475.261	,,		
Transmis	alon Maintenance Expenses	1,200,514			A	1,200,514			
Administ	milve And General Operations Expenses	15,215,834	6,248,957	3,761 527	, i	468 731	534 804	4 201 816	
Administ	nitve And General Maintenance Expenses	120,700	D	0,,02/			0	120 700	
Deprecia	den	25,581.072	9,476.067	11,246,826	0	3,903,185	1.150	851.814	
Taxes &	Other	3,963,697	2,033,742	1,318,458	i o	405,341	49,750	118,408	
Total Inte	rrest & Op. Margins	32,480,437	11,396,832	14,923,223	0	5,997,602	141,965	20,796	
Non-ope	rating Mergins	(7,703,797)	(2,417,801)	(4,475,449)	(455.229)	(180.820	(20.010	(154.64	
Non-Mer	nber Sales	(8,006,085)	0	(6,006,085)	0	0	0		
internot	ble Sales	(5,137,708)		(5.137.704)		0	1 0		
Martel S	lies .	(62,606)	0	(62 606)	1 0				
Other Or	. Revenue	(1,224,777)			0		0	(1.224.77	b
Cost of	Service	553,789,741	171,056,692	330,293,761	33,595,448	13,330,013	1.476,741	4.036.067	í l

Exhibit__- (WSS-1)

Cost-of-Service Study

Equivalent Peaker Method

	FY 2000							
	Budgel							
Accl #	Totels	KW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
COS Excluding Payroll & Gross Receipts Tax, Reg'd Margins,	Lint. on LT Debt							
Required Operating Margins	32,280,437	11,296,832	14,923,223	0	5,997,602	141,965	(79,204)	
Total Op Exp	543,444,477	182,077,661	333,052,605	34,051,875	7,513,032	1,354,766	5,394,737	
Cost of Service (excl. nonoperating interest and other income)	561,293,538	173,374,493	334,789,229	34,051,875	13,510,634	1,496,751	4,090,755	
COS Ratio (Prelim.)	1.000	0.308	0.596	0.061	0.024	9.003	0.007	
Non-Power Supply COS Ratio (Prelim.)	1.000	0.000	0.000	0.000	0.707	0.078	0.214	
RATIOS								
Power Production	1.000	0.099	0.901	0.000	0.000	0.000	0.000	
Purchased Power	1.000	0.551	0.448	0.000	0.000	0.004	0.000	
Transmisaion	1.000	0.000	0.000	0.927	0.073	0.000	0.000	
Admin, & General	1.000	0.407	0.245	0.000	0.031	0.035	0.282	
Taxes (Payroll & Property)	1.000	0.413	0.412	0.000	0.159	0.005	0.006	
Cost of Service Ratio	1.000	0.309	0.596	0.061	0.024	0.003	0.007	
PAYROLL RATIO							1	
Operations Supervision And Engineering	2,661,634	2,881,634	Ð	0	0	0	} 0	
Maintenance Supervision and Engineering	5,428,515	5,428,515	0	0	0	0 O	1 o	
Maintenance Supervision and Engineering	2,207,873	2,287,873	0	0	i 0	l o	i o	1
Operations Supervision And Engineering	177,341	0	0	· 0	177.341	i o	ة ا	
Administrative & General Salaries	10,605,074	4,890,317	3,787,480	Ő	565,660	485,177	1.076.420	
Total	21,380,437	15,288,339	3,787,480	Ö	743.021	485,177	1.076.420	1
Payroli Ratio	1.000	0.715	0.177	0.000	0.035	0.023	0.050	}
TOTAL UTILITY PLANT RATIO					{		{	
Production Plant Ratio	1.000	0.433	0.567	0.000	0.000	0.000	0.000	
Transmission Plant Retio	1.000	0.000	0.000	0.000	1.000	0.000	0.000	[
Prod/Xmsn/Dist Plant Ratio	1.000	0,354	0,462	0.000	0.184	0.000	0.000	1
Total Utility Plant Ratio	1.000	0.361	0.459	0.000	0.185	0.004	0.001	

Bums & McDonnell

Exhibit_- (WSS-1)

Part II

Cost-of-Service Study

Table II-8

COMPARISON OF YEAR 2000 BUDGET ASSIGNMENT Seminole Electric Cooperative, Inc.

Assignment Method	Year 2000 Budget	kW	KWH	ACC	T-KW	CONS	GENL
TRADITIONAL	\$553,789,741	\$211,041,972	\$290,308,500	\$33,596,446	\$13,330,013	\$1,476,741	\$4,036,067
EQUIVALENT PEAKER	\$553,789,741	\$171,056,692	\$330,293,781	\$33,596,446	\$13,330,013	\$1,476,741	\$4,036,067
ENERGY	\$553,789,741	\$136,967,004	\$364,383,468	\$33,596,446	\$13,330,013	\$1,476,741	\$4,036,067

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Exhibit_- (WSS-1)

Exhibit_- (WSS-1)

Purchased Power

- Purchased power supply costs were assigned 55% to the power supply demand function, 44.6% to the power supply energy function and .4% to the consumer function consistent with Seminole's purchased power contracts.
- System control and load dispatch and other power supply expenses are fixed with respect to capacity purchased and were assigned 100% to the power -supply demand function.

Transmission Operation Expense

- Operations supervision and engineering was assigned to transmission-demand since large portions of these costs are salaries and the number of employees is dependent on the capability of the facilities.
- Station expenses, miscellaneous transmission expenses and rents are dependent on the capability of facilities, based on capacity requirements, and were assigned to transmission-demand.
- Transmission of electricity by others or to others was directly assigned to the transmission access function.

Transmission Maintenance Expense

• Transmission maintenance expenses related to station equipment and overhead lines are dependent on the demand capability of the facilities and were therefore assigned to transmission-demand.

Administrative and General O&M Expense

- Based on a brief review of payroll provided by Seminole staff, administrative and general salaries were assigned to various functions.
- Office supplies and expenses, injuries and damages, and employee pension and benefits were assigned to all categories using the payroll ratio.
- Administrative expense-transferred credit and property insurance were assigned to all categories based on the total utility plant ratio.
- Outside services employed and general advertising and miscellaneous general were all considered general services and were therefore assigned to that function.
- Maintenance of general plant was considered to be a general service and was therefore assigned to the general function.

Exhibit_- (WSS-1)

Depreciation and Amortization Expense

- Steam depreciation and nuclear production depreciation were assigned with the equivalent peaker method (as well as the traditional and energy methods for comparison).
- Transmission plant is based on the capacity of the facilities and therefore, depreciation was assigned to transmission-demand.
- Depreciation transferred, miscellaneous depreciation and amortization, and amortization of electric plant acquisition were assigned based on the total utility plant ratio.
- General plant was assigned to the general category.
- Amortization of leasehold improvements applies only to Palatka #2 and was assigned consistent with the equivalent peaker method.

Other Expenses

- Property tax, overhead allocated tax transferred, miscellaneous depreciation and amortization, and amortization of debt discount and expense were assigned based on the total utility plant ratio.
- Payroll taxes (social security, state unemployment and federal unemployment) were assigned based on the payroll ratio.
- Other taxes and donations were assigned to the general category.

Annual Investment Cost

- Required margins and patronage capital were assigned based on the total utility plant ratio.
- Interest from non-operating margins and other non-operating margins were assigned using the cost-of-service ratio.
- Disposition of clean air allowances depends on the capability of the units and therefore, the gain was assigned to the demand function.
- Other capital credits and patronage dividends were assigned to the general function.
- Interest on long-term debt was assigned based on the total utility plant ratio.
- Revenue from non-member sales was assigned to energy.
- Other electric revenues were assigned to the general function.

COST ALLOCATION

Generally, the next step in a cost-of-service study is to allocate the unbundled costs to the appropriate customer classes. In this part of a study, costs are allocated based on various classes use of different services, i.e., kWh, kW, meters, etc. For this study, Seminole requested that all member distribution

systems be considered as one class. To the extent that all member cooperatives receive the same level of service, this is an appropriate approach. Actual allocation between the various member systems then becomes covered in the actual rate design, which is discussed in Part III of this report. For these reasons, there were no allocation of costs in this study.

SUMMARY

The unbundled costs listed on Table II-7 were subsequently summarized into the following major areas:

- Power supply energy Power supply energy costs are expected to vary directly with the
 production or purchase of energy measured in kilowatt-hours (kWh). The power supply
 energy portion of Seminole's budgeted costs totaled \$330,293,781. Power supply energy
 costs included Seminole's expenditures associated with electricity generation and purchases.
 Power supply energy costs were defined as the costs incurred to meet the energy needs of
 the consumers and consisted primarily of fuel costs and variable generation operation and
 maintenance (O&M) costs.
- Power supply demand Power supply demand costs are expected to vary directly with the capacity installed or purchased to meet the demand requirements of Seminole's system measured in kilowatts (kW). The power supply - demand portion of Seminole's budgeted costs totaled \$171,056,692. Power supply - demand costs were defined as the costs incurred to meet the peak demand needs of the customers and included Seminole's expenditures associated with electricity generation and purchases. These costs consisted primarily of the equivalent peaker portion of investment costs for Seminole's generation resources, fixed generation O&M costs, and demand-related purchased power costs.
- Transmission Transmission costs are expected to vary directly with the transmission
 capacity installed or purchased to meet the transmission demand requirements of Seminole's
 system measured in kilowatts (kW). The transmission demand portion of Seminole's
 budgeted costs totaled \$46,926,459. Transmission demand costs were defined as the costs
 incurred to transmit the peak demands of Seminole's customers and consisted primarily of
 transmission facilities and operating expenses.
- Consumer Consumer costs for the Seminole system totaled \$1,476,741. Consumer service costs included expenditures that are directly related to providing member services to Seminole's ten distribution cooperatives.

General – General costs totaled \$4,036,067. These general costs are necessary to support all
of the above functions of the utility. For this reason, the general costs wre broken down into
sub-functions in proportion of the subtotal of the costs for power supply – energy, power
supply – demand, transmission, and consumer costs.

These costs have been summarized in Table II-9. The costs are expressed in total dollars and in cents per kilowatt-hours. Also, the costs have been expressed in dollars per unit cost where the applicable units are: kilowatt-hours for power supply - energy, coincident kilowatts for power -supply - demand, coincident peak demand kilowatts for transmission, and number of consumers for consumer costs. The general service costs, split up by their contribution to the other four functional categories (Power supply – energy, power supply – demand, transmission and consumer) are also shown on Table II-9. These costs reflect the equivalent peaker method of assignment. Table II-10 has been provided to compare the cost summary using the traditional and energy methods for assigning costs. The costs included in Table II-9 for the equivalent peaker method has provided the basis for designing rates which are discussed in the next part of this report.

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Exhibit_- (WSS-1)

Table II-9

SUMMARY OF COST-OF-SERVICE

Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Category	Cost	Cents/kWh	Applicable Unit Cost	Unit cents per kWh	
Power Supply - Energy	\$330,293,781	2.71	2.71		
Power Supply - Demand	171,056,692	1.40	\$5.79	per kW*	
Transmission	46,926,460	0.38	\$1.59	per kW*	
Consumer	1,476,741	0.01	\$12,306.18	per consumer per month	
General					
Power Supply - Energy	\$2,424,882	0.02	0.02	cents per kWh	
Power Supply - Demand	\$1,255,828	0.01	\$0.04	per kW*	
Transmission	\$344,515	0.00	\$0.01	per kW*	
Consumer	\$10,842	0.00	\$90.35	per consumer per month	
Total	\$553,789,741	4.54			

* Per sum of monthly coincident peak.

Table II-10

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Exhibit_- (WSS-1)

SUMMARY OF COST-OF-SERVICE FOR ALTERNATIVE METHODS Seminole Electric Cooperative, Inc.

Traditional Method

Category	Cost	Cents/kWh	Applicable Unit Cost	Unit	
Power Supply - Energy	\$290,308,500	2.38	2.38	cents per kWh	
Power Supply - Demand	211,041,972	1.73	\$ 7.15	per kW*	
Transmission	48,926,460	0.38	\$1.59	per kW*	
Consumer	1,476,741	0.01	\$12,306.18	per consumer	
General					
Power Supply - Energy	2,131,327	0.02	0.02	cents per kWh	
Power Supply - Demand	1,549,384	0.01	\$0.05	per kW*	
Transmission	344,515	0.00	\$0.01	per kW*	
Consumer	10,842	0.00	\$90.35	per consumer per month	
	\$ 553,789,741	4.54			

Energy Method

Category	Cost	Cents/kWh	Applicable Unit Cost	Unit
Power Supply - Energy	\$364,383,468	2.99	2.99	cents per kWh
Power Supply - Demand	136,967,004	1.12	\$ 4.64	per kW*
Transmission	46,926,460	0.38	\$1.59	per kW*
Consumer	1,476,741	0,01	\$12,306.18	per consumer per month
General				
Power Supply - Energy	2,675,155	0.02	0.02	cents per kWh
Power Supply - Demand	1,005,556	0.01	\$0.03	per kW*
Transmission	344,515	0.00	\$0.01	per kW*
Consumer	10,842	0.00	\$90.35	per consumer per month
	\$553 789 741	4.54		

* Per sum of monthly coincident peak.

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Exhibit_- (WSS-1)

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PART III - RATE DESIGN



Exhibit_- (WSS-1)

PART III WHOLESALE RATE DESIGN

Having completed the cost-of-service study as discussed in the previous part of this report, Burns & McDonnell's efforts then turned to developing wholesale rates for Seminole to charge its member distribution systems. Good cost information provides the basis for rate design. Other factors such as revenue stability, rate stability, practicality, social and environmental objectives, etc. should also be considered when rates are designed. However, Seminole requested that Burns & McDonnell only consider the cost of service for this assignment. Therefore, the rates discussed in this part of the report are cost-based only and did not consider other rate-making criteria.

Costs developed in Part II of this report provided the basis for the rate design. Appropriate billing determinants were identified that provided the basis for applying rates to recover the costs previously discussed. Per unit rates were developed for wholesale service to the member distribution cooperatives. As a final step, the proposed rates were applied to the billing units so Seminole could see the effects that the proposed rates would have on each member cooperative. The remainder of this report describes in greater detail the methodology used to develop cost-based wholesale rates.

COSTS

For reasons discussed in Part II of this report, Burns & McDonnell used the cost-of-service study results that were based on the equivalent peaker method of assigning costs to design the proposed wholesale rates. The costs were combined into three major categories: commodity, capacity, and customer costs. These costs are summarized on Table III-1. Commodity costs included the power supply – energy costs. Capacity costs included the power supply – demand and transmission costs. Customer costs included the consumer costs. General costs were included in each category based on the sub-function breakdown discussed in Part II. The three major categories of costs provided the basis for developing three separate charges to recover revenues from the member distribution cooperatives on a cost basis.

Although the equivalent peaker costs provided the basis for the recommended rates, costs from the traditional method and the energy method were also evaluated. The resulting rates have been included at the end of this section of the report.

Exhibit_- (WSS-1)

Table III-1

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COST TO BE RECOVERED THROUGH WHOLESALE RATES Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Category	Cost
Commodity	\$332,718,663
Capacity	219,583,495
Customer	1,487,583
Total Cost of Service	\$553,789,741

BILLING UNITS

Exhibit_- (WSS-1)

Having determined the costs to be collected, the next task in designing wholesale rates was to identify the billing units that would be applied to the resulting rates. Table III-2 summarizes the billing units that were selected for recovering each of the three cost categories.

The most common billing unit is kilowatt-hour sales to distribution members. As shown on Table III-2, 12,194,143,481 megawatt- hours of sales to the member cooperatives are expected during the year 2000. Kilowatt-hour sales will be the billing units to which the commodity portion of the wholesale rate is applied.

The sum of monthly coincident peaks provided the basis for developing the billing units for capacity costs. Since monthly capacity costs are a function of Seminole's monthly peak demand, it was felt that each cooperative's contribution to this peak demand should provide the basis for billing for this service. Table III-2 not only shows Seminole's total system demand on a monthly basis, but also each member system's monthly contribution to this demand.

The number of member systems was considered the unit by which to charge customer costs. As shown on Table III-2, Seminole provides service to ten member cooperatives.

PROPOSED RATES

Having defined the costs and the billing units, developing the proposed rates basically became a matter of dividing costs by billing units. The proposed cost-based rates for Seminole's member systems are summarized in Table III-3. The commodity charge of 2.73 cents per kilowatt-hour is applied to all energy sales. The capacity charge is applied to the members' contribution to Seminole's monthly peak. The actual rate was developed by dividing the sum of monthly capacity costs by the sum of Seminole's monthly peak demand and then dividing this result by 12. Since the billing units used to determine this rate were the sum of the 12 months' demands, no ratchet is included in this rate. Finally, the customer charge is a monthly charge assessed to each member system.

To provide an indication of how these rates would collect revenue from the 10 member systems, a table was prepared showing revenue from each cooperative. Table III-4 shows the expected revenue that will be received from each cooperative each month during the year 2000. Revenues have been summed by

BILLING UNITS Seminole Electric Cooperative, Inc.

Units	Florida	Clay	Glades	Lee County	Peace River	Sumter	
kWh Purchased	401,047,636	2,522,169,887	,887 325,643,638 2,671,185,760 387,81		387,811,955	1,955 1,658,790,641	
Sum of Monthly Coincident Peaks (kW)	973,941	5,908,709	657,585	5,966,874	880,499	4,304,641	
Customer	1	1	1	1	1		
Units	Suwannee	Talquin	Tri-County	Withlacoochee	Total		
kWh Purchased	302,701,398	856,509,058	185,508,871	2,882,794,637	12,194,143,481		

231,021

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74,856

1

42,104

1

838,935

1

12,194,143,481

19,879,165

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Part III

Rate Design

Exhibit_- (WSS-1)

Table III-3

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PROPOSED WHOLESALE RATES

Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Commodity 2.73 cents per kWh

Capacity	\$7.43	kW per month
		Monthly member contribution to SECI peak.

Customer Charge \$12,397 per member

MONTHLY BILLS WITH PROPOSED RATES

Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumler
January	\$1,656,541	\$10,195,368	\$1,214,475	\$11,306,915	\$1,684,652	\$7,239,933
February	1,481,331	9,660,678	1,191,767	9,933,126	1,624,597	7,091,542
March	1,378,580	8,393,220	1,121,679	9,405,689	1,475,112	5, 881,8 87
April	1,227,159	7,483,793	1,065,837	7,993,188	1,161,454	5,344,565
May	1,547,623	8,908,334	1,198,484	9,496,042	1,454,208	5, 797,6 51
June	1,62 8,952	10,087,907	1,122,408	10,465,147	1,440,174	6,693, 3 42
July	1,827,155	10,927,590	1,234,758	11,030,244	1,466,897	6,764,056
August	1,763,708	10,996,674	1,205,653	11,296,672	1,496,500	6,973,244
September	1,546,178	10,332,414	1,136,832	9,983,467	1,371,622	6,834,014
October	1,266,492	8,387,213	1,115,749	9,101,109	1,320,076	6,166,370
November	1,396,082	8,058,179	1,105,602	7,884,849	1,292,685	6,120,190
December	1,612,149	9,462,148	1,209,418	9,494,855	1,488,160	6,504,212
Total	\$18,331,950	\$112,893,517	\$13,922,661	\$117,391,303	\$17,276,138	\$77,411,006

Rate Design

Exhibit__- (WSS-1)

PartIII

Part III

MONTHLY BILLS WITH PROPOSED RATES Seminole Electric Cooperative, Inc.

Equivalent Peaker Method

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Total
January	\$1,215,046	\$3,777,937	\$755,694	\$13,127,872	\$52,174,433
February	1,057,095	3,507,823	688,617	12,509,221	48,745,799
March	1,002,212	3,094,052	643,969	11,105,249	43,501,650
April	850,145	2,481,014	523,224	8,194,651	36,325,028
May	1,020,013	3,128,227	645,867	10,914,815	44,111,264
June	1,359,290	3,481,410	738,004	11,754,541	48,771,176
July	1,535,292	3,774,000	872,878	11,878,011	51,310,881
August	1,461,497	3,659,002	796,122	12,390,266	52,039,337
September	1,194,176	3,319,344	717,592	11,092,593	47,528,233
October	902,073	2,533,270	555,755	9,231,077	40,579,184
November	989,420	2,960,941	623,669	10,164,278	40,595,896
December	1,203,908	3,578,195	727,487	12,826,330	48,106,861
Total	\$13,790,167	\$39,295,216	\$8,288,877	\$135,188,905	\$553,789,741

Exhibit_-- (WSS-1)

Rate Design

columns to show each member's expected annual cost and by month to show how the revenue would be collected throughout the year.

Rates Under Alternate Assignment Methodologies

To provide an indication of how assigning the investment costs of baseload generation would affect the rates, rates were also calculated using the traditional and energy methods. These rates have been summarized in a manner similar to the recommended rates on Table III-5 and Table III-6. Similarly, the affect of these rates on the member systems has also been included and is shown on Table III-7 and Table III-8.

Table III-9 was included to compare the effect of using different assignment methods on each of the member systems. The average cost of service, expressed in cents per kilowatt-hour, was calculated for each member cooperative using each of the three assignment methods.

As stated in Part II of this report, the equivalent peaker method was selected because it was felt that it would provide a fair allocation of costs between member systems. It was also felt that it would produce results that would allow Seminole to further its transition from the traditional utility world to the future, competitive electric power industry.

Exhibit_- (WSS-1)

Table III-5

PROPOSED WHOLESALE RATES

Seminole Electric Cooperative, Inc.

Traditional Method

Commodity

2.40 cents per kWh

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Capacity

\$8.80 kW per month Monthly member contribution to SECI peak.

Customer Charge

\$12,397 per member

Seminole Electric Cooperative, Inc. Cost-of-Service & Rate Design Study

Exhibit_- (WSS-1)

Table III-6

PROPOSED WHOLESALE RATES

Seminole Electric Cooperative, Inc.

Energy Method

Commodity

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3.01 cents per kWh

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Capacity

\$6.27 kW per month Monthly member contribution to SECI peak.

Customer Charge

\$12,397 per member
Table III-7

MONTHLY BILLS WITH PROPOSED RATES

Seminole Electric Cooperative, Inc.

Traditional Method

Units	Florida	Clay	Glades	Lee County	Peace River	Sumter
January	\$1,675,549	\$10,255,418	\$1,209,142	\$11,515,179	\$1,716,791	\$7,370,046
February	1,506,050	9,789,564	1,189,805	10,076,768	1,660,017	7,265,400
March	1,385,185	8,410,072	1,106,896	9,376,788	1,480,182	5,959,856
April	1,222,610	7,456,033	1,054,878	7,877,018	1,144,199	5,327,109
Мау	1,543,069	8,854,675	1,180,581	9,383,639	1,433,107	5,748,860
June	1,624,626	9,987,437	1,098,899	10,351,277	1,420,088	6,691,612
July	1,811,324	10,832,542	1,208,820	10,866,392	1,441,928	6,733,432
August	1,748,219	10,897,836	1,182,499	11,123,787	1,464,468	6,952,972
September	1,535,631	10,247,430	1,113,190	9,839,107	1,353,334	6,816,807
October	1,260,424	8,326,028	1,101,489	8,984,150	1,297,300	6,157,579
November	1,401,207	8,063,544	1,096,850	7,742,520	1,281,005	6,166,813
December	1,621,499	9,499,550	1,200,713	9,568,460	1,503,457	6,611,529
Total	\$18,335,395	\$112,620,130	\$13,743,762	\$116,705,082	\$17,195,876	\$77,802,015

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Exhibit_- (WSS-1)

Rate Design

Table III-7

MONTHLY BILLS WITH PROPOSED RATES Seminole Electric Cooperative, Inc.

Traditional Method

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Total
January	\$1,228,203	\$3,845,041	\$761,021	\$13,439,201	\$53,015,591
February	1,075,403	3,593,714	700,928	12,878,680	49,736,328
March	1,008,080	3,146,710	645,183	11,269,672	43,788,625
April	844,287	2,452,101	514,451	8,116,031	36,008,717
May	1,001,919	3,110,445	636,225	10,883,638	43,776,157
June	1,355,027	3,463,510	732,037	11,710,285	48,434,797
July	1,520,381	3,738,374	860,732	11,775,152	50,789,078
August	1,450,349	3,614,186	783,353	12,329,768	51,547,436
September	1,192,516	3,307,208	709,383	11,035,385	47,149,991
October	896,801	2,502,285	546,885	9,216,401	40,289,342
November	995,113	3,001,032	624,570	10,267,313	40,639,967
December	1,209,493	3,585,379	726,046	13,087,585	48,613,711
Total	\$13,777,572	\$39,359,986	\$8,240,813	\$136,009,112	\$553,789,742

Rate Design

Page 2 of 2

Part III

Seminole Electric Cooperative, Inc. Cost-of-Service & Rate Design Study Table III-8

MONTHLY BILLS WITH PROPOSED RATES Seminole Electric Cooperative, Inc.

Energy Method

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
January	\$1,640,336	\$10,144,172	\$1,219,022	\$11,129,358	\$1,657,252	\$7,129,004
February	1,460,257	9,550,796	1, 193,43 9	9,810,665	1,594,399	6, 9 43,318
March	1,372,949	8,378,852	1,134,282	9,430,328	1,470,791	5,815,414
April	1,231,037	7,507,459	1,075,179	8,092,230	1,176,164	5,359,447
Мау	1,551,504	8,954,081	1,213,747	9,591,873	1,472,198	5,839,248
June	1,632,640	10,173,564	1,142,450	10,562,228	1,457,299	6,694,817
July	1,840,652	11,008,623	1,256,873	11,169,937	1,488,184	6,790,164
August	1,778,913	11,080,939	1,225,392	11,444,066	1,523,809	6,990,527
September	1,555 ,16 9	10,404,868	1,156,987	10,106,542	1,387,214	6,848,685
October	1,271,666	8,439,377	1,127,906	9,200,823	1,339,494	6,173,865
November	1,391,713	8,053,604	1,113,065	8,006,193	1,302,642	6,080,441
December	1,604,176	9,430,261	1,216,839	9,432,103	1,475,119	6,412,719
Total	\$18,329,014	\$113,126,596	\$14,075,182	\$117,976,345	\$17,344,567	\$77,077,649

Part III

Exhibit_-- (WSS-1)

Rate Design

Table III-8

MONTHLY BILLS WITH PROPOSED RATES Seminole Electric Cooperative, Inc.

Energy Method

<u> </u>	Suwannee	Talquin	Trl-County	Withlacoochee	Total
January	\$1,203,828	\$3,720,727	\$751,153	\$12,862,446	\$51,457,299
February	1,041,487	3,434,597	678,122	12,194,237	47,901,317
March	997,208	3,049,159	642,934	10,965,070	43,256,987
April	855,140	2,505,663	530,703	8,261,679	36,594,701
May	1,035,440	3,143,388	654,087	10,941,395	44,396,962
June	1,362,926	3,496,671	743,090	11,792,272	49,057,957
July	1,548,004	3,804,373	883,234	11,965,704	51,755,747
August	1,471,000	3,697,210	807,008	12,441,844	52,458,709
September	1,195,591	3,329,691	724,590	11,141,366	47,850,705
October	906,568	2,559,687	563,316	9,243,589	40,826,291
November	984,567	2,926,761	622,902	10,076,435	40,658,324
December	1,199,146	3,572,070	728,715	12,603,595	47,674,744
Total	\$13,800,906	\$39,239,997	\$8,329,854	\$134,489,633	\$553,789,741

Burns & McDonnell Cost-of-Service & Rate Design Rate Design

Exhibit_- (WSS-1)

Part III

Table III-9

COMPARISON OF COST TO MEMBER SYSTEMS WITH DIFFERENT ASSIGNMENT METHODS Seminole Electric Cooperative, Inc.

(cents/kWh)

Units	Central Florida	Clay	Glades	Lee County	Peace River	Sumter
TRADITIONAL	4.57	4.47	4.22	4.37	4.43	4.69
EQUIVALENT PEAKER	4.57	4.48	4.28	4.39	4.45	4.67
ENERGY	4.57	4.49	4.32	4.42	4.47	4.65

Units	Suwannee	Talquin	Tri-County	Withlacoochee	Average
TRADITIONAL	4.55	4.60	4.44	4.72	\$4.54
EQUIVALENT PEAKER	4.56	4.59	4.47	4.69	\$4.54
ENERGY	4.56	4.58	4.49	4.67	\$4,54

Burns & McDonnell

Exhibit_- (WSS-1)

Rate Design



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PART IV - CONCLUSIONS AND RECOMMENDATIONS

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PART IV

Exhibit_- (WSS-1)

CONCLUSIONS AND RECOMMENDATIONS

This study was based on information provided by Seminole, including the 2000 budget numbers, and other sources. The information was also used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. These assumptions provided the basis for this cost-of-service and rate design study.

ASSUMPTIONS

Important assumptions made in performing the cost-of-service study and rate design are that:

- 1. energy and demand will be as forecast for Seminole and its members;
- 2. costs will be as budgeted by Seminole; and
- 3. all member cooperatives will be considered as one customer class.

CONCLUSIONS

Based on the cost-of-service study and rate design, Burns & McDonnell concludes that:

- 1. Seminole will need to meet a load of 37,907 MW and produce 12,194,143,000 kWh for its members in 2000.
- 2. The total cost of service for Seminole to provide service to its ten member distribution systems in the year 2000, will be \$553,789,741;
- This total cost of service can be assigned to the major utility functions using the equivalent peaker method to:
 - Commodity costs \$332,718,663;
 - Capacity costs \$219,583,495; and
 - Consumer cost \$1,487,583.
- 4. Using the traditional method of assigning costs transfers \$40,278,836 from power supply energy to power supply – demand. The total cost of service can be assigned to the major utility functions using the traditional method to:

Exhibit_- (WSS-1)

- Commodity costs \$292,439,827;
- Capacity costs \$259,862,331; and
- Consumer cost \$1,487,583.
- 5. Using the energy method of assigning costs transfers \$34,339,960 from power supply demand to power supply energy. The total cost of service for Seminole in the year 2000 using the energy method consists of:
 - Commodity costs \$367,058,623;
 - Capacity costs \$185,243,535; and
 - Consumer cost \$1,487,583.
- 6. The following rates (based on the equivalent peaker method of assigning costs) are cost-based and can provide the basis for designing wholesale rates for Seminole's ten members systems:
 - Commodity costs \$332,718,663;
 - Capacity costs \$219,583,495; and
 - Consumer cost \$1,487,583.

RECOMMENDATIONS

Based on conclusions as stated above, it is recommended that:

- 1. The equivalent peaker method be used for the assignment of costs;
- 2. Assignments based on the equivalent peaker method be the basis for developing final rates;
- 3. Seminole compare the cost-based rates with Seminole's existing rates to consider rate stability;
- 4. Seminole compare the cost-based rates with its strategic plans and other long- and short-term goals;
- 5. Seminole modify the rates, if necessary, after making comparisons with existing rates and Seminole and member goals;
- 6. Seminole implement the rate among its member systems;

- 7. Seminole's cost of service be re-evaluated regularly to ensure full cost recovery; Exhibit_- (WSS-1)
- 8. Seminole continue to review the effectiveness of its rates, especially if changes in member status or the electric utility occur;
- Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry; and
- 10. Seminole continue to position itself to be prepared as changes occur through the deregulation of the electric utility industry and consider investigating the appropriateness of rate concepts in the future including time-of-use rates, performance-based rates and accelerated recovery of investments.

STATEMENT OF OPERATIONS

Seminole Electric Cooperative, Inc.

Source: RUS Form 12a, Section A. Statement of Operations, for Year Ended 1998.

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	Item	1998 Year End
1.	Electric Energy Revenues	548,631,677
2.	income From Leased Property (Net)	
3.	Other Operating Revenue and Income	11,306,105
4.	Total Oper. Revenue & Patronage Capital (1 thru 3)	559,937,782
5.	Operations Expense - Production - Excluding Fuel	53,911,443
6.	Operations Expense - Production - Fuel	168,291,838
7.	Operations Expense - Other Power Supply	207,608,605
8.	Operations Expense - Transmission	23,849,089
9.	Operations Expense - Distribution	
10.	Operations Expense - Consumer Accounts	
11.	Operations Expense - Consumer Service & Information	
12.	Operations Expense - Sales	
13.	Operations Expense - Administrative & General	14,842,678
14.	Total Operation Expense (5 thru 13)	468,503,653
15.	Maintenance Expense - Production	25,468,879
16.	Maintenance Expense - Transmission	934,086
17.	Maintenance Expense - Distribution	
18.	Maintenance Expense - General Plant	196,784
19.	Total Maintenance Expense (15 thru 18)	26,599,749
20,	Depreciation and Amortization Expense	24,964,220
21.	Taxes	89,430
22.	Interest on Long-Term Debt	34,150,418
23.	Interest Charged to Construction - Credit	(176,522)
24.	Other Interest Expense	675,481
25.	Other Deductions	14,058,636
26.	Total Cost of Electric Service (14 plus 19 thru 25)	568,865,065
27.	Operating Margins (4 minus 26)	(8,927,283)
28.	Interest Income	10,269,310
29.	Allowances for Funds Used During Construction	
30.	Incomes (Loss) from Equity Investments	254,070
31.	Other Nonoperating Income (Net)	732,205
32.	Generation and Transmission Capital Credits	
33.	Other Capital Credits and Patronage Dividends	166,764
34.	Extraordinary Items	
35	Net Patronage Capital or Margins (27 thru 34)	2,495,066

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BALANCE SHEET

Seminole Electric Cooperative, Inc.

Source: RUS Form 12a, Section B. Balance Sheet, for Year Ended 1998.

	ASSETS AND OTHER DEBITS	1998 Year End
1	Total Utility Plant In Service	\$45,908,346
2	Construction Work in Progress	15,252,830
3	Total Utility Plant (1+2)	861,161,176
4.	Accum. Provision for Depreciation & Amort.	337,141,968
5.	Net Utility Plant (3-4)	524,019,208
6.	Non-Utility Property (Net)	
7.	Investments In Subsidiary Companies	4,472,883
8.	Invest. In Assoc. Org Patronage Capital	547,183
9.	Invest. In Assoc. Org Other - Gen. Funds	17,928
10.	Invest. In Assoc. Org Nongen. Funds	7,247,150
11.	Investments in Economic Development Projects	
12.	Other Investments	
13.	Special Funds	91,548,374
14.	Total Other Property and Investments (6 thru 13)	103,833,328
15.	Cash - General Funds	25,103
16.	Cash - Construction Funds - Trustee	113,672
17.	Special Funds	
18.	Temporary Investments	71,285,386
19.	Notes Receivable (Net)	
20.	Accounts Receivable - Sales of Energy (Net)	21,932,202
21.	Accounts Receivable - Other (Net)	886,831
22.	Fuel Stock	37,796,297
23.	Materials and Supplies - Electric and Other	17,545,183
24.	Prepayments	2,722,430
25.	Other Current and Accrued Assets	77,016
26.	Total Current and Accrued Assets (15 thru 25)	152,383,220
27.	Unamortized Debt Disc. & Extraordinary Prop. Losses	4,216,048
28.	Regulatory Assets	3,832,178
29.	Other Deferred Debits	48,747,783
30.	Accumulated Deferred Income Taxes	2,675,843
31.	Total Assets and Other Debits (5+14+25 thru 30)	839,807,608

LIABILITIES AND OTHER CREDITS	
32. Memberships	1,000
33. Patronage Capital	
a. Assigned and Assignable	79,309,964
b. Retired This Year	676,441
c. Retired Prior Years	13,144,828
d. Net Patronage Capital	65,488,695
34. Operating Margins - Prior Years	
35. Operating Margins - Current Year	(8,760,519)
36. Non-Operating Margins	11,255,585
37. Other Margins and Equities	31,715
38. Total Margins and Equities (32 plus 33d thru 37)	68,016,476
39. Long-Term Debt - REA (Net)	7,371,070
(Payments-Unapplied)	
40. Long-Term Debt - Other - Econ. Devel. (Net)	
41. Long-Term Debt - FFB - REA Guaranteed	420,832,678
42. Long-Term Debt - Other - REA Guaranteed	
43. Long-Term Debt - Other (Net)	206,414,147
44. Total Long-Term Debt (39 thru 43)	634,617,895
45. Obligations Under Capital Leases - Noncurrent	18,581,800
46. Accumulated Operating Provisions	5,392,515
47. Total Other Noncurrent Liabilities (42+43)	23,974,315
48. Notes Payable	18,697,049
49. Accounts Payable	24,624,492
50. Taxes Accrued	101,034
51. Interest Accrued	819,591
52. Other Current and Accrued Llabilities	34,686,632
53. Total Current & Accrued Liabilities (45 thru 48)	78,928,798
54. Deferred Credits	31,694,281
55. Accumulated Deferred Income Taxes	2,675,843
56. Total Liabilities and Other Credits (36+41+44+49 thru 51)	839,807,608

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CosmodelBF3.xis Form12 Financial (2) Page 1

PLANT-IN-SERVICE

Beningle Electric Cooperative, Inc. Beningle Electric Cooperative, Inc. Sources: RUS Form 12a, Annuel Supplement Section A. Utility Plant, for Year Ended 1998 and 1999 & 2000 Capital Budget

					[1		_	
L	Kem	Total				ŀ			
	1. Total Intangible Plant (301 - 303)	5 779 220	2011070	KWH	ACC	T-KW	CONS	(E).	
Т	2. Total Production Plant - Steam (310 - 316)	673 348 929	203 651 204	2,672,372	•	1.061.971		GEAL	Description of Assignment
	3. Total Production Plant - Nuclear (320 - 325)	22,306 484	8,006,000	379,797,668		}			Prod/Xman Plant Ratio
E	4 Total Production Plant - Hydro (330 - 336)		0,000,028	14,290,456				1	XW, XWH - 625 MW Capacity
F	D. Total Production Plant - Other (340 - 346)								KW, KMH - CR3
F	6. SUBTOTAL - Production (2 Ihru 5)	688,688,413	301 666 780					1	KW
	7. Land and Land Rights (350)	16,406,249		394,096,124			· · ·	1	KW
L	o. Structures and Improvements (352)			1 1		16,406,249			
Ι.	 Sumon Equipment (353) 			1 1		-	1		T-KW
H	C. Other Transmission Plant (354 - 359)	140,203,133		1 1		1 .		1	The
Ľ	10) SUBTOTAL - Transmission Plant (7 thru					140,203,133			THOM
h	2 I and and I and Picky takes	158,609,382	•						14.44
H	3 Stortime and Improves (360)	•			· · ·	164,609,382	L		
1	4 Station Ecolometric (361)	•		1 1					OPT OP & OF P OF P
1	5. Other Distribution Direct (352)	•							OP-T OP-S OF D CONS
H	8.	- <u> </u>		1 1					OP-T OP-S OP-D, CONS
ľ	SUSTOTAL - Distribution (10 the co)								Dist Piers Batto
3	7. Land and Land Richts (380)		•						
1	5. Structures and improvements (200)	796,157	282,414	369.078				•	
1	9. Office Furniture & Equipment (301)				-	140,667			Prod/Xman Plant Date
2	Transportation Equipment (397)	1,597,554							Prod/Xman Plant Balls
2	I. Stores, Tools, Shon, Games, and inh	748,182		748,182		1 1	1,597,554		CONS
	Equipment (393, 394, 345)								KONH
Z	Power - Operated Equipment (198)	•	i						
23	Communication Equipment (397)					1			9% to 11 Functional Areas
24	Miscellaneous Equipment (398)	5,648,731	228,989	338,964		2 250 602			9% to 11 Functional Areas
2	Other Tangible Property (399)	15,591,733	5,516,867	7 209,780		2 845 (000	2,259,892	564,973	Standerd/Judoment
Z	SUBTOTAL - General Plant (16 Ibos 24)					2,003,000			Prod/Xmsn Plant Ratio
27	Other Utility Plani (101, 114, 120)	44,348,387	6,028,271	8,668,022		8 971 846			Prod/Xmsn Pient Ratio
28	SUBTOTAL (1+5+12+16+26+27)	442 434 374		•			3,867,446	664 873	
25	Construction Work in Progress (107)		309,629,437	405,434,818	-	162 642 687		· · ·	Prod/Xman Plant Ratio
30	TOTAL UTRITY PLANT (28+29)	417 476 170	-	· · ·			4,001,446	564,973	
			309,628,437	406,434,818		162 642 987	1411	·	Prod/Xman Plant Ratio
							4,997,998	64 971	

SUBTOTALS	Total						
Sublotal - Production Plant		KWV	KWH	ACC	Tunu		
Subiotal - Transmission Riset	090,000,413	301,559,269	394,095,124			CONS-D	GENL
Subjected - Distribution	156,609,382			-		•	•
Total Bradition				-	155,609,382	•	-
Total ProcessmanyDiet Plant	052,264,795	301 559 200	201000101	-			-
Subtotal - General	24 385 357	8.005.034	394,046,124	•	155,609,382		
intangibies i	5 770 220	6.025,271	8,666,022		5 271 645		•
All Other Utility Plant	0,110,220	2,044,878	2,672,372	_	1.001.074	3,03/,446	564,973
CWIP	0 I	•	•	•	1,001,9/1	•	
Total Diffs Direct	•			•	•		-
Form County Filling	662,429,372	309 629 417	ANE 434 544		· · ·		_
			4.0,434,518	· · ·	162,942,997	3 857 444	
RATIO CALCULATION							504,973
Production Plant Ratio	4 6 6 6						
Transmission Plant Ratio	1.000	0.433	0.567				
Distribution Plant Ratio East dia and	1.000	•			•	• 1	•
ProdVerse/Vers	•			•	1,900	•	
Total Internet Print Ratio	1.000	0 364		•	•		-
roun comp Prent Ratio	1.000		0.462	-	0.184		•
		0.361	0.460		0 184		•
					0.100	0.004	0.001

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TRIAL BALANCE

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Seminole Electric Cooperative, Inc. G&T Cooperative Source: General Ledger Balance, for Year Ended 1998. Verify range names "Acct" and "Acct_Bal" extend to bottom of list. Add or delete accounts as necessary.

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ļ	4007	BERRING W	1998 Year End
	ACCI	DESCRIPTION	Balance
Ì	101.00	UELECTRIC PLANT IN SERVICE	\$2,465
ĺ	101.11	I LEASED ASSET-TRANSPORTATION LEASES	39,328,827
İ	107.10	D CONSTRUCTION WORK IN PROGRESS	15,244,930
l	108.10	DEPRECIATION STEAM PLANT	(244,903,148
I	108.20	DIDEPRECIATION NUCLEAR PROD. PLANT	(6,293,017
ĺ	108.50	DEPRECIATION TRANSMISSION	(41,295,681
ł	108.70	DEPRECIATION GENERAL PLANT	(11,139,890
l	108.91	COST OF REMOVAL - NUCLEAR CLEARING	
ļ	111.10	ACCUMULATED AMORTIZATION	(18.452.426)
İ	111.12	ACCUMULATED AMORTIZATION	(1734.479)
ł	111.12	ACCUMULATED AMORTIZATION	(6.334.000)
	114.100	ACQUISITION ADJUSTMENT	557 907
	115.10	ACCUMULATED AMORTIZATION - ACQUISITION ADJUSTMENT	(D94(689)
	120.100	NUCLEAR FUEL IN PROCESS	131.755
	120.200	NUCLEAR FUEL STOCK	1.132.002
	120.300	NUCLEAR FUEL IN REACTOR	1
	120.400	SPENT NUCLEAR FUEL	4.131.020
	120.500	ACC. AMORTIZATION - NUCLEAR FUEL	(8 504 470)
	123.105	PATRONAGE CAPITAL	647 103
	123.110	SECI INVESTMENT	2330.000
	123.225	CFC	3476 112
	123.230	OTHER INVESTMENT IN ASSOCIATE ORGANIZATIONS	2.51.617
	123.235	INVESTMENT IN CFC	
	123.245	SUBTERM CERTIFICATE - TBT.	1772 038
	128.220	POL CNTRL BOND FUND	252 878
	128.225	INT REC PC BOND FUND	State States
	128.305	SPECIAL FUND DSR	14.832.000
	128.315	DSR DISCOUNT	(43750)
	128.329	AMORT DSR DISCOUNT	10.205
	128.335	ACRD INT REC DSR	121 577
	128.400	TRANS SERVICES	36 290 483
	128.410	INTEREST - LLB	28.781.633
	128.507	NUCLEAR DECOMM TRUST FUND	2 532 149
	128.517	NDTF INTEREST RECEIVABLE	71 349
	131.111	CASH. OPERATING	(9.522.106)
	131.205	CAST. TRUST	113 672
	134.107	NDTF TRADING	1,202,975
	135.100	PETTY CASH	1,000
	135.200	TRAVEL ADVANCES	1.289
	136.200	CASH EQUIVILANT INVESTMENT	83 256,000
	136.210	CASH EQUIVILANT ACCR INTEREST	11.809
	142.105	ACCOUNTS RECEIVABLE - ELECTRIC	17.613.707
	142.114	ACCOUNTS RECEIVABLE - INTCH	4.118.496
	142.225	ACCOUNTS RECEIVABLE - MEMBER WORKORDERS	7.096
	143.200	ACCOUNTS RECEIVABLE - BY-PRODUCT SALES	25.013
	143.240	CCOUNTS RECEIVABLE - MISCELLANEOUS	667.379
	143.250	CCOUNTS RECEIVABLE - RENT	125
	143.270	CCOUNTS RECEIVABLE - PC LOAD REPAYMENT	188 538
	143.280	CCOUNTR RECEIVABLE - MEDICAL INS NON-EMPLOYEES	2.331
	151.100 0	COAL - CURRENT YEAR THE REPORT OF THE REPORT OF THE REPORT OF	163,297,720
	151.109	COAL - CONSUMMED CURRENT YEAR	(129.379.042)
•	151.200 F	ETROLEUM COKE INVENTORY	10,001.812
•	151.209 P	ETCOKE - CONSUMED CURRENT	(6,854.572)
•	151.300 7	UEL OIL - CURRENT YEAR	947.747
•	151.309	UEL OIL . CONSUMED CURRENT YEAR	(\$38.688)
•	151.309 P	UEL OIL . ACCUMULATED HISTORY	79.222
•	62.100 F	UEL STOCK EXP - CURRENT YEAR	3,426.183
•	52,107 P	ETCOKE HANDLING	(124.252)
1	52,109 F	UEL STOCK EXP TSF - CURRENT YEAR	(2,669.834)
1	54.110 N	ATERIALS & SUPPLIES - I&I MMIS	15.750.847
1	54.117 N	ATERIALS & SUPPLIES - LIMESTONE	160.610
1	54.120 N	ATERIALS & SUPPLIES - CRYSTAL RIVER	\$56.031

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Cosmodel8F3.xls Trial Balance Page 1

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		1998 Year End
ACCT	DESCRIPTION	Balance
154.1	IO MATERIALS & SUPPLIES	1,073,860
154.1	IS MATERIALS & SUPPLIES	3,331
154.14	IS MMIS CLEARING	158
154.3	GASOLINE INVENTORY	557
165.1	0 PPD CR3	3,193,643
165.10	A PPD FPC	6,490,000
165.10	9 PPD COAL	2,083,442
185.20	O PPD TRAVEL EXPENSE	8,239
165.30	RIPPD OTHER	204,775
760.30		23,755
100.40	SINT MC DEC. CEC	10,163
473.40		A STATE OF A STATE
173 24	O ACCRUED SALES	(407 000)
174.10	CAPITALIZED ACCRUED P/R	
181.10	9 UMAMORTIZED DEBT EXPENSE - OPEN	
181.11	9 UNAMORTIZED DEBT EXPENSE - CLOSED	3.886.000
182.32	9 UI LEASE	3.932.178
183.10	O PRELIMINARY SURVEY & INVESTMENT	132.888
184.01	9 OVERHEAD ALLOCATION - PR	1,528,910
184.02	9 OVERHEAD ALLOCATION - PR	(1,514,815)
184.24	O ACCOUNTS PAYABLE SUSPENSE	429
184.27	OVERHEAD ALLOCATION - CLEARING	(32,787)
186.50	9 DEF DEBITS - COAL TRANSPORTATION	1,574,202
189.11	UNAMORTIZED DEBT - CLOSED	41,816,422
189.13	REFINANCE CU-BASIS	5,245,534
190.00	UEPERKEU INCOME TAX ASSET	48,015,231
190.01		(43,339,388)
200.10		(1,000)
201.10		[76,604,197]
201.10		(101,556,535)
201 12		
201.20	PATRONAGE CAPITAL ASSIGNANT E	13,144,828
201.20	TAX MARGINS ASSIGNARI I	- (2,/U0;/0/)
201.30	ACRUED STOCK ISSUED	7 330 000
208.000	DONATED CAPITAL	(31 745)
221.10	PRTN LTD-PC S&H	(137.650.000)
224.128	L ST PRTN LTD-CFC	(8.743.919)
224.145	PRTN LTD-REA	(5.963.425)
224.155	PRTN LTD-REA C8	(429,406,593)
224.305	PRTN LTD-RUS	(7.634.743)
224.600	FINANCE OBL UNIT I LEASE	(63,916,264)
227.000	NON-CURRENT CAPITAL LEASE	(18,581,800)
228,100	PROPERTY INSURANCE	(185,667)
228.300	FAS 112 PROV FOR PENSION & BENEFITS	(356,500)
228.310	PROVISION FOR PENSION & BENEFITS -SERP	(143,626)
228.320	FAS 106 SICK LEAVE POST RETIREMENT BENEFIT	(2,740,384)
228.328	PAS 106 MEDICALIOTHER POST RETIREMENT	(1,663,416)
228,400	CRJ CUIAGE RESERVES - CYCLE #11	(302,922)
232,100	ACCOUNTS PAYABLE GENERAL	(6,212,856)
232.200		(8,705,391)
232.300	ACCOUNTS PATABLE CRIN	(95,070)
236 200	CITA TAY DAVADI E	(3,981)
238.300	FICA/OASDI TAX PAYARLE	(360)
236.310	FICA/MEDICARE TAX PAYARI F	(16,647)
236.400	SUTA TAX PAYABLE	[4,386]
236.500	STATE SALES TAX	31 744
234.505	ACCR STATE SALES TAX - UZ LEASE	(3.811)
234.550	ACCR HILLS CO SALES TAX	(371)
238.600	ACCR GROSS RECEIPTS TAX	(21)
236.700	ACCRUED STATE SALESTAX	(106.858)
237.305	ACCR INTEREST PC	(819.591)
241.200	FED WW - PAYABLE	9,978
242,200	ACCR PAYROLL	(345,602)
242.310		(770,537)
242.505	ACCR MISC FEE	(132,314)

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ACCT DESCRIPTION Balance 242.510 ACCR CONTROLLABLE EDXY (7.819.64) 242.530 ACCR CONTROLLABLE EDXY (7.849.64) 242.530 ACCR CONTROLTS (7.849.64) 242.530 ACCI LEASE - PAT - U2 (7.322.282) 242.540 ACCI LEASE - PAT - U2 (7.822.282) 242.540 ACCI LEASE - PAT - V2 (7.822.282) 242.540 ACCR UED SANK SET COMPL (7.802.09) 242.540 ACCRUED BANK SERVICE CHANGES (7.909.09) 242.540 ACCRUED BANK SERVICE CHANGES (7.909.09) 23.540 MEMBER RELATE DEFERIED CREDET (7.909.09) 23.540 URRENT CAPITAL LEASE (7.809.09) 23.540 U				1998 Year End
242.50 ACC R CONTROLLABLE EDXP (1.4818.482) 242.50 ACC R CR - DBY COST (2.8488) 242.50 ACC R CR - DBY CONTRACTS (1.665.602) 242.50 ACC LEASE - PMT - U2 (1.822.810) 242.50 ACC LEASE - PMT - U2 (1.822.810) 242.50 ACC LEASE - PMT - U2 (1.822.810) 242.50 ACC LEASE (1.622.310) 242.50 ACC RUED FUEL WONTORY PAYABLE (1.60.600) 242.50 ACC RUED FUEL DECERFTS (1.60.600) 242.50 ACC RUED FUEL DECERFTS (1.60.600) 242.50 ACCRUED FUEL DECERFTS (1.60.600) 242.50 ACCRUED FUEL DECERFTS (1.60.600) 242.50 ACCRUED TELENED CORDET (1.60.600) 243.50 ACCRUED TELENED CORDET (1.60.600) 233.60 UZ DEF LASE FNANCE (1.60.600) 233.40 UZ DEF LASE FNANCE (1.60.600) 233.40 UZ DEF GAIN SALE OF UNT 2 (1.60.600) 234.60 UZ MORDAR OWER REAT LEASE (1.60.700) 234.60 UZ WOROAD DEF FIN (1.60.777.716) 234.60 UZ MORDAR OWER ACT LEASE (1.60.777.716) 234.60 UZ MORDAR OWER ACT LEASE (1.60.777.716) 234.60 UZ MORDAR OWER ACT LEASE	AC	CT	DESCRIPTION	Balance
242.327 ACCR CR3 - DISP COST (23.420) 242.300 RETENTION - CURRENT CONTRACTS (173.480) 242.400 DEDUCTIONS (173.480) 242.400 DEDUCTIONS (173.480) 242.450 ACC LEASE - PMT - U2 (183.282) 242.451 ACC LEASE - PMT - V2 (183.282) 242.450 ACC LEASE - PMT - V2 (183.282) 242.450 ACC LEASE - PMT - V2 (183.282) 242.450 ACC LEASE - PMT - V2 (180.282) 242.450 ACC RUED SANK ST COMPT (180.282) 242.450 ACC RUED BANK ST COMPT (182.472) 232.460 ACP RUED RUE AND ST COMPT	24	2.510	ACCR CONTROLLABLE EDXP	(1,618,544)
222.30 INETENTION - CURRENT CONTRACTS (1.064.000) 222.400 ICC LEASE - PAT - U2 (1.322.202) 224.500 ICC LEASE - PAT - U2 (1.322.202) 224.501 ICC LEASE - PAT - U2 (1.322.202) 224.501 ICC RUED FUEL INVENTORY PAYABLE (1.022.201) 224.501 ICC RUED FUEL INVENTORY PAYABLE (1.022.201) 224.501 ICC RUED FUEL DECERPTS 7.722.201) 224.500 ICCAL SURVEY ADJUSTMENT (1.022.201) 224.500 ICCAL SURVEY ADJUSTMENT (1.022.201) 224.500 ICCAL SURVEY ADJUSTMENT (1.022.201) 234.500 ICRENT CONTA LEASE (1.202.201) 234.500 ICRENT CONTA LEASE (1.202.201) 234.500 ICRENT CONTA MISCIC CONT (1.623.201) 234.500 IDECOMINISSION CONT (1.624.201) 234.500 IDECOMINISSION CONT (1.624.201) 234.500 IDECRENT CONTACLESA (1.77.201) 234.500 IDECRENT CONTACLESA (1.77.201) 234.500 IDECRENT CONTACLESA (1.77.201)	24	2.527	ACCR CR3 - DISP COST	(28,968)
12.3.50 JEDUC HUNS (173,480) 12.3.50 JECUC LEASE - NUT - 1/2 (132,222) 22.3.51 JECC LEASE - NUT - 1/2 (132,222) 22.3.52 JECC LEASE - NUT - 1/2 (132,222) 22.3.53 JECC LEASE - NUT - 1/2 (153,227) 22.3.56 JECC RUE DAWK PAYABLE (160,050) 22.4.56 JECR STUDE ST COMPL (160,050) 22.4.56 JECR ST JUEST ST COMPL (160,050) 23.4.50 JUEST LEASE TO DEFERRED CREDT (71,132) 23.4.60 JUEST LEASE TO ANACE (24,89,332) 23.4.60 JUEST LEASE TO ANACE (24,89,722) 23.4.60 JUEST LEASE TO ANACE (24,722) 23.4.60 JUEST LEASE TO ANACE (24,722) 23.4.60 JUEST LEASE TO ANACE (24,722) 23.4.60 JUEST LEASE TO ANACE (24,724) 23.4.60 JUEST LEASE TO ANACE	24	2.530	RETENTION - CURRENT CONTRACTS	(1,055,604)
21.2500 CC (LEASE (1.282,280) 21.2500 CCC RPUR PWR PATABLE (1.282,280) 22.2500 CCCR PUR PWR PATABLE (1.150,237) 22.2580 CRCRUED FUEL RECEIPTS (1.00,050) 22.2580 CCRUED FUEL RECEIPTS (1.00,050) 22.2500 CCAL SURVEY ADJUSTMENT (1.00,050) 22.3500 CCRUED ADMK SERVICE CHARGES (1.00,050) 23.3000 CURENT CAPTAL LEASE (1.00,050) 23.3000 LORENT CAPTAL LEASE (1.00,050) 23.3000 LORENT CAPTAL LEASE (1.280,720) 23.3000 LORENT CAPTAL LEASE (1.280,720) 23.3000 LORENT CAPTAL LEASE (1.280,720) 23.3000 LINEASE CITY OCALA (1.280,720) 23.400 LIPETERD INCOMECTIY OCALA (1.280,720) 23.4000	24	2.540	DEDUCTIONS	(173,568)
242.570 ACCR PUR PWR PAYABLE (2.452,310) 242.580 ACCRUED FUEL RWENTORY PAYABLE (8,464,272) 242.480 ACCRUED FUEL RWENTORY PAYABLE (8,464,272) 242.480 ACCRUED BALK SET COMP. (30,000) 242.500 COLL SURVEY ALAULISTMETHT (23,284) 242.500 COLL SURVEY ALAULISTMETHT (23,284) 242.500 CORRENT CAPITAL LEASE (13,000) 23.100 CR3 DECOMMISSION COST (24,884,730) 23.400 DEFERRED DEFERRED CREDITE (14,984,000) 23.400 DEFERRED CR - 483C (74,984,000) 23.400 DEFERRED CR - 483C (77,234) 23.400 DEFERRED CR - 483C (77,234) 24.100 DEFERRED CR - 483C (77,234) 23.400 DEFERRED CR - 483C (77,234) 24.100 DEFERRED CR - 483C (77,234) 23.100 DEFERRED CR - 483C (77,234) 23.100 DEFERRED BROMECHTY (24,23,240) 21.400 DEFERRED BROMECHTY (24,23,240) 22.100 STRAMET ACUPHANT <th>24</th> <th>2.360</th> <th>ACC LEASE - PHI - UZ</th> <th>(1,262,262)</th>	24	2.360	ACC LEASE - PHI - UZ	(1,262,262)
242.500 ACCRUED FUEL INVENTORY PAYABLE (11,536,227) 242.500 ACCRUED FUEL RECEPTS (10,000,000,000,000,000,000,000,000,000,	24	2.30J		(2,552,310)
242.583 OTHER STL-UZ BAT COMPL (64.04.272) 242.706 COLA SURVEY ADJUSTMENT (22.2361) 242.706 COLA SURVEY ADJUSTMENT (22.2361) 242.500 PREPAD POWER BLING) (22.361) 242.500 CRUED BAIK SERVICE CHARGES (23.562) 243.600 CURRENT CAPITAL LEASE (24.567) 233.600 URBER RELATED DEFERRED CREDTE (24.567) 233.400 DEF LEASE FINANCE (24.567) 233.400 UDEF LEASE FINANCE (24.567) 233.400 UREARNED INCOME CITY OCALA (76.77) 245.100 DEFERRED CRIMET ACL LABILITY (24.54.53.57) 234.500 UREARNED INCOME CITY OCALA (76.77) 245.100 DEFERRED CRIMET ACL LABILITY (24.54.53.57) 234.500 DEFERRED CRIMET ACL LABILITY (24.54.53.57) 231.000 LERFERED CRIMET ACL LABILITY (24.54.53.57) 231.000 DEFERRED CRIMET ACL LABILITY (24.54.54) 231.000 LERFERED CRIMET ACL LABILITY (24.54.54) 231.000 DEFERERED CRIMET ACL LABILITY (24.54.54) </th <th>242</th> <th>2 680</th> <th></th> <th>(11,136,237)</th>	242	2 680		(11,136,237)
342.600 MARS UNIANT CHED RECEIPTS (100,000) 342.700 COALS UNIVEY ADJUSTMENT (100,000) 342.800 ACCRUED BANK SERVICE CHARGES (120,000) 342.800 ACCRUED BANK SERVICE CHARGES (120,000) 342.800 ACCRUED BANK SERVICE CHARGES (120,000) 342.800 MEMBER RELATED DEFERRED CREDITE (140,000) 323.400 U2 DEF LEASE FNANCE (140,000) 233.400 U2 DEF LEASE FNANCE (140,000) 233.400 U2 DEF LEASE FNANCE (140,000) 234.400 DEFERED INCOME_CITY OCALA (160,000) 243.600 UNEARNED IN COME_CITY OCALA (160,000) 243.600 DEFERED INCOME_CITY OCALA (160,000) 244.000 DEFERED INCOME_CITY OCALA (160,000) 244.000 DEFERED INCOME TAX LIABILITY (247,438) 304.000 TANGIBLE PLANT - AUERA (160,000,000) 310.000 TANGIBLE PLANT - AUERA (160,000,000) 310.000 CAND AND LAND RIGHTS (160,000,000) 314.000 TURE OPLEART COUPMENT (373,897) <	242	7 525	OTHER STILLT EST COMP	(4,404,272)
342700 COAL SURVEY ADJUSTMENT	243	2.600	MUS INMATCHED RECEIPTS	(100,000)
342.800 PREPAD POWER BILING (10.383) 342.880 ACCRUED BANK SERVICE CHANGES (13.000) 343.000 CURRENT CAPTAL LEASE (13.000) 323.000 CURRENT CAPTAL LEASE (13.000) 323.000 LEASE FRUARCE (14.000) 323.400 LD DEF LEASE FRUARCE (14.000) 323.400 LD DEF CARLE TO CALL (14.000) 323.400 LD DEF CARLE ASE FRUARCE (14.000) 323.400 DEFERRED CR - MISC (14.000) 323.400 DEFERRED CR - MISC (14.000) 323.400 DEFFERED RCOME CTX CLABILITY (12.44.3187) 323.400 DEFFERED RCOME CALLELITY (24.74.843) 30.000 INTANGIBLE PLANT - MCUERAS (36.77.234) 31.000 STRUCTURES & MEROVEMENTS (49.76.238) 31.000 DEFFERED RCOME CAUERAT (36.77.234) 31.000 DEFFERED RCOME CAUERAT (49.76.238) 31.000 LAND AND LAND RIGHTS (49.76.248) 31.000 LAND AND RCHTS (37.33.807) 32.000 LAND CAUE RUMENT	242	2,700	COAL SURVEY ADJUSTMENT	72.361
243.00CURRENT CAPITAL LASIECLANGES243.00CURRENT CAPITAL LASIECLANE, 139233.40CURRENT CAPITAL LASIECLANE, 139233.40LOR J DECOMMESSION COSTCLANE, 130233.40LU DEF LEASE FINANCECLANE, 139233.40LU ZWEGOAD DEF FINCLANE, 132233.40LU ZWEGOAD DEF FINCLANE, 132233.40LU ZWEGOAD DEF FINCLANE, 132233.40LUE FLEASE FINANCECLANE, 132234.40DEFRERED CR. MSC.CLANE, 142235.400DEFRERED CR. MSC.CLANE, 142235.400DEFRERED CR. MSC.CLANE, 142236.100AMORTIZATION OF DEFERRED GAIRSJUNT ZCLATA, 142236.100DEFRERED INCOME TAX LABILITYCLATA, 142231.000DEFRERED INCOME TAX LABILITYCLATA, 142231.000DEFRERED INCOME TAX LABILITYCLATA, 142231.000DEFRERED INCOME TAX LABILITYCLATA, 142231.000DEFRERED INCOME TAX LABILITYCLATA, 142231.000DER PLANT EQUIPMENT360322.88310.000LAND AND LAND RUGHTSCLATA, 142311.000TRUCTURES & IMPROVEMENTS3773.387321.000TURBOGENERATOR UMITS373.387321.000CLARCTOR PLANT EQUIPMENT33.137,83321.000CLARD AND LAND RIGHTS373.387322.000NEGOCONCHARD RUGHTS38.465,112323.000TURBOGENERATOR UMITS38.465,112331.000CLAND AND LAND RIGHTS38.465,112331.000STRUCTURES &	242	2.800	PREPAID POWER BELLING	
243.000CURRENT CAPTAL LASSECLEME233.000ICR3 DECOMINISSION COST(1.023)233.400IU2 DEF LEASE FINANCE(1.4.090,009)233.400IU2 DEF LEASE FINANCE(1.4.090,009)233.400DEFERED CR - MISC(1.4.090,009)233.400DEFERED CR - MISC(1.4.090,009)234.400DEFERED CR - MISC(1.4.090,009)234.400DEFERED CR - MISC(1.4.091,009)234.100DEFERED CR - MISC(1.4.091,009)234.100DEFERED ROME TAX LABILITY(1.4.091,009)234.100INTANGIBLE PLANT - ACUERA(1.4.091,009)301.000INTANGIBLE PLANT - ACUERA(1.4.091,009)303.000INTANGIBLE PLANT - ACUERA(1.4.091,009)314.000INTANGIBLE PLANT CURRENTS(1.4.091,009)314.000INTANGIBLE PLANT EQUIPMENT(1.4.091,009)310.000INTANGIBLE PLANT EQUIPMENT(1.4.091,009)320.000INTROCURES & MAPROVEMENTS(1.4.091,009)	242	2.950	ACCRUED BANK SERVICE CHARGES	
233.000 MEMBER RELATED DEFERRED CREDT: 71.023 233.100 CAS DECOMMISSION COST CLAMS, CZS 233.400 UZ DEF LEASE FINANCE CLAMS, CZS 233.400 UZ DEF LEASE FINANCE CLAMS, CZS 233.400 UZ DEF LEASE FINANCE CLAMS, CZS 233.400 UREARNED INCOME CITY OCALA (122,272 245.100 DEF CRED, CAS, CASE OF LANS, CASE (127,072) 245.100 DEFTERED, INCOME CITY OCALA (127,072) 245.100 DEFTERED, INCOME TAX LUBRS, LINIT 7 (127,043) 231.000 EFFERED, INCOME TAX LUBRS, LINIT 7 (127,043) 301.000 INTANGIBLE PLANT - ACUERA (127,043) 301.000 INTANGIBLE PLANT - ACUERA (128,043) 310.000 INTANGIBLE PLANT EQUIPMENT (13,046,043) 310.000 INTANGIBLE PLANT EQUIPME	243	5.000	CURRENT CAPITAL LEASE	7 666 4161
231.100 CR3 DECOMMISSION COST CL898(72) 231.400 LD DF LEASE PRANCE (4.400,000) 233.400 DEFERRED CR - MASC (4.400,000) 233.400 DEFERRED CR - MASC (6.400,000) 233.400 DEFERRED CR - MASC (6.400,000) 234.100 ADORTUATION OF DEFERRED GAINS-UNIT 2 (18,274,274) 24.100 ADORTUATION OF DEFERRED GAINS-UNIT 2 (18,274,274) 231.000 INTANGIBLE PLANT - ACUERA (2,474,84) 231.000 INTANGIBLE PLANT - ACUERA (2,474,84) 31.000 INTANGIBLE PLANT - ACUERA (3,423,38) 31.000 INTANGIBLE PLANT - ACUERA (3,423,38) 31.000 INTANGIBLE PLANT EQUIPMENT (3,472,234) 31.000 INDA OR LAND RUMENT (3,472,234) 31.000 INDA AND LAND RUGHT3 (4,44,400) 31.000 INDA AND LAND RUGHT3 (4,44,400) 32.000 RACTOR PLANT EQUIPMENT (3,73,397) 32.000 STRUCTURES & MAPROVEMENTS (4,44,440) 32.000 STRUCTURES & MAPROVEMENTS (4,44,441)	253	1.050	MEMBER RELATED DEFERRED CREDIT	
233.400 LIZ DEF LEASE FINANCE 11.221.272 233.400 LIV ROBOGO DEF FIN 11.221.272 233.400 LIFERRED CR - MISC. (MISC) 234.100 DEFERRED CR - MISC. (MISC) 234.100 DEFERRED CR CALL OF UNIT 2 (A.242,321) 234.100 DEFFERRE NCOME TAX LUBINS UNIT 2 (A.242,321) 231.000 ENTANCIBLE PLANT - ACUERA (A.271,443) 231.000 INTANCIBLE PLANT - ACUERA (A.271,443) 301.000 INTANCIBLE PLANT - ACUERA (A.271,443) 310.000 INTANCIBLE PLANT EQUIPMENT (A.313,347,443) 314.000 TURBOGENERATOR UNITS (A.31,347,443) 314.000 TURBOGENERATOR UNITS (A.31,347,443) 314.000 TURBOGENERATOR UNITS (A.31,347,443) 314.000 TURBOGENERATOR UNITS (A.31,347,443) 314.000 TURBOGENERATOR UNITS (A.31,347,443) <th>253</th> <th>1.100</th> <th>CR3 DECOMMISSION COST</th> <th>1 BOR 7711</th>	253	1.100	CR3 DECOMMISSION COST	1 BOR 7711
233.466 LIZ WOBOGAD DEF FIN 1222.072 233.466 UNEARNED INCOME-CITY OCALA (1877) 234.100 DEF FERRED CA MISC (1877) 234.100 DEF GAN - SALE OF UNIT 2 (1842,43,817) 234.100 DEF FERRED NCOME TAX LUBELTY (2878,453) 231.000 DEFFERED INCOME TAX LUBELTY (2878,453) 231.000 INTANGIBLE PLANT - ACUERA (8873) 311.000 LAND AND LAND RIGHTS (8978,456) 314.000 TURDOGENERATOR UNITS' (36,752,285) 314.000 TURDOGENERATOR UNITS' (36,752,285) 314.000 TURBOGENERATOR UNITS' (36,752,285) 314.000 TURBOGENERATOR UNITS' (36,352,885) 314.000 TURBOGENERATOR UNITS' (37,33,87) 315.000 ACCESSORY ELECTRIC EQUIPMENT (438,534) 320.000 TURBOGENERATOR UNITS' (37,33,87) 321.000 TRUCTURES & MPROVEMENTS (37,33,87) 322.000 REACTOR PLANT EQUIPMENT (438,54) 324.000 ACCESSORY ELECTRIC EQUIPMENT (384,53)	253	.400	U2 DEF LEASE FINANCE	(14,000,000)
233.460 DEFERRED CR - MISC. (7.877) 234.800 UNERANED INCOME CITY OCALA (3.2.4.3.84) 234.800 DEF GAIN - SALE OF UNIT 2 (3.2.4.3.84) 234.800 DEFFERED BROME TAX LIABLITY (3.2.4.3.84) 231.800 DEFFERED BROME TAX LIABLITY (2.878.83) 231.800 INTANGBLE PLANT - ACUERA (3.8.3.84) 230.800 INTANGBLE PLANT - ACUERA (3.8.3.3.84) 21.000 LAND AND LAND RIGHTS (3.8.3.3.84) 21.000 INTROGENERATOR UNITS (3.8.3.3.84) 21.000 DER PLANT EQUIPMENT (3.8.3.3.84) 21.000 STRUCTURES & MEROVEMENTS (3.7.3.3.87) 22.000 REACTOR PLANT EQUIPMENT (3.8.4.3.7.8.3.84) 23.000 LAND AND LAND RIGHTS (3.8.4.3.7.8.3.84) 23.000 LAND AND LAND RIGHTS (3.8.4.3.8.8.8.1.1.7.1.8.1.8	253	.406	UZ WOSOO4D DEF FIN	20 272
235.000 UNEARNED INCOME CITY OCALA (242-43.87) 234.100 DEFFERED INCOME TAX LUBILITY (242-43.87) 234.101 AMORTIZATION OF DEFERRED GAINS-UNIT 2 (257.843) 301.000 INTANGBLE PLANT : ACUERA (58.87) 301.000 INTANGBLE PLANT : MPS (57.843) 311.000 STRUCTURES & MARCOVEMENTS (48.738) 311.000 STRUCTURES & MARCOVEMENTS (57.85,946) 314.000 TURBOGENERATOR UNITS (10.896,846) 314.000 TURBOGENERATOR UNITS (53.137,453) 314.000 NEROCOMER PLANT EQUIPMENT (53.137,453) 315.000 ACCESSORY ELECTRIC EQUIPMENT (54.354) 322.000 REACTOR PLANT EQUIPMENT (54.354) 324.000 ACCESSORY ELECTRIC EQUIPMENT (54.354) 324.000 AGCOSSORY ELECTRIC EQUIPMENT (54.354) 325.000 AGCOSSORY ELECTRIC EQUIPM	253	.460	DEFERRED CR - MISC	New Martin
254.109 DEF GAN - SALE OF UNIT 2 Dia243.387 254.109 MORTIZATION OF DEFERED GAINS UNIT 2 11,728,95 233.000 DEFFERED INCOME TAX LLABILITY 12,8778,93 301.000 LAND AND LAND RIGHTS 68,83 311.000 STRUCTURES & MAPROVE MENTS 68,87 312.000 BOILER PLANT - ACUERA 360,362,866 314.000 STRUCTURES & MAPROVE MENTS 360,362,866 314.000 BOILER PLANT EQUIPMENT 35,378,964 316.000 ACCESSORY ELECTRIC EQUIPMENT 35,798,943 316.000 MISC POWER PLANT EQUIPMENT 35,792,274 320.000 IND AND LAND RIGHTS 10,896,893 314.000 TURBOGENERATOR UNITS 17,33,967 321.000 TRUCTURES & MPROVEMENTS 3,73,967 322.000 REACTOR PLANT EQUIPMENT 3,86,831 324.000 ACCESSORY ELECTRIC EQUIPMENT 3,86,831 324.000 TURBOGENERATOR UNITS 3,27,33 324.000 TURUCTURES & MPROVEMENTS 3,27,33 325.000 TUCUTURES & MPROVEMENTS 3,27,33 326.001 TURUSTURES 30,000,860 <	253	.600	UNEARNED INCOME-CITY OCALA	7.577
235.109 JAMORTIZATION OF DEFERRED GAINS-UNIT 2 11,722,914 231.000 DEFFERRED NCOME TAX LIABILITY 2,878,833 301.000 INTANGIBLE PLANT - ACUERA 2,878,833 301.000 INTANGIBLE PLANT - MPS 4,882 301.000 LAND AND LAND RIGHTS 4,882 311.000 STRUCTURES & IMPROVEMENTS 69,764,546 312.000 BOILER PLANT EQUIPMENT 36,732,883 316.000 NGC POWER PLANT EQUIPMENT 36,137,653 316.000 NGC POWER PLANT EQUIPMENT 36,137,653 316.000 NGC POWER PLANT EQUIPMENT 36,174,534 322.000 REACTOR PLANT EQUIPMENT 3,174,533 322.000 REACTOR PLANT EQUIPMENT 1,443,634 324.000 NGC ESSORY ELECTRIC EQUIPMENT 3,847,733 324.000 NGC CESSORY ELECTRIC EQUIPMENT 3,845,511 325.000 STATION EQUIPMENT 3,845,511 326.000 STATION EQUIPMENT 3,845,711 326.000 CONERS AND FUTURES 33,857,112 326.000 ONCERS AND FUTURES 33,857,112	256.	.100	DEF GAIN - SALE OF UNIT 2	(35,243.361)
23.000 LEFFERD INCOME TAX LIABILITY C.878,853 301.000 INTANGIBLE PLANT - KUERA S.873 301.000 INTANGIBLE PLANT - KUERA S.772,344 301.000 LAND AND LAND RUGHTS S.786,348 311.000 STRUCTURES & IMPROVEMENTS S.6786,348 312.000 BOILER PLANT EQUIPMENT S.6786,348 314.000 TURBOGENERATOR UNITS S.6782,285 314.000 ACCESSORY PLANT EQUIPMENT S.6792,274 320.000 LAND AND RUGHTS S.6792,274 321.000 STRUCTURES & IMPROVEMENTS S.733,987 322.000 REACTOR PLANT EQUIPMENT S.6792,274 321.000 STRUCTURES & IMPROVEMENTS S.733,987 323.000 STRUCTURES & IMPROVEMENTS S.733,987 324.000 LAND AND LAND RUGHTS S.6792,274 325.000 STRUCTURES & IMPROVEMENTS S.733,987 324.000 LAND CHANG RUGHTS S.867,112 325.000 STRUCTURES & IMPROVEMENTS S.748,231 326.000 STRUCTURES & IMPROVEMENTS S.262,113 326.000 STRUCTURES & IMPROVEMENTS S.267,113 <t< th=""><th>256.</th><th>.109</th><th>AMORTIZATION OF DEFERRED GAINS-UNIT 2</th><th>19,728,914</th></t<>	256.	.109	AMORTIZATION OF DEFERRED GAINS-UNIT 2	19,728,914
303.000 INTANGUELE PLANT : ACUERA 56,000 303.000 LAND AND LAND RIGHTS 5,772,384 310.000 LAND AND LAND RIGHTS 5,772,384 312.000 BOLLER PLANT EQUIPMENT 360,352,885 314.000 TURBOGENERATOR UNITS 316,300 316.000 MCSE SORY ELECTRIC EQUIPMENT 35,137,483 316.000 MCSE COWER PLANT EQUIPMENT 35,773,887 321.000 LAND AND LAND RIGHTS 373,387 322.000 REACTOR PLANT EQUIPMENT 3,773,387 322.000 REACTOR PLANT EQUIPMENT 1,844,854 324.000 ACCESSORY ELECTRIC EQUIPMENT 1,844,854 324.000 ACCESSORY ELECTRIC EQUIPMENT 3,864,371 324.000 MISC POWER PLANT EQUIPMENT 3,864,371 324.000 MISC POWER PLANT EQUIPMENT 3,864,371 324.000 MISC POWER PLANT EQUIPMENT 3,864,371 324.000 MISC POWER PLANT EQUIPMENT 3,864,371 324.000 MISC POWER PLANT EQUIPMENT 3,864,371 325.000 MISC POWER PLANT EQUIPMENT 3,864,371 <t< th=""><th>283.</th><th>.000</th><th>DEFFERED INCOME TAX LIABILITY</th><th>(2,675,843)</th></t<>	283.	.000	DEFFERED INCOME TAX LIABILITY	(2,675,843)
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359.000 ROADS AND TRALS 1,399,446 389.000 LAND AND LAND RIGHTS 798,157 390.000 STRUCTURES & IMPROVEMENTS 7,448,923 391.000 OFFICE FURNITURE & EQUIPMENT 3,760,317 392.000 TRANSPORTATION EQUIPMENT 818,048 393.000 STORES EQUIPMENT 818,048 393.000 TOOLS, SHOP, & GARAGE EQUIPMENT 818,048 394.000 TOOLS, SHOP, & GARAGE EQUIPMENT 202,030 395.000 LABORATORY EQUIPMENT 202,030 395.000 POWER OPERATED EQUIPMENT 210,916 397.000 COMMUNICATION EQUIPMENT 5,722,993 398.000 MISC EQUIPMENT 90,530 399.000 OTHER TANGIBLE PROPERTY 90,530 403.049 DEPRECIATION EXPENSE-TRANSFERRED 44,611 403.049 DEPRECIATION EXPENSE-SECI COMMON 17,973,063 403.049 DEPRECIATION EXPENSE-SECI COMMON 17,973,063 403.048 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.768 DEPRECIATION HDOTRS LEASED 41,697 404.018 AMORTIZATION EXPENSE-ERS HDWR 17,263 <tr< th=""><th>356.0</th><th>00 0</th><th>H CONDUCTORS & DEVICES</th><th>38,528,113</th></tr<>	356.0	00 0	H CONDUCTORS & DEVICES	38,528,113
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332.000RTARSPORTATION EQUIPMENT\$18,046193.000STORES EQUIPMENT43,443394.000TOOLS, SHOP, & GARAGE EQUIPMENT183,291385.000LABORATORY EQUIPMENT202,030395.000POWER OPERATED EQUIPMENT201,916387.000COMMUNICATION EQUIPMENT5,722,993398.000OTHER TANGIBLE PROPERTY90,530399.000OTHER TANGIBLE PROPERTY90,530403.049DEPRECIATION EXPENSE-TRANSFERRED(6,900)403.108DEPRECIATION EXPENSE-SECI COMMON17,973,063403.030DEPRECIATION EXPENSE-GENERAL PLANT588,001403.718DEPRECIATION EXPENSE3,858,097403.718DEPRECIATION EXPENSE-GENERAL PLANT588,001403.708DEPRECIATION HOUTRS LEASED41,597404.018AMORTIZATION EXPENSE-CR3 AQUIS ADJ17,259406.048AMORTIZATION EXPENSE-CR3 AQUIS ADJ17,269408.018PROPERTY TAX8,568,061408.118PROPERTY TAX-HQ ALLOCABLE194,160	301.0			3,760,317
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403.108 DEPRECIATION EXPENSE-SECI COMMON. (6,900) 403.208 DEPRECIATION EXPENSE-SECI COMMON. 17,973,063 403.208 DEPRECIATION EXPENSE-GRYSTAL RIVER 1,100,908 403.508 DEPRECIATION EXPENSE-GENERAL PLANT 3,858,007 403.718 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.708 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.708 DEPRECIATION NO FLEASED 41,597 404.018 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 1,088,337 405.008 AMORTIZATION EXPENSE-FRS INT 2588,605 406.043 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 17,259 408.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX 8,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	403.04	ISIDE	PRECIATION EXPENSE TRANSFERDER	44,611
403.208 DEPRECIATION EXPENSE-CRYSTAL RIVER 17,973,063 403.508 DEPRECIATION EXPENSE-CRYSTAL RIVER 1,100,906 403.718 DEPRECIATION EXPENSE-GENERAL PLANT 3,858,097 403.718 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.708 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.708 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.708 DEPRECIATION FOR EXPENSE-GENERAL PLANT 17,253 403.708 DEPRECIATION FOR LEASED 41,597 404.018 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 1,086,337 405.008 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 17,269 406.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX 8,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	403.10	BDE	PRECIATION EXPENSE-SECI COMMON	(5,900)
403.508 DEPRECIATION EXPENSE 1,100,909 403.718 DEPRECIATION EXPENSE-GENERAL PLANT 3,858,097 403.718 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.783 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.708 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.708 DEPRECIATION EXPENSE-GENERAL PLANT 17,253 403.708 DEPRECIATION OF LEASEHOLD IMPROVEMENTS 11,597 404.018 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 1,086,337 405.008 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 238,605 406.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX 8,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	403.20	8 DE	PRECIATION EXPENSE-CRYSTAL BIVER	17,973,063
403.718 DEPRECIATION EXPENSE-GENERAL PLANT 588,001 403.768 DEPRECIATION EXPENSE-EMS HOWR. 588,001 403.768 DEPRECIATION EXPENSE-EMS HOWR. 17,253 403.708 DEPRECIATION HORTRS LEASED 41,597 404.018 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 1,086,337 405.008 AMORTIZATION EXPENSE-HPS INT 258,605 406.049 OVERHEAD TRANSFERS 17,269 408.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX 8,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	403.50	8 DE	PRECIATION EXPENSE	1,100,905
403.763 DEPRECIATION EXPENSE-EMS HOWR 584,001 403.708 DEPRECIATION HORTRS LEASED 17,253 404.018 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 1,086,337 405.008 AMORTIZATION EXPENSE-HPS INT 258,605 406.043 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 17,269 408.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX 5,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	403.71	8 DE	PRECIATION EXPENSE-GENERAL PLANT	3,656,097
403.708 DEPRECIATION HDQTRS LEASED 41,597 404.018 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 41,597 405.008 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 1,086,337 405.008 AMORTIZATION EXPENSE-HPS INT 258,605 406.043 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 17,269 408.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX \$,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	403.76	B DE	PRECIATION EXPENSE-EMS HOWR	47 959
404.018 AMORTIZATION OF LEASEHOLD IMPROVEMENTS 1,086,337 405.008 AMORTIZATION EXPENSE-MPS INT 1,086,337 406.043 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 17,269 408.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX 8,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194.160	403.70	8 DE	PRECIATION HOUTRS LEASED	41 497
405.008 AMORTIZATION EXPENSE-HPS INT 1,006,537 406.043 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 258,605 408.049 OVERHEAD TRANSFERS 17,269 408.108 PROPERTY TAX 8,568,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	404.01	8 AM	ORTIZATION OF LEASEHOLD IMPROVEMENTS	1 086 337
406.048 AMORTIZATION EXPENSE-CR3 AQUIS ADJ 17,269 408.049 OVERHEAD TRANSFERS (10,247,160) 408.108 PROPERTY TAX \$,568,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194,160	405.00	8 AM	ORTIZATION EXPENSE-HPS INT	288 605
408.049 OVERHEAD TRANSFERS (10.247,160) 408.108 PROPERTY TAX 8,568,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194.160	404.04	MA 8	ORTIZATION EXPENSE-CR3 AQUIS ADJ	17.280
408.108 PROPERTY TAX 8,558,061 408.118 PROPERTY TAX-HQ ALLOCABLE 194.160	408.04	9 01	ERHEAD TRANSFERS	(10.247.160)
408.118 PROPERTY TAX-HQ ALLOCABLE	408.10	S PR(OPERTY TAX	8,558,061
	408.11	a PR(DPERTY TAX-HQ ALLOCABLE	194,160

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Exhibit_- (WSS-1)

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·		1998 Year End
ACCT	DESCRIPTION	Baiance
408.21	SFEDERAL UNEMPLOYMENT TAX	18,504
408.31	STATE INFIDE OVNENT TAX	6.603
408.70	OTHER TAXES	68.863
408.75	TAXES TRANSFERRED	(20,230)
409.04	INCOME TAXES	10,000
411.80	GAINS/DISP OF CLEAN AIR ALLOWANCES	(59,060)
419.01	CTC & SCTC	(1,213,798)
419.02		(3,437,966)
419.02	SCI ACIERA AND NONCASH FOLIN MENT	(1,4(7,436)
419.06	WHOLESALE RATE CASE REFUND	(418,714)
419.07	MISC INTEREST INCOME	(17,289)
419.08	INTEREST INCOME	(22,855)
421.003	NDTF TRADING SEC UNREALIZED GAINS	(232,875)
421.10	GAIN ON DISPOSAL OF PROPERTY	(10,014,919)
421.31	COLLALLOW	(700)
421.340	LEASE INCACUERA GROUND LEASE	(176,607)
421.40	MISCELLANEOUS NON-OPERATING INCOME	
424.100	CAPITAL CREDITS - CFC	(166.572)
424.206	CAPITAL CREDITS - CLAY	(182)
425.008	AMORTIZATION-ACUERA CORP	
426.104	DONATIONS	10,406
425.304	PENALTIES	1700
426.504	OTHER DEDUCTIONS . WRITE OFFS	14,01 0
427.105	INTEREST EXPENSE	318 689
427.205	INTEREST EXPENSE	28,257,024
427.225	WEEKLY INTEREST EXPENSE	2,612,750
427.235	1984H SENIS INTEREST EXPENSE	2,227,733
427.240	UT LEASE INTEREST EXPENSE	\$83,922
427.315	IDC, INTEREST EXPENSE - 3905	(178,622)
428.103	SARH WEEKLYS	3,003,023
428.235	1984H SEMIS	187.482
428.247	NDT - TRUSTEE FEES	284
431.105	INTEREST - MEMBER EARLY PAYMENT	302,918
431.115	INTEREST EXPENSE - MEMBER MISCELLANEOUS	343,374
431.205	INTEREST EXPENSE	29,192
447 140		(541,130,006)
447,150	INTERRUPTIBLE POWER SALES	(1 #12 270)
447.160	MARTEL DEL PT REVENUE	(67.329)
447.200	INTERCHANGE SALES	(5,125,448)
447.300	LOAD FOLLOWING SALES	(255,027)
456.210	TFUC	(806,365)
456.220	TELC - WALEST ING DEVICENCE	(30,711)
455.247	OFF SYSTEM SALES WHEFT ING	(139,691)
456.304	MISCELLANEOUS OPERATING REVENUE	(1/0,0/0)
500.017	1ST AID SUPPLIES & SAFETY	573
500.017	SALARIES & MEALS	1,691,669
500.019	EMPLOYEE MEMBERSHIP	1,301,700
500.208	TRAINING - EXISTING REQUIREMENTS	10,625
500.209	NEW TRAINING	358
500.219	APPLIED OVERHEAD	2,012
501.017	ALLOCATION OF ACCOUNTS 151 AND 152	160.347.625
501.027	COST OF IGNITION OIL	\$53,238
501.037	NBAND FUEL	(397,254)
001.047	ALLOCATION OF PETCOKE	6,978,824
501.518	NISCELI ANFOLIS OPERATING ELIDOL IZE	89,217,387
501.519	DUTSIDE SERVICES	101,203
501.527	SENERAL OPERATING SUPPLIES	26.128
501.528	BALARIES	1,123,286
501. 29	OTHER OUTSIDE SERVICES	2.237.199

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		1998 Year End
ACCT	DESCRIPTION	Balance
501.53	7 EQUIPMENT FUELS	33,611
501.99	3 1 3 PD 501.51, 501.52, 502.53	119,779,200
502.01		758 848
502.01		1.080.322
502.02	SALARIES	8,277
502.02	OVERHEAD TRANSFERS - PR HOURS	180
502.03	MISCELLANEOUS	2,352,128
502.03	SALARIES	881,638
502.03	OVERHEAD	46,337
502.04	CHEMICALS AND FUELS	1,410,500
502.04		778 474
502.05	SALARIES	210.588
502.05	OVERHEAD TRANSFERS . PR HOURS	5,444
502.20	TRAINING - EXISTING REQUIREMENTS	13,130
502.20	OVERHEAD TRANSFERS - PR HOURS	1,576
502.21	NEW TRAINING	4,219
502.21	OVERHEAD TRANSFERS . PR HOURS	1,091
005.017 505.041	CALADIES	247,ZJT
505.010	OVERHEAD TRANSFERS . DR	
506.017	OPERATINGMAINTENANCE	642.776
506.018	SALARIES	1.117.623
506.011	OTHER OUTSIDE SERVICES	8,863,768
506.208	TRAINING - EXISTING REQUIREMENTS	471
506.209	APPLIED OVERHEAD	196
507.205	U2	29,250,235
510.017	TOOLS UNDER \$500	
510.010		1,143,248
510.208	TRAINING EXISTING RECHIREMENTS	26 178
510.209	OVERHEAD TRANSFERS	7,884
510.218	NEW TRAINING	17,786
510.21	OVERHEAD TRANSFERS	6,461
511.017	GENERAL OPERATING SUPPLIES	142,347
511.018	SALARIES	38,577
511.019		1,495,175
512017		73,007
512.019	CONTRACT LABOR	1.028.667
512.027	GENERAL OPERATING SUPPLIES	406,713
512.028	SALARIES	321,620
512.029	OVERHEAD TRANSFERS	250,516
512.037	GENERAL OPERATING SUPPLIES	286,327
512.038	SALARIES	171,516
512.033		144,643
512.048	SALARIES	12 467
512.049	OVERHEAD TRANSFERS	17.124
512.057	GENERAL OPERATING SUPPLIES	562.996
512.058	SALARIES	248,845
512.059	OVERHEAD TRANSFERS	1,015,490
512.067	GENERAL OPERATING SUPPLIES	353,775
512.068	SALARIES	345,876
512.069		451,175
512.078	SALARIES	/9,010
512.079	OVERHEAD TRANSFERS	2.010
512.087	GENERAL OPERATING SUPPLIES	387.091
512.088	BALARIES	43,449
512.089	OVERHEAD TRANSFERS	67,353
512.097	GENERAL OPERATING SUPPLIES	36,851
512.098	SALARIES	61,652
512.099		1,707
512.108	SALARIES	117,130
512.109	OVERHEAD TRANSFER	491 776

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Exhibit_- (WSS-1)

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		1998 Year End
ACCT	DESCRIPTION	Balance
512.12		127,225
512.12	OVERHEAD TRANSFER	124,810
512.13	GENERAL OPERATING SUPPLIES	10 870
512.13	SALARIES	11.147
512.13	OVERHEAD TRANSFER	6.124
512.14	GENERAL OPERATING SUPPLIES	400,778
512.14	SALARIES	18,638
512.14	OVERHEAD TRANSPER	344,021
512.15		762,258
612.16	OVERHEAD TRANSFERS	175,205
512.167	GENERAL OPERATING SUPPLIES	
512.168	SALARIES	The Case of the
512.161	OVERHEAD TRANSFER	571,210
512.178	SALARIES	315
512,178		198,182
513.017	SALADIES	250,991
513.019	OVERHEAD TRANSFER	
513.027	GENERAL OPERATING SUPPLIES	
513.028	SALARIES	12 654
513.029	OVERHEAD TRANSFERS	
513.037	GENERAL OPERATING SUPPLIES	40,206
513.038		232,627
513.047		686,435
513.048	SALARIES	29,972
513.049	OVERHEAD TRANSFERS	18,879
513.057	GENERAL OPERATING SUPPLIES	
513.058	SALARIES	84 394
513.059	OVERHEAD TRANSFERS	\$50,070
513.067	GENERAL OPERATING SUPPLIES	402
513.066		8,085
514.017	GENERAL OPERATING SUDDIES	
514.018	SALARIES	338,905
514.019	OVERHEAD TRANSFERS	1,394,8/2
514.027	GENERAL OPERATING SUPPLIES	70,219
514.028	SALARIES	64,547
514.029	OVERHEAD TRANSFERS	18,783
514.038	AT ADIES	25,283
517.039	VERHEAD TRANSFERS	-14,379
514.047	ENERAL OPERATING SUPPLIES	17,081
514.048 5	ALARIES	3/3,039
514.049 0	VERHEAD TRANSFERS	143 366
517.010 C	PER SUPY & ENGINEERING	755.081
518.017 N	UCLEAR FUEL	509,506
520.010 S	TEAM EXPENSES CR3	4,814
524.010 M	ISC NUCLEAR BOWER EVO CRA	1,302
524.019 0	VERHEAD TER-PROP TAX	449,031
525.010 R	ENTS CR3	128,572
528.010 M	AINT SUPV & ENG CR3	754 138
529.010 M	AINT OF STRUCTURES CR3	107.850
530.010 M	AINT REACTOR PLT EQUIP	147,331
532.010 M	ANT ELECTRIC PLANT CR3	28,673
555.100 IN	TERRUPTIBLE POWER NOASTEL	31,622
555.107 IN	TERRUPTIBLE POWER-FUEL	\$39,573
555.110 FL	ILL REQUIREMENTS - NON-FUEL	883,324
555.117 FL	LL REQUIREMENTS - FUEL	1,007,321
665.120 P/	RTIAL REQUIREMENTS - NON-FUEL	89.061.720
555.127 P/	RTIAL REQUIREMENTS - FUEL	32,307.947
555 200 HAT	FREHANCE NONSIE	67,329
555.207 IN		45,291,873
1		32,446,253

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		1998 Year End
ACCT	DESCRIPTION	Batance
555.280	RESERVES - NON-FUEL	386,257
555.287	RESERVES - FUEL	6,523
555.300	LOAD FOLLOWING - NON-FUEL	49,938
565.307	LOAD FOLLOWING - FUEL	332,909
556.010	OPS & LOAD CONTROL CR3	303
556.017	GENERAL OPERATING SUPPLIES	23,807
556.018	SALARIES	1.112.663
556.019	OVERHEAD TRANSFERS	440.366
557.017	USE CHARGE & PARTICIPATION ALLOCATION	617.890
557.019	INSURANCE CR3	
560.018	SALARIES	111.940
560.019	OVERHEAR TRANSFERS	47.781
562.018	UTILITIES & FURNITURE	7 629
565.100	TFUC	36,860
565.200	WHEELING	22.216.365
665.207	WHEELING . FUEL	50.374
566.017	IST AID SUP & SAFETY EQUIPMENT	
566.180	SALARIES	41.067
556.019	OVERHEAD TRANSFERS	1.286.390
567.019	RENT - OTHER	· · · · · · · · · · · · · · · · · · ·
570.017	GENERAL OPERATING SUPPLIES	
570.018	SALARIES	378.067
570.019	OVERHEAD TRANSFERS	- MARRIE CONTRACTOR
571.017	SENERAL OPERATING SUPPLIES	3.00-1-5-7-FA
571.019	THER OUTSIDE SERVICES	104 020
920.018	ALARIES	2 201 840
920.0190	VERHEAD TRANSFERS	1 817 684
920.048	ALARIES	
920.068	ALARIES	1 893 171
920.069	VERHEAD TRANSFERS	2 786 760
921.017	ENERAL OPERATING SUPPLIES	
921.018	RAVEL	
921.019	THER OUTSIDE SERVICES	176 697
921.048	ALARIES	30 047
921.068	RAVEL	
922.049 F	AYROLL TEST - DRECT	R41 0411
923.018 7	ENPORARY HELP	100 470
923.019 L	EGAL	1 019 220
923.049 1	ENPORARY HELP TSF - INDIRECT	(44 244)
923.069 F	NANCIAL AND OTHER	273 764
924.049	VERHEAD TRANSFERS	1787 020
924.069 0	THER PROPERTY	474 977
925.019	SURANCE	445,077
925 049 1		615,024
975 069 13		(107,530)
926 048 0		414,732
976 040	VEDUEAD TDANGEEDS	6,034,706
930 010 11		(8,126,653)
830.013		128,931
930.02910	VENIERU INANSPER · FRUPERIT TAX & PROPERTY INS	210,393
530.043 M	IJU CAF IJFU · LIKEUI	(3,318)
530.065 Pl		245,958
330.069 0	IMER OU ISIDE SERVICES	552,801
a37.018[O	IMER OUISIDE SERVICES	196,784

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POWER REQUIREMENTS DATA BASE

Seminole Electric Cooperative, Inc.

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Source: RUS Form 12a, Sales of Electricity, for Year Ended 1998.

Rate Class	Data	Total
Sales for Pasale - RUS	Consumers	10
1. Borrowers	kWh Sold	8,945,919,000
Donomers	Revenue	\$420,529,947
Sales for Resale -	Consumers	2
2. Special Sales to RUS	kWh Sold	53,143,000
Borrowers	Revenue	\$1,899,599
Sales for Resale -	Consumers	27
3. Others	ikWh Sold	2,786,908,000
	Revenue	\$126,202,131
Sales to Ultimate	Consumers	and the second se
4. Consumers	kWh Sold	
	Revenue	\$0
Other Sales to Public	Consumers	
5. Authorities	kWh Sold	
	Revenue	\$0
	Consumers	The second second second second second second second second second second second second second second second s
6. Other Sales	kWh Sold	
	Revenue	\$0
7. TOTAL No. Consumers (1a thru 6a)	
	•	39
8. TOTAL kWh Sold (1b thr	1 66)	
		11 785.970.000
9 TOTAL Revenue Receive	d From Sales of	
Electric Revenue (1c thru	Sc)	\$548 631 677
10 Total MAD Concented	~~,	4040,001,077
IU. FOTAL KAAL Generated		
		9,263,609,000
11. Iotal Kvvn Purchased		Carl Charles 12 Mary
		2,842,345,000
12. Cost of Generation		
		\$300,726,664
13. Cost of Purchases		
		\$205,551,542
14. Cost of Purchases and G	eneration	
		\$506,278,206
15. Interchange - kWh - Net		
		(21,303)
16. Wheeling - kWh - Net		L HERL & LELL
-		1.072
17. Total Energy Available - K	Wh	
•••••••••••••••••••••••••••••••••••••••		12,105,933,769
18. Total Energy Sold - kWb		
ter term Energy Cons - Attil		11 785 070 000
19 Energy Sumished Mithaut	Chama Like	11,103,310,000
to: FlietAA contrailed AARIOOL	Goarge - Kvyn	
20 Energy Llead - MAR		
zo. Energy Used - Kaan		and the second se
21 Total France Accounts		
21. Total Energy Accounted P		44 705 400 444
		11,785,970,000
22. Energy Losses - kWh		
		319,963,769
23. Energy Losses - Percenta	ge	
		2.71%
24. Peak Demand - kW		1. AN 187
	1	2,555,063

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CLASS DATA VERIFICATION

Seminole Electric Cooperative, Inc. Compares Form 12a Data to Rate Class Summaries

			Form 12a Data		Su	mmarized Rate CI	ass Data	Vadapos kam Kaun 40a		
rom 12a Classifications	Code	Consumers	kWh Sold	Revenue	Consumera	HAD Cold	Deuter			
Sales for Resale - RUS Borrowers	1	10	8 945 919 000	420 520 047	Consumers	DOC HVV	Kevenue	Consumers	kwn Sold	Revenue
Sales for Resale - Special Sales to	•		0.343,815,000	420,529,947	10	11,565,891,000	541,351,605		29.3%	28.7%
RUS Borrowers	2	2	53,143,000	1 800 500						
Sales for Resale - Others	3	27	2 786 008 000	100 000 101		•	•	-100.0%	-100.0%	-100.0%
Sales to Ultimate Consumers	4		2,100,900,000	126,202,131	•	-	-	-100.0%	-100.0%	-100.0%
Other Sales to Public Authorities	5	1 - 1		-	•	•	-			
Other Sales	6	-	-		-	-	-			
Total		30	11 785 070 000		•	•	<u> </u>			
			11,105,910,000	548,631,677	10	11,565,891,000	541,351,605	-74.4%	-1.9%	-1.3%

			Actual FY 1994			Forecasted FY	2000	1	
Seminole Electric Cooperative, Inc. Rate Classes & Other Splits	Class Summarized in Form 12a Classification Code	Consumers	Consumers kWh Sold	Revenue	Projected Consumers	Projected kWh Sold	Projected	Cachilation of Total	Salas (as 52 4000
Sales for Resale - Member Sales	1	10	11,565,891,000	541,351,605	10	12,194,143,481	553 789 741	FY 1998	Sales for FT 2000
0 0 0 0 0 0 0 0 0 0 0		• • • •	• • • • •	-	· · · ·			Purchased Power Generation Energy Reqmts Total Class Sales Losses Losses	2,842,345,000 9,263,609,000 12,105,954,000 11,565,891,000 540,063,000 4.46%
0			•	-	•			Purchased Power Generation	3,394,850,000 9,824,832,000
0				•	•			Energy Reqmts	13,019,682,000
0	•							Total Class Sales	12,194,143,481
0		•	-	-		步力與自動的	建 物的 计算	Assumed Losses	825,538,519
Total Sales		10	11,565,891,000	541,351,605	10	12.194.143.481	553 789 741	ASSUMED LOSSES	6.34%

:

		FY 2000			·	·		·	
		Budget							
Acct	L	Totals	КW	KWH	ACC	т-кw	CONS	GENL	Description of Assignment
		ļ							
500	Constitute Supervision And Engineering	3 891 634	7 884 024			1			lasi
501	Fuel Evnence	162 184 262	2,001,034	102 104 202					KVV
502	Steam Emenses	7 720 824		7 720 824					
505	Fiechic Excenses	1 694 210		1,720,024					
506	Misc Sleam Power Expenses	10 557 901		10 557 001					
507	Power Plant Rents	28,641,657	13 261 087	15 380 570					
510	Maintenance Supervision and Engineering	5.428.515	5 428 515	10,000,010					KW
511	Maintenance of Structures	349.878	349.878						ikw .
512	Maintenance of Boller Plant	14,443,520		14.443.520					KWH
513	Maintenance of Electric Plant	1,105,936		1,105,936					KWH
514	Maintenance of Misc. Steam Plant	5,554,701		5.554.701					KWH
518	Nuclear Fuel Expense	648,000		648.000					KWH)
528	Maintenance Supervision and Engineering	2,287,873	2,287,873	• • • • • • • • • •					KW .
	PURCHASED POWER								
555	Purchased Power	216,750,478	118,545,653	97,435,770			769.055		KW.KWH. CONS - BY CONTRACT
558	System Control and Load Dispatch	1,717,774	1,717,774						kw
557	Other Power Supply Expenses	48,461	48,461					1	KW
	TRANSMISSION OPERATIONS EXPENSES								
580	Operations Supervision And Engineering	177,341				177,341			lт-кw
562	Station Expenses	9,604				9,604		-	T-KW
565	Transmission of Electricity by Others	34,051,675			34,051,675				ACC
566	Miscellaneous Transmission Expenses	1,285,816				1,285,816			T-KW
567	Rents	2,500				2,500			T-KW
I	TRANSMISSION MAINTENANCE EXPENSES				_				1
570	Maintenance of Station Equipment	1,195,105				1,195,105			T-KW
571	Maintenance Of Overhead Lines	5,409				5,409			T-KW
	ADMINISTRATIVE AND GENERAL OPERATIONS EXPENSES	3							
920	Administrative & General Salaries	10,805,074	4,890,317	3,787,480	0	565,680	485,177	1,076,420	Personnel Function
921	Office Supplies And Expense	2,276,213	1,627,634	403,224	0	79,104	51,653	114,598	PAYROLL RATIO
922	Administrative Expenses Transferred - Credit	(1,007,800)	(353,620)	(463,036)	0	(186,093)	(4,405)	(645)	TOTAL UTILITY PLANT RATIO
923	Outside Services Employed	1,668,460						1,666,460	GENL
1924	Property Insurance	35,944	12,612	16,515	0	6,637	157	23	TOTAL UTILITY PLANT RATIO
925	Injuries And Damages	39,607	28,321	7,016	0	1,376	899	1,994	PAYROLL RATIO
926	Employee Pensions and Benefits	58,306	41,692	10,329	0	2,026	1,323	2,935	PAYROLL RATIO
930	General Advertising and Miscellaneous General Expenses	1,342,030		l				1,342,030	GENL
-	ADMINISTRATIVE AND GENERAL MAINTENANCE EXPENSI	ES							
932	Mainienance Of General Plant	120,700				l		120,700	GENL

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ASSIGNMENT OF CUSIS

Seminoie Electric Cooperative, Inc.

Acct Budgetti KW KW KW ACC T-W CONS GEN Description of Assignment 105 State Production Plant 13221398 4.537,710 9,784,285 3.000 680.399 3.054,282 40,000 400,000,000 400,000,0000,0000,000,000 400,000,000,000,000,000			FY 2000							
Act 5 Cent Book Trible NW KW KW KW KW Constraint Description of Assignment CB1 Biseam Production Flued 16.273,000 6.477,710 0,788,266 South Straint	ł		Budget			(ļ		
BERRECATION AND ANONTEXTION EXPENSE 18.223.095 4.437,710 9.786.265 Distant Production Park 1.01.446 38.000 60.099 3.554.282 FWXXWH Distant Production Park 1.02.20.95 6.33.000 60.099 3.554.282 FWXXWH FWXXWH Distant Production Park 1.02.20.95 6.33.000 60.099 3.554.282 FWXXWH FWXXWH 600.0 Deproduction Transformed 1.02.000 555.156 647.460 9.3.265 1.282 FWXXWH FWXXWH FWXXWH 640.0 Anontation Exect frant Aguidation 1.282.000 555.156 647.460 9.3.265 1.282 FWXXWH FWXXWH FWXXWH 640.0 Anontation Exect frant Aguidation 1.282.341 300.728 0 6.518 556 557 558 559 559 559 559 559 559 559 550 550 550 550 550 550 550 550 550 550 550 550 550 550 550	Acct #		Totals	ĸw	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
43.1 Stater Production Plant 12.23.067 8.47.710 8.78.869 Stater Production Plant 1.08.144 33.060 69.389 3.854.262 Stater Production Plant 1.08.144 33.060 69.389 3.854.262 Stater Production Plant 1.08.144 33.060 69.389 3.854.262 Stater Production Plant 1.08.142 Stater Plant 1.08.142 Stater Plant Stater Plant 1.08.142 Stater Plant 1.08.142 Stater Plant		DEPRECIATION AND AMORTIZATION EXPENSE								
432.2 Multicles Production Plant 1,001,446 381,060 680,380 3,844,322 Multicles Production Plant 437.7 General Plant 383,442 683,446 (10,220) 0 (4,322) (104) 437.7 General Plant 1283,846 (10,220) 0 (4,322) (104) 1203,846 (10,220) 0 (4,322) (104) 1203,846 (10,220) 0 (4,322) (104) NUMMER 1203,846 (10,220) 0 (4,322) (104) NUMMER 1203,846 (105,220) 0 (14,322) (106) NUMMER 1203,846 (105,220) 0 (14,322) (106) NUMMER 1203,846 (106,320) 0 (14,322) (116) 1203,847 (116) 1203,847 (116) 1203,847 (116) 1203,847 (116) 1203,847 (116) 1203,847 (116) 1203,847 (116) 1203,843 (116) 1203,843 (116) 1203,843 (116) 1203,843 (116) 1203,843 (116) 1203,843 (116) 1203,843 (116) 1203,843 (116) 1203,843	403.1	Steam Production Plant	18,223,995	8,437,710	9,786,285					KW,KWH
403.5 Transmission Plant 3,854,282 State	403.2	Nuclear Production Plant	1,081,449	381,060	680,389	}]		KWKWH
43.7 Gammi Plant 993,846 (0.22) (0.22) (0.4) (0.22) (0.4) (0.32) (0.4) (0.32) (0.4) (0.32) (0.4) (0.10) </td <td>403.5</td> <td>Transmission Plant</td> <td>3,854,282</td> <td></td> <td></td> <td></td> <td>3,854,282</td> <td>ľ</td> <td></td> <td>T-KW</td>	403.5	Transmission Plant	3,854,282				3,854,282	ľ		T-KW
080.2 Descretation Transformed (22,783) (63,48) (10,222) 0 (45,292) (106) (10,122) 128 12	403.7	General Plant	953,646		ł		., ,)	953,646	GENL
40.0 Anotiziston Lassabilit Improvements 1.205.605 565.195 647.410 City C	0.008	Depreciation Transferred	(23,785)	(8,346)	(10.928)	0	(4.392)	(104)	(15)	TOTAL UTILITY PLANT RATIO
46.0 Ministanceup Dependention/Amoritation 226.524 101,273 132,085 1,282 183 182 183	404.0	Amortization Leasehold Improvements	1,205,605	558,195	647,410	-	···,		••••	KW.KWH
db.0 Anadication Electry Park Acquisition 17.258 6.166 11.091 Non-Xet High Non-Xet High 0THER REPENSES 6.616.067 3.052,853 3.969,664 0 1.591,350 37.673 5.518 TOTAL UTILITY PLANT RATIO 06.1 Property Taxes 2.4168 7.728 4.244 0 6.811 5.912 5.918 PAYROLL RATIO 06.3 Payrol Taxes 1.5116 10.089 2.275 0 6.55 3.91 761 PAYROLL RATIO 06.0 Owner-declation/Americation 72 2.5 3.2 0 1.3 0 0 10714.UTILITY PLANT RATIO 0731.00 Owner-declation/Americation 72 2.5 3.2 0 1.3 0 0 10714.UTILITY PLANT RATIO 0732.00 Owner-declation/Americation 0.3120 1.232.676 1.237.047 0 680,114 1.6227 2.421 10714.UTILITY PLANT RATIO 0733.00 Declation 0.3120 Declation 0.3120 Declation 0.3120	405.0	Miscellaneous Depreciation/Amortization	288,624	101,273	132,609	0	53,295	1.262	185	TOTAL UTILITY PLANT RATIO
OTHER EXPENSES 6.516.067 3.023,833 3.696,564 0 1.591,330 37.773 5.518 TOTAL UTILITY PLANT RATIO 00.2 Payrol Taxes 2.118 17.284 4.224 0 6.514 35.269 71.18 1.218 PAYROLL RATIO 00.3 Payrol Taxes 1.731,755 1.333,417 30.672 0 6.55 345 751 PAYROLL RATIO 00.40.4 Payrol Taxes 1.5116 10.009 2.673 0 6.55 345 751 PAYROLL RATIO 00.6 Onthose Allocation and Taxes Translered (10.212,080) (3.432,400) (4.691,960) 0 10.751,UTILITY PLANT RATIO 0.722 25 33 0 1.326,573 7.413,022 2.423 10.711,UTILITY PLANT RATIO 0.724 Department and Taxes Translered 1.232,573 1.232,574 33.052,605 34.051,675 7.413,022 2.424 10.71111Y PLANT RATIO 0.724 Department and Taxes Translered 1.232,574 1.232,574 0 431,42 10.207	406.0	Amortization Electric Plant Acquisition	17,258	6,195	11,061					KW,KWH
40.1 Property Taxes 8.616.067 3.023,833 3.898,964 0 1.591,330 37.773 5.518 TOTAL UTUTY PLANT RATIO 403.2 Payrof Taxes 1.731,785 1.238,941 306,762 0 6.614 39.289 7.181 PAYROLL RATIO 403.7 Taxes, Other 1.731,785 1.238,941 306,762 0 6.255 312 711 PAYROLL RATIO 403.7 Taxes, Other 101,212,0691 (1,232,091 (4,691,900) 0 (1,865,680) (4,417) (4,223) 100 31,30 0 30,131 0 0 1071AL UTUTY PLANT RATIO 428 Chanalon 1,326,378 1,334,072 33 0 13,10 0 31,310 31,310 31,310 31,310 31,310 31,310 31,310 31,310 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312 31,312		OTHER EXPENSES								
40.2 Peyrol Taxes 24,198 17,294 4,224 0 541 546 1,228 Party Taxes 40.3. Peyrol Taxes 15,118 10,808 2,678 0 60,164 39,299 67,169 Party PLATY DUAR TO COMPARE ALL UTILITY PLANT RATIO 40.4. Peyrol Taxes (12,222) 0 0 (1,805,880) (44,641) (6,359) 731 PARTYCLL RATIO 40.5. Docalions 33,100 72 25 33 0 13 0 0 10 TOTAL UTILITY PLANT RATIO 428 Docalions 3,100 1,228,579 1,737,047 0 68,114 15,527 2,421 TOTAL UTILITY PLANT RATIO 428 Docalions Constructure 5,34,417 12,007,601 33,362,003 7,413,022 1,347,766 5,344,737 43 Anontization of Deb Discount and Expense 5,34,4447 12,007,707 0 431,442 10,207 1,448 10,207 1,448 10,207 1,448 10,207 1,448 10,4000 1,442	408.1	Property Taxes	8,618,067	3,023,933	3,959,594	0	1.591.350	37.673	5.518	TOTAL UTILITY PLANT RATIO
403.3 Payrol Taxes 1,737,765 1,238,341 306,762 0 60,14 392,296 67,169 PAYROLL RATIO 408.7 Txxes, Other (12,2282) (13,282,240) (4,691,960) 0 (14,855,860) (4,6411) (6,353,050) (14,6411) (6,353,050) (14,6411) (6,353,050) (14,6411) (12,220) (14,6411) (14,6411) (14,6411) (14,6411) (14,6411) (14,6411) (14,6411)	408.2	Payroll Taxes	24,186	17,294	4,284	0	841	549	1,218	PAYROLL RATIO
408.4 Payrol Taxes 15.116 10.009 2.878 0 525 543 781 PAYROLL RATIO 980.0 Overhead Allocation and Taxes Transfered (12.22) (12	408.3	Payroll Taxes	1,731,795	1,238,341	306,782	0	60,184	39,299	87,189	PAYROLL RATIO
408.7 Trass, Other (12,220) (3,283,240) (4,691,600) 0 (12,220)	408.4	Payroll Taxes	15,116	10,809	2,678	0	525	343	761	PAYROLL RATIO
990.0 Overhaed Allocation and Taxes Transferred (10.212,065) (2,481,9240) 0 (1,882,680) (4,641) (6,831) (7,831) (7,81,032)	408.7	Taxes, Other	(12,282)					_	(12,282)	GENL
425 Maceltaneous Depreciation/Amortization 72 25 33 0 13 0 133 0 133 0 133 0 133 0 133 0 133 0 133 0 133 133 0 133 133 0 133 133 0 133 133 0 133 13	990.0	Overhead Allocation and Taxes Transferred	(10,212,065)	(3,583,240)	(4,691,960)	o	(1.885,686)	(44.641)	(8.538)	TOTAL UTILITY PLANT RATIO
426 Donations 38,120 38,120 58,120 58,120 58,120 58,120 58,120 58,120 58,120 58,120 58,120 58,120 58,121 77,513,032 1,356,766 5,39,032 1,356,766 5,39,032 1,356,766 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,787 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,4,737 5,39,49,737 5,39,49,737 5,39,49,737 5,39,49,737 5,39,49,737 5,39,49,737 5,39,49,737 5,39,49,737	425	Miscellaneous Depreciation/Amortization	72	25	33	0	13	o	0	TOTAL UTILITY PLANT RATIO
428 Amoritzation of Debt Discount and Expense 3,280,586 1,328,579 1,737,047 0 668,114 16,527 2,421 TOTAL UTILITY PLANT RATIO ANNUAL INVESTMENT COST: 643,444,477 162,077,661 333,052,005 34,061,875 7,513,032 1,354,766 5,394,737 Y Target Margins & Patronage Capital 2,334,880 819,270 1,072,767 0 431,442 10,207 1,465 TOTAL UTILITY PLANT RATIO Required Margins & Patronage Capital 2,334,880 819,270 1,072,767 0 431,442 10,207 1,465 TOTAL UTILITY PLANT RATIO Required Margins A patronage Capital 2,334,880 819,270 1,072,767 0 431,442 10,207 1,465 Non Operating Margins - Interest (7,010,135) (2,165,317) (4,161,016) (425,280) (168,023) (5,1000) COS RATIO - PREL. Kill Non Operating Margins - Other (493,682) (152,480) (145,229) 250,522 (9,030) (153,163) V1 Indicate and Patronage Dividends 53,346,751 1,356,	426	Donations	38,120			_		-	38,120	GENL
TOTAL OPERING EXPENSE 543,444,477 162,077,661 333,052,805 34,061,675 7,513,032 1,354,768 5,394,737 Y Target Margin Dolar Amount Required Margins & Patronage Capital 2,334,880 819,270 1,072,767 0 431,442 10,207 1,485 TOTAL UTILITY PLANT RATIO Required Margins & Patronage Capital 2,334,880 819,270 1,072,767 0 431,442 10,207 1,485 TOTAL UTILITY PLANT RATIO Non-Operating Margins - Interesi (7,010,155) (2,165,317) (4,181,016) (425,280) (168,788) (15,000) COS RATIO - PREL. 411 Gain on Disposition of Clean AV Altowances (100,000) (100,000) (11,883) (1,316) (3,880) COS RATIO - PREL. 421 Non Operating Margins - Other (493,682) (13,776) (100,000) (11,833) (13,817) (1,508,533) 423 Untered operating Margins Bargins 30,149,597 (1,508,533) (3,402,682) (455,229) 25,0522 (9,803) (153,303) 424 Other Caphat Barginss 24,775,685 <t< td=""><td>428</td><td>Amortization of Debt Discount and Expense</td><td>3,780,688</td><td>1,326,579</td><td>1,737,047</td><td>0</td><td>698,114</td><td>16.527</td><td>2.421</td><td>TOTAL UTILITY PLANT RATIO</td></t<>	428	Amortization of Debt Discount and Expense	3,780,688	1,326,579	1,737,047	0	698,114	16.527	2.421	TOTAL UTILITY PLANT RATIO
ANNUAL INVESTIBLENT CO3T: V Target Margin Sub-Amount Required Margins & Patronage Capital 2,334,880 819,270 1,072,767 0 431,142 10,207 1,485 TOTAL UTILITY PLANT RATIO Required Margins & Patronage Capital 2,334,880 819,270 1,072,767 0 431,142 10,207 1,485 TOTAL UTILITY PLANT RATIO Non-Operating Margins - Interest (7,010,155) (2,165,317) (4,181,06) (425,280) (168,738) (15,600) COS RATIO - PREL. 410 Non Operating Margins - Other (493,682) (132,484) (29,443) (29,449) (11,803) (1,316) (13,688) COS RATIO - PREL. 421 Non Operating Margins and Patronage Dividends (5386,917) (1,588,532) (3,402,882) (455,229) 250,522 (0,803) (162,132) 427 Interest on L-T DoN 30,445,557 10,577,565 13,365,556 0 5,586,460 131,778 18,361 TOTAL UTILITY PLANT RATIO 7 total Operating Expense 54,344,477 12,977,7681 33,052,605 0 5,568,460 131,778 <t< td=""><td></td><td>TOTAL OPERATING EXPENSE</td><td>543,444,477</td><td>162,077,661</td><td>333,052,605</td><td>34,051,675</td><td>7,513,032</td><td>1.354.766</td><td>5.394.737</td><td></td></t<>		TOTAL OPERATING EXPENSE	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1.354.766	5.394.737	
Y Target Margita Dollar Amount Required Margita S Petronage Capital 2.334,880 819,270 1,072,767 0 431,142 10,207 1,485 TOTAL UTILITY PLANT RATIO Required Margita S Petronage Capital Non-Operating Margitas - Interest (7,010,135) (2,165,317) (4,181,016) (425,280) (168,738) (168,033) (51,090) COS RATIO - PREL. 411 Gain to Disposition of Clean Ar Allowances (100,000) (100,000) (148,10,16) (425,280) (168,738) (13,598) (53,988) (53,988,917) (1,598,532) (3,402,682) (155,129) (155,128) (100,000) KW 421 Non Operating Margins - Other (493,682) (15,77,853) (3,402,682) (455,229) 250,522 (9,803) (153,193) (100,000) KW 424 Other Capital Gradits and Patronage Dividends (100,000) (455,279) 250,522 (9,803) (107,121,171,177) (153,193) (100,121,171,177) (153,193) (153,193) 47 Interest On L-T Dobit 30,145,557 (153,793) (153,1793) (153,1793) (153,193,177)		ANNUAL INVESTMENT COST:								
Required Margins 4 Patronage Capital 2.334,880 619,270 1,072,767 0 431,142 10,207 1,485 TOTAL UTILITY PLANT PATIO Required Margins Angins - Interest 2,334,880 819,270 1,072,767 0 431,142 10,207 1,485 TOTAL UTILITY PLANT PATIO Non-Operating Margins - Interest (7,010,135) (2,165,317) (4,181,016) (425,280) (168,273) (15,693) (55,693) (53,690) COS RATIO - PREL. All Gain o Disposition of Clean Air Allowances (100,000) (294,432) (29,490) (11,883) (13,316) (3,580) COS RATIO - PREL. 421 Non-Operating Margins - Other (493,662) (152,484) (294,432) (29,490) (11,883) (13,316) (35,980) COS RATIO - PREL. 421 Unterest & Op. Margins (53,46,717) (1,586,527) (29,490) (11,883) (153,910) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000) (100,000)	Ϋ́	Target Margin Dollar Amount								
Required Margins & Petronage Capital 2.334.850 819.270 1,072,767 0 431,142 10,207 1,495 419 Non Operating Margins - Interest (7.010,135) (2,165,317) (4,181,016) (425,280) (168,738) (16,693) (51,040) COS RATIO - PREL. 411 Gain on Disposition of Clean Nr Allowances (100,000) (100,000) (100,000) (11,843) (1,316) (455,229) 250,522 (9,804) (100,000) (100,000) (100,000) (100,000) (100,000) (11,813) (13,183) (133,98) (153,98) (153,98) (153,98) (153,98) (153,98) (153,98) (153,98) (153,98) (153,98) (153,98) (153,98) (133,98) <	<u> </u>	Required Margins & Patronage Capital	2,334,880	819,270	1,072,767	0	431,142	10,207	1,495	TOTAL UTILITY PLANT RATIO
Non-Operating Margins Interest (7.010.135) (2.165.317) (4.181.016) (425.280) (18.693) (51.990) COS RATIO - PREL. 411 Gain on Disposition of Clean Air Allowances (100.000) (100.000) (100.000) (100.000) (110.432) (28,949) (11.883) (13.16) (3.508) COS RATIO - PREL. KW 421 Non Operating Margins - Other (493.682) (15.244) (294.432) (28,949) (11.883) (13.16) (3.508) COS RATIO - PREL. 421 Unter Sate on L-T DeN (5.386.917) (1.586.532) (3.402.682) (455.229) 5.505.220 (5.5177) (13.303) 421 Interest & Op. Margins 24.776.640 8.979.031 10.447.775 (45.5229) 5.518.640 131.778 (13.303) 421 Interest & Op. Margins 543.444.77 162.077.661 333.052.605 3.4051.675 7.513.032 1.354.786 \$.394.737 Less Other Revenues (5.137.708) (62.809) (62.809) (62.809) (62.800) KWH Non-Power Supply	[Required Margins & Patronage Capital	2,334,880	819,270	1,072,767	0	431,142	10,207	1,495	
419 Non Operating Margins - Interest (7,010,155) (2,165,317) (4,181,016) (425,280) (168,736) (16,603) (51,090) (COS RATIO - PREL. 421 Other Capital Credits and Patronage Dividends (100,000) (100,000) (100,000) (11,883) (1,316) (3,598) COS RATIO - PREL. 424 Other Capital Credits and Patronage Dividends (100,000) (152,484) (294,432) (29,949) (11,883) (1,316) (3,598) COS RATIO - PREL. 424 Other Capital Credits and Patronage Dividends (100,000) (455,229) 250,522 (9,803) (153,193) 427 Interest on L-T Debt 30,143,557 10,377,081 13,850,456 0 5,566,460 131,778 (13,389) Total Operating Expense 24,776,641 33,052,605 34,061,775 (455,229) 5,816,001 13,869 KWH Non-Member Sales (5,137,706) (6,137,706) (6,206,085) KWH KWH Non-Member Sales (1,224,777) (62,806) (1,224,777) (2,603) (0,007) (1,224,777) (2,604) (1,224,777) (2,604) (1,224,777) <	ļ	Non-Operating Margins		-			· ·		• -	}
411 Gain on Disposition of Clean Air Allowances (100,000) (100,000) (100,000) (11,83) (11,83) (1,18) (3,589) COS RATIO - PREL. 424 Other Capital Credits and Patronage Dividends (100,000) (152,484) (294,432) (29,499) (11,83) (1,358) COS RATIO - PREL. 424 Other Capital Credits and Patronage Dividends (153,485) (152,484) (294,432) (29,499) (11,883) (13,589) COS RATIO - PREL. 427 Interest on L-T Debt 131,778 113,580,456 0 5,586,460 131,778 133,889,31 Total Dearting Expense 543,444,477 182,077,681 333,052,805 34,051,675 7,513,032 1,354,786 5,394,737 Less Other Revenues (6,137,708) (6,137,708) (62,806) KWH KWH Non-Member Sales (60,000,085) (62,000) (77 KWH (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777)	419	Non Operating Margins - Interest	(7,010,135)	(2,165,317)	(4,181,016)	(425,280)	(168,738)	(18,693)	(51,090)	COS RATIO - PREL.
421 Non Operating Margins - Other (493,662) (122,484) (294,432) (29,949) (11,863) (13,16) (3,588) COS RATIO - PREL. (100,000) GENL 424 Other Capital Credits and Patronage Dividends (100,000) (153,083) (153,083) (153,083) (153,083) (153,083) (153,083) (13,160) (13,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508) (14,508)	411	Gain on Disposition of Clean Air Allowances	(100,000)	(100,000)						ĸw
424 Other Capital Credits and Patronage Dividends (100.000) (5386.917) (1,508.522) (1,508.522) (3,402.682) (455.229) (455.229) 250,522 (9,803) (100,000) (53,182) 427 Interest on L-T Debt Total Interest & Op. Margine 24,776,640 8,979,031 10,447,775 (455,229) 250,522 (9,803) (153,182) Total Interest & Op. Margine 24,776,640 8,979,031 10,447,775 (455,229) 5,816,841 121,875 (133,893) Total Control Operating Expenses 543,444,477 162,077,861 333,052,605 34,061,675 7,513,032 1,354,766 5,394,737 Less Other Revenues (5,137,708) (5,137,708) (6,137,708) (1,224,777) (1,224,777) (1,224,777) Martel Sales (62,806) (62,806) (1,224,777) (1,224,777) (0,000 0,000	421	Non Operating Margins - Other	(493,662)	(152,484)	(294,432)	(29,949)	(11,883)	(1,316)	(3,598)	COS RATIO - PREL.
Required Operating Margins (5,368,017) (1,698,532) (3,402,682) (455,229) 250,522 (9,803) (153,183) 427 interest on L-T Debt 30,145,557 10,577,663 13,850,458 0 5,566,460 131,775 (153,183) 427 total Interest & Op. Margins 24,776,640 8,970,031 10,447,775 (455,229) 5,816,491 121,975 (133,883) Total Operating Expense 543,444,477 162,077,661 333,052,605 34,051,675 7,513,032 1,354,786 5,394,737 Less Other Revenues (5,137,708) (5,137,708) (5,137,708) (5,137,708) KWH Mon-Member Sales (8,006,085) (8,006,085) (8,006,085) KWH KWH 456 Other Electic Revenues (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777) (1,224,777)	 424	Other Capital Credits and Patronage Dividends	(100,000)]	(100,000)	GENL
427 Interest on L-T Debt 30,145,557 10,577,663 13,850,456 0 5,566,460 131,778 19,301 TOTAL UTILITY PLANT RATIO Total Interest an L-T Debt 24,776,840 8,979,031 10,447,775 (455,229) 5,816,861 121,075 (13,3693) Total Coperating Expense 543,444,477 182,077,681 333,052,005 34,051,675 7,513,032 1,354,766 5,304,737 Less Other Revenues (5,137,708) (5,137,708) (6,137,708) KWH KWH Non-Member Sales (65,060,085) (60,060,085) (62,060) (1224,777) (1224,777) (1224,777) TOTAL COST OF SERVICE 5537,809,741 171,056,682 330,283,781 33,390,448 13,330,013 1,476,741 4,036,067 Cost-of-Service Ratio 1.000 0.30e 0.685 0.061 0.024 0.007 0.077 0.214 SUMMARY OF COST OF SERVICE 243,299,011 24,008,987 219,290,024 0 0 0 0 0 0 0 0 0 0	<u> </u>	Required Operating Margins	(5,368,917)	(1,598,532)	(3,402,682)	(455,229)	250,522	(9,803)	(153,193))i
Total Interret & Op. Margins 24,776,640 8,979,031 10,447,775 (455,229) 5,816,981 121,975 (133,893) Total Operating Expense 543,444,477 182,077,861 333,052,805 34,051,675 7,513,032 1,354,766 5,394,737 Less Other Revenues (5,137,708) (5,137,708) (5,137,708) KWH Non-Member Sales (6,006,085) (62,800) (82,806) KWH 456 Other Electric Revenues (1,224,777) (82,806) (1,224,777) (12,24,777) TOTAL COST OF SERVICE 553,789,731 171,056,692 330,293,781 33,596,446 13,330,013 1,476,741 4,038,067 Cost-of-Sarvice Ratio 1.000 0.306 0.586 0.061 0.024 0 0 0 0 Non-Power Supply COS Ralio 1.000 0.000 0.000 0.000 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 <td< td=""><td>427</td><td>Interest on L-T Debt</td><td>30,145,557</td><td>10,577,563</td><td>13,850,456</td><td>0</td><td>5,566,460</td><td>131,778</td><td>19,301</td><td>TOTAL UTILITY PLANT RATIO</td></td<>	427	Interest on L-T Debt	30,145,557	10,577,563	13,850,456	0	5,566,460	131,778	19,301	TOTAL UTILITY PLANT RATIO
Total Operating Expenses 543,444,477 162,077,661 333,052,605 34,051,675 7,513,032 1,354,766 5,364,737 Less Other Revenues (5,137,708) (5,137,708) (5,137,708) KWH Non-Member Sales (6,006,085) (8,006,085) (8,006,085) KWH Martel Sales (62,806) (82,806) (1,224,777) KWH TOTAL COST OF SERVICE 553,788,741 171,056,692 330,596,446 13,330,013 1,476,741 4,038,007 Cost-of-Service Ratio 1.000 0.309 0.596 0.061 0.024 0.003 0.007 Non-Power Supply COS Rallo 1.000 0.000 0.000 0.000 0.000 0.001 0.014 SUMMARY OF COST OF SERVICE 243,299,011 24,008,987 219,290,024 0 0 0 0 0 Purchased Power 218,516,713 120,311,888 97,435,770 0 0 0 0 0 0 0 0 0 0 0 0 0 0	ļ	Total Interest & Op. Margins	24,776,640	8,979,031	10,447,775	(455,229)	5,816,981	121,975	(133,893)	
Less Oriner Revenues Interruptable Sales (5,137,708) (5,137,708) (5,137,708) (KWH) Non-Member Sales (6,006,085) (6,006,085) (6,006,085) (KWH) Martel Sales (62,806) (62,806) (62,806) (1,224,777) TOTAL COST OF SERVICE 553,789,741 171,056,602 330,293,781 33,596,446 13,330,013 1,476,741 4,036,007 Cost-of-Service Ratio 1,000 0.306 0.696 0.061 0.024 0.003 0.007 Non-Power Supply COS Ratio 1,000 0.000 0.000 0.000 0.000 0.001 0.017 0.024 0.003 0.007 Power Production 243,299,011 24,008,967 219,290,024 0 0 0 0 0 Power Production 243,299,011 24,008,967 219,290,024 0 <	1	Total Operating Expense	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,766	5,394,737	
Interruptable Sales (5,137,708) (5,137,708) (6,137,708) (KWH) Non-Member Sales (6,006,085) (8,006,085) (8,006,085) KWH Martel Sales (62,800) (62,800) (62,800) KWH 456 Other Electric Revenues (1,224,777) KWH (1,224,777) KWH TOTAL COST OF SERVICE 553,789,741 171,056,602 330,293,781 33,596,446 13,330,013 1,476,741 4,036,067 Cost-of-Service Ratio 1.000 0.309 6.6586 0.061 0.024 0.003 0.007 Non-Power Supply COS Ralio 1.000 0.000 0.000 0.000 0.000 0.000 0.000 0.000 0.007 0.078 0.214 SUMMARY OF COST OF SERVICE 243,299,011 24,008,987 219,290,024 0]	Less Other Revenues	1	}]		} ·	1
Non-Nember Sales (8,006,085) (8,006,085) (8,006,085) (8,006,085) (8,006,085) (8,006,085) (8,006,085) (8,006,085) (8,006,085) (1,224,777)	1	Interruptable Sales	(5,137,708)	Į	(5,137,708)			}	ļ	KWH
Martel Sales (62,806) (62,806) (62,806) (KWH 456 Other Electric Revenues (1,224,777) KWH (1,224,777) (1,224,777) TOTAL COST OF SERVICE 553,780,741 171,056,692 330,293,781 33,596,446 13,330,013 1,476,741 4,038,087 Cost-of-Service Ratio 1.000 0.306 0.656 0.061 0.024 0.000 0.000 Non-Power Supply COS Ratio 1.000 0.000 0.000 0.000 0.000 0.007 0.078 0.214 SUMMARY OF COST OF SERVICE 243,290,011 24,008,987 219,200,024 0 0 0 0 0 Power Production 218,516,713 120,311,888 97,435,770 0 0 789,055 0 1t Transmission Operations Expenses 35,528,936 0 0 34,051,675 1,475,281 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 <td>}</td> <td>Non-Member Sales</td> <td>(8,006,085)</td> <td></td> <td>(8,006,085)</td> <td></td> <td></td> <td></td> <td></td> <td>КМН</td>	}	Non-Member Sales	(8,006,085)		(8,006,085)					КМН
13:00 Utility (1,224,777) (1,224,777) (1,224,777) GENL TOTAL COST OF SERVICE 553,789,741 171,056,692 330,293,781 33,598,446 13,330,013 1,476,741 4,038,087 Cost-of-Service Ratio 1.000 0.308 0.696 0.001 0.002 0.003 0.007 Non-Power Supply COS Ratio 1.000 0.000 0.000 0.000 0.000 0.000 0.007 0.078 0.214 SUMMARY OF COST OF SERVICE 243,299,011 24,008,987 219,290,024 0 0 0 0 0 0 Power Production 218,516,713 120,311,888 97,435,770 0 <td>450</td> <td>Martel Sales</td> <td>(62,806)</td> <td></td> <td>(62,806)</td> <td></td> <td></td> <td></td> <td>ł</td> <td>KWH</td>	450	Martel Sales	(62,806)		(62,806)				ł	KWH
TOTAL COST OF SERVICE 553,780,741 171,056,692 330,293,781 33,596,446 13,330,013 1,476,741 4,036,067 Cost-of-Service Ratio 1.000 0.309 0.696 0.001 0.024 0.003 0.007 Non-Power Supply COS Ratio 1.000 0.000 0.000 0.000 0.000 0.000 0.007 SUMMARY OF COST OF SERVICE 243,299,011 24,008,987 219,290,024 0 0 0 0 0 Power Production 218,516,713 120,311,888 97,435,770 0 0 0 0 0 0 Purchased Power 218,516,713 120,311,888 97,435,770 0 0 769,055 0 1 Transmission Operations Expenses 35,526,936 0 0 34,051,675 1,475,281 0 <td< td=""><td>400</td><td>Other Electric Revenues</td><td>(1,224,777)</td><td>L</td><td>l</td><td></td><td></td><td></td><td>(1,224,777</td><td>GENL</td></td<>	400	Other Electric Revenues	(1,224,777)	L	l				(1,224,777	GENL
Cost-of-Service Ratio 1.000 0.309 0.696 0.061 0.024 0.003 0.007 Non-Power Supply COS Ratio 1.000 0.000		IDIAL COST OF SERVICE	553,789,741	171,056,692	330,293,781	33,596,446	13,330,013	1,476,741	4,036,067	
Non-Power Supply COS Ratio 1.000 0.000 0.000 0.000 0.000 0.007 0.078 6.214 SUMMARY OF COST OF SERVICE 243,299.011 24,008,987 219,290,024 0	1	Cost-of-Service Ratio	1.000	0.309	0.596	0.061	0.024	0.003	0.007	
BUMMARY OF COST OF 8ERVICE 243,299,011 24,008,987 219,290,024 0	<u> </u>	Non-Power Supply COS Ralio	1.000	0.000	0.000	0.000	0.707	0.078	0.214	
Power Production 243,299,011 24,008,987 219,290,024 0 0 0 0 Purchased Power 218,516,713 120,311,888 97,435,770 0 0 769,055 0 17 Transmission Operations Expenses 35,526,938 0 0 34,051,675 1,475,281 0 0 0 Transmission Maintenance Expenses 1,200,514 0 0 0 1,200,514 0 0 468,731 534,804 4,203,816<	BUILDE	BY OF COST OF REPUICE			ļ					
243,259,011 243,008,857 219,290,024 0 0 0 0 Purchased Power 218,516,713 120,311,888 97,435,770 0 0 0 769,055 0 Transmission Operations Expenses 35,526,938 0 0 34,051,675 1,475,281 0 0 0 Transmission Maintenance Expenses 1,200,514 0 0 0 1,200,514 0 0 468,731 534,804 4,203,816	Power	Visi or over ur erraios	049 000 044	24 000 00-						
Transmission Operations Expenses 218,016,713 120,311,868 97,435,770 0 0 769,055 0 0 Transmission Maintenance Expenses 35,526,936 0 0 0 34,051,675 1,475,281 0 0 0 Transmission Maintenance Expenses 1,200,514 0 0 0 1,200,514 0 0 0 Administrative And General Operations Expenses 15,215,834 6,246,957 3,761,527 0 468,731 534,804 4,203,816 V	Durcha		243,288,011	24,008,987	219,290,024	(<u> </u>	i 0	0	0	i iii
35,220,930 0 0 34,051,675 1,475,261 0 0 Transmission Maintenance Expenses 1,200,514 0 0 0 1,200,514 0 0 Administrative And General Operations Expenses 15,215,834 6,246,957 3,761,527 0 468,731 534,804 4,203,816	Tranem	Istin Operations Evances	210,010,/13	120,311,888	97,435,770	0	0	789,055	0	i it
Administrative And General Operations Expenses 1,200,514 0 0 0 1,200,514 0 0 Administrative And General Operations Expenses 15,215,834 6,246,957 3,761,527 0 468,731 534,804 4,203,816	Transm	Islan Meintenenze Evrenzes	39,526,936	D	0	34,051,675	1,475,281	0	1 0	1
	Admini	Intive And General Operations Evender	1,200,014	0	0	0	1,200,514	0		· ·
VSS-1)	1. conserved and	and an celeral cherenous crheises	1 19,219,834	0,240,957	3,761,527	0	468,731	534,804	4,203,816	3
S-1)										
-1)										ល័
										i)

	FY 2000			1				
	Budget			-				
Acct #	Totals	кw	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
Administrative And General Maintenance Expenses	120,700	0	0	0	0	0	120,700	
Depreciation	25,581,072	9,476,087	11,246,826	ol	3,903,185	1,158	953,818	
Taxes & Other	3,983,697	2,033,742	1,318,458	0	465,341	49,750	116,406	
Total Interest & Op, Margins	32,480,437	11,396,832	14,923,223	a	5,997,602	141,985	20,796	
Non-operating Margins	(7,703,797)	(2,417,801)	(4,475,449)	(455,229)	(180,620)	(20,010)	(154,688)	
Non-Member Sales	(8,006,085)	0	(8,006,085)	0	0	O	0	
interruptible Sales	(5,137,708)	0	(5,137,708)	0	0	0	0	
Martel Sales	(62,806)	0	(62,806)	a	0	a	0	
Other Op. Revenue	(1,224,777)	0	0	0	a	D	(1.224.777)	
Cost of Service	553,789,741	171,056,692	330,293,781	33,596,446	13,330,013	1,476,741	4,036,067	
COS Excluding Payroll & Gross Receipts Tax, Req'd Margins, & Int.	on LT Debt							
Required Operating Margins	32,280,437	11,298,832	14,923,223	0	5,997,602	141,985	(79,204)	
Total Op Exp	543,444,477	162,077,661	333,052,605	34,051,675	7,513,032	1,354,768	5,394,737	{
Cost of Service (excl. nonoperating interest and other income)	561,293,538	173,374,493	334,769,229	34,051,675	13,510,634	1,498,751	4.090,755	l .
COS Ratio (Prelim.)	1.000	6.309	0.596	0.061	0.024	0.003	0.007	{
Non-Power Supply COS Ratio (Prelim.)	1.000	0.000	0.000	0.000	0.707	0.078	0.214	}
RATIOS	}							
Power Production	1.000	0.099	0.901	0.000	0.000	0.000	0.000	Į –
Purchased Power	1.000	0.551	0.446	0.000	0.000	0.004	0.000	1
Transmission	1.000	0.000	(0.000 j	0.927	0.073	0.000	0.000	[
Admin. & General	1.000	0.407	{ 0.245	0.000	0.031	0.035	0.262	}
Taxes (Payroll & Property)	1.000	0.413	0.412	0.000	0.159	0.008	0.008	}
Cost of Service Rano	1.000	0.309	0.598	0.061	0.024	0.003	0.007	1
PATROLL RATIO					1	ł	l I	{
Operations Supervision and Engineering	2,681,834	2,651,634	{ 0	0	0	0	0	
Maintenance Supervision and Engineering	5,428,515	5,428,515] 0	0	0	6 0	} 0	}
Invaluentative Supervision and Engineering	2,287,873	2,287,873	0	0	0	0	0	1
Operations Supervision And Engineering	177,341	0	0	D	177,341	0	0	}
Annunsustative or Oenetal Salanes	10,805,074	4,890,317	3,787,480	0	565,680	485,177	1,076,420	1
10iai Paura II Casta	21,380,437	15,288,339	3,787,480	0	743,021	485,177	1,076,420	
	1.000000	0.715	0.177	0.000	0.035	0.023	0.050	

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RATE BASE

Seminole Electric Cooperative, inc.

	rT									
						(0.5.1	Description of Appingment
	RATE BASE CALCULATION	Total	kW	kWh	ACC	T-KW	T-KWH	CONS	GENL	Description of Assignment
	Total Utility Plant	882,429,372	309,629,437	405,434,518	0	162,942,997	0	3,857,446	564,973	Plant in Service
	Depreciation Reserve:									LAN MARI CIE SEAL COORCHU
108.1	Steam Plant	(281,169,188)	(130,181,334)	(150,987,854)		1				KAA' KAAL CO3
108.2	Nuclear Plant	(8,413,949)	(3,020,608)	(5,393,341)						NYY, NYYN - CR3
108.5	Transmission Plant	(49,002,883)			} }	(49,002,883)			10 100	Direct
108.7	General Plant	(12,791,254)	(4,488,233)	(5,876,976)	0	(2,361,940)	0	(55,916)	(8,190)	Iotal Utiny Plant Raus
108.9	Cost of Removal - Nuclear	(94,379)	(33,882)	(60,497)			}			RAY, RAVEL - CRU
111.1	Transportation Lease	(23,444,300)		(23,444,300)						KVV, KVVH - 023 MVV Capacity
111.1	Intangible Plant (HPS-Acuera)	(2,311,850)	(818,008)	(1,069,024)	((424,818)				Prod/Amsn Plant Kello
11111	Leasehold improvements - U2	(8,650,311)	(4,005,094)	(4,645,217)			• ·			KW, KWH - 625 MW Capacity
115.1	Acquisition Adjustment	(429,202)	(154,084)	(275,118)	1					KW, KWH - CR3
120.5	Nuclear Fuel	(6,504,475)		(6,504,475)					ļ	Direct
1	Working Capital:		T				{	{	1	
í	Power Production	9,998,589	986,671	9,011,919	}) ·)	1	Operating Expense
]	Purchase Power Expense	8,980,139	4,944,324	4,004,210				31,605	Ì	Operating Expense
	Transmission	4,528,042	{	i	4,198,152	329,890	} 0	})	T-KW
ļ.	Administrative & General	1,890,806	770,173	463,750) 0	57,789	0	65,935	533,159	Admin. & General Ratio
	Pavroli & Property Taxes	1,279,342	914,809	226,632	0	44,460	0	29,032	64,410	Tax Expense Ratio
135	Working Funds	4,289	1	1	1	ł		4,289		Direct
154	Plant Materials and Operating Supplies	17,545,183	6,156,306	8,061,181	0	3,239,766	0	76,697	11,233	Total Utility Plant Ratio
165	Prepayments	12,021,018	4,217,970	5,523,089) 0	2,219,714) 0	52,549	7,696	Total Utility Plant Ratio
<u> </u>	Deductions:	1		1				[1	
235	Consumer Deposits	(3,981)	ł	· · · · · · · · · · · · · · · · · · ·		L	(3,981)	24	CONS
	TOTAL RATE BASE	545,861,008	184,918,447	234,468,495	4,198,152	117,044,975	0	4,057,656	1,173,282	L
	Rate Base Ratio	1.000	0.339	0.430	0.008	0.214	0.000	0.007	0.002	1.00

Exhibit _ - (WSS - 2)

LCEC COST OF SERVICE ANALYSIS

Rate Base Assignment Seminole Electric Cooperative, Inc.

Account		Year 2000		,					
Number	item	Budget	kW	КЖН	ACC	T-KW	CONS	GENL	Description of Assignment
301-303	Total Intangible Plant	5,779,220	4,717,249	-		1,061,971			Production/Transmission Plant
310-318	Total Production Plant - Steam	673,348,929	673,348,929	-					ĸw
320-325	Total Production Plant - Nuclear	22,306,484	22,306,484	•					ĸw
	Total Production Plant	701,434,633	700,372,662	•		1,061,971	-	-	
050	hand and hand Dishes	10 100 010							
350	Land and Land Hights	16,406,249	•	•	-	16,406,249	-	•	T-KW
352	Structures and improvements	•	•	•	-	•	•	-	T-KW
353	Station Equipment	-	•	-	-		•	-	T-KW
354-358	Other Transmission Plant	140,203,133	·	<u> </u>	<u>.</u>	140,203,133		•	T-KW
	Total Transmission Paint	156,609,382	•	-	-	156,609,382	-	•	
	Total Prod/Trans Plant	858,044,015	700,372,662	•	•	157,671,353	•	-	
389	Land and Land rights	798,157	651,490	-		146,667	-		Production/Transmission Plant
391	Office Furiture & Equipment	1,597,554	•	•	-	• •	1,597,554	-	CONS
392	Transportation Equipment	748,182	748,182	-	-	•	•	-	KW
397	Communication Equipment	5,649,731	225,989	338,984		2,259,892	2,259,892	564.973	Standard/Judgement
398	Miscellaneous Equipment	15,591,733	12,726,647	-	•	2,865,086			Production/Transmission Plant
	Total General Plant	24,385,357	14,352,308	338,984		5,271,645	3,857,446	564,973	
	All Other Utility Plant	-			-	•	-	-	Prod/Xmsn Paint Ratio
107	Construction Work in Progress	-			-		•	-	Prod/Xmsn Paint Ratio
	Total Utility Plant	662,429,372	714,724,970	338,984	-	162,942,998	3,857,446	564,973	
	Utility Plant Ratio	100%	81.00%	0.04%	0.00%	18.47%	0.44%	0.06%	

Rate Base Assignment Seminole Electric Cooperative, Inc.

Account		Year 2000	· · · · · · · · · · · · · · · · · · ·	···					
Number	Item	Budget	kW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
	Depreciation Reserve:								
108.1	Steam Plant	(281,169,188)	(281,169,188)	0	0	0	0	0	ĸw
108.2	Nuclear Plant	(8,413,949)	(8,413,949)	0	0	0	0	0	ĸw
108.5	Transmission Plant	(49,002,883)	0	0	0	(49,002,883)	0	0	ĸw
108.7	General Plant	(12,791,254)	(10,360,295)	(4,914)	0	(2,361,940)	(55,916)	(8,190)	Utility Plant Ratio
108.9	Cost of Removal - Nuclear	(94,379)	(94,379)	0	0	0	0	Ó	ĸw
111.1	Transporatalon Lease	(23,444,300)	(23,444,300)		0	0	0	0	ĸw
111.1	Intangiole Plant (HPS-Acurea)	(2,311,850)	(1,887,032)	0	0	(424,818)	0	0	Production/Transmission Plant
111.1	Leasehold Improvements - U2	(8,650,311)	(8,650,311)	0	0	0	0	0	ĸw
115.1	Acquisiton Adjustment	(429,202)	(429,202)	0	0	0	0	0	ĸw
120.2	Nuclear Fuel	(6,504,475)	(6,504,475)	0	0	0	0	0	ĸw
	Total Depreciation	(392,011,791)	(340,953,131)	(4,914)	0	(51,789,641)	(55,916)	(8,190)	
l .									
1	Net Plant	489,617,581	373,771,839	334,070	•	111,153,357	3,801,530	556,783	
•	Net Plant Ratio	100%	76.34%	0.07%	0.00%	22.70%	0.78%	0.11%	
l	Martin - Control	Į.							1
	Working Capital:	0.000 690	0 440 00 4	7.640.005					
	Power Production	9,998,569	2,449,004	7,548,935	•	•	•	•	Power Production Expenses Hatio
	Furchase Power Expense	8,980,139	4,944,324	4,004,210			31,605	•	Operating Expenses
		4,528,042	-		4,198,152	329,890	-	•	I-KW
	Administrative & General	1,890,000	770,173	403,750	•	57,789	65,935	533,159	Admin & General Hallo
	Haylos Cupdo Sundo	1,279,342	814,809	220,032	•	44,400	29,032	64,410	Lax Expense Ratio
1.54	Working Fullus Right Materials and Operation Supplies	4,209	- A 150 000	- D.021.101	•	•	4,289	•	Direct
1.04	Prana Materials and Operating Supplies	17,545,163	4 017 070	8,001,181	•	3,239,700	10,091	11,233	Total Uliniy Plant Plant
105	Prepayments	12,021,010	4,217,970	5,523,089		2,218,714	52,548	(,080	Colar Uturiy Plank Ratio
	Working Capital	56 247 408	19 453 236	25 R27 797	4 198 152	5 891 619	260 107	616 40 8	
			10,100,200	20,021,107	4,100,102	0,001,010	200,101	010,400	
	Deductions:								
235	Consumer Deposits	(3,981)	0	0	0	0	(3,981)	0	CONS
	•			-				-	
	TOTAL RATE BASE	545,861,008	393,225,076	26,161,867	4,198,152	117,044,976	4,057,656	1,173,261	

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2 of 2

Year 2000 Budget Assignment

Seminole	Electric	Cooperat	ive, Inc.
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Account		Year 2000							
Number	llem	Budget	kW	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
	POWER PRODUCTION EXPENSE								
5	00 Operations Supervison and Engineering	2,681,634	2,681,634	•	•	-	-	- 1	FERC PREDOMINANCE
5	01 Fuel Expense	162, 184, 362	-	162,184,362	-	-	-	-	FERC PREDOMINANCE
5	02 Steam Expense	7,720,824	7,720,824	•		-		- 1	FERC PREDOMINANCE
5	05 Electric Expenses	1,694,210	1 694,210	•		•	•	•	FERC PREDOMINANCE
5	06 Misc Steam power Expenses	10.557,901	10,557,901	•	-	•		- 1	FERC PREDOMINANCE
5	07 Power Plant Rents	28,641,657	28,641,657	-	•	-		-	FERC PREDOMINANCE
5	10 Maintenance Supervision and Engineering	5,428,515		5,428,515		•	-	•	FERC PREDOMINANCE
5	511 Maintenance of Structures	349.878	349,878		•	•	-	-	FERC PREDOMINANCE
5	12 Maintenance of Boiler Plant	14.443.520		14.443.520	•	-		-	FERC PREDOMINANCE
	13 Maintenance of Electric Plant	1 105 936		1.105.936	-	-		-	FERC PREDOMINANCE
	514 Maintenance of Misc Steam Plant	5.554.701	5.554.701					-	FERC PREDOMINANCE
	18 Nuclear Fuel Expense	648 000	-,	648,000					FERC PREDOMINANCE
	28 Maintenance Supervision and Engineering	2 287 873	2.287.873	-	-	•	-		FERC PREDOMINANCE
·									
	PURCHASED POWER								
	555 Purchased Power	216 750 478	118.545.653	97.435.770	•		769.055		KW, KWH, CONC- By Contract
	556 System Control and Load Dispatch	1.717.774	1.717.774						KW
	557 Other Power Supply Expenses	48 461	48 461		-				KW
<u>`</u>	TRANSMISSION OPERATIONS EXPENSES			· · · · · · · · · · · · · · · · · · ·					
	560 Operations Supervision and Engineering	177 341				177 341			T-KW
	562 Station Expanses	9.604				9.604			T-KW
	565 Transmission of Electricity by Others	34 051 675		-	34 051 675	2,001		-	ACC
	566 Miscellaneous Transmission Exnenses	1 285 816	•			1 285 816		-	T-KW
	567 Renis	2 500		-	-	2 500	-		T-KW
	TRANSMISSION MAINTENACE EXPENSES								
	570 Maintenance of Station Souinment	1 105 105				1 195 105		_	T.KW
l '	571 Maintenance of Overhead Lines	5 409				5 409			T.KW
<u>├</u>	ADMINISTRATIVE AND GENERAL OPERATIONS EXPL	INSES							
J	920 Administrative & General Salaries	10 805 074	3 900 632	6 094 062	734 745	54 025	21.610		OAM SUB-TOTAL
1	921 Office Supplies and Expense	2 276 213	1 827 634	403 224		79,104	51.653	114 598	PAYBOLL BATIO
ļ	922 Administative Expenses Transferred - Credit	(1.007.800)	(769 355)	(705)	-	(228 771)	(7.661)	(1 109	NET PLANT BATIO
	923 Outside Services Employed	1 666 460	601 592	939 883	113 319	8 332	3 333		OAM SUB-TOTAL
1	924 Property Insurance	35 944	27.440	25		8,159	280	40	NET PLANT BATIO
ſ	925 Injuries and Damages	39.607	28.321	7.016		1,376	899	1,994	PAYROLL RATIO
]	026 Employee Pensions and Renetits	58,306	41 692	10 329		2 026	1 323	2 935	PAYBOLL BATIO
ļ	930 General Advertision and Miscelloneous General Eventse	1 342 030	484 473	758 905	B1 258	8 710	2 684	-,000	OAM SUB-TOTAL
}	ADAMNESTRATIVE AND GENERAL MAINTENANCE FY	PENSES	403,410	1.00,000	01,200				
	012 Maintenance (Y General Plant	120 700						120 700	GENL
├ ───	DEDBECIATION AND AMORTIZATION EXPENSE	120,700	······································		·····				
4	AS 1 Steam Production Plant	18 223 995	18 223 995						Sleam Plani
	03.2 Nuclear Brocketion Plant	1 061 449	1 061 449					_	Nuclear Plant
	03.2 Muchae Frouddon Freit	3.854.282	1,001,440			3 854 282			Transmission Plant
	03.0 Hensinsson Field	051 844				303,-10,0		953 444	GENI
	00.7 Optional Fight	(21 785)	/10 1671	(17)		16 2001	/1861	000,040 (04	NET PLANT BATIO
9	av.u Legisculturi i lanskeligu 04.0. Amerikatika Lassheld Imerukanania	(23,703)	(10,137)	847 410		(3,388)	(100)	(20	IKW KWH
1	0%.0 Amonazarion Leashold Improvements	1,203,003	330,183	202		45 610	2 251		NET BLANT DATIO
1	US.U MISCHIANOUS DEprecision/Amorization	206,024	220,336	202		00,010	2,231	31	
4	UD,U Amonization Electric Plant Acquisition	1 17,256	6,195	11,061	<u> </u>	<u> </u>	· · · · · · · · · · · · · · · · · · ·		[AW, AW?]

Exhibit __- (WSS-2)

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Year 2000 Budget Assignment Seminole Tectric Cooperative, Inc.

Account		Year 2000							
Number	ilem	Budgel	k₩	KWH	ACC	T-KW	CONS	GENL	Description of Assignment
0	THER EXPENSES								
408.1 P	roperty Taxes	8,618,067	6,579,032	6,033	-	1,956,301	67,221	9,480	NET PLANT RATIO
408.2 Pi	ayroli Taxes	24,168	17,294	4,284	-	841	549	1,218	PAYROLL RATIO
408.3 P	ayroll Taxes	1,731,795	1,238,341	306,782	•	60,184	39,299	87,189	PAYROLL RATIO
408.4 P	ayroll Taxes	15,116	10,809	2,678	-	525	343	761	PAYROLL RATIO
408.7 Ta	axes, Other	(12,282)	•	•	-	•	•	(12,282)	GENL
990.0 O	verhead allocation and Taxes Transferred	(10,212,065)	(7,795,890)	(7,148)	•	(2,318,139)	(79,654)	(11,233)	NET PLANT RATIO
425 M	liscellaneous Deprecialtion/Amortization	72	55	0	•	16	١	0	NET PLANT RATIO
426 D	onations	38,120	•	-	•	•	-	38,120	GENL
428 A	mortization of Debt Discout and Expense	3,780,688	2,886,177	2,646	•	858,216	29,489	4,159	NET PLANT RATIO
TT	OTAL OPERATING EXPENSE:	543,444,477	208,730,825	290,430,773	34,990,997	7,079,083	902,290	1,310,507	
						_			
i A	NNUAL INVESTMENT COST:								
ן אַז	arget Margin Dollar Amount								
R	equired Margins & Patronage Capital	2,334,880	1,782,447	1,634	•	·530,018	18,212	2,568	NET PLANT RATIO
R R	lequired Margins & Patronage Capital	2,334,880	1,782,447	1,634	•	530,018	18,212	2,566	
} N	ion-Opertaing Margins]
419	Non-Opertaing Margins - Interest	(7,010,135)	(2,165,317)	(4,181,016)	(425,280)	(168,738)	(18,693)	(51,090)	COS RATIO - PREL
411	Gain on Disposition of Clean Air Allowances	(100,000)	(100,000)	•	•	•	•	•	ĸw
421	Non-Opertaing Margins - Other	(493,662)	(152,484)	(294,432)	(29,949)	(11,883)	(1,316)	(3,598)	COS RATIO - PREL
424	Other Capital Credit and Patronage Dividends	(100,000)	•	•	-	-	-	(100,000	GENL
<u> </u>	Required Operating Margins	(5,368,917)	(635,354)	(4,473,814)	(455,229)	349,397	(1,797)	(152,120	
427 1	nterest on L-T Debt	30,145,557	23,013,118	21,102	-	6,843,041	235,135	33,160	NET PLANT RATIO
٦	otal Interest & Op. Margins	24,776,640	22,377,765	(4,452,712)	(455,229)	7,192,438	233,338	(118,960)
Г <u> </u>	otal Opertaing Expense	543,444,477	208,730,825	290,430,773	34,990,997	7,079,083	902,290	1,310,507	
ի լ	ess Other Revenues								Į.
1	Interruptable Sales	(5,137,708)	-	(5,137,708)	•	•	-	•	KWH
	Non-Member Sales	(8,006,085)	•	(8,006,085)	•	-	-	-	KWH
	Martel Sales	(62,606)	•	(62,606)	-	-	-	•	KWH
456	Other Electric Revenues	(1,224,777)	•	•	-	-	<u> </u>	(1,224,777	GENL
	Cost of Service (With allocation to GENL)	553,789,741	231,108,590	272,771,462	34,535,768	14,271,521	1,135,629	(33,230)
									1
	Aliocation of General		(13,866.69)	(16,366.50)	(2,072.17)	(856.30)	(68.14)		COS Ratio
	•								
									1
· ·	TOTAL COST OF SERVICE:	553,789,740	231,094,723	272,755,096	34,533,696	14,270,665	1,135,560		
RATIOS									
	POWER PRODUCTION EXPENSE	100%	24.5%	75.5%					
	O&M SUB-TOTAL	100%	36.1%	56.4%	6.8%	0.5%	0,2%		1
1	PRODUCTION/TRANSMISSION PLANT	100%	81.62%			18.38%			

Exhibit _ - (WSS - 3)

Cost Recovery Under SECI-7b Compared to Actual Cost from Cost of Service Study

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Cost Recovery Under SECI-7b Compared to Actual Cost from Cost of Service Study

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	C	LECE's ost of Service Study	Percentage of Total Cost	SECI- 7b	
Commodity (Energy Related)	\$	272,755,096	49.25%	58.46%	
Capacity (Demand Related)		279,899,084	50.54%	41.54%	
Customer (Customer Related)		1,135,560	0.21%	0.00%	
	\$	553,789,740	100.00%	100.00%	

Exhibit _ - (WSS - 4)

Revenues Produced by LCEC's Proposed Rate Alternatives Compared to SECI-7b

(Based on Estimated 2001 Billing Units)
Seminole Electric Cooperative, Inc.

Comparision of Various Rate Alternatives

8 Months Demand Transmission Kw-Mo. Distribution Kw-Mo.

- A flar method f		Charges		Revenue
Rate Alternative 7	\$	9.126	\$	279,275,184
Demand Charge (Applied to all 12 months) - Revisio	ŝ	0.02243	S	282,670,370
Energy Charge - kWh	Š	1.260	\$	360,557
Distribution Delivery Criarge = Kawado	•			
Total Revenue			<u>\$</u>	562,306,111

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Pata Alternative 2	Charges	Revenue
Production Demand Charge (Applied to 8 peak months)	\$ 10.586	\$ 233,667,954
Transmission Demand Charge (Applied to all 12 months)	\$ 1.490	\$ 45,597,198
Distribution Delivery Charge (Applied to all 12 months)	\$ 1.260	\$ 360,557
Fuel Charge	\$ 0.01989	\$ 250,660,439
Non-fuel Energy Charge	\$ 0.00254	\$ 32.009.930
Total Revenue		\$ 562,296,078

Rate Alternative 3	 Charges	Revenue
Production Demand Charge (Applied to 8 peak months)	\$ 8.500	\$ 187,623,050
Production Fixed Demand Charge *		\$ 46,046,418
Transmission Demand Charge (Applied to all 12 months)	\$ 1.490	\$ 45,597,198
Distribution Delivery Charge (Applied to all 12 months)	\$ 1.260	\$ 360,557
Fuel Charge	\$ 0.01989	\$ 250,660,439
Non-fuel Energy Charge	\$ 0.00254	\$ 32,009,930
Total Revenue		\$ 562,297,592

* allocated on the basis of the member system demands for 12 months

SECI-7B	Charges		Revenue
Demand Related Costs:			· · · · · · · · · · · · · · · · · · ·
Demand Rate \$/Kw - Mo.	\$ 8.500	\$	187,623,050
Transmission \$/Kw -Mo.	\$ 1.490	s	45,597,198
Distribution \$/Kw -Mo.	\$ 1.260	\$	360,557
Total Demand Related Revenue		S	233,580,804
Energy Related Costs:			
Fuel \$/Kwh	\$ 0.01989	\$	250,660,439
Non-Fuel \$/Kwh	\$ 0.00254	\$	32,009,930
Production Fixed Energy		\$	46,046,418
		\$	328,716,788
Total Revenue		\$	562,297,592

Exhibit $_$ - (WSS – 5)

Individual Member Billings Under Proposed Rate Alternatives Compared to SECI-7b

(Based on Estimated 2001 Billing Units)

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Revenues Produced by LCEC's Proposed Rate Alternatives Compared to SECI-7b

(Based on Estimated 2001 Billing Units)

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		Rate	Rate	Rate
Member Systems	SECI-7B	Alternative 1	 liternative 2	Alternative 3
Central Florida	\$ 18,424,552	\$ 18,580,113	\$ 18,426,665	\$ 18,456,887
Clay	114,208,590	114,337,255	113,877,332	113,967,868
Glades	13,811,488	13,916,441	13,626,860	13, 683,91 2
Lee County	118,950,590	117,446,519	117,736,724	117,679,446
Peace River	17,802,945	17,703,522	17,725,899	17,721,475
Sumter	79,128,390	80,042,527	79,670,497	79,743,738
Suwannee	14,113,357	13,972,706	14,123,320	14,093,630
Talquin	40,063,194	40,096,245	40,290,468	40,252,163
Tri-County	8,296,027	8,176,482	8,229,393	8,218,960
Withlacoochee	137,498,460	138,034,301	 138,588,920	 138,479,513
	\$ 562,297,592	\$ 562,306,111	\$ 562,296,078	\$ 562,297,592

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SECI-7B		Charges	-	Determinants		Revenue
(Based on Estimated 2001 Billin	ig Ui	nits)				
Total System						
Demand Helated Costs:	•	0.500		00 070 000	¢	187 623 050
Demand Hate \$/Kw - Mo.) j	8.500		22,073,300	Ŷ	AE 507 109
Transmission \$/Kw -Mo.	\$	1.490		30,002,140	¢	40,097,190
Distribution \$/Kw -Mo.	\$	1.260		286,150	<u> </u>	300,557
Total Demand Related Revenue					\$	233,360,604
Energy Balatod Coste:						
Energy Related Costs.	¢	0.01089		12 802 334 814	\$	250 660 439
	¢	0.01909		12,002,004,014	Ě	32,009,930
Roduction Fixed Energy	4	100 00%	¢	12,002,004,014 A6 0A6 A18	¢	46 046 418
Production Fixed Energy		100.00%	3	40,040,410		328 716 788
					Φ	320,710,700
Total Revenue					\$	562.297.592
l otal nevende					_ <u></u>	
Central Florida						
·····						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	8.500		714,004	\$	6,069,034
Transmission \$/Kw -Mo.	ŝ	1.490		1.009,939	\$	1,504,809
Total Demand Related Revenue	•				\$	7,573,843
Energy Related Costs:						
Fuel \$/Kwb	\$	0.01989		417,450,261	\$	8,303,086
Non-Fuel \$/Kwh	Ś	0.00254		417,450,261	\$	1,060,324
Production Fixed Energy	*	3.23%	\$	46.046.418	\$	1,487,299
			-		5	10,850,709
					Ť	10,000,00
Total Revenue					\$	18.424.552
rotal nevenue					_ <u></u>	
Clav				,		
Demand Related Costs:						
Demand Rate S/Kw - Mo.	\$	8.500		4,379,619	\$	37,226,762
Transmission \$/Kw -Mo.	Ŝ	1,490		6,131,819	\$	9,136,410
Total Demand Related Revenue	•				\$	46,363,172
						·
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		2,602,687,225	\$	51,767,449
Non-Fuel \$/Kwh	\$	0.00254		2,602,687,225	\$	6,610,826
Production Fixed Energy		20.56%	\$	46,046,418	\$	9,467,144
					\$	67,845,418
Total Revenue					\$	114,208,590

SECI-7B		Charges		Determinants		Revenue
(Based on Estimated 2001 Billin	ng Ùi	nits)				
(•					
Glades						
Demand Related Costs:					-	
Demand Rate \$/Kw - Mo.	\$	8.500		476,587	\$	4,050,990
Transmission \$/Kw -Mo.	\$	1.490		698,629		1,040,957
Total Demand Related Revenue					\$	5,091,947
Energy Related Costs						
Energy Helated Costs.	\$	0.01989		336,190,488	\$	6.686.829
	š	0.00254		336 190 488	Š	853,924
Reduction Fixed Energy	Ψ	2 56%	¢	46 046 418	Š	1.178.788
Production Fixed Energy			Ψ	-0,0-0,-10	\$	8.719.541
					•	
Total Revenue						13,811,488
Lee County						
Demand Belated Costs:						
Demand Bate \$/Kw - Mo.	\$	8,500		4.439.930	\$	37,739,405
Transmission \$/Kw -Mo	ŝ	1.490		6.117.194	\$	9,114,619
Total Demand Related Revenue	•				\$	46,854,024
Energy Related Costs:						
Fuei \$/Kwh	\$	0.01989		2,747,258,419	\$	54,642,970
Non-Fuel \$/Kwh	\$	0.00254		2,747,258,419	\$	6, 978,03 6
Production Fixed Energy		22.75%	\$	46,046,418	_\$	10,475.560
					\$	72,096,566
					_	
Total Revenue					<u></u>	118,950,590
Peace River						
reace inver				·		
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	8.500		665,019	\$	5,652,662
Transmission \$/Kw -Mo.	\$	1.490		919,004	\$	1,369,316
Distribution \$/Kw -Mo.	\$	1.260		255,625	\$	322,088
Total Demand Related Revenue					\$	7,344,065
Energy Helated Costs:	•	0.04000		401 007 700	•	7 070 044
Fuel \$/Kwh	\$	0.01989		401,007,763	\$	1,970,044
Non-Fuel \$/Kwh	\$	0.00254		401,007,763	\$	1,018,000
Production Fixed Energy		3.18%	\$	40,040,418	->	1,404,270
					Φ	10,430,000
Total Revenuo					\$	17,802,945

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SEC1-7B		Charges		Determinants		Revenue
(Based on Estimated 2001 Billin	ng Un	its)				
•						
Sumter						
Demand Related Costs:	•	0 500		2 226 629	¢	27 426 338
Demand Hate \$/Kw - Mo.	\$ \$	8.300		3,220,020	¢ ¢	6 737 609
Transmission \$/Kw -Mo.	\$	1.490		4,521,005	<u></u>	34 163 947
Total Demand Related Revenue					Ψ	04,100,047
France Balatad Capita						
Energy Related Costs.	¢	0.01989		1 728 747 415	\$	34.384.786
	¢	0.01303		1 728 747 415	Ś	4.391.018
Non-ruel a/Kwill	Ψ	13 44%	\$	46 046 418	Š	6.188.639
Production Fixed Energy		10.4470	¥		<u> </u>	44.964.443
					•	.,
Total Revenue					\$	79,128,390
Suwannee						
Demand Related Costs:	•					
Demand Rate \$/Kw - Mo.	\$	8.500		558,834	\$	4,750,089
Transmission \$/Kw -Mo.	\$	1.490		755,003	\$	1,124,954
Transmission \$/Kw -Mo.	\$	1.260		30,531		38,469
Total Demand Related Revenue					\$	5,913,513
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		314,047,252	\$	6,246,400
Non-Fuel \$/Kwh	\$	0.00254	_	314,047,252	\$	797,680
Production Fixed Energy		2.51%	\$	46,046,418		1,155,765
					5	8,199,845
- ·-					æ	14 112 257
Total Revenue					<u></u>	14,113,357
Taiquin						
Domand Balated Casta						
Demand Helated Costs.	¢	9 500		1 614 401	\$	13 722 409
Transmission \$/Kw -Mo	¢	1 490		2 212 654	ŝ	3 296 854
Total Demand Belated Revenue	Ψ	1.400		2,212,007		17.019.263
Total Demand Related Hevende					•	
Energy Related Costs						
Fuel \$/Kwh	\$	0.01989		887,363.576	\$	17,649.662
Non-Fuel \$/Kwh	š	0.00254		887,363.576	\$	2,253.903
Production Fixed Energy	•	6.82%	\$	46,046,418	\$	3,140,366
			•		\$	23,043,931
Total Revenue					\$	40,063,194

	Billing							
SECI-78		Charges		Determinants		Revenue		
(Based on Estimated 2001 Billin	ng Ur	nits)						
Tri-County								
Demand Related Costs:								
Demand Rate \$/Kw - Mo.	\$	8.500		314,619	\$	2,674,262		
Transmission \$/Kw -Mo.	\$	1.490		429,236	\$	639,562		
Total Demand Related Revenue					-\$	3,313,823		
Energy Related Costs:								
Fuel \$/Kwh	\$	0.01989		189,891,868	\$	3,776,949		
Non-Fuel \$/Kwh	\$	0.00254		189,891,868	\$	482,325		
Production Fixed Energy		1.57%	\$	46,046,418	5	722,929		
					\$	4,982,203		
Total Bayanua					\$	8 296 027		
total nevenue					<u> </u>			
Withlacooche								
Demand Related Costs								
Demand Bate \$/Kw - Mo	\$	8.500		5.683.659	\$	48.311.102		
Transmission \$/Kw -Mo.	ŝ	1.490		7,806,783	\$	11,632,107		
Total Demand Related Revenue	•				\$	59,943,208		
Energy Related Costs:								
Fuel \$/Kwh	\$	0.01989		2,977,690,547	\$	59,226,265		
Non-Fuel \$/Kwh	\$	0.00254		2,977,690,547	\$	7,563,334		
Production Fixed Energy		23.38%	\$	46,046,418		10,765,653		
					\$	77,555,251		
					.	127 409 460		
lotal Hevenue					<u> </u>	137,490,400		

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Alternative 1		Charges	Determinants		Revenue	
(Based on Estimated 2001 Billin	ng Ur	nits)			•	
Total System						
Demand Related Costs:						
Transmission \$/Kw -Mo.	\$	9.126	30,602,146	\$	279,275,184	
Distribution \$/Kw -Mo.	\$	1.260	286,156	\$	360,557	
Total Demand Related Revenue				S	279,635,741	
Energy Related Costs:						
Energy Charge \$/Kwh	\$	0.02243	12,602,334,814	S	282,670,370	
Total Revenue					562,306,111	
Central Florida						
Demand Related Costs:		•				
Transmission \$/Kw -Mo.	\$	9.126	1,009,939	<u> </u>	9,216,703	
Total Demand Related Revenue				\$	9,216,703	
Energy Related Costs:	•	0.000/0			0.000.400	
Fuel \$/Kwh	5	0.02243	417,450,261	5	9,363,409	
Total Revenue				<u> </u>	18,580,113	
Clay						
Demand Related Costs:						
Transmission \$/Kw -Mo.	\$	9.126	6,131,819	<u> </u>	55,958,980	
Total Demand Related Revenue				S	55,958,980	
Energy Related Costs:	_					
Fuel \$/Kwh	\$	0.02243	2,602,687,225	5	58,378,274	
Total Revenue				<u> </u>	114,337,255	
Glades						
Demand Related Costs:						
Transmission \$/Kw -Mo.	\$	9.126	698,629		6.375,688	
Total Demand Related Revenue				\$	6,375,688	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.02243	336,190,488	\$	7,540,753	
Total Revenue				<u>\$</u>	13,916,441	

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Alternative 1		Charges	Determinants	Revenue		
(Based on Estimated 2001 Billi	ng U	nits)				
Lee County						
Customer Related Costs						
Designed Deleted Operation						
Demand Helated Costs:	¢	0 106	C 117 104		EE 005 E10	
Total Demand Polated Povonue	Ð	9.120	0,117,194	<u>~</u>	55 825 512	
TOTAL Demain Related Revenue				ۍ ا	55,025,512	
Energy Belated Costs:						
Fuel \$/Kwh	S	0.02243	2.747.258.419	S	61.621.006	
	-			·		
Total Revenue				S	117,446,519	
					<u></u>	
Peace River						
Customer Related Costs						
Domand Related Costs:						
Transmission S/Kw -Mo	¢	0 126	010 004	ç	8 386 831	
Distribution S/Kw-Mo	ę	1 260	255 625	3 ¢	322 088	
Total Demand Belated Bevenue	Ψ	1.200	200,020	<u> </u>	8 708 918	
Total Demand Related Revenue				Ŭ	0,700,010	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.02243	401,007,763	\$	8,994,604	
Total Revenue				<u> </u>	17,703,522	
C						
Sumter						
Demand Belated Costs:						
Transmission S/Kw -Mo	\$	9 126	4 521 885	s	41 266 723	
Total Demand Related Revenue	•	3.720	4,523,605	<u>-</u>	41 266 723	
				Ŭ	41,200,720	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.02243	1,728,747,415	S	38,775,805	
Total Revenue				<u></u>	80.042,527	
			· · · · · · · · · · · · · · · · · · ·			
Suwannaa						
Sumainiee						
Demand Related Costs:						
Transmission \$/Kw -Mo.	\$	9.126	755,003	S	6,890,157	
Transmission \$/Kw -Mo.	\$	1.260	30,531	S	38,469	
Total Demand Related Revenue				\$	6,928,626	
Energy Related Costs:	•	0.00040		-	7	
ruel \$/Kwn	\$	0.02243	314,047,252	5	7,044,080	
Total Revenue				s	13 972 706	
					10,012,100	

	Billing					
Alternative 1		Charges	Determinants		Revenue	
(Based on Estimated 2001 Billin	ng Ur	nits)				
Taiquin						
Demand Related Costs: Transmission \$/Kw -Mo.	\$	9.126	2,212,654		20,192,680	
Total Demand Related Revenue				\$	20,192,680	
Energy Related Costs: Fuel \$/Kwh	\$	0.02243	887,363,576	\$	19,903,565	
				e	40.006.245	
Total Revenue				<u> </u>	40,090,245	
Tri-County						
Demand Related Costs:	•		400.000	æ	2 017 209	
Transmission \$/Kw -Mo.	\$	9.126	429,230	<u> </u>	3,917,208	
Total Demand Related Revenue				-		
Energy Related Costs:	æ	0.02242	180 801 868	s	4 259.275	
Fuel S/Kwn	3	0.02243	103,031,000	Ŭ	1,200,270	
Total Revenue				<u></u>	8,176,482	
Withlacooche						
Demand Related Costs:					74 044 700	
Transmission \$/Kw -Mo.	\$	9.126	7,806,783	<u> </u>	71,244,702	
Iotal Demand Related Revenue				·		
Energy Related Costs:			0 077 000 547	¢	66 780 500	
Fuel \$/Kwh	5	0.02243	2,977,090,547	2	00,109,099	
Total Revenue				<u>\$</u>	138,034,301	

			Billing			
Alternative 2	(Charges	Determinants		Revenue	
(Based on Estimated 2001 Billin	ng U	nits)				
Total Overham						
lotal System						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586	22,073,300	\$	233,667,954	
Transmission \$/Kw -Mo.	\$	1.49	30,602,146	5	45,597,198	
Distribution \$/Kw -Mo.	\$	1.26	286,156	<u> </u>	360,557	
Total Demand Related Revenue				5	279,625,708	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989	12,602,334,814	\$	250,660,439	
Non-Fuel \$/Kwh	\$	0.00254	12,602,334,814	\$	32,009,930	
Production Fixed Energy		0.00%	\$ •	<u>\$</u>	-	
•				\$	282,670,370	
Total Revenue				\$	562,296,078	
Central Florida						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586	714,004	\$	7,558,446	
Transmission \$/Kw -Mo.	\$	1.49	1,009,939	<u>\$</u>	1,504,809	
Total Demand Related Revenue				\$	9,063,255	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989	417,450,261	\$	8,303,086	
Non-Fuel \$/Kwh	\$	0.00254	417,450,261	\$	1,060,324	
Production Fixed Energy		0.00%	\$ -	\$	-	
				\$	9,363,409	
Total Revenue				\$	18,426,665	
Clay						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586	4,379,619	\$	46,362,647	
Transmission \$/Kw -Mo.	\$	1.49	6,131,819	\$	9,136,410	
Total Demand Related Revenue				\$	55,499,057	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989	2,602,687,225	\$	51,767,449	
Non-Fuel \$/Kwh	\$	0.00254	2,602,687,225	\$	6,610,826	
Production Fixed Energy		0.00%	\$ -	\$	-	
				\$	58,378,274	
Total Revenue				\$	113,877,332	

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Alternative 2		Charges	 Determinants	Revenue		
(Based on Estimated 2001 Billi	ng U	Inits)				
Glades						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586	476,587	\$	5,045,150	
Transmission \$/Kw -Mo.	\$	1.49	698,629	<u> </u>	1,040,957	
Total Demand Related Revenue				\$	6,086,107	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989	336,190,488	\$	6,686,829	
Non-Fuel \$/Kwh	\$	0.00254	336,190,488	\$	853,924	
Production Fixed Energy		0.00%	\$ •		-	
				\$	7,540,753	
Total Revenue				<u></u>	13,626,860	
Lee County						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586	4,439,930	\$	47,001,099	
Transmission \$/Kw -Mo.	\$	1.49	6,117,194	\$	9,114,619	
Total Demand Related Revenue				\$	56,115,718	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989	2,747,258,419	\$	54,642,970	
Non-Fuel \$/Kwh	\$	0.00254	2,747,258,419	\$	6,978,036	
Production Fixed Energy		0.00%	\$ -	<u>\$</u>		
				\$	61,621,006	
Total Revenue				<u> </u>	117,736,724	
Peace River						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586	665,019	\$	7,039,891	
Transmission \$/Kw -Mo.	\$	1.49	919,004	\$	1,369,316	
Distribution \$/Kw -Mo.	\$	1.26	255,625	\$	322,088	
Total Demand Related Revenue				\$	8,731,295	
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989	401,007,763	\$	7,976,044	
Non-Fuel \$/Kwh	\$	0.00254	401,007,763	\$	1,018,560	
Production Fixed Energy		0.00%	\$ -	\$		
				\$	8,994,604	
Total Revenue				\$	17,725,899	

Alternative 2		Charges		Determinants		Revenue
(Based on Estimated 2001 Billi	ing l	Jnits)				
Sumter						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586		3,226,628	\$	34,157,084
Transmission \$/Kw -Mo.	\$	1.49		4,521,885	\$	6,737,609
Total Demand Related Revenue					\$	40,894,693
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		1,728,747,415	\$	34,384,786
Non-Fuel \$/Kwh	\$	0.00254		1,728,747,415	\$	4,391,018
Production Fixed Energy		0.00%	\$	-		-
					\$	38,775,805
Total Revenue					<u></u>	79,670,497
Suwannee						
Demand Related Costs:						
Demand Rate \$/Kw - Mo	¢	10 586		558 834	¢	5 915 817
Transmission \$/Kw -Mo	ŝ	1 49		755.003	Š	1 124 954
Transmission \$/Kw -Mo.	ě	1.45		30,531	¢ ¢	38 469
Total Demand Related Revenue	Ψ	1.20		30,331	\$	7,079,240
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		314.047.252	\$	6,246,400
Non-Fuel \$/Kwh	Ŝ	0.00254		314.047.252	Ś	797.680
Production Fixed Energy	•	0.00%	\$		Ś	
			*		\$	7,044,080
Total Revenue						14,123,320
Taiquin						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	10.586		1,614,401	\$	17,090,049
Transmission \$/Kw -Mo.	\$	1.49		2,212,654		3,296,854
Total Demand Related Revenue					\$	20,386,903
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		887,363,576	\$	17,649,662
Non-Fuel \$/Kwh	\$	0.00254		887,363,576	\$	2,253,903
Production Fixed Energy		0.00%	\$	•	\$	-
					\$	19,903,565
Total Revenue					\$	40.290.468

			Billing		
Alternative 2		Charges	 Determinants		Revenue
(Based on Estimated 2001 Billi	ng U	Inits)			
Tri-County					
Demand Related Costs:					
Demand Rate \$/Kw - Mo.	\$	10.586	314,619	\$	3.330.557
Transmission \$/Kw -Mo.	ŝ	1.49	429.236	Š	639,562
Total Demand Related Revenue	•			\$	3,970,118
					·
Energy Related Costs:					
Fuel \$/Kwh	\$	0.01989	189,891,868	\$	3,776,949
Non-Fuel \$/Kwh	\$	0.00254	189,891,868	\$	482,325
Production Fixed Energy		0.00%	\$ -	\$	-
				\$	4,259,275
Total Revenue				<u>\$</u>	8,229,393
Withlacooche					
Demand Related Costs:					
Demand Bate \$/Kw - Mo.	\$	10.586	5.683.659	\$	60,167,214
Transmission \$/Kw -Mo.	ŝ	1.49	7.806.783	ŝ	11.632.107
Total Demand Related Revenue	•		 	\$	71,799,321
Energy Related Costs:					
Fuel \$/Kwh	\$	0.01989	2,977,690,547	\$	59,226,265
Non-Fuel \$/Kwh	\$	0.00254	2,977,690,547	\$	7,563,334
Production Fixed Energy		0.00%	\$ •	\$	•
•				\$	66,789,599
Total Revenue				\$	138,588,920
				<u> </u>	

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Alternative 3		Charges		Determinants		Revenue
(Based on Estimated 2001 Billi	ing Q	inits)				
Total System						
Demand Related Costs:						
Demand Bate \$/Kw - Mo	\$	8.500		22 073 300	\$	187 623 050
Transmission \$/Kw -Mo	ŝ	1 490		30 602 146	¢.	107,020,000
Distribution \$/Kw -Mo	ŝ	1 260		286 156	¢	360 557
Total Demand Related Revenue	¥	1.200		200,100	\$	233,580,804
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		12.602.334.814	\$	250.660.439
Non-Fuel \$/Kwh	Ŝ	0.00254		12.602 334 814	ŝ	32 009 930
Production Fixed Energy	•	100.00%	\$	46 046 418	Š	46 046 418
r roddoloff fixed Enorgy			÷	,0,0+0,+10		328,716,788
Total Revenue					\$	562,297,592
Central Florida						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	8.500		714,004	\$	6,069,034
Transmission \$/Kw -Mo.	\$	1.490		1,009,939	\$	1.504,809
Total Demand Related Revenue					\$	7,573,843
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		417,450,261	\$	8,303,086
Non-Fuel \$/Kwh	\$	0.00254		417,450,261	Ŝ	1,060,324
Production Fixed Energy	·	3.30%	\$	46.046.418	Ŝ	1.519.634
,			·		s	10,883,044
Total Revenue					\$	18,456,887
					_ <u></u>	<u> </u>
Clay						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	8.500		4,379,619	\$	37,226,762
Transmission \$/Kw -Mo.	\$	1.490		6,131,819	\$	9,136,410
Total Demand Related Revenue					\$	46,363,172
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		2,602,687,225	\$	51,767,449
Non-Fuel \$/Kwh	\$	0.00254		2,602,687,225	\$	6,610,826
Production Fixed Energy		20.04%	\$	46,046,418	\$	9,226,422
					\$	67,604,696
Total Revenue					_\$	113,967,868

Individual Member Billings

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Alternative 3		Charges	Determinants		Revenue	
(Based on Estimated 2001 Billing	ng U	nits)				
Glades						
Giades						
Demand Related Costs:						
Demand Rate \$/Kw - Mo.	\$	8.500		476,587	\$	4,050,990
Transmission \$/Kw -Mo.	\$	1.490		698,629	\$	1,040,957
Total Demand Related Revenue					\$	5,091,947
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		336,190,488	\$	6,686,829
Non-Fuel \$/Kwh	\$	0.00254		336,190,488	\$	853,924
Production Fixed Energy		2.28%	\$	46,046,418	\$	1.051,213
••					\$	8,591,965
Total Revenue					\$	13,683,912
Lee County						
Demand Belated Costs:						
Demand Bate \$/Kw - Mo	\$	8.500		4 439 930	\$	37 739 405
Transmission \$/Kw -Mo	Š	1 490		6 117 194	Š	9 1 1 4 6 1 9
Total Demand Related Revenue	Ŧ	1.100		0,111,104	5	46,854,024
					¥	10,001,021
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		2,747,258,419	\$	54,642,970
Non-Fuel \$/Kwh	\$	0.00254		2,747,258,419	\$	6,978,036
Production Fixed Energy		19.99%	\$	46,046,418	\$	9,204,416
					\$	70,825,422
Total Revenue					S	117.679.446
					<u> </u>	
Peace River						
Demand Related Costs:						
Demand Rate \$/Kw - Mo	¢	8 500		665.019	¢	5 652 662
Transmission S/Kw - Mo	ě	1 490		919 004	e e	1 369 316
Distribution \$/Kw -Mo	¢	1.260		255 625	¢	322 088
Total Demand Related Revenue	Ψ	1.200		200,020	\$	7,344,065
Energy Belated Costs:						
Fuel \$/Kwh	\$	0.01989		401 007 763	\$	7 976 044
Non-Fuel \$/Kwh	š	0.00254		401 007 763	¢	1 018 560
Production Fixed Energy	Ψ	3.00%	¢	46 046 419	¢	1 382 806
, idealion inted chergy		0.0070	Ψ	10	\$	10,377,410
					•	43 80
i otal Hevenue					5	17,721,475

			_			
Alternative 3		Charges		Determinants	Revenue	
(Based on Estimated 2001 Billing	ng U	nits)				
Sumter						
Demand Related Costs:	~	0 500		0.000.000	¢	07 406 000
Demand Hate \$/Kw - Mo.	\$	8.500		3,225,528	<u>ې</u>	27,420,338
I ransmission \$/KW -Mo.	3	1.490		4,521,885	<u></u>	0,737,009
Total Demand Helated Hevenue					2	34,103,947
Energy Belated Costs:						
Energy Helated Costs.	\$	0.01989		1 728 747 415	\$	34 384 786
	ě	0.00254		1 728 747 415	é	4 391 018
Production Fixed Energy	Ψ	14 78%	¢	46 046 418	¢	6 803 987
FIGUERON FIXEd Energy		14.7076	Ψ	40,040,410		45 579 792
					Ŷ	40,010,102
Total Revenue					\$	79,743,738
Suwannee						
Demand Related Costs:						
Demand Rate \$/Kw ~ Mo.	\$	8.500		558,834	\$	4,750,089
Transmission \$/Kw -Mo.	\$	1.490		755,003	\$	1,124,954
Transmission \$/Kw -Mo.	\$	1.260		30,531	_\$	38,469
Total Demand Related Revenue					\$	5,913,513
Energy Related Costs:					•	
Fuel \$/Kwh	\$	0.01989		314,047,252	5	6,246,400
Non-Fuel \$/Kwh	\$	0.00254		314,047,252	\$	797,680
Production Fixed Energy		2.47%	\$	46,046,418		1,136,037
					\$	8,180,117
Total Davisaria					e	14.002.620
lotal Hevenue					<u></u>	14,093,630
Talquip						
Talquin						
Demand Belated Costs:						
Demand Bate \$/Kw - Mo	\$	8 500		1.614.401	\$	13,722,409
Transmission \$/Kw -Mo	ŝ	1.490		2.212.654	ŝ	3,296,854
Total Demand Related Revenue	•				<u>-</u> \$	17,019,263
					•	,
Energy Related Costs:						
Fuel \$/Kwh	\$	0.01989		887,363,576	\$	17,649,662
Non-Fuel \$/Kwh	\$	0.00254		887,363,576	\$	2,253,903
Production Fixed Energy		7.23%	\$	46,046,418	\$	3,329,335
•					\$	23,232,900
Total Revenue					\$	40,252,163

				Billing			
Alternative 3		Charges		Determinants		Revenue	
(Based on Estimated 2001 Billing	ng Ui	nits)					
Tri-County							
•							
Demand Related Costs:							
Demand Rate \$/Kw - Mo.	\$	8.500		314,619	\$	2,674,262	
Transmission \$/Kw -Mo.	\$	1.490		429,236		639,562	
Total Demand Related Revenue					\$	3,313,823	
Energy Related Costs:							
Fuel \$/Kwh	s	0.01989		189 891 868	\$	3,776,949	
Non-Fuel \$/Kwh	ŝ	0.00254		189.891.868	Š	482.325	
Production Fixed Energy	•	1.40%	\$	46.046.418	Š	645,863	
			·		\$	4,905,137	
Total Revenue					<u></u>	8,218,960	
Withlacooche							
Demand Related Costs:							
Demand Rate \$/Kw - Mo.	\$	8.500		5,683,659	\$	48,311,102	
Transmission \$/Kw -Mo.	\$	1.490		7,806,783	\$	11,632,107	
Total Demand Related Revenue					\$	59,943,208	
Energy Related Costs:							
Fuel \$/Kwh	\$	0.01989		2,977,690,547	\$	59,226,265	
Non-Fuel \$/Kwh	\$	0.00254		2,977,690,547	\$	7,563,334	
Production Fixed Energy		25.51%	\$	46,046,418	\$	11,746,705	
•.					\$	78,536,304	
Total Revenue					s	138,479,513	