BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 001748-EC

In the Matter of

PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

_____/

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VOLUME 2

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PROCEEDINGS:	**HEARING**
BEFORE:	**CHAIRMAN E. LEON JACOBS, JR.** **COMMISSIONER J. TERRY DEASON** **COMMISSIONER LILA A. JABER** **COMMISSIONER BRAULIO L. BAEZ** **COMMISSIONER MICHAEL A. PALECKI**
DATE:	**Monday, February 12, 2001**
TIME:	**Commenced at 9:35 a.m.** **Concluded at 10:40 a.m.**
PLACE:	**Betty Easley Conference Center** **Room 148** **4075 Esplanade Way** **Tallahassee, Florida**
REPORTED BY:	**TRICIA DeMARTE** **Official FPSC Reporter**
APPEARANCES:	**(As heretofore noted.)**

FLORIDA PUBLIC SERVICE COMMISSION

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MR. WRIGHT: Mr. Chairman, Calpine's next witness is Kenneth J. Slater. Mr. Slater filed amended direct testimony on January the 12th. There are no changes to his prefiled testimony. I have given a clean copy of it to the court reporter for inclusion in the record. And with that, I would move the admission of Mr. Slater's amended direct testimony into the record as though read.

CHAIRMAN JACOBS: Without objection, show Mr. Slater's testimony as amended into the record as though read.

MR. WRIGHT: Mr. Slater also sponsors as exhibits to his amended direct testimony Exhibits KJS-1 through KJS-22. In addition to that, last week we filed supplemental graphic exhibits that simply present in graphic form numeric data that is contained in Exhibits KJS-2 and KJS-3. These have been designated in our supplemental filing as KJS-2A and KJS-3A. I would ask that all of Mr. Slater's exhibits, KJS-1 through KJS-22, including KJS-2A and KJS-3A, be marked for identification.

CHAIRMAN JACOBS: That will be marked as Composite Exhibit 8.

(Exhibit 8 marked for identification.)

MR. WRIGHT: Thank you, Mr. Chairman. And with that, I move the admission into evidence of Composite Exhibit 8.

CHAIRMAN JACOBS: Without objection, show Exhibit 8 is admitted.

(Exhibit 8 admitted into the record.)

IN RE: PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER

AMENDED DIRECT TESTIMONY OF KENNETH J. SLATER

Q: Please state your name and business address.

A: My name is Kenneth J. Slater. My business address is 3370 Habersham Road, Atlanta, Georgia 30305.

Q: By whom are you employed and in what positions?

A: I am President and Chief Executive Officer of Slater Consulting, which I founded in August 1990. The firm is a small engineering-economic and management consultancy with particular expertise in energy and public utility matters. The services, which the firm offers to various participants in the utility business, include analysis of supply/demand options, reliability, operating situations and events, new technologies and industry developments, strategic decisions, public policy matters and ratemaking issues.

Q: Please describe your duties with Slater Consulting.

A: I am the President and Chief Executive Officer of Slater Consulting. Although I am responsible for the overall management and operation of the Company, I spend most of my time working on client projects.

AMENDED DIRECT TESTIMONY OF KENNETH J. SLATER

PROFESSIONAL QUALIFICATIONS AND EXPERIENCE

Q: Please summarize your educational background and experience.

A: I obtained a Bachelor of Science degree in Pure Mathematics and Physics in 1960 and a Bachelor of Engineering degree in Electrical Engineering in 1962, both at the University of Sydney, Australia. I also received a Master of Applied Science degree in Management Sciences at the University of Waterloo in Ontario, Canada in 1974.

Q: Please summarize your employment history and work experience.

A: I have almost forty years of experience in the energy and utility industries in the United States, Canada and Australia. Prior to founding Slater Consulting, I was Senior Vice President and Chief Engineer at Energy Management Associates, Inc. ("EMA") in Atlanta, where I worked from 1983 to 1990. At EMA, after initially contributing to the firm's utility software development functions, I became the head of its consulting practice, leading or making significant contributions to a number of consulting engagements related to valuation or analysis of power supplies and power supply contracts, supply/demand planning, damages assessments, operating reserve requirements, replacement power cost calculations, utility merger valuations, operational integration of utility systems, power pooling, system

reliability, ratemaking, power dispatching and gas supply studies. From 1969 until 1983, I worked in the Canadian utility industry. From 1975 to 1983, I ran my own firm, Slater Energy Consultants, Inc., in Toronto, Canada and consulted widely in Canada and the United States for utilities, governments, public enquiry commissions, utility customers and other consulting firms. It was during this time and my time at EMA that I was a major developer of PROMOD III®, (now renamed PROMOD IV®), a widely recognized electric utility planning and reliability model.

From 1969 through 1974, I worked as an Engineer, and then as a Senior Engineer at Ontario Hydro, where I headed the Production Development Section of the utility's Operating Department. There I developed computer models, including one which, for more than 20 years, produced the daily generation schedules for the Ontario Hydro system, and another, the original PROMOD, which was used for coordination and optimization of production planning and resource management. In 1974 and 1975, I worked as Manager of Engineering at the Ontario Energy Board (Ontario's utility regulatory commission) and in 1975 and 1976, I served as Research Director for the Royal Commission on Electric Power Planning (also in Ontario).

Prior to 1969, I was employed by the Electricity Commission of New South Wales, the largest electric utility in Australia, where I was responsible for the day-to-day

operation of one of the six regions comprising that system. A copy of my resume' is included as Exhibit KJS-1.

Q: Have you previously testified before regulatory authorities or courts?

A: Yes. I have provided expert testimony in regulatory proceedings in California, Florida, Georgia, Idaho, Indiana, Iowa, Louisiana, New Mexico, New York, Nova Scotia, Ontario, Pennsylvania, Prince Edward Island, South Carolina, Texas, Virginia, and Wisconsin, and at the Federal Energy Regulatory Commission. I have also appeared in Federal Bankruptcy Court and state courts in Florida, Nebraska, Texas and Virginia, and in civil arbitration proceedings in Louisiana, Nevada, New England, and Pennsylvania. I have also served on many occasions as an expert examiner for a Royal Commission in Ontario that was charged with studying and evaluating electric power planning in the Province of Ontario. I have also served as a member of a panel of arbitrator/valuers in a proceeding under the American Arbitration Association concerned with the value of a cogeneration plant.

Q: Are you a registered professional engineer?

A: Yes, I am a registered professional engineer in Ontario.

AMENDED DIRECT TESTIMONY OF KENNETH J. SLATER

PURPOSE AND SUMMARY OF TESTIMONY

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

A: I am testifying on behalf of Calpine Construction Finance Company, L.P. ("Calpine") to provide the results of various analyses, prepared by me or under my direction and supervision, that address various aspects of the Osprey Energy Center (the "Osprey Project" or simply the "Project") and its projected impacts on the Peninsular Florida power supply system. Specifically, my testimony addresses:

1. how the Osprey Project will operate in the Peninsular Florida power supply system;
2. the impacts that the Osprey Project will have on overall fuel consumption, power supply costs, and emissions from electricity generation for Peninsular Florida power supply;
3. the cost-effectiveness of the Osprey Project as a power supply resource for Peninsular Florida; and
4. the impact of the Osprey Project's presence on Peninsular Florida reserves and reliability.

My analyses assume that the Project's output will be sold to Seminole Electric Cooperative, Inc. ("Seminole"), with whom Calpine has a firm power purchase agreement, and potentially to other Peninsular Florida retail-serving utilities pursuant to appropriate contractual commitments.

AMENDED DIRECT TESTIMONY OF KENNETH J. SLATER

Q: Please summarize your understanding of the Osprey Project.

A: I understand the Osprey Project to be a 529 megawatt ("MW") natural gas-fired combined cycle electric generating plant that will be located in Auburndale, Florida, and interconnected to the Peninsular Florida power supply grid at the Recker Substation of Tampa Electric Company ("TECO"). The Project will have summer generating capability of approximately 496 MW and winter capability of approximately 578 MW, without duct-firing and power augmentation. The Project will utilize advanced technology Siemens-Westinghouse Model 501F combustion turbines in a combined cycle configuration. This design is typical of modern, efficient, advanced technology power plants. Finally, although the fact does not impact my analyses, because my analyses address the operation of the Osprey Project within Peninsular Florida considered as a whole, I understand that Calpine will sell 350 MW of firm capacity and associated energy to Seminole beginning in 2004 pursuant to an executed power purchase agreement.

Q: Please summarize the main conclusions of your testimony.

A: My staff and I prepared analyses of the Peninsular Florida power supply system with and without the Osprey Project using the PROMOD IV® production modeling program. My conclusions

reflect the assumption that the Project's output will be sold to Seminole and potentially to other Peninsular Florida retail-serving utilities pursuant to appropriate contracts, e.g., the power purchase agreement between Calpine and Seminole. Based on these analyses, it is my opinion that the Osprey Project will make significant and economically valuable contributions to the Peninsular Florida power supply system. Even modeled with conservative assumptions, the Osprey Project is projected:

1. to operate at annual capacity factors between 86 and 93 percent for the entire analysis period, which in our modeling was the first ten years of the Project's commercial life;
2. to provide significant savings -- 6 trillion to 9 trillion Btu per year -- of primary energy used to generate electricity for use in Peninsular Florida;
3. to result in significant savings of petroleum fuels and coal;
4. to improve the overall efficiency of electricity production and natural gas use in and for Peninsular Florida;
5. to result in wholesale power supply cost savings of approximately $794 million (Net Present Value) over the first ten years of the Projects's operations;
6. to provide enhanced reliability of the power supply

system in Peninsular Florida; and

7. to result in significant reductions -- approximately 8,000 to 23,000 tons per year -- in combined emissions of sulfur dioxide and nitrogen oxides from the generation of Peninsular Florida's power supply.

The results are substantially the same under both our base case assumptions and under "sensitivity cases" that we modeled in which we analyzed the Project's operations and impacts assuming a higher natural gas price forecast, lower load growth, and higher load growth in Peninsular Florida.

Q: Are you sponsoring any exhibits to your testimony?

A: Yes. I am sponsoring the following exhibits.

KJS-1. Resume' of Kenneth John Slater.

KJS-2. Fuel Price Assumptions for PROMOD IV® Analyses of Osprey Project Operations.

KJS-3. Efficiency and Cost-Effectiveness of Peninsular Florida Generating Units, 2003.

KJS-4. Efficiency and Cost-Effectiveness of Peninsular Florida Generating Units, 2008.

KJS-5. Peninsular Florida Summary of Existing Capacity As of January 1, 2000.

KJS-6. Peninsular Florida, Historical and Projected Summer and Winter Firm Peak Demands, 1991-2012.

KJS-7. Peninsular Florida, Historical and Projected Net Energy for Load and Number of Customers, 1991-2012.

KJS-8. Osprey Energy Center - Summary of Projected Operations, 2003-2012.

KJS-9. Osprey Energy Center - Summary of Projected Operations, 2003-2012, Higher Natural Gas Price Sensitivity Analysis.

KJS-10. Osprey Energy Center - Summary of Projected Operations, 2003-2012, Load Growth Sensitivity Analyses.

KJS-11. Illustration of Impacts of Osprey Energy Center on Operations of Other Peninsular Florida Power Plants.

KJS-12. Market Indicators - Average Electric Production Costs by NERC Region, 1997-1999.

KJS-13. Peninsular Florida, Impacts of Osprey Energy Center on Average Electricity Generation Heat Rates and Total Fuel Consumption, 2003-2012.

KJS-14. Peninsular Florida, Fuel Consumption Impacts of Osprey Energy Center, 2003-2012.

KJS-15. Peninsular Florida, Summary of Projected Wholesale Energy Cost Savings Due to Osprey Energy Center, Base Case, 2003-2012.

KJS-16. Peninsular Florida, Summary of Projected Wholesale Energy Cost Savings Due to Osprey Energy Center,

Higher Fuel Price Sensitivity Case, 2003-2012.

KJS-17. Peninsular Florida, Summary of Projected Wholesale Energy Cost Savings Due to Osprey Energy Center, Low Load Growth Sensitivity Case, 2003-2012.

KJS-18. Peninsular Florida, Summary of Projected Wholesale Energy Cost Savings Due to Osprey Energy Center, High Load Growth Sensitivity Case, 2003-2012.

KJS-19. Comparison of Peninsular Florida Planned and Proposed Generating Units.

KJS-20. Summary of Peninsular Florida Capacity, Demand, and Reserve Margin at Time of Summer Peak, Without and With Osprey Energy Center.

KJS-21. Summary of Peninsular Florida Capacity, Demand, and Reserve Margin at Time of Winter Peak, Without and With Osprey Energy Center.

KJS-22. Peninsular Florida, Emissions Impacts of Osprey Energy Center, 2003-2012.

I am also sponsoring the projected annual output values in Table II-2 in Volume II of the Amended Exhibits in support of Seminole's and Calpine's Amended Joint Petition for Determination of Need for the Osprey Energy Center filed on January 8, 2001 (the "Amended Joint Petition") and Tables II-4, II-5, II-6, II-7, II-8, II-9, II-10, II-11, II-12, II-13.A, II-13.B, II-14, II-15.A, II-15.B, II-16, II-17, II-18.A, II-II-18.B, and II-18.C of those Amended Exhibits. I am also

sponsoring the text associated with these tables in Volume II of the Amended Exhibits to the Amended Joint Petition, and Appendix II-C to those Amended Exhibits, which is titled DESCRIPTION of PROMOD IV® GENERATION MODELING PROGRAM.

MODELS, ASSUMPTIONS, AND METHODOLOGY

Q: How did you analyze the operations of the Osprey Project within the Peninsular Florida power supply system and the impacts of the Project on that system?

A: Under my direction and supervision, Slater Consulting prepared several analyses of the Peninsular Florida power supply system, both with and without the Osprey Project, using the PROMOD IV® computer modeling program. Our analyses treated the Peninsular Florida power supply system as an integrated system. Our analyses studied the period beginning with the first year that the Osprey Project is expected to be in service and continued for ten years. Thus, our analyses begin with the Osprey Project coming into commercial service in 2003 and continue through 2012. I should note that our analyses actually covered the period through 2014 in order to avoid certain artificial results that may occur in power system modeling when the system is modeled as effectively "shutting down" at the end of the analysis period. (This can occur because if the model is programmed not to have to serve load

after a certain date, it will simply postpone maintenance.)

The analyses that we performed included a base case and three sensitivity cases, one with a higher natural gas price forecast, one with a lower load growth forecast, and one with a higher load growth forecast.

Q: What, if any, assumptions do your analyses and conclusions reflect regarding the sale of the Project's output?

A: As noted above, our analyses and conclusions reflect the assumption that the Project's output will be sold to Seminole and potentially to other Peninsular Florida retail-serving utilities pursuant to appropriate contractual commitments, e.g., the power purchase agreement between Calpine and Seminole. Based on my basic understanding of that agreement and of the Florida power market generally, I believe that this assumption is wholly reasonable and appropriate.

Q: Please briefly describe the PROMOD IV® computer model, including a summary of the main input variables used by the model and the main output data produced by the model.

A: PROMOD IV® is a widely known and widely used model that simulates the operations of electric power systems. PROMOD IV® is primarily used as a production costing model and can also be used to evaluate electric system reliability. A brief

description of PROMOD IV® is included in Appendix C to Volume II of the Amended Exhibits accompanying the Amended Joint Petition. PROMOD IV® can be used to prepare utility fuel budget forecasts, evaluate the economics and operations of proposed generating capacity additions, project utility operating costs, estimate the prices of firm power and energy in defined markets, project hourly marginal energy costs, and calculate avoided energy costs.

The inputs to PROMOD IV® include generating unit data for existing and planned power plants in a defined power supply system, fuel consumption and fuel cost data, load and other utility system data, and data regarding transactions both within and external to the system. The primary outputs are individual utility or system production costs, generation by unit, fuel usage, and reliability information. PROMOD IV® utilizes computationally efficient algorithms that yield results identical to those that would be produced with direct specification of values for all availability states of all units in a power supply system.

Q: Who uses the PROMOD IV® model?

A: A significant number of electric utility companies in North America have used and continue to use PROMOD IV®. To the best of my knowledge, all four of the major investor-owned

utilities in Florida, Seminole, and some of the larger municipal utilities in Florida, have used PROMOD IV®.

Q: Before leading us through your detailed results, please summarize the cost structure and performance you have assumed for the Osprey Energy Center.

A: I have assumed that the heat rate of the Osprey Energy Center Project will be 6,800 Btu per kilowatt-hour ("kWh") at full load. I assumed that the variable operating and maintenance cost of the Osprey Energy Center Project will be $1.85 per megawatt-hour ("MWH") in 2000 (the base year for my projections), escalating at 3.0 percent per year. I should add that I also made the conservative assumption that the Osprey Project would have exactly the same heat rate characteristics as all of the other similar technology, new gas-fired combined cycle units planned for Florida except FPL's proposed repowering projects at Sanford and Ft. Myers. I made this assumption in order to avoid "favoring" the Osprey Project in our dispatch modeling, despite the fact that the available evidence indicates that the Osprey Project would in fact be slightly more cost-effective than nearly all of the other planned gas-fired combined cycle units. For FPL's proposed repowering projects, I used heat rate information extracted from FPL's permit applications to the Florida

Department of Environmental Protection; these data indicate that, as one would expect, the repowering projects are somewhat less efficient than the other new, "greenfield" plants. For example, our analyses indicate that, on an "as-dispatched" basis, FPL's repowering projects will have heat rates of approximately 7,150 to 7,280 Btu/kWh, as compared to heat rates of approximately 6,970 to 7,040 Btu/kWh for the new combined cycle units, e.g., the Osprey Project, Cane Island 3, Okeechobee, Payne Creek, Hines 2, Duke New Smyrna Beach, and Purdom. This information is shown in Exhibits _____ and _____ (KJS-3 and KJS-4).

Q: Did your analyses include the possibility of the Osprey Project's having increased output capability from duct-firing and power augmentation?

A: No. Our modeling analyses were conducted assuming no output from duct-firing or power augmentation. If included in the Project's final design configuration, these features would be expected to increase the Project's output during peak conditions and further enhance the reliability of the Peninsular Florida power supply system.

Q: Did you model the Osprey Project as an additional unit, i.e., a unit that was assumed to be brought into service in addition to all other power plants planned for Peninsular Florida, or did you assume that the Osprey Project would displace another unit or units that might otherwise have been built by Florida retail-serving utilities or other entities?

A: I modeled the Osprey Project as an additional unit, that is, as one that was incorporated into the Peninsular Florida power supply system in addition to all other existing and planned units. The planned units were identified through my review of all of the ten-year site plans that were submitted to the Florida Public Service Commission this year.

Q: Why did you model the Osprey Project in this manner?

A: I modeled the Osprey Project in this way because it will give the most conservative results regarding the Project's expected cost savings impacts, fuel savings impacts, and emissions impacts. This is a conservative assumption because it models the impacts of the Osprey Project within a more efficient system.

Q: Has anything changed since you prepared your analyses?

A: Since I originally prepared my analyses reported here, Calpine and Seminole have executed an agreement by which Calpine will

sell Seminole 350 MW of firm capacity from the Osprey Project beginning in 2004. This agreement has caused Seminole's previously planned 2004 combined cycle unit to be taken out of the generation expansion plan.

Q: How would the Osprey Project affect power supply costs if it were developed as a "displacement" unit instead of as an "additional" unit?

A: The Osprey Project's actual impact on power supply costs would depend on the precise terms of the contract or contracts that Calpine entered into with the utilities whose units were displaced by the Project. However, if one were to model the Project's impact on Peninsular Florida power supply costs treating the system as an integrated whole, the Osprey Project would show greater fuel savings, cost savings, and emissions reductions than in the analyses that we performed treating the Project as an "additional" unit. This is because in the "displacement" case, there is less new, efficient gas-fired combined cycle capacity (like the Osprey Project) in the Peninsular Florida system, and thus the Project would be operating within a system which was, overall, less efficient and more costly to run, which would result directly in its providing greater fuel savings and power supply cost reductions.

In fact, this would now be expected to be the case because of the agreement between Seminole and Calpine for the purchase by Seminole of 350 MW of firm capacity from the Project, instead of building its own combined cycle unit in 2004 as previously planned. This means that my reported results actually understate the cost savings, fuel savings, and emissions reduction benefits of the Osprey Project because now, without Seminole's 2004 combined cycle unit, the Osprey Project will be operating within a slightly less efficient system, thus yielding greater benefits from its operation.

Q: What, if any, documents did you review in preparing your analyses?

A: We initially reviewed the 1999 Regional Load & Resource Plan published in July 1999 by the Florida Reliability Coordinating Council (the "FRCC 1999 Resource Plan") and all ten-year site plans submitted to the Commission in the spring of 2000. We also reviewed the 2000 Regional Load & Resource Plan published by the FRCC in July 2000.

Q: What assumptions did you make regarding future fuel prices over the period that you analyzed?

A: In developing the fuel price projections for our analyses, we examined historical Florida-specific fuel costs for

electricity generation and evaluated the major publicly available fuel price forecasts, which are presented in the Energy Information Administration's ("EIA") Annual Energy Outlook 2000 publication. Our base case fuel price projections were based primarily on the forecasts prepared by EIA but with the gas price projections following those of Resource Data International, Inc. ("RDI"). For the higher gas price sensitivity case, we assumed the EIA projections (the EIA's "reference case") for all fuels. Exhibit _____ (KJS-2) shows the projected fuel prices for both our base case analysis and for the higher natural gas price sensitivity case.

Q: What assumptions did you make regarding the electric power plants that would be available to serve Peninsular Florida?

A: The assumptions used in our evaluations regarding available power plants to provide capacity and energy to Peninsular Florida are summarized in Exhibits _____ and _____ (KJS-3 and KJS-4), which present the projected Peninsular Florida generating fleet for 2003 and 2008, respectively. For reference, Exhibit _____ (KJS-5) presents a summary of existing capacity as of January 1, 2000. These data were obtained from the FRCC 2000 Resource Plan.

Q: What assumptions did you make regarding the growth rates of summer and winter peak demands and energy consumption in Peninsular Florida?

A: Exhibit _____ (KJS-6) presents the historical and projected summer and winter firm peak demands for Peninsular Florida. Exhibit _____ (KJS-7) presents the historical and projected net energy for load, number of customers, and load factors for Peninsular Florida. For the base case, the load forecast was developed on a company-by-company basis from the 2000 ten-year site plans. Some adjustments were necessary to account for loads which were included in more than one site plan, for one system which does not file a site plan, and for some overstatement of load management impact. We reconciled our company-by-company forecasts with the FRCC 1999 Resource Plan in order to achieve accuracy and completeness.

Q: What assumptions did you make regarding imports of electric power from outside Peninsular Florida and exports of power from Peninsular Florida to other regions?

A: We assumed that imports into Peninsular Florida would be as projected in the FRCC 1999 Resource Plan. We assumed that there would be no significant exports of power from Peninsular Florida to other regions.

Q: What assumptions did you make regarding the effects of energy conservation and demand-side management programs?

A: We generally assumed that the forecasts of peak demands and net energy for load presented in the FRCC 1999 Resource Plan and the 2000 ten-year site plans reflected the achievement of the Florida retail-serving utilities' Commission-approved energy conservation goals. There was one exception to this assumption, however: the FRCC projections and some of the site plans assume that net energy for load (total energy consumption) will reflect maximum possible reductions from interruptible, load management, and other energy conservation measures and programs. In my opinion, this systematically understates total energy consumption because it assumes far greater reductions in energy use from interruptible and load management customers than are actually realized. Accordingly, we adjusted the net energy for load projections upward to reflect more realistic energy consumption levels where necessary.

Q: How was transmission modeled or treated in your analyses?

A: We modeled Peninsular Florida as an integrated power supply system, with all generation resources available to serve all loads. Transmission was assumed to be costless for all transactions, such that the most efficient generation

resources would be dispatched to serve the Peninsular Florida load, without regard to transmission constraints or tariffs.

Q: Do you consider this to be a realistic assumption?

A: Yes. Because it is not known what transmission augmentations will be carried out in the FRCC region in the next twelve years, it is best to make an assumption which would not favor the Osprey Project over any other new project or over existing generation. We made such an assumption.

Q: What, if any, effect would altering this assumption have on your analyses of the operations of the Osprey Energy Center?

A: Altering this assumption would likely have very little effect on the actual dispatch of the Osprey Project.

Q: Did you review any documents that you understood to be confidential or proprietary to Calpine or Seminole?

A: No.

Q: Do you consider any of your input or output data to be confidential, proprietary business information from Slater Consulting's perspective?

A: Yes. Our compilation of the generating units and their dispatch characteristics, and to some extent the load forecast

data, are the intellectual work product of Slater Consulting, developed through significant and substantial effort. We consider this to be confidential, proprietary business information, but we are, of course, willing to disclose it pursuant to appropriate confidentiality protections.

OPERATIONS OF THE OSPREY ENERGY CENTER

Q: What does your base case analysis show regarding the projected operations of the Osprey Energy Center?

A: For the base case, our analyses show that the Osprey Energy Center will generally produce between 4,000 and 4,400 gigawatt-hours ("GWH") annually, indicating annual capacity factors between 86 and 93 percent, for the 2003-2012 analysis period. Exhibit ____ (KJS-8) shows the projected annual energy production from the Osprey Project and the annual capacity factors based on the indicated output amounts.

Our analyses also indicate that, in peak demand periods, the Project will make sales equal to the Project's full rated capacity, subject only to outages.

Q: What do your analyses show regarding the projected operations of the Osprey Project if natural gas prices are higher than your base case forecast?

A: Exhibit _____ (KJS-9) displays the results of this

sensitivity analysis, and shows that the Osprey Project will produce between 3,900 and 4,400 GWH annually in this case. That is, it will operate at annual capacity factors between 83 and 92 percent.

Q: What do your analyses show regarding the projected operations of the Osprey Project if Peninsular Florida's load growth is higher or lower than in your base case?

A: Exhibit _____ (KJS-10) shows that load growth will have virtually no impact on the operations of the Osprey Project.

Q: What, if any, impacts will the Osprey Project's operation have on other power plants in Peninsular Florida?

A: Generally, the Project will cause less efficient and more costly plants to operate at lower output levels. Exhibit _____ (KJS-11) shows the modeled impacts of the Osprey Project's operations on other units supplying Peninsular Florida during two representative days in 2005, one a June weekday and one a December weekday. Of course, the actual impacts would depend on the actual availability status of all units in Peninsular Florida on any given day.

Q: In your opinion, how likely is it that the Osprey Project would make any significant amount of power sales outside Peninsular Florida?

A: Based on my general knowledge of the Florida and Southeastern Electric Reliability Council ("SERC") markets, including both existing and planned generating capacity for both, and the transmission systems in both markets, I believe that it would be highly unlikely that the Project would make any significant amount of sales outside Peninsular Florida. This is generally because Florida's generation resources are high-cost.

Q: Are you aware of other evidence that supports your opinion that the Osprey Project will not make significant sales of power outside Peninsular Florida?

A: Yes, I am. The PowerDAT® data base maintained by Resource Data International, Inc. and reported on a regular basis in Public Utilities Fortnightly shows that the average generation cost (defined as fuel cost plus reported non-fuel operating and maintenance cost) in the FRCC region, i.e., Peninsular Florida, was the highest of all of the reliability regions in the United States for 1997, 1998, and 1999. Exhibit _____ (KJS-12) shows that for 1999, the FRCC region's average generating cost was 2.59 cents per kWh, which equals $25.90 per MWH. The region with the next highest cost was the

Electric Reliability Council of Texas ("ERCOT"), with an average cost of $24.10 per MWH. The average cost for electricity generation in Florida's nearest neighbor regions was significantly less than in the FRCC region: the average cost for the SERC region was $17.60, approximately 32 percent less than in FRCC, the average cost for the Southwestern Power Pool ("SPP") region was $21.10 per MWH, approximately 19 percent less than in FRCC, and the average cost for the East Central America Reliability ("ECAR") region was $21.20 per MWH, approximately 18 percent less than in FRCC.

In addition, I am aware from reading the power generation trade press that there are significant amounts of new, efficient, relatively low-cost capacity being installed in SERC, ECAR, and other regions. The addition of this new capacity will further reduce the economic viability of power exports from Florida to other regions.

FUEL CONSUMPTION IMPACTS OF THE OSPREY ENERGY CENTER

Q: What, if any, effects will the Osprey Project have on the total consumption of primary fuels used to generate the electric power supply for Peninsular Florida?

A: Exhibit _____ (KJS-13) shows the estimated impacts of the Osprey Project's operations on total primary energy consumption for generating Peninsular Florida's electricity

supply for each year from 2003 through 2012. (Again, these impacts are based on the reasonable assumption that the Project's output will be sold to Seminole and to other Peninsular Florida retail-serving utilities, pursuant to appropriate contractual commitments, when such transactions are cost-effective.) Our modeling analyses show that the Osprey Project can be expected to reduce total fuel consumption by roughly 6 trillion Btu per year to 9 trillion Btu per year over the analysis period. This is a tremendous amount of energy: 6 trillion Btu is approximately the amount of energy in 6 million Mcf (equivalent to 6 billion cubic feet) of natural gas, or the amount of energy in 1 million barrels of residual fuel oil.

Q: What effects would the Osprey Project have on the specific fuels used to generate the electric power supply for Peninsular Florida?

A: Exhibit _____ (KJS-14) shows the impacts of the Osprey Project's operations on the total use of natural gas, No. 6 (residual) fuel oil, No. 2 fuel oil, nuclear, and coal and other solid fuels to generate Peninsular Florida's electricity supply for the 2003-2012 analysis period. Page 1 of 2 of this exhibit shows the impact on fuel use in millions of Btu, and page 2 of 2 of the exhibit shows the impact in terms of

gigawatt-hours (i.e., thousands of megawatt-hours) generated using each fuel type. Generally, the Project results in significant decreases in the use of coal and No. 6 oil, with a corresponding increase in natural gas use. The Project's specific impacts are also illustrated in Exhibit _____ (KJS-11), which shows the expected impacts of the Osprey Project's operations on the operations of other units in Peninsular Florida during representative days.

Q: It is relatively easy to understand how the Osprey Project, with its relatively low heat rate, would reduce the use of gas or oil used in less efficient power plants. Can you explain, however, how the Osprey Project would displace generation from coal-fired power plants?

A: Of course. Certain coal plants, while they have relatively low fuel costs, also have relatively high non-fuel operating and maintenance ("O&M") costs. Because dispatch decisions are based on total variable costs, in some instances, the sum of the Osprey Project's incremental fuel and non-fuel variable O&M cost (and the corresponding costs for the other planned gas-fired combined cycle units as well) will be less than the sum of those costs for coal units. This results in the economic dispatch decision being to operate the Osprey Project at higher output levels and the relatively higher-cost coal

units at lower levels.

Q: Please summarize the expected impact of the Osprey Project's operations on the consumption of petroleum fuels for electricity generation for Peninsular Florida?

A: The Osprey Project's operations can be expected to result in significant reductions in the use of petroleum fuels for electricity generation for Peninsular Florida. For example, Exhibit ____ (KJS-14) shows savings of approximately 13,122 billion Btu of No. 6 oil and another 518 billion Btu of No. 2 oil in 2004. This translates to a total savings of petroleum fuels of 13.6 trillion Btu, or approximately 2.2 million barrels for 2004.

Q: Will the Osprey Project have any effect on the overall efficiency of natural gas use in Florida?

A: Yes. The Osprey Project will increase the overall efficiency of natural gas use in Florida. This will occur as the Osprey Project, with its heat rate of approximately 6,970 Btu/kWh (as dispatched), is dispatched economically in preference to other gas-fired units with less efficient heat rates, e.g., the numerous gas-fired steam units in Florida that have heat rates in the range of 10,000 to 11,000 Btu/kWh.

Q: What, if any, effect will the Osprey Project have on the overall efficiency of electricity generation for Peninsular Florida?

A: The Osprey Project will significantly increase the overall efficiency of electricity generation for Peninsular Florida. Exhibit _____ (KJS-13) shows not only that the Project will result in overall savings of 6 trillion to 9 trillion Btu per year for electricity generation, but that the Project will also reduce the average heat rate for Peninsular Florida electricity generation by 24 to 44 Btu per kilowatt-hour, a reduction on the order of 0.4 percent. This is a significant improvement in the overall efficiency of producing approximately 200,000,000 MWH of electricity per year for the fourth largest state in the nation.

Q: Why will the Osprey Project have these effects?

A: The Osprey Project will have these fuel and energy savings effects because it is significantly more efficient and cost-effective than the vast majority of electric generating plants that currently exist in Peninsular Florida and at least as efficient as virtually all of the new capacity that is planned for Peninsular Florida. Exhibit _____ (KJS-3) shows the estimated dispatch costs and heat rates (as assumed in our PROMOD IV® modeling) for all of the power plants that are

expected to be serving Peninsular Florida in 2003. The Osprey Project's dispatch cost of $28.09 per MWH is lower than the dispatch costs of approximately 34,000 MW of the total capacity of approximately 47,000 MW (including 3,877 MW of nuclear capacity operated as "must run" generation) that is projected to be available to serve Peninsular Florida in that year. In addition, the Osprey Project's heat rate of 6,967 Btu per kWh (as dispatched in 2003) is more efficient than virtually all of the generating capacity that is projected to be available to serve Peninsular Florida in that year. Similarly, Exhibit _____ (KJS-4) shows the estimated dispatch costs and heat rates for all of the power plants that are expected to be serving Peninsular Florida in 2008. The Osprey Project's dispatch cost of $32.57 per MWH is lower than the dispatch costs of approximately 38,000 MW of the total of approximately 51,000 MW (again including 3,877 MW of nuclear as "must run") that is projected to be available to serve Peninsular Florida in that year. In addition, the Osprey Project's as-dispatched heat rate of 6,984 Btu per kWh (as dispatched in 2008) is more efficient than virtually all of the generating capacity that is projected to be available to serve Peninsular Florida in that year.

Q: Will there be any adverse effect on primary fuel consumption and the efficiency of electricity generation for Peninsular Florida if the Osprey Project is not brought into service as requested by Calpine in this proceeding?

A: Yes. If the Osprey Project is either delayed or not brought into operation at all, Florida will lose the primary fuel savings benefits that the Project will provide. As shown above, these primary fuel savings are quite significant -- on the order of 6 trillion to 9 trillion Btu per year for each year of the Project's operation.

COST-EFFECTIVENESS OF THE OSPREY ENERGY CENTER

Q: Did your analyses address the cost-effectiveness of the Osprey Project as an additional power supply resource in the Peninsular Florida power supply system?

A: Yes. Our analyses addressed the Project's cost-effectiveness by evaluating the impact that it would have as an incremental power supply resource added into the Peninsular Florida power supply system in addition to all other planned additions, as indicated by the ten-year site plans filed with the Commission this year. Basically, our analyses modeled the total power supply costs for serving Peninsular Florida without the Osprey Project and with the Project. The difference in costs represents the cost savings properly attributable to the

Osprey Project. Again, these results are predicated upon the reasonable assumption that the Osprey Project's output will be sold, pursuant to appropriate contractual commitments, to Seminole and to other Peninsular Florida retail-serving utilities when such transactions are cost-effective.

Q: And what did your analyses show?

A: Our "base case" analyses and our sensitivity analyses showed that the Osprey Project will provide significant power supply cost savings to Peninsular Florida. Exhibit _____ (KJS-15) shows that for the base case, the Project would result in power supply cost savings between $113 million and $204 million per year (in nominal terms), with projected total savings of $794 million in Net Present Value terms over the Project's first ten years of operations (2003-2012).

For the higher natural gas price sensitivity case, Exhibit _____ (KJS-16) shows that the Project will provide power supply cost savings between $115 million and $218 million per year (in nominal terms), with projected total savings of $806 million in Net Present Value terms over the Project's first ten years of operations (2003-2012).

For the low load growth sensitivity case, Exhibit _____ (KJS-17) shows that the Project will provide power supply cost savings between $47 million and $219 million per year (in

nominal terms), with projected total savings of $627 million in Net Present Value terms over the Project's first ten years of operations (2003-2012).

For the high load growth sensitivity case, Exhibit _____ (KJS-18) shows that the Project will provide power supply cost savings between $88 million and $410 million per year (in nominal terms), with projected total savings of $1.12 billion in Net Present Value terms over the Project's first ten years of operations (2003-2012).

Q: How do these total cost savings translate into reductions in the estimated wholesale cost of power for Peninsular Florida?

A: Exhibit _____ (KJS-15) shows that for the base case, the estimated reduction in the average wholesale cost of power for Peninsular Florida is approximately $0.54 to $0.84 per MWH over the 2003-2012 study period. Exhibit _____ (KJS-16) shows that the impact of the Osprey Project in the higher natural gas price scenario would be approximately $0.55 to $0.88 per MWH over the study period. Exhibit _____ (KJS-17) shows that for the low load growth scenario, the impact of the Osprey Project would be a reduction in average power supply costs of approximately $0.23 to $0.94 per MWH, and that for the high load growth scenario, the impact of the Osprey Project would be a reduction in average power supply costs of

approximately $0.41 to $1.47 per MWH.

Q: What, if any, effect would the fact that the Osprey Project is now going to fulfill Seminole's 2004 capacity need have on these cost reduction impacts?

A: The fact that the Osprey Project is now committed to serving Seminole's 2004 need will presumably cause Seminole's previously planned 2004 combined cycle unit to drop out of the projected statewide power supply plan. In turn, because the Osprey Project will now be operating within a slightly less efficient system, this will cause the cost reduction benefits available from the Osprey Project's operation to be slightly greater than the values reported above.

Q: Will the Osprey Project be the most cost-effective alternative available to serve Peninsular Florida's needs for cost-effective, reliable power?

A: In my opinion, yes. The Osprey Project has a favorable heat rate and favorable direct construction costs, as reported by Calpine, when compared to other generating units that are planned or proposed for Peninsular Florida. Combining these factors with the fact that the Project will not be included in any retail-serving utility's rate base, but rather the Project's output will only be purchased for resale to the

customers of retail-serving utilities, such as Seminole's member cooperative utility systems that obtain their wholesale power from Seminole, when such purchases are cost-effective, it is obvious that it is the most cost-effective alternative available. Exhibit _____ (KJS-19) lists planned and proposed generating units for Peninsular Florida. Among the gas-fired combined cycle units, the Osprey Project compares quite favorably: only the Cane Island 3, Duke New Smyrna Beach, and Okeechobee units have comparable heat rates and lower construction costs. Most of the proposed combined cycle capacity has significantly higher direct construction costs.

Again, this conclusion is based upon the assumption that the Project's output will be sold, pursuant to appropriate contractual commitments, to Seminole and to other Peninsular Florida retail-serving utilities, when such transactions are cost-effective. As explained above, I believe that this assumption is entirely reasonable.

Q: What, if anything, could prevent the Osprey Project from being a cost-effective power supply resource in the Peninsular Florida region?

A: Only highly unlikely developments, such as the total failure of the Project to become operational or a technological change so dramatic as to make <u>all</u> of the existing and planned

Peninsular Florida generating capacity obsolete, could cause the Osprey Project not to be cost-effective.

Q: How does the Osprey Project compare to other existing and planned Peninsular Florida power plants in terms of its projected operating costs?

A: In terms of its operating costs, the Osprey Project compares quite favorably to all existing generating plants in Peninsular Florida except those fueled by nuclear fuel and some of those fueled by coal. Referring back to Exhibit _____ (KJS-3), the Commission will see that the Osprey Project is more cost-effective, in terms of its dispatch costs, than approximately 34,000 MW out of the total of 47,000 MW (including nuclear as "must run") available to serve Peninsular Florida in 2003. Similarly, Exhibit _____ (KJS-4) shows that the Project is more cost-effective than approximately 38,000 MW of the total of approximately 51,000 MW (including nuclear as "must run") of capacity that is projected to be available to serve Peninsular Florida in 2008. As noted above, the Project also compares favorably to other planned and proposed gas-fired combined cycle units.

I should add that in our modeling, we intentionally assumed identical heat rate characteristics for all of the new gas-fired combined cycle capacity. We did so in order to be

conservative with respect to the Osprey Project's impacts and operations.

Q: One of the criteria that the Commission must consider in a need determination proceeding is whether the proposed power plant will contribute to meeting the need for adequate electricity at a reasonable cost. As you understand this term, will the Osprey Project contribute to meeting the needs of Florida retail-serving utilities for adequate electricity at a reasonable cost?

A: Yes. In the simplest terms, the Osprey Project is available to Seminole and potentially to other Peninsular Florida retail-serving utilities, and our PROMOD IV® modeling analyses show that it can save between $627 million and $1.12 billion (Net Present Value) in power supply costs for Peninsular Florida in the first ten years of its life, depending on variations in fuel prices and load growth rates. Clearly, if Florida can obtain its needed power supply at savings between half a billion and more than one billion dollars, it would only be reasonable to take advantage of the opportunity. Given the availability of these savings, paying the extra half billion dollars or more would represent paying an unreasonable amount for needed power.

Q: Will the Project have any effect on potential "price spikes" for wholesale power in Peninsular Florida?

A: Yes, the Project can be expected to suppress and reduce the magnitude of prices in basically all hours when the Project is available to serve. (The Project would be expected to be available to serve continuously during all summer and winter peak periods, except for unplanned or forced outages.) While our modeling analyses did not address extreme peak conditions, it is obvious that the Project's presence would suppress prices in any extremely tight supply conditions that might be experienced in Peninsular Florida.

Q: What, if any, value would the Project have with respect to other services? For example, would the Project suppress the price of ancillary services to Seminole and to other Peninsular Florida retail-serving or load-serving utilities?

A: Generally, the Project will also suppress the cost or price of other services, including ancillary services. (Ancillary services are defined by the Federal Energy Regulatory Commission as (a) Scheduling, System Control and Dispatch Service; (b) Reactive Supply and Voltage Control from Generation Sources Service; (c) Regulation and Frequency Response Service; (d) Energy Imbalance Service; (e) Operating Reserve - Spinning Reserve Service; and (f) Operating Reserve

Supplemental Reserve Service.) While our PROMOD IV® analyses only addressed the Osprey Project's value in supplying energy and did not include any analyses of the Project's impact on the prices of ancillary services, from my experience I can say that the Project's presence will suppress the prices of ancillary services for retail-serving utilities in Peninsular Florida, especially the prices of the various types of reserve services. These effects are likely to be quite significant in Florida once the transmission function is transferred to some form of regional transmission organization that would have the responsibility for procuring ancillary services in the market.

Q: Do your analyses take account of the value of economic production (e.g., fertilizer, chemicals, services, food products, and so on) that could, and presumably would, be realized by commercial enterprises in Florida if they were able to stay in operation as a result of the Project's presence and operation?

A: No. Our analyses address only the direct impacts on power supply costs. The value of maintaining electric service is generally significantly greater than the cost of providing incremental energy, even in instances where power supplies are tight and incremental power is available only at extremely high prices, for example, $1,000 or more per MWH. In my

experience, the value of "lost production" is frequently several times that amount.

Q: What, if anything, do your analyses of the Osprey Energy Center's operations show regarding the need for the Project?

A: Our analyses show that the Project will meet significant need in Peninsular Florida for cost-effective power, even if the Project were added onto the projected Peninsular Florida generating fleet in addition to all other planned resources. This is demonstrated by the significant, even dramatic, power supply cost reductions that the Osprey Project will provide.

Again, as I indicated above, these analyses provide the most conservative estimate of the Project's contributions to Peninsular Florida, because they model the Project's operations against the backdrop of the greatest amount of new efficient generation in the area. Given that the bulk of the Osprey Project's capacity is now firmly committed to Seminole, with the corresponding replacement of Seminole's previously planned 2004 combined cycle unit in the statewide generation expansion plan, the Project can be expected to provide even greater total benefits in terms of reduced power supply costs.

Q: Based on your analyses, and in your opinion, will there be any adverse effects on total power supply costs for Seminole and for other Peninsular Florida retail-serving or load-serving utilities if the Osprey Project is not brought into service as requested by Calpine and Seminole?

A: Yes. Our analyses demonstrate quite clearly that the Project will provide significant, even dramatic, benefits to Seminole and potentially to other Peninsular Florida retail-serving and load-serving utilities (subject to appropriate contracts) if and when it is brought into service as proposed by Calpine and Seminole. With respect to power supply costs, if the Project were not brought into service as proposed by Calpine and Seminole, these benefits, specifically the projected cost savings of about $800 million (Net Present Value) over the Project's first ten years of operation, would be lost. Losing these benefits would be a significant adverse effect of the Project's not being brought into service as requested by Calpine and Seminole. Similarly, delaying the Project's commercial operation will "cost" on the order of $150 million in lost power supply cost reductions annually for each year of delay.

AMENDED DIRECT TESTIMONY OF KENNETH J. SLATER

RELIABILITY IMPACTS OF THE OSPREY ENERGY CENTER

Q: How should the Commission evaluate the impact of the Osprey Energy Center on the reliability of the power supply system for Peninsular Florida?

A: The Commission should include the Osprey Project in its reliability evaluation for Peninsular Florida as a committed resource, in this case to Seminole.

Q: What impact will the Osprey Project have on the reliability of Peninsular Florida's power supply system?

A: The Osprey Project will improve Peninsular Florida reliability by increasing Peninsular Florida reserve margins by approximately 1.1 to 1.3 percent in both summer and winter seasons following the Project's achievement of commercial in-service status. For example, Exhibit _____ (KJS-20) shows that in the summer of 2003, the Project will increase Peninsular Florida's reserve margin from 15.3 percent to 16.5 percent. Exhibit _____ (KJS-21) shows similar improvement in winter reserve margins.

Q: What, if any, impact would the availability of the Osprey Project have on the ability of Peninsular Florida's retail-serving utilities to maintain service to their retail customers during periods when power supply was short relative to demand?

A: The Osprey Project will have significant beneficial effects on the ability of Seminole and potentially other Peninsular Florida retail-serving utilities, subject to appropriate contracts, to maintain uninterrupted service to their firm and non-firm customers. This would apply not only during extreme seasonal peak demand conditions, but any time that supply was "tight" relative to demand. Such conditions have occurred in what are typically regarded as "shoulder" months when demand was higher than projected (though far below annual peak levels) but supply was tight due to scheduled maintenance outages and unexpected outages of generating units.

In an extreme winter peak event, the Project's capacity of approximately 578 MW would enable Seminole and other Florida retail-serving utilities, subject to appropriate contracts, to maintain service to between 115,000 and 165,000 residential customers, at an average coincident peak demand of 3.5 to 5.0 kilowatts per household. Even in less extreme conditions, the Project's capacity would enable Florida retail-serving utilities to maintain service to more of their

customers without implementing direct load control measures or without interrupting service to commercial and industrial interruptible customers. In an extreme summer event, the Project's summer capacity of 496 MW would enable Florida's retail-serving utilities to maintain service to between 99,000 and 142,000 residential customers or equivalent load.

Q: In your opinion, would it be accurate to say that Florida has a need for the Osprey Project from a reliability perspective?

A: Yes. Given the firm commitment of 350 MW of the Project's capacity to Seminole and the availability of the balance of the Project's capacity to Seminole on a reserve capacity option basis, the Osprey Project will enhance the reliability of Seminole's system and of Peninsular Florida's electric power supply system as a whole.

Q: Will there be any adverse effects on the reliability of the Peninsular Florida power supply system if the Osprey Project is not brought into service as requested by Calpine and Seminole?

A: Yes. Considering the firm commitment of 350 MW of the Project's capacity to Seminole and the availability of the balance of the Project's capacity to Seminole on a reserved firm capacity basis, reserve margins will be greater, by a

measurable, significant amount, than if the Project is not added. More significantly, in practical terms, subject to appropriate contracts, Seminole and potentially other Peninsular Florida retail-serving utilities will be unable to serve approximately 500 MW of load (up to approximately 660 MW of load with duct-firing and power augmentation) that they could serve if the Project were constructed as sought by Calpine and Seminole. This means that, in periods when supply is short relative to demand, the equivalent of 99,000 to 185,000 homes will not be served, or will have their service interrupted, if the Project is not built. The actual impacts could be felt by residential customers or by industrial and commercial customers who would have to shut down their operations as a result of power supply shortages. The actual amount of load affected depends on the season and the final configuration of the Project.

IMPACTS OF THE OSPREY ENERGY CENTER ON ENVIRONMENTAL EMISSIONS FROM ELECTRICITY GENERATION

Q: Did you evaluate the impacts of the Osprey Energy Center's operations on the emissions of pollutants that are associated with electricity generation?

A: Yes. Our PROMOD IV® analyses evaluated the impacts on total emissions of sulfur dioxide and nitrogen oxides from the operation of the power plants included in our analyses. In

this application, we evaluated the emissions of sulfur dioxide and nitrogen oxides in the various cases with and without the Osprey Project included as a power supply resource for Peninsular Florida. (Again, these results are predicated on the reasonable assumption that the Project's output will be sold to Seminole and to other Peninsular Florida retail-serving utilities, pursuant to appropriate contractual commitments, when such transactions are cost-effective.)

Q: What are the projected impacts of the Osprey Energy Center on the emissions of sulfur dioxide and nitrogen oxides associated with producing the electric power supply for Peninsular Florida?

A: Exhibit _____ (KJS-22) shows that with the Osprey Project in service in our base case scenario, the emissions of sulfur dioxide are approximately 4,600 to 16,000 tons per year less than if the Osprey Project is not in service. Similarly, Exhibit _____ (KJS-22) shows that the Osprey Energy Center's operations are expected to result in reductions of nitrogen oxides emissions of approximately 3,900 to 7,000 tons per year.

Q: Will there be any adverse effects on Florida's environment if the Osprey Project is not brought into service as requested by Calpine and Seminole in this proceeding?

A: Yes. The combined emissions of sulfur dioxide and nitrogen oxides from producing Peninsular Florida's electricity supply will be more than eight thousand tons greater in each year that the Osprey Project's operation is delayed.

Q: Does this conclude your direct testimony?

A: Yes. It does.

CHAIRMAN JACOBS: Next witness.

MS. KIESLING: Yes. As to the testimony of Michel P. Armand, there is one minor change on Page 9, Line 4. Insert the word "amended" before the word "exhibits," and also insert the words "amended joint" prior to the word "petition." And I have a copy for the court reporter that has that change reflected in it.

CHAIRMAN JACOBS: Very well.

MS. KIESLING: And with that change, I would ask that the testimony of Michel P. Armand be admitted into the record as though read.

CHAIRMAN JACOBS: Without objection, show the testimony of Michel Armand entered into the record as though read.

MS. KIESLING: Also, attached to the testimony of Michel P. Armand were five exhibits, MPA-1 through MPA-5, and I would ask that you assign a composite exhibit number to those.

CHAIRMAN JACOBS: That is Composite Exhibit 9.

(Exhibit 9 marked for identification.)

MS. KIESLING: And I would move that Composite Exhibit 9 be admitted into the record.

CHAIRMAN JACOBS: Without objection, show Exhibit 9 is admitted.

(Exhibit 9 admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: JOINT PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE, INC., AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

DIRECT TESTIMONY OF MICHEL P. ARMAND, P.E.

Q: Please state your name and business address.

A: My name is Michel Armand, and my business address is 3113 Lawton Road, The Carr Building, Suite 130, Orlando, Florida 32803-3519.

Q: By whom are you employed and in what position?

A: I am employed as a Principal of Navigant Consulting, Inc. ("NCI").

Q: Please describe your duties with NCI.

A: I am responsible for conducting transmission planning and operations studies for NCI clients. These studies cover proposed generating plants and their associated transmission interconnections, actual system performance based on projected seasonal loading conditions, and the determination of potential operating constraints necessary to insure reliable operation of the bulk transmission system.

DIRECT TESTIMONY OF MICHEL P. ARMAND, P.E.

QUALIFICATIONS AND EXPERIENCE

Q: Please summarize your educational background and experience.

A: I graduated from the City College of the City University of New York in June 1968, with the degree of Bachelor of Engineering - Electrical. In June 1971, I graduated from the Bernard Baruch College of the City University of New York with the degree of Master of Business Administration.

In 1971, I attended the General Electric Company's one-year course in Advanced Power System Engineering, in Schenectady, New York. In 1978, I attended the one-month Public Utility Executive Program of the Graduate School of Business Administration of the University of Michigan. In 1983, I attended the two-month Executive Program of the Colgate Darden Graduate School of Business Administration of the University of Virginia.

Upon graduation, I was employed by the Consolidated Edison Company of New York. I was assigned to the Distribution Engineering, Station Design, and System Planning Departments. My permanent assignment was in the Transmission Planning Section of the System Planning Department.

In April 1974, I was employed by Florida Power & Light Company ("FPL") in the System Planning Department. In April 1976, I was put in charge of the Reliability and System Security Section, responsible for testing and assessing the

dynamic performance of the planned generation and transmission system, and for making recommendations based on our tests and assessments. In June 1984, I was transferred to FPL's Power Supply Department as Manager of Technical Services responsible for daily analysis of system performance, monitoring the adequacy of performance of transmission protective systems, and coordinating the protection and control settings of FPL's generation, transmission, and distribution systems. In May 1991, I became Director of Protection and Control Systems responsible for the design, engineering, installation, and maintenance of all protections and control systems for the generation, transmission, and distribution systems of FPL. In October 1993, I took early retirement from FPL.

From December 1994 to December 1996, I was employed as Energy Consultant in the Office of the Prime Minister of Haiti. In 1997, I assumed my present position as Principal Executive Consultant with NCI, formerly Resource Management International, Inc.

I am a registered professional engineer in the State of Florida, and I am a member of the Institute of Electrical and Electronic Engineers and a member of the Society of Professional Engineers.

Q: What is your experience in power plant engineering, construction, operations, permitting, and licensing?

A: As a manager for NCI, I provided transmission planning analyses for Duke Energy Power Services ("Duke") in support of a 500 MW plant at New Smyrna Beach, Florida. I was the project manager for this work and prepared testimony in support of Duke's petition to the Florida Public Service Commission. NCI conducted Power Flow Studies to determine the best configuration to integrate a 500 MW power plant into the transmission grid.

As Supervisor of Reliability and System Security for Florida Power & Light Company, responsible for modeling the dynamic response of the system to disturbances, I was involved with the Power Plant Engineering Department in specifying the electrical parameters of new generators such as power factor, short circuit ratio, high initial response exciter, power system stabilizer, generator step-up and auxiliary transformers, tap ratio coordination, and switchyard connections. I also initiated studies to add power system stabilizers and modify relay protection schemes for existing high capacity generating units (600 MW and above) on the FPL system.

I was heavily involved in the licensing of FPL's St. Lucie Unit No. 2, a nuclear unit. In this activity, I

participated in the Final Safety Analysis Report for the unit's operating license and testified at the evidentiary hearing in Miami, in November 1979, on the issue of grid reliability.

Q: What is your experience in generation planning, transmission planning, transmission design, and load flow studies?

A: In my professional work, the size and location of generation was always a given. My responsibility was the integration of the generators in the transmission grid for optimum delivery of the power under all postulated transmission outages.

I have extensive professional experience in transmission planning. At Consolidated Edison of New York, I was responsible for transmission planning for the borough of Manhattan, representing at that time about 45 percent of ConEd's total system demand. At FPL, I was responsible for transmission planning in Dade and Broward Counties, representing, at that time, about 60 percent of FPL's total system demand. While not involved in the physical design of transmission lines, studies initiated and conducted by me resulted in the partial transposition of the 500 kV transmission corridor on the East Coast of Florida. The deleterious effects of unbalanced, negative sequence currents on the generators along the corridor were considerably

reduced.

Load flow and transient stability studies were the principal tools used to assess the seasonal, yearly, and long-range performance of the Florida Grid. Such studies were conducted by me and by my section internally for FPL, and in participation with the Florida Electric Power Coordinating Group (FCG). Such tools were also used to update the Florida under-frequency load shedding program and to establish the various remedial action systems on FPL's system to mitigate loss of heavily loaded transmission corridors.

Q: Have you previously testified before regulatory authorities or courts?

A: I have testified before the Atomic Safety and Licensing Appeal Board of the U.S. Nuclear Regulatory Commission, in an evidentiary hearing on the alleged inadequacy of electric power systems for St. Lucie Unit No. 2. The operating license was granted after it was clearly demonstrated that the planned transmission grid would provide adequate and reliable off-site power in an emergency. I have testified before the Florida Public Service Commission in the Duke New Smyrna need determination hearing. I have also testified in court in an eminent domain proceeding for the condemnation of property for transmission line right-of-way.

DIRECT TESTIMONY OF MICHEL P. ARMAND, P.E.

Q: Are you a registered professional engineer?

A: Yes. I am a registered professional engineer in the State of Florida.

SUMMARY AND PURPOSE OF TESTIMONY

Q: What is the purpose of your testimony?

A: I am testifying on behalf of Calpine Construction Finance Company, L.P., ("Calpine") for the Commission's determination of need for the Osprey Energy Center ("the Osprey Project" or "the Project"). My testimony describes the transmission interconnection facilities that will connect the proposed power plant to the Tampa Electric Company Recker Substation located adjacent to the southeastern boundary of the site. My testimony also presents and describes the load flow analyses that NCI conducted to evaluate the transmission impacts of the Osprey Energy Center under various power delivery scenarios.

Q: Please summarize your testimony.

A: The Osprey Energy Center will be connected to Tampa Electric Company's Recker Substation located adjacent to the southeastern boundary of the Project site. This interconnection, together with some identified transmission upgrades, will enable power from the Project to be delivered to virtually any retail-service utility in Peninsular Florida

under almost all conditions on the Florida transmission grid. The Project's output will not adversely affect any of the "constrained transmission paths" identified by the Florida Reliability Coordinating Council ("FRCC"). System impact studies conducted for Calpine included load flow analyses, transient stability analyses, and short circuit analyses. These studies indicated that, under normal operating conditions, that is, with all facilities in service, the Project will not materially burden the transmission system or violate any transmission constraints or contingencies in Peninsular Florida. These studies suggested that some upgrades may be needed and those are discussed in detail later in my testimony.

Q: Are you sponsoring any exhibits to your testimony?

A: Yes. I am sponsoring the following exhibits:

MPA-1. Qualifications of Michel P. Armand, P.E.;

MPA-2. Proposed 530 MW Florida Generating Facility, Osprey Energy Center, February 2000;

MPA-3. Analysis of Transmission System Improvements in support of Osprey Energy Center, April 18, 2000;

MPA-4. Regional Transmission Map of West Central Florida; and

MPA-5 Calpine-Osprey Energy Center Transmission Service

Request Facilities Study Report by Tampa Electric Company.

I am also sponsoring the portions Volume II of the Amended Exhibits to the Amended Joint Petition for Determination of Need, including text and figures, related to transmission.

NCI'S ROLE REGARDING THE OSPREY ENERGY CENTER

Q: Please describe Navigant Consulting, Inc. and its business.

A: Navigant Consulting, Inc. provides comprehensive consulting and engineering services to a wide range of clients, including the electric power industry. NCI provides consulting and engineering services on power system design, power plant design, and transmission and distribution system design and operations.

Q: What are your responsibilities with respect to the electrical power plant project that is the subject of this proceeding?

A: NCI has been retained to evaluate the transmission impacts of the Osprey Energy Center's operation as a power plant selling wholesale power to other utilities that provide retail electric service in Peninsular Florida. I have the primary responsibility for conducting the studies by which we have analyzed the Project's transmission impacts.

Q: With what similar projects has NCI been involved, and in what capacity?

A: NCI has conducted numerous evaluations of the load flow impacts of planned and proposed interconnections of generating units, including wholesale power plants, with high-voltage transmission systems, including projects in Oregon, Minnesota, New York, Hawaii, Texas, California, and the East Central Area Reliability ("ECAR") Region.

TRANSMISSION INTERCONNECTION AND ASSOCIATED DOWNSTREAM TRANSMISSION FACILITIES FOR THE OSPREY ENERGY CENTER

Q: Please describe the transmission facilities by which the Osprey Energy Center will be connected to the Florida transmission grid.

A: The Osprey Energy Center Project will be connected to the existing Tampa Electric Company's Recker Substation. The interconnection will include switchgear, circuit breakers, and related equipment appropriate for this type of interconnection.

Q: How did you and NCI evaluate the capability of the Osprey Energy Center Project to deliver wholesale power to other retail-service utilities in Florida?

A: We evaluated the transmission system impacts of the Project by conducting power flow studies (also known as load flow studies or load flow analyses) in which we simulated the power flows that would result from sales from the Project to other key utilities in Peninsular Florida. Our power flow studies utilized standard transmission modeling techniques and assumptions. Basically, as discussed in more detail below, we compared the simulated operations of the Florida transmission system with and without the Project's output being delivered to Florida Power & Light Company ("FPL"), Florida Power Corporation ("FPC"), Tampa Electric Company ("TECO"), Jacksonville Electric Authority ("JEA"), and Seminole Electric Cooperative ("Seminole" or "SEC").

We reviewed and utilized the following documents and reports in preparing our power flow studies.

1. FPL's 1999 Ten-Year Plant Site Plan.
2. FPC's 1999 Ten-Year Site Plan.
3. TECO's 1999 Ten-Year Site Plan.
4. Florida Reliability Coordinating Council ("FRCC"), 1997 Final Transmission System Constraints Maps.
5. FRCC, 1997 Transfer Capability Study: FLA/SOV Interface.
6. FRCC, 1999 Reliability Study.

We utilized these documents and reports because at the time

our study was done, the 2000 Ten-Year Site Plans were not available. We used the most current data available.

Q: What are the relevant import and export capabilities of the transmission interface between Peninsular Florida and the Southeastern Electric Reliability Council ("SERC") region?

A: Peninsular Florida has the capability of importing approximately 3,600 MW of power from the SERC region, and the capability of exporting approximately 2,100 MW of power to the SERC region. This difference exists because the transmission system in southern Georgia becomes constrained, on a first-order contingency basis, at lower loads than does Peninsular Florida.

Q: Please summarize the results of the power flow studies you conducted for the Osprey Project.

A: The analyses conducted by NCI indicate that at average loading conditions on the Florida transmission system (60% for the rest of the state, 70% for Tampa), no overload occurs for all the contingencies simulated and for all dispatch scenarios. The studies also indicate that in order to support the delivery of wholesale power from the Project to utilities providing retail service in Florida, under eighteen base cases modeled, none of the transmission lines in the vicinity of the

Osprey Project would be overloaded under normal conditions with all facilities in service. Under summer 2004 peak load, when importing 2400 MW from Southern Company, loss of the Recker-Gapway 230 kV line (a single contingency) causes the Ariana 230/69 kV transformer to load up to 103.8 percent of its emergency rating for all dispatch scenarios. Similarly, loss of the McIntosh-Lake Agnes 230-kV circuit causes the Lake Agnes-Recker 230-kV circuit to load up to 102.6 of its emergency rating when the plant output is scheduled for FPL, FPC, JEA, and SEC. Also, loss of the Griffin-Lakeland West 230-kV circuit causes the Osceola-Lake Agnes 230-kV circuit to load up to 100 percent of its emergency rating when the plant output is scheduled to FPC, JEA and SEC.

During the summer 2004 peak load period, when importing 3600 MW from Georgia, loss of the Recker-Gapway 230-kV circuit causes the Ariana 230/69-kV transformer to load up to 104.6 percent of its emergency rating.

Q: Did NCI conduct any additional load flow studies?

A. Yes. NCI then conducted additional load flow analyses to determine the capacity of the surrounding transmission system to effectively transform and transmit the Project's generated electric power to its customers via the Florida transmission grid. This study, using a single contingency approach,

identified four critical facilities owned by TECO. Those four critical facilities are the Recker to Lake Agnes 230 kV transmission line, the Recker to Crews Lake 230 kV transmission line, the Crews Lake to Pebbledale 230 kV transmission line, and the 150 MVA, 225Y/130 - 69Y/38.8 kV transformer at Ariana Substation. The analysis conducted by NCI indicates that under maximum loading conditions and single contingency failure of related facilities, the transmission lines interconnecting the Project with the grid should be rated a minimum of 478 MVA. According to TECO, however, the load carrying capacity of the critical transmission lines is 398 MVA. The NCI analysis also indicates that under maximum loading conditions and single contingency failure of associated facilities, the transformer at TECO's Ariana Substation would be overloaded to 220 MVA, or 47 percent above its nominal rating of 150 MVA.

Q: Please describe any downstream transmission system upgrades that may be needed in connection with the Project.

A: Based on the single contingency load flow studies, NCI has identified the following downstream transmission upgrades that may be needed:

1. Upgrading the conductor and poles on a 1.4-mile section of the Recker to Crews Lake transmission line;

2. Upgrading all conductor on the 6.3-mile Crews Lake to Pebbledale line and upgrading the poles on approximately 3.2 miles of that line; and

3. Upgrading the transformation capacity at TECO's Ariana Substation, which may include adding cooling capacity to the existing 150 MVA transformer or adding another 150 MVA transformer.

A map showing the transmission interconnection and the transmission facilities in the Osprey Energy Center area is included here as MPA-4.

Q: Did you evaluate the Project's capability to deliver power outside Florida?

A: No. I understand that Calpine's intent is to sell wholesale power from the Project within Peninsular Florida, and accordingly, NCI was not asked to perform any power flow studies for sales outside Peninsular Florida.

Q: Are you aware of any other transmission studies that have been done for the Project?

A: Yes. TECO performed a preliminary transmission service request facilities study and provided a draft to Calpine on May 22, 2000. TECO's study considered double second-order contingencies as well as first single-order contingencies and

was therefore more restrictive than NCI's studies. TECO's study also had no cost information related to its suggested upgrades.

Q: Has TECO performed an additional detailed Facilities Study?

A: Yes, TECO's final Facilities Study Report, attached hereto as MPA-5, was completed on August 31, 2000.

Q: What did TECO recommend?

A: Under a second contingency scenario, TECO recommended a new Recker-South Eloise 230-kV line, 11.1 miles of new 230kV pole line and five new breakers, creating a loop from the North Bartow-West Lake Wales line through South Eloise, splitting the line up into two 2-terminal 230kV circuits.

Q: Did TECO estimate the total cost of the interconnection and network upgrades?

A: Yes. The cost to interconnect the Osprey Energy Center to TECO's Recker Substation is estimated at $2.4 million. The cost of the network upgrades required to provide 526 MW of firm point-to-point transmission service is estimated at $11.5 million.

Q: Does the TECO study alter your opinion?

A: No. My analysis and conclusions remain entirely valid in light of the TECO study. My analysis assumes that under a single contingency and NCI's proposed modifications, the plant output can be delivered without causing undue burden on the Florida Transmission Grid. However, the TECO study is also supportable since it postulates a double contingency scenario and an appropriate solution that will provide the needed point-to-point transmission service that is needed.

Q: How will the actual transmission system upgrades be decided?

A: Calpine and TECO will reach an appropriate solution under TECO's Open Access Transmission Tariff. Assuming that Calpine and TECO agree to the transmission upgrades detailed in the Facilities Study Report, those upgrades will support delivery of Osprey Project power to any other utility in Peninsular Florida without materially burdening the transmission grid and without causing any violation of any constraints or contingencies in the grid. Calpine is fully prepared to do what it must to support delivery of its full output to any utility in Peninsular Florida. The details will be a matter to be negotiated between Calpine and TECO pursuant to TECO's tariff.

Q: Based on your analyses and the TECO study, what is your

opinion regarding Calpine's ability to deliver the Osprey Project's output to Seminole?

A: In my opinion, based on my analyses and the TECO study, with the upgrades contemplated by the TECO study, Calpine will be able to deliver the Osprey Project's output to Seminole under all realistic scenarios (excluding extreme force majeure events) without materially burdening the transmission grid and without causing any violation of any constraints or contingencies in the Peninsular Florida grid.

Q: Does this conclude your direct testimony?

A: Yes, it does.

MR. LaVIA: Calpine's next witness is Michael D. Petit. And Mr. Petit also had two minor corrections to his prefiled testimony. I will provide a copy to the court reporter. On Page 5, Line 6, again insert the word "amended" before "exhibits," and on Page 5, Line 7, insert the word "amended" before "joint petition." And with those changes, I would request that Mr. Petit's prefiled testimony be admitted into the record as though read.

CHAIRMAN JACOBS: Without objection, show Mr. Petit's testimony --

MR. LaVIA: Excuse me. Mr. Petit had four exhibits. He has MDP-1 through MDP-4. He also filed a supplemental exhibit, MDP-5, last week on January 30th. It is an update on the permitting status of the Gulfstream pipeline. I would request that MDP-1 through MDP-5 be assigned a composite exhibit number.

CHAIRMAN JACOBS: That's Composite Exhibit 10.

(Exhibit 10 marked for identification.)

MR. LaVIA: And then I would move that Composite Exhibit 10 be admitted into the record.

CHAIRMAN JACOBS: Without objection, show Exhibit 10 as admitted.

(Exhibit 10 admitted into the record.)

MR. LaVIA: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: JOINT PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE, INC., AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

DIRECT TESTIMONY OF MICHAEL D. PETIT

Q: Please state your name and business address.

A: My name is Michael D. Petit. My business address is the Pilot House, 2nd Floor, Lewis Wharf, Boston, MA 02110.

Q: By whom are you employed and in what position?

A: I am employed by Calpine Eastern Corporation ("Calpine Eastern") as the Director of Fuels Management.

Q: Please describe your duties with Calpine Eastern.

A: My role is to manage the fuel arrangements for existing electric generation facilities and to provide fuel supply expertise to support the Electric Power Plant Development and Acquisitions Groups of Calpine Eastern. This includes managing contract optimization and restructuring, coordinating fuel regulatory activities, developing fuel supply strategies, sourcing fuel supplies and transportation services and negotiating the terms and conditions of these services for Calpine Eastern in the eastern United States and Canada.

Q: What are your responsibilities with respect to the Osprey Energy Center Project?

A: I am primarily responsible for developing the fuel supply strategy and negotiating the term fuel supply and transportation contracts for the Osprey Energy Center Project (the "Osprey Project"). In addition, in the regulatory process, I provide fuel supply support for the Osprey Project as needed.

QUALIFICATIONS AND EXPERIENCE

Q: Please summarize your educational background and experience.

A: In 1977, I graduated with a B.S. in Accounting from Villanova University. I have over 20 years of experience in various commercial positions in the energy industry. As previously noted, I am currently Director of Fuels Management for Calpine Eastern Corporation. My resumé is attached to this testimony and identified as Exhibit ____ (MDP-1).

Q: Please summarize your employment history and work experience.

A: My employment history and work experience include 13 years of employment in positions working with natural gas issues of which the last nine years were with power generation

companies as a manager or director. For the majority of the last eight years, I have worked for two major power plant developers (Calpine Eastern and PG&E Generating, formerly known as U.S. Generating Company). As Director of Fuels Management for Calpine Eastern, I am responsible for developing fuel strategies, coordinating regulatory issues involving fuels management, assisting with acquisition matters, and negotiating fuel supply contracts and transportation services. I support Calpine Eastern's existing assets and the Calpine Eastern development group's work with proposed competitive wholesale generation facilities throughout the eastern United States and Canada.

Q: What is your experience with regard to natural gas supply arrangements, fuel plans, and regulatory support?

A: Over the past few years, I have developed fuel supply strategy and fuel plans for several announced new electric generation facilities in the eastern United States, some of which are either currently in operation or under construction. In addition, during the same period I have been responsible for all aspects of fuels management for Calpine Eastern's and PG&E Generating's existing natural gas-fired generation facilities in the eastern United States. More detail regarding my experience is provided in Exhibit ____ (MDP-1).

Q: **Have you previously testified before regulatory authorities or courts?**

A: Yes. I have provided testimony to the Massachusetts Siting Board in a proceeding involving fuel supply issues for PG&E Generating's Millennium Merchant Power Plant, the National Energy Board (NEB) of Canada on alternative fuel supply arrangements and the Maine Public Utility Commission on gas lateral transportation service.

SUMMARY AND PURPOSE OF TESTIMONY

Q: **Please summarize your testimony.**

A: My testimony describes the fuel supply arrangements for the Osprey Project. The objective of the fuel supply arrangements is to provide the Osprey Project with a low cost, reliable and flexible fuel supply that closely matches the operational demands of a successful wholesale electric generation facility and our customer's--i.e., Seminole Electric Cooperative's--requirements.

Q: **Are you sponsoring any exhibits to your testimony?**

A: Yes. I am sponsoring the following exhibits:

Exhibit _____ (MDP-1): Resumé of Michael D. Petit;

Exhibit _____ (MDP-2): Precedent Agreement (redacted to protect confidential, proprietary terms and conditions of

the Agreement from public disclosure.)

Exhibit _____ (MDP-3): Gulfstream report on status of permitting; and

Exhibit _____ (MDP-4): Gulfstream Pipeline Maps.

In addition, I am sponsoring Figures II-13, II-14 and II-15 and Appendix II-B of Volume II of the Amended Exhibits accompanying the Amended Joint Petition for Determination of Need for the Osprey Project, as well as the text that accompanies those figures.

PIPELINE FACILITIES TO SERVE THE OSPREY PROJECT

Q: Please describe the proposed Gulfstream Natural Gas System and its permitting status.

A: Please see Exhibit _____ (MDP-3), which was provided by the Gulfstream Natural Gas Pipeline System and which describes the proposed gas transmission system and its permitting status. In addition, maps of the Gulfstream System in the vicinity of the Osprey Project site are included as Exhibit _____ (MDP-4). For convenience, I will use the term "Gulfstream System" to refer to the physical pipeline systems, and the term "Gulfstream" to refer to the corporate entity proposing this system.

Q: Please describe the natural gas pipeline facilities by which

the Osprey Project's natural gas supply will be delivered.

A: The Gulfstream System will directly serve the Osprey Project by an approximately 1200 foot long underground lateral extending from the main Gulfstream pipeline onto the Osprey Project site. The diameter of the Gulfstream pipeline directly servicing the plant is 16 inches. The pipeline pressure at the Osprey Project site is guaranteed by Gulfstream to meet the pressure requirements of the Osprey Project.

NATURAL GAS SUPPLY ARRANGEMENTS FOR THE OSPREY PROJECT

Q: Please summarize the natural gas supply and transportation arrangements for the Osprey Project.

A: Supply Arrangements:

An affiliate of Calpine Eastern, Calpine East Fuels, L.L.C., ("Calpine East Fuels") will purchase natural gas for the Osprey Project from gas producers and gas marketing companies that have access to those gas treatment plants, processing plants and interstate natural gas transmission systems with supply located in the vicinity of Mobile Bay, Alabama and Pascagoula, Mississippi. There is an estimated volume of approximately 2 billion cubic feet per day of natural gas available in the vicinity of Mobile Bay, Alabama and Pascagoula, Mississippi. In its application to the Federal Energy Regulatory Commission ("FERC"), Gulfstream

proposes interconnections with the Mobile Bay Pipeline (Koch), the Destin Plant, the Dauphin Island Gathering System Plant, the Williams plant and the Mobil Mary Ann Plant. The capacity of the proposed Gulfstream facilities will be over 1 billion cubic feet per day. The natural gas suppliers will be responsible for delivery into the Gulfstream System. Natural gas fuel supply for the Osprey Project will be provided to Gulfstream receipt points by natural gas marketing companies or producers through an optimized combination of term contract purchases and spot market purchases. The supply will satisfy the anticipated fuel requirements of the Osprey Project.

Transportation Arrangements:

Pursuant to the Precedent Agreement, Exhibit ___ (MDP-2), Calpine East Fuels will enter into a long-term, 20-year firm gas transportation agreement with Gulfstream. This firm transportation service will provide natural gas transportation capacity for the anticipated daily fuel supply required by the Osprey Project. Firm transportation service will be available for the Osprey Project on the Gulfstream System from the Mobile Bay, Alabama and Pascagoula, Mississippi area to the Osprey Project site at the required pressure on a firm basis for 365 days per year, for the 20-year term of the contract. The cost of capacity

on the Gulfstream System is very economical and will allow the Osprey Project to provide reliable low cost electricity to the State of Florida.

Q: Please describe the basic provisions of the natural gas transportation agreement between Gulfstream and Calpine Eastern for the Osprey Project.

A: The basic provisions of the natural gas transportation agreement between Gulfstream and Calpine East Fuels for the Osprey Project are as follows:

- Nature of Service: Firm, 365-day natural gas transportation service on the Gulfstream System from the vicinity of Mobile Bay, Alabama and Pascagoula, Mississippi to the Osprey Project.
- Commencement of Service: Service will commence at the time the plant is in service, which is projected to be in the second quarter of 2003.
- Term of firm service: 20 years from projected plant in-service date
- Rate: confidential
- Minimum Delivery Pressure: sufficient to meet plant requirements

Q: What is the character of the firm natural gas transportation

service to be provided by Gulfstream?

A: The Precedent Agreement calls for Gulfstream to provide long-term firm natural gas transportation service for 365 days per year for the anticipated fuel requirements of the Osprey Project from the supply area to the Osprey Project site, at appropriate delivery pressure.

Q: **What would happen if, for some reason, the Osprey Project's natural gas suppliers should fail to procure sufficient gas to meet the requirements of the Osprey Project?**

A: Calpine East Fuels may purchase natural gas for the Osprey Project from any other party if gas supply is temporarily unavailable.

Q: **What would happen in the event of an outage on the Gulfstream System?**

A: Upon becoming operational, Gulfstream anticipates connecting the Gulfstream System to the Florida Gas Transmission ("FGT") Pipeline System. In the event of an outage, Calpine East Fuels may purchase natural gas supply from the FGT system.

Q: **What would happen to the Osprey Project if construction of the Gulfstream System is delayed or if the Gulfstream System**

is not constructed?

A: Calpine Eastern is confident that the Gulfstream System will be constructed. The Osprey Project and others like it provide a primary impetus for the development and construction of a second natural gas pipeline in Peninsular Florida, in that these projects will be major and significant customers. Having a second natural gas pipeline available in Peninsular Florida will help avoid a serious power disruption if the State's existing gas transportation system is interrupted, such as occurred when a lightning strike at the FGT compressor station near Perry, Florida, caused gas supply problems in August, 1998.

While Calpine Eastern is fully confident of the Gulfstream System's ultimate success, it could obtain natural gas transportation from an alternative source if necessary.

Q: Does this conclude your direct testimony?

A: Yes.

MS. KIESLING: Calpine's last witness is Richard A. Zwolak. I have several, I guess, corrections to the direct testimony. We previously filed a supplemental filing with substitute pages for Pages 12, 14, and 15. And I have a copy for the court reporter that has those pages inserted.

Essentially, those changes simply bring up to date the current situation such as that the City of Auburndale's Comprehensive Plan was amended on January 8th, 2001, so we updated it to reflect that.

We also updated it to reflect that the Central Florida Regional Planning Council has found the proposal consistent with their Strategic Regional Policy Plan, and that on February 21st, the Auburndale Planning Commission found it consistent; that's Page 14.

And on Page 15, the change, again, reflects consistency with current events. Additionally, in that supplemental filing, there were two amendments by Mr. Zwolak to the Volume 2 of the amended exhibits.

Page 46, which will be inserted into the amended exhibits Volume 2, reflects that the land use hearing has occurred, and some other changes such as that.

And then Pages 47, 48, and 49 simply bring up to date the schedule for this project in light of a little slippage that has occurred up to this point. So those

changes will be reflected in Volume 2. With that, we would ask that the direct testimony of Richard A. Zwolak as amended be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show the testimony of Mr. Zwolak entered into the record as though read.

MS. KIESLING: And I would also ask that the exhibit attached to that testimony, RAZ-1, be given a composite number.

CHAIRMAN JACOBS: That is Composite Exhibit 11.

(Exhibit 11 marked for identification.)

MS. KIESLING: And we would move the admission of Composite Exhibit 11.

CHAIRMAN JACOBS: Without objection, show Exhibit 11 is admitted.

(Exhibit 11 admitted into the record.)

MS. KIESLING: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: JOINT PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE, INC. AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

DIRECT TESTIMONY OF RICHARD A. ZWOLAK, AICP

Q. Please state your name and business address.

A: My name is Richard A. Zwolak, and my business address is 5405 West Cypress Street, Suite 215, Tampa, Florida 33607.

Q: By whom are you employed and in what position?

A: I am employed by Golder Associates, Inc. ("Golder") as Director of Environmental Planning.

Q: Please describe Golder Associates Inc., and its business.

A: Golder is an international environmental and engineering firm providing services to many public agencies and private businesses, including the electric power industry.

Q: Please describe your duties with Golder.

A: I am responsible for managing projects, providing environmental planning services, and ensuring that Golder has the appropriate technical expertise to assist electric power companies to develop, construct, and operate power plants.

DIRECT TESTIMONY OF RICHARD A. ZWOLAK, AICP

QUALIFICATIONS AND EXPERIENCE

Q: **Please summarize your educational background and experience.**

A: I received my Bachelor of Arts degree in 1976 and a Master of Arts degree in 1979, both in Geography from the University of South Florida. From 1978 to 1979, I was a Planning Research Assistant for Hillsborough County and from 1979 to 1985 I was a Senior Associate Scientist with Environmental Science and Engineering, Inc., a subsidiary of Reynolds, Smith and Hills. Also at Reynolds, Smith and Hills, I was the Environmental Planning Department Head from 1985 to 1988 and the Planning Director for 1988 and 1989. I joined KBN Engineering and Applied Sciences in 1989 and served as the Principal Environmental Planner until 1996. KBN became part of Golder Associates, Inc., in 1996 and I have been in my current position since then. During the last 20 years, I have worked on a wide variety of environmental projects and studies across the United States and in several foreign countries. I have conducted more than 200 environmental studies. I have been responsible for the regulatory work associated with siting twenty electric power plants (9 of them in Florida) and obtaining numerous air, land and water resource permits and approvals. The clients I have worked with include governmental agencies, industrial companies, and power companies, some of which are investor-owned utilities in

Florida.

Q: What is your experience in power plant siting and licensing?

A: As I just mentioned, my experience in this area is extensive. I have worked on power plant siting, licensing, and permitting projects for much of my career, and have worked on projects located in many states within the United States and a number of foreign countries. For example, I was the Land Use Discipline Manager for Seminole Electric's 660 MW combined-cycle unit and an expansion to add a third unit. I had land use discipline responsibilities for Florida Power & Light Company's Lauderdale Repowering Project, for Florida Crushed Stone Company's coal-fired project, for Mid-South Utilities' Grand Bahamas Island Power Plant, for Potomac Electric Power Company's Dickerson Plant, for Atlantic City Electric Company's 290 MW coal-fired generating station, and for Soyland Power Cooperative's Compressed Air Energy Storage System.

I also have been the Land Use Planner responsible for socioeconomic and impact analyses for two Site Certification Applications filed by Florida Power Corporation. I had similar responsibilities for Tampa Electric Company's site selection study for 3200 MW of capacity in west-central Florida. Finally, I have been the Task or Project Manager

for seven other generating projects as more fully described in my resume', which is attached to my testimony and identified as Exhibit _____ RAZ-1.

In addition to these generating projects, I have been Task Manager or Project Manager for thirteen transmission projects, including TECO Power Services and Seminole Electric Cooperative's Hardee Power Station Site Certification, two 230kV transmission line projects for Florida Power Corporation, Transmission Line Post-Certification activities for Florida Power & Light, a Liquid Fuel Pipeline Corridor for TECO Power Services, and the Florida-Georgia 500kV Transmission Line Siting Study for Florida Power Corporation.

In the projects conducted in the past few years, I have been responsible for socioeconomic, land use, environmental, water resource, ecological, archaeological, threatened and endangered species, and land use compatibility studies and surveys.

I have performed similar functions on highway projects and airport projects.

Further, I have provided similar expertise to governmental agencies in various projects, including benefit-cost analyses for the Green Swamp for the Southwest Florida Water Management District ("SWFWMD"), the Myakka Wild and Scenic River Management Plan for the Florida Division of

Natural Resources, Hazardous Waste Management Plans for the Tampa Bay Regional Planning Council, the Hazardous Waste Transfer Facility Site Selection for the West Florida Regional Planning Council, the Dredged Material Disposal Siting Study for the Jacksonville Port Authority, the Halifax Harbor Marina ADA/DRI for the City of Daytona Beach, Florida, and numerous Post Office Site Selection and Environmental Assessment reports for the U.S. Postal Service.

Finally, I have provided land and environmental planning, feasibility studies, and permitting for several private land development projects.

Q: Have you previously testified before regulatory authorities or courts?

A: Yes, I have. I have provided expert testimony in one proceeding before the Florida Public Service Commission, several proceedings under the Power Plant Siting Act, a proceeding under the Transmission Line Siting Act, and general and individual permit administrative hearings. I have also provided expert testimony in Circuit Court.

Q: What are your responsibilities with respect to the electrical power plant project that is the subject of this proceeding?

A: I am Golder's project manager, responsible to Calpine for all

aspects of the licensing efforts for the Osprey Energy Center Project ("Osprey Project" or the "Project") that have been assigned to Golder, including the entire Site Certification Application. My duties include:

- Day-to-day management of technical, budgetary, and scheduling aspects of the Project.
- Providing overall technical leadership.
- Coordination of Golder's work activities and the preparation of all work products.

I work closely with the project engineering team from Calpine in identifying and addressing environmental issues associated with the Project.

Q: Do you hold any professional certification or registration?

A: Yes, I am a certified planner with the American Institute of Certified Planners, the only recognized professional certification available to planning professionals.

Q: Are you sponsoring any exhibits to your testimony?

A: Yes. I am sponsoring Composite Exhibit _____ (RAZ-1), my resume'.

Q: Are you sponsoring any of the Exhibits to the Joint Petition for Determination of Need filed in this case?

A: Yes. In Volume II of Exhibits to the Joint Petition for Determination of Need for the Osprey Project, I am sponsoring Figures II-2 through II-5, II-7 through II-9, II-16, and II-17, and Tables II-2, II-3, and II-16, as well as the text that accompanies those figures and tables.

THE OSPREY ENERGY CENTER - SITE EVALUATION

Q: Have you prepared an analysis of the proposed site for the Osprey Project?

A: Yes, I have prepared an analysis of the proposed Project site that is reflected in the Site Certification Application that was filed on March 16, 2000. Golder Associates, including me as Project Manager and several other professional planners, environmental scientists, and engineers, is responsible for the entire Site Certification Application. The Site Certification Application is considerably more detailed than any analysis needed for this need determination proceeding. I have not attached the Site Certification Application as an exhibit because it is quite voluminous, it is already publicly available, and it has been filed with the FPSC in accordance with the Power Plant Siting Act.

Q: Please describe the scope of Golder's site and environmental analyses.

A: As part of the licensing proceeding, Golder had to characterize the site and surrounding area; and characterize the Project's conceptual features, especially discharges and emissions. We have also analyzed the Project's anticipated environmental impacts and assessed the viability of the site selected for the proposed Project.

Q: What sources of information did you consult in gathering information for Golder's analysis?

A: My project team and I have consulted a variety of publicly available data and information concerning the site and its surroundings, including air quality monitoring data, information on site geology and hydrogeology, and information on land use, to cite a few examples. In addition, the Golder project team has completed several field studies of its own, including a thorough characterization of the site's ecological resources and a monitoring program to determine existing noise levels.

Q: What are the main components of the analyses contained in the Site Certification Application?

A: The key features of the Site Certification Application are analyses of the site and surrounding areas, the Project's air emissions, the water supply sources and the water discharges,

the impacts of groundwater withdrawals, stormwater management, traffic, public services, zoning and comprehensive land use plan designations, land use compatibility, noise, economic benefits, and environmental benefits.

Q: What did Golder find generally about the suitability of this site for the Osprey Energy Center?

A: Golder has found that the proposed site is well-suited for its proposed use as the Osprey Energy Center. Through the use of modern, state-of-the-art generation technology and clean natural gas fuel, air quality impacts will be minimal, and no sensitive environmental resources will be noticeably affected.

Q: Describe the site and surrounding area.

A: The Osprey Energy Center will be built on 19.5 acres of vacant land that were used in the past as an orange grove, but now are neglected and overgrown. The site does not contain any water bodies, wetlands, significant wildlife habitat, threatened or endangered species, or known historic or archaeological resources. The site is not within a 100-year floodplain. The construction and operation of the Osprey Project will not adversely affect any natural or

biological resources on the site. The site is located in an area that has been developed over the years by predominantly industrial and commercial activities. The site is bordered on the east by the Auburndale Power Plant (a 150 MW cogeneration facility) and Tampa Electric Company's Recker Substation. Citrus processing plants and other industrial facilities are east of the Auburndale Power Plant. The site is bordered on the south by Recker Highway and on the north by West Derby Avenue. There are several commercial businesses and a few houses along these two roadways in the vicinity of the site. A cemetery is located along the western border of the site.

Q: What are the major findings of your analysis?

A: The major findings of Golder's analysis of the site address air resources, water resources, ecology, and land use and socioeconomic aspects of the site and Project.

Air Emissions

The Osprey Energy Center will use the Best Available Control Technology to minimize the facility's airborne emissions. Emissions of nitrogen oxides ("NO_x") will be reduced to very low levels (3.5 ppmvd) through the use of modern dry low-NO_x combustion technology and a selective catalytic reduction ("SCR") system. Emissions of other pollutants also will be

reduced to very low levels by using clean-burning natural gas and advanced combustion turbines.

The Project's impacts on ambient air quality will be minimal. The Project will not cause or contribute to any violations of state or national ambient air quality standards ("AAQS"), or any Class I or II increments for the prevention of significant deterioration ("PSD") of air quality. Based on Environmental Protection Agency's and Florida Department of Environmental Protection's criteria, the Project's impacts are insignificant.

Water Resources and Discharges

The current proposed water use plan anticipates use of treated wastewater to be pumped from the City's Allred Wastewater Treatment Plant to the Osprey Energy Center for reuse. The Project will use all the reclaimed water that this treatment plant can provide while maintaining technical and economic feasibility. The supply of reclaimed water is estimated to be approximately 800,000 gallons per day ("gpd") from the City's Allred Wastewater Treatment Plant when the Project commences operation and is anticipated to grow in the future. The use of reclaimed water will minimize use of groundwater and will potentially reduce disposal of reclaimed water by the City in Lake Lena Run, a nearby surface water. The Project will implement water conservation measures and

will recycle water to the greatest extent possible, but the Project will still need approximately 3.55 mgd of water on an annual average basis. The additional water needs will be met from three new on-site wells (2 active; 1 standby). The peak daily water consumption is projected to be 4.79 mgd.

Based on the current plan to use .8 mgd of reclaimed water, the project will withdraw approximately 2.75 mgd (annual average) of ground water initially, but will likely decrease that withdrawal rate as the supply of reclaimed water increases. When .8 mgd of reclaimed water is used, the peak withdrawal will be approximately 3.99 mgd.

There will not be any on-site discharges of industrial or domestic wastewater to any surface or ground water. All the wastewater from the plant will be sent by pipeline to the City of Auburndale's wastewater treatment facilities for disposal.

The Project's use of groundwater will not adversely affect wetlands, surface waters, or existing legal uses of water. A numerical computer model, Visual MODFLOW, was used to evaluate several different operating scenarios. That analysis demonstrates that the Project's groundwater withdrawals will cause a drawdown at the site boundary of only 0.36 feet in the surficial aquifer and only 2.8 feet in the Upper Floridan aquifer. The impacts are well within the

range allowed by the SWFWMD.

The stormwater management plan for the Osprey Energy Center has been designed to comply with all of the applicable requirements of the SWFWMD, the Florida Department of Environmental Protection ("FDEP"), and the City of Auburndale. That plan calls for stormwater to be collected, routed to and treated in detention basins prior to discharge into drainage swales along West Derby Avenue and Recker Highway. These stormwater drainage and discharge patterns will mimic current conditions.

Ecology

The ecology of the Project site is characterized by vegetative communities consisting of a non-producing citrus grove and undeveloped urban land. The grove is comprised of orange trees which are overgrown with weedy species. No aquatic resources exist on-site. Disturbed areas found on-site include roadways, electrical transmission lines, and an open area.

Flora and fauna found on-site are typical of central Florida community types. No federally-listed or state-listed (as threatened or endangered) plant species were found during field surveys. No wildlife species listed as threatened or endangered by the Florida Fish and Wildlife Commission ("FFWC") or the United States Fish and Wildlife Service

("USFWS") were found on-site, although it is possible some species may forage on or traverse portions of the site. No areas characterized as ecologically unique or sensitive are found on-site. In summary, the Project will not have significant ecological effects on the site or the region.

Land Use and Socioeconomics

The proposed site is located in an incorporated portion of Polk County. The only local government comprehensive plan applicable to the Osprey Energy Center is the City of Auburndale Comprehensive Plan, as adopted on March 18, 1991 and last amended on January 8, 2001. A Future Land Use Map amendment for the City of Auburndale Comprehensive Plan was sent to the Department of Community Affairs ("DCA") to request that the proposed site be designated as Future Land Use category Business Park Centers. The DCA found the proposal in compliance with Ch. 163.3184, 163.3187 and 163.3189, F.S. Central Florida Regional Planning Council found the proposal consistent with their Strategic Regional Policy Plan. On February 21, 2000, the Auburndale Planning Commission and the City Commission found the Osprey Project to be consistent and in compliance with the City of Auburndale Comprehensive Plan and land use designation of Business Park Centers.

Surrounding and nearby land uses are the adjacent Auburndale Power Plant, the City of Auburndale's wastewater treatment facilities, a Cutrale citrus processing plant, a Florida Distillers distillery, and another citrus processing plant owned by SFE Citrus Processors, Ltd. Additionally, the

Tampa Electric Company Recker Substation is adjacent to the proposed Osprey Energy Center.

The proposed zoning district for the site is LI-Light Industrial as defined in Chapter 5, Section 5.6.14, Auburndale Land Development Regulations ("LDR"), adopted November 4, 1991. The adjacent gas-fired combined-cycle Auburndale Power Plant has a future land use plan classification of Business Park Centers and is zoned Light Industrial by Polk County. The Light Industrial zoning district from the City of Auburndale is consistent with the Light Industrial zoning district used by Polk County for the adjacent power plant. The designation of the Project site as a Light Industrial zoning district is consistent with the existing zoning patterns and the existing and future land use patterns of the adjacent properties and is suitable for the proposed Project.

The site does not contain any parks, recreation areas, or natural resource areas. The State Division of Historical Resources has concluded that the Project will have no effect on known or potential historical or archaeological resources.

The Project will have a positive effect on local economies. The construction workforce needed for the Project (up to 162 people during the construction period) will mean more employment opportunities and more direct and indirect

economic expenditures. Upon completion, the Project will provide an economic and reliable source of clean energy for Florida and provide the city and county with tax revenues. No significant impacts to existing infrastructure or essential services are anticipated due to the relatively small permanent workforce (approximately 25 full-time employees) required for plant operation.

While there may be a temporary increase in traffic on local roads during construction of the Osprey Project, the roads will continue to operate at acceptable levels. The Project will not cause significant impacts on traffic or public services.

The Project will include sophisticated noise suppression techniques and an enclosed building to reduce impacts on adjacent land use. The Project will comply with a variance from the City's current noise standards, which are presently being revised.

In summary, the Project will represent a clean and consistent land use compatible with the site vicinity and provide social and economic benefits with minimal impact to the residents of Polk County.

Q: What are the direct economic benefits of the Project?

A: The Project's direct economic benefits include between $0.8

and $1.16 million annually in additional ad valorem tax revenue to Polk County, between $0.9 and $1.3 million annually in additional ad valorem tax revenue to the Polk County School district, and approximately $500,000 per year to the City of Auburndale in ad valorem taxes and municipal service fees. The Project will support approximately 25 new permanent jobs with an average salary of $40,000, plus benefits, with a total payroll of approximately $1,000,000 annually and approximately 162 construction jobs and construction wages of approximately $13 million over two years.

Q: What are the environmental benefits of the Project?

A: The environmental benefits to the citizens of Auburndale, Polk County and the State of Florida include funding improvements to the City of Auburndale's wastewater treatment facilities that result in decreased discharges to surface water, increasing available reclaimed water, and enhancing disinfection, and providing a new, clean, cost-effective and energy efficient source of electricity to meet the growing demands for power in Florida. Additionally, the Osprey Project will use less fuel than existing power plants in Florida when producing an equivalent amount of electricity, thereby saving 6.85 billion cubic feet of natural gas and 1.1

million barrels of oil each year (based on my staff's assumptions regarding the current fuel mix). Finally, the Osprey Energy Center will produce less air pollution than existing power plants in Florida when producing the same amount of electricity. By reducing the use of older, less efficient power plants in Florida, the Project will reduce the amount of air pollution associated with power generation in Florida. The Project will likely reduce total combined sulfur dioxide and NO_x emissions by about 20,000 tons per years ("TPY"), including 10,600 TPY of NO_x (assuming displacement of the current mix of oil and gas fired plants, which is about 41 percent and 59 percent, respectively).

Q: Are the savings in fuel and the reductions in emissions that you just quantified consistent with the testimony of Mr. Slater in this case?

A: They are essentially consistent. Any differences are the result of the use of different assumptions.

Q: Do you still agree with the contents of the Site Certification Application?

A: Yes, I do.

Q: What is the licensing schedule for the Osprey Project?

A: The Site Certification Application ("SCA") was filed with the Department of Environmental Protection on March 16, 2000. Project construction is anticipated to begin in 2001, with commercial operation scheduled for the second quarter of 2003.

Q: Do you have a conclusion with respect to the ability of the Osprey Project to obtain all necessary licenses within the time frames described in the licensing schedule?

A: Yes, I do.

Q: What is your conclusion?

A: Based on our analyses, Golder and I have concluded that the site is appropriate for the Osprey Project, that the site can support the Project as proposed, and that the Project as proposed can obtain all necessary licenses and approvals within the times allotted in the licensing schedule.

Q: Does this conclude your direct testimony?

A: Yes, it does.

MR. WRIGHT: Mr. Chairman?

CHAIRMAN JACOBS: Yes.

MR. WRIGHT: Calpine filed as exhibits to the amended joint petition this document identified as Amended Exhibits Volume 2 to the Amended Petition for Determination of Need for the Osprey Energy Center. Through their testimonies, Calpine's witnesses collectively sponsor all portions of this document, including the corrections just noted by Ms. Kiesling to update the status of the environmental permitting processes. I would ask that Calpine's amended exhibits Volume 2 be given an exhibit number for identification, please.

CHAIRMAN JACOBS: That is Composite Exhibit 12, Volume 2 of Calpine's amended exhibits.

(Exhibit 12 marked for identification.)

MR. WRIGHT: And I would move the admission into evidence of Composite Exhibit 12.

CHAIRMAN JACOBS: Without objection, show Exhibit 12 is admitted.

(Exhibit 12 admitted into the record.)

MR. WRIGHT: That concludes Calpine's case.

COMMISSIONER JABER: May I ask a question? I may have missed it. Where is the actual agreement? Have we already identified that?

CHAIRMAN JACOBS: I think he mentioned it was one of the --

MR. WRIGHT: I believe that the agreement in redacted form is part of what has been designated -- Volume 1 to the exhibits what has been designated Composite Exhibit 5, Commissioner Jaber.

COMMISSIONER JABER: Okay. So it's included in Volume 1 of the joint petition is what you're saying?

MR. WRIGHT: Volume 1 of the exhibits to the joint petition, yes, ma'am.

COMMISSIONER JABER: Okay.

CHAIRMAN JACOBS: Very well. That concludes Calpine. Staff.

MS. ISAAC: Staff has one composite exhibit containing the information on the bottom of Page 14 through 15 of the prehearing order, including Calpine and Seminole's responses to Staff's interrogatories from Docket 000442-EI; the late-filed exhibit to the deposition of Garl Zimmerman, Document Number 01316; Late-Filed Exhibit Number 2 to the deposition of Garl Zimmerman; Seminole and Calpine's purchased power agreement, Document Number 00277-01.

CHAIRMAN JACOBS: Are these all composite, or did you want to identify them separately?

MS. ISAAC: We would like them as a composite

exhibit.

CHAIRMAN JACOBS: Okay.

MS. ISAAC: Timothy R. Eves' deposition on January 19th, 2001; Kenneth J. Slater's deposition, January 23rd, 2001; Timothy S. Woodbury's deposition, January 25th, 2001; Garl S. Zimmerman's deposition, January 25th, 2001; and the affidavit of publication of the notice in The Ledger. We would like all of these to be assigned an exhibit number.

CHAIRMAN JACOBS: All right. Show those as Composite Exhibit 13.

(Exhibit 13 marked for identification.)

MS. ISAAC: Staff moves those into evidence.

CHAIRMAN JACOBS: Without objection, show Exhibit 13 as admitted.

(Exhibit 13 admitted into the record.)

MS. ISAAC: Mr. Chairman, I have one more thing to bring up. In the notice, it states that the public has a chance to present testimony if they would like, and this would be an appropriate time to inquire.

CHAIRMAN JACOBS: Very well. Are there any members of the public in attendance that would like to present testimony at this time?

Let the record reflect that no one has come forward. And did we have any requests? Do we have any

written requests?

MS. ISAAC: No, we don't.

CHAIRMAN JACOBS: Very well. Does that take care of your exhibits?

MS. ISAAC: Yes.

CHAIRMAN JACOBS: That concludes the case in chief; is that correct?

MS. ISAAC: Yes. We could bring up the matter of the motion for the expedited decision, which also includes the motion for bench decision.

CHAIRMAN JACOBS: Right.

MS. ISAAC: It was discussed in the prehearing order and the prehearing conference.

CHAIRMAN JACOBS: Commissioners, I have a copy -- do you have copies of that? Any questions -- we don't need to have any discussion from the parties on the motion itself, do we?

MS. ISAAC: If you would like to have the parties speak on this motion, you can ask them to.

CHAIRMAN JACOBS: Is there any need to, Commissioners?

COMMISSIONER DEASON: There's no need on my part.

CHAIRMAN JACOBS: Okay. Very well. Is there a motion on the motion?

COMMISSIONER PALECKI: I would move that the motion be granted, and that the Commission move forward with making a bench decision on this matter.

COMMISSIONER JABER: Second.

CHAIRMAN JACOBS: Been moved and seconded. All in favor say aye.

COMMISSIONER JABER: Aye.

COMMISSIONER PALECKI: Aye.

COMMISSIONER DEASON: Aye.

COMMISSIONER BAEZ: Aye.

CHAIRMAN JACOBS: Aye.

Oppose? The motion is granted.

COMMISSIONER JABER: Now, what about the proposed stipulation, Mr. Chairman? Shouldn't we rule on that?

MR. ELIAS: As part of the consideration of the recommendation on the issues, yes. You can take that up first, if you'd like.

COMMISSIONER JABER: I can move that we adopt the stipulation as acceptable, Mr. Chair.

COMMISSIONER PALECKI: I would second that.

CHAIRMAN JACOBS: Very well. I have a motion and second that the proposed stipulation included in the prehearing -- as described, I should say, in the prehearing order be accepted.

COMMISSIONER DEASON: This is Item 10, Page 15 of the prehearing order?

CHAIRMAN JACOBS: Correct. All in favor, aye.

COMMISSIONER JABER: Aye.

COMMISSIONER DEASON: Aye.

COMMISSIONER PALECKI: Aye.

COMMISSIONER BAEZ: Aye.

CHAIRMAN JACOBS: Aye.

Oppose? Show that the stipulation is accepted. Then do we now move to discussion from Staff, or are the parties to argue their positions?

MS. ISAAC: Yes. We have a recommendation ready for you.

CHAIRMAN JACOBS: Very well. Proceed.

MS. HARLOW: Staff has prepared an oral recommendation for your consideration today. We are prepared at this time to stipulate on the parties' position on Issues 1 and 8, and pretty much stipulate on Issues 6 and 7 with slight additions.

Our positions on the remaining issues are consistent with those of the parties, but we have added detail; for example, added detail on such things as cost-effectiveness. So I'd like to move on to Issue 2.

CHAIRMAN JACOBS: Any questions, Commissioners, about where we stand on those issues? So with the

exception of the three stipulated issues, all -- you essentially move to adopt the positions that were set out by the parties?

MS. HARLOW: Yes, sir, we would stipulate on Issues 1 and 8 completely. On Issues 6 and 7, we have a slight addition.

CHAIRMAN JACOBS: Okay.

MS. HARLOW: And on the remaining issues, our positions are relatively consistent with those of the parties with added detail.

CHAIRMAN JACOBS: Very well. Proceed.

MS. HARLOW: On Issue 2, it's Staff's position that the output of the proposed Osprey Energy Center is fully committed for use by Florida retail electric customers in compliance with the order in the Duke decision.

Under the purchased power agreement with Seminole, 350 megawatts of capacity is firmly committed to Seminole from the period June 2004 through May 2009. Subject to reopener provisions, the 350 megawatts is also firmly committed to Seminole in five-year increments beginning June 2009 through May 22, 2020. The contract also establishes a notice provision for capacity prior to June 1st, 2004. Further, subject to notice provisions, terms and pricing are established for the capacity over

350 megawatts for the period June 2004 through May 2020.

Staff believes that the firm commitment for 350 megawatts out of the total plant capacity of 529 megawatts is sufficient to meet the requirement that the capacity be fully committed. At deposition, Witness Woodbury stated that in lieu of the contract, Seminole would have built a similar combined cycle unit with the same total capacity to meet its need. Seminole provided sufficient evidence to assert that a self-build option of a nearly identical combined cycle unit was the next most cost-effective option to meet its need.

I'd like to move on to Issue 3, please.

CHAIRMAN JACOBS: Before you do that, questions, Commissioners?

Legal, for the additional, I guess whatever 530 less 350 is, how does that stand in the context of the decision?

MR. ELIAS: Well, first, let's note that Seminole has options on the full output of the plant. Secondly, let's recognize that we recently granted a determination of need where the demonstrated megawatt need the first year was approximately 110 megawatts, recognizing that there were -- that that capacity would be available to serve the retail customers of the utility seeking a determination of need if needed. We think this

situation is analogous.

CHAIRMAN JACOBS: And the likelihood is that Seminole and/or one of its Members would grow to utilize that additional capacity?

MR. ELIAS: To the extent that it's not otherwise committed to serving Florida retail customers, it will be available for that purpose.

CHAIRMAN JACOBS: Very well.

MS. HARLOW: I'd just like to add to that, that in 2007 the full capacity of the plant would be needed for reliability reasons.

CHAIRMAN JACOBS: Okay. Thank you.

MS. HARLOW: If we can move on to Issue 3 then. It's Staff's position that the Osprey Energy Center is needed when taking into account Seminole's need for electric system reliability and integrity. According to the prefiled testimony of Seminole Witness Garl Zimmerman, Seminole uses a 15 percent reserve margin as its planning criterion. Witness Zimmerman also testified that Seminole is occasionally required to maintain total reserves which exceed 15 percent due to Seminole's share of operating reserves allocated by the FRCC. Witness Zimmerman testified that Seminole began its analysis of various capacity alternatives by determining reliability need.

Staff reviewed the load forecast for each of the

11 systems comprising Seminole's retail load used in the analysis. Based on this review, Staff believes that Seminole's aggregate load forecasts are based on appropriate forecast models and assumptions, and that the projected megawatt hour summer and winter kW forecast presented in Witness Lawton's Exhibit WTL-1 are reasonable.

In order to meet its reserve margin standard, Seminole has a reliability need beginning in 2004. As depicted in Exhibit Number GSZ-1, if no capacity additions were made, Seminole's reserve margin is 11.6 percent in 2004. Due to load growth and the termination of two purchased power agreements, reserve margin is expected to decline to a negative 14.9 percent in 2009 without the contract in place. In order to maintain a 15 percent reserve margin, this indicates a reliability need of 88 megawatts in 2004, growing to 911 megawatts by 2009.

According to Exhibit GSZ-1, the contract for 350-megawatts firm will satisfy Seminole's reliability need through 2006. The contract also provides Seminole with the option of obtaining additional capacity up to the total plant capacity of 529 megawatts. This additional capacity, along with a portion of the 350-megawatt firm capacity during 2004 through 2006, is not projected to be necessary to meet the reserve criterion of 15 percent.

However, this capacity provides greater assurance that the reserve criterion will be met in the event that peak loads are higher than currently anticipated. This additional capacity also provides Seminole with the flexibility to reduce the use of potentially less economic resources.

And that's our recommendation on Issue 3.

CHAIRMAN JACOBS: Any questions? Very well. We'll just vote on all of these at the end, or, Commissioners, would you rather take them issue by issue?

COMMISSIONER JABER: It doesn't matter.

COMMISSIONER PALECKI: I think all at the end.

CHAIRMAN JACOBS: Okay. Go ahead.

MS. HARLOW: Moving on to Issue 4. It's Staff's position that the Osprey Energy Center is needed, taking into account Seminole's need for adequate electricity at a reasonable cost. Seminole provided sufficient evidence that the purchased power contract with Calpine is the most cost-effective option to meet its need. The contract provides substantial savings over the next most attractive option, a self-build option of a near identical combined cycle unit of similar total capacity.

Confidential information in Exhibit GSZ-5 provides specific savings of the Calpine proposal relative to the next most attractive options over the five-year period beginning in 2004. Seminole also provided evidence

in confidential Late-Filed Exhibit 1 to Witness Zimmerman's deposition that the Calpine contract is less costly than the alternatives in each year of the five-year period. At deposition, Witness Woodbury stated that if the contract with Calpine were not available, Seminole would build a near identical combined cycle unit. Seminole provided sufficient evidence that this self-build option would be the next most cost-effective option to meet its need.

In addition to the reduced cost, as stated by Witness Woodbury at deposition, the Calpine contract provides Seminole with added flexibility over the self-build option. The contract provides 350 megawatts on a firm basis from June 2004 through May 2009. Subject to reopener provisions, this 350 megawatts is also firmly committed in five-year increments through May 22nd, 2020. The contract also provides Seminole with the option to obtain additional capacity up to the full 529 megawatts from the in-service date until May 2020.

The reopener provisions and option to take additional capacity provides Seminole with the flexibility to adjust to meet current market conditions or unexpected demand. Given the uncertainty in the current electric market, as stated by Witness Woodbury at deposition, there is a benefit to Seminole of diversifying its supply-side

options to include ownership, both long-term and short-term contracts.

CHAIRMAN JACOBS: That's Issue 4. No questions. Okay.

MS. HARLOW: Moving on to Issue 5. It's Staff's position that the purchased power agreement for capacity from the Osprey Center is the most cost-effective alternative available to meet Seminole's needs. According to the testimony of Witness Zimmerman, Seminole used PROMOD IV and PROSCREEN software to simulate the operation of its system over time and calculated the net present value of revenue requirements associated with adding various increments of capacity.

Seminole modeled the present worth revenue requirements of various technologies, including combustion turbines, combined cycles, and pulverized coal units. Pulverized coal units were excluded at an early stage in the evaluation due to the high capacity factor needed to make the units cost-effective. This would require Seminole to rely on off-system sales to justify a pulverized coal unit. Witness Woodbury also testified at deposition that pulverized coal units were excluded due to the long construction lead times necessary. The outcome of this initial stage of the analysis was that a combined cycle unit would be the best self-build option to meet

Seminole's need.

After Seminole determined the reliability need and analyzed the impact of various technologies, a request for proposals was issued. The RFP requested both demand and supply-side options to meet the need, and stated that proposals in the range of 160 to 600 megawatts would be considered. Seminole received 14 supply-side proposals and response. Seminole evaluated the present worth revenue requirements of these proposals, the purchased power agreement with Calpine, and a self-build option of a combined cycle unit.

Seminole's analysis shows that the Calpine purchased power agreement is the most cost-effective option for a five-year period beginning in 2004 and provides substantial savings over the next most cost-effective option, Seminole's self-build proposal.

Confidential information in Exhibit GSZ-5 provides the total savings of the Calpine proposal relative to the self-build options and the next best alternatives over the five-year period. Confidential information in Late-Filed Exhibit 1 of Witness Zimmerman's deposition shows that the Calpine contract is more cost-effective than the next most attractive options in each year of the five-year contract period.

The fuel price forecast used by Seminole in its

cost-effectiveness analysis are reasonable. Further, as stated by Witness Zimmerman at deposition, all the proposals in the final analysis were natural gas-fired. Therefore, changes in the natural gas forecast would not significantly affect the cost-effectiveness rankings of the proposals.

Staff reviewed the financial assumptions used in Seminole's cost-effectiveness analysis and found them to be reasonable as well. The 5.85 percent discount rate used is reasonable because it is based on Seminole's cost of long-term capital as guaranteed by the Rural Utilities Services. The 2.7 percent inflation rate is reasonable based on rates used in other need determinations and based on Calpine's original analysis using 3 percent.

In summary, Staff believes the Calpine purchased power contract is the most cost-effective alternative available to meet Seminole's need.

CHAIRMAN JACOBS: Commissioners, any questions? You made one point, but it really goes to the next issue. You indicate that your analysis of the gas market wouldn't have an impact on this. Given the spikes that we have seen recently, you don't expect that the downward trend would be anywhere significant to affect any of these calculations?

MS. HARLOW: According to our analysis, we

agreed with Seminole's analysis that early in the -- early in the analysis they knocked out the coal, as Witness Woodbury stated earlier in response to your question, due to long lead times and also due to the high capacity factor that would be required.

They didn't receive any DSM proposals, as he stated in response to their RFP, and we were okay with the amount of DSM that they're using at this point in time. So the remaining proposals that they examined were all natural gas-fired. If you take proposals that all have the same type of fuel and you adjust the fuel and the sensitivity, it's very unlikely that it would change the ranking of those.

CHAIRMAN JACOBS: Okay. Very well.

MS. HARLOW: Continuing with Issue 6. We're prepared to stipulate to the position of the parties, except we'd like to add the following language: Neither Seminole nor its Members are currently subject to the conservation goals requirements of FEECA. However, Seminole's Members offer various demand-side management and conservation programs. According to the testimony of Garl Zimmerman, Seminole's projections of its power supply needs reflect the effect of the Members conservation and demand-side management programs.

CHAIRMAN JACOBS: Very well. No questions.

MS. HARLOW: Moving on to Issue 7. It's Staff's position that we would like to stipulate to the parties' position with the added language: Calpine provided information confirming that the Gulfstream permitting process is on schedule and is, therefore, expected at this time to be operational prior to the in-service date of the Osprey Energy Center. Further, the plant location is in close proximity to the FGT system which could provide an additional source of natural gas transportation.

CHAIRMAN JACOBS: Very well. Commissioners, any questions? Next issue.

MS. HARLOW: As I said earlier, we were prepared to stipulate to the language in the parties' position in Issue 8.

CHAIRMAN JACOBS: Very well. Any questions? Go ahead. Issue 9.

MS. HARLOW: And finally, it's Staff's position in Issue 9 that the Commission should grant Seminole's and Calpine's petition to determine the need for the Osprey Energy Center. Seminole's purchased power agreement with Calpine is the most cost-effective option available to meet Seminole's capacity needs beginning in 2004. There are no cost-effective conservation or demand-side measures available to offset Seminole's need, and the purchased power agreement is the lowest cost supply-side option

available.

Staff believes that the need order is specific to the Osprey Project with the understanding that Seminole and Calpine are co-applicants. Staff's analysis has focussed on the cost-effectiveness of the purchased power agreement from Seminole's perspective. As mentioned previously, there are conditions subsequent to the Commission's decision which may allow Seminole to terminate the purchased power agreement. In light of this, Staff believes that Calpine should report on the status of the purchased power agreement with Seminole in Calpine's annual Ten-Year Site Plan.

And that concludes our oral recommendation.

CHAIRMAN JACOBS: Commissioners, questions?

COMMISSIONER JABER: Yes. The added requirement is that Calpine report on the status of the Ten-Year Site Plan. To the degree there are any changes, what is it we can do? Or slippage, I guess.

MR. ELIAS: It's more in the nature of information, to the extent that we have to exercise our authority under the Grid Bill to require resources be added or take some other action that's within the Commission's jurisdiction. This is just a trigger. I mean, it's not specific to this project. It's just so that we can keep tabs on our responsibility to make sure

that there's an adequate supply of electricity.

COMMISSIONER BAEZ: Mr. Elias, do independent power producers normally file Ten-Year Site Plans?

MR. ELIAS: Seminole has agreed in the stipulation to --

COMMISSIONER BAEZ: Has agreed for Calpine?

MR. ELIAS: For Calpine to file one.

COMMISSIONER BAEZ: So that's not a normal occurrence?

MR. ELIAS: The question of whether other independent power producers are required to file Ten-Year Site Plans is one that has not been answered affirmatively or negatively at this point in time.

COMMISSIONER BAEZ: Thank you.

CHAIRMAN JACOBS: Any other questions? Do you have a motion?

COMMISSIONER JABER: Didn't the stipulation speak to that, Mr. Elias?

MR. ELIAS: Yes.

CHAIRMAN JACOBS: Yes, that was the stipulation.

COMMISSIONER JABER: So the stipulation is that Calpine has agreed to file --

MR. ELIAS: As to Calpine, yes. The question was a little broader than that. It went to all independent power producers.

CHAIRMAN JACOBS: No other questions? A motion?

COMMISSIONER DEASON: Mr. Chairman, I can make a motion.

CHAIRMAN JACOBS: Very well.

COMMISSIONER DEASON: First of all, before I make the motion, I want to congratulate the parties on the process that they entered into and the results that they obtained and the very thorough review by our Staff. And having said that, I can move Staff's recommendation in its entirety.

COMMISSIONER PALECKI: Second.

CHAIRMAN JACOBS: Been moved and seconded that Staff's recommendation, Issues 1 through 9, be accepted. All in favor, aye.

COMMISSIONER DEASON: Aye.

COMMISSIONER JABER: Aye.

COMMISSIONER BAEZ: Aye.

COMMISSIONER PALECKI: Aye.

CHAIRMAN JACOBS: Aye.

Opposed? Show Staff's recommendation is approved.

MS. ISAAC: Mr. Chairman, we also need to rule on a close-the-docket issue. If you're going to close the docket, can you make a motion on that?

CHAIRMAN JACOBS: Without objection, show that

the Staff recommendation to close the docket is approved.

I, too, would like to congratulate the parties. This application came at a particularly important time, and I was -- it was very gratifying to see the cooperation that occurred to work through the issues that were quite challenging at the point in time this was filed. So I think this is worthy of note, and we look forward to seeing this plant come up.

Anything else to come before the Commission today?

MS. ISAAC: No.

CHAIRMAN JACOBS: Then this hearing is adjourned. Thank you.

(Hearing concluded at 10:40 a.m.)

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official Commission Reporter, do hereby certify that the Hearing in Docket No. 001748-EC was heard by the Florida Public Service Commission at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 126 pages, Volume 2 constitutes a true transcription of my notes of said proceedings and the insertion of the prescribed prefiled testimony of the witnesses.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorneys or counsel connected with the action, nor am I financially interested in the action.

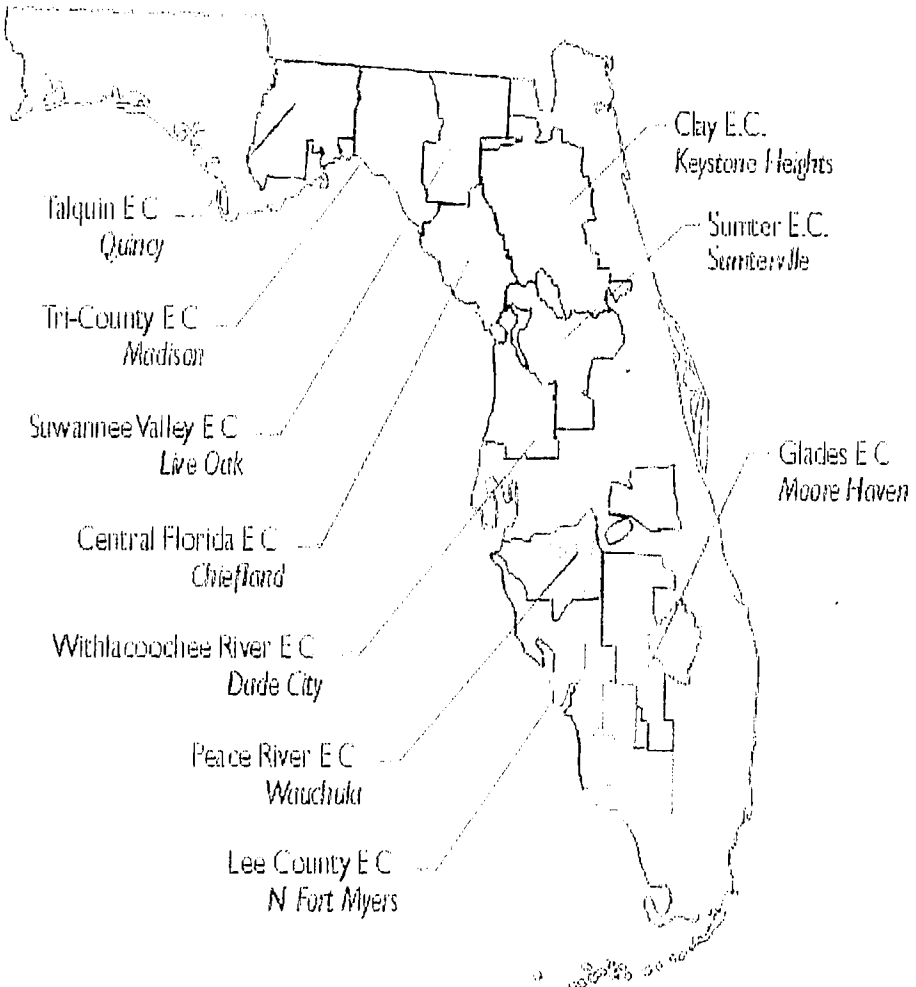
DATED THIS 14th DAY OF FEBRUARY, 2001.

Tricia DeMarte

TRICIA DeMARTE
FPSC Official Commission Reporter
(850) 413-6736

Docket No. _____
Witness: Timothy S. Woodbury
Exhibit No. _____ (TSW-1)

Seminole's Member Distribution Cooperatives



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001748-EC EXHIBIT NO. 1
COMPANY/
WITNESS: Woodbury
DATE 2-13-01

DOCUMENT NUMBER-DATE
00437 JAN 10 01
FPSC-RECORDS/REPORTING

SEMINOLE'S YEAR ROUND PURCHASED POWER RESOURCES

Resource	MW	Term
FPC Partial Requirements (FPC supplies Seminole's load requirements in the FPC control area that are above an annually defined commitment level (1,327 MW for 2001) that is supplied by Seminole resources.)	Load following- (713 MW peak 2001 projected)	Initial term through 2013[1]
1995 FPC Agreement - Structured System Capacity System Peaking Capacity (305 MW in 2000, 455 MW in 2001 $ 300 NW in 2002) System Intermediate Capacity	 300 up to 455 150	 Through December 31, 2001 Through December 31, 2002 Through December 31, 2013[2]
TECO Power Service Agreement (Entitlement to 145 MW (with annual MWh limitations) of capacity from Tampa Electric's Big Bend Unit No. 4 facility.)	145	Through December 31, 2002
TECO Power Service Agreement (Provides backup power for Seminole's Units 1 & 2 and Seminole's Crystal River 3 entitlement)	362	Through December 31, 2012
Orlando Utilities Commission Capacity (125 MW through 12/31/00 then 75 MW)	75	Through May 31, 2004
JEA Capacity Purchase	63	Through May 21, 2004
Lee County Resource Recovery Facility	35	Initial term through 11/30/04[3]
Reliant Energy Power Generation Capacity	364	12/01/01 through 12/31/06
Constellation Power Development Capacity (364 MW for 12/01/02 through 5/01/03 period)	546	12/01/02 through 12/31/09

[1]The partial requirements service from FPC may be terminated by either party giving notice in any calendar year after calendar year 2007 that it wishes to terminate the agreement at end of the fifth future calendar year (i.e., notice in 2008 to terminate at end of 2013).

[2]FPC System Intermediate Capacity may be terminated or reduced before 12/31/13 by Seminole upon three years' notice to FPC.

[3]The Lee County Resource Recovery Agreement's obligations will continue through 12/31/15 with provisions to alter the arrangement after the initial period.

SEMINOLE'S SEASONAL PURCHASED POWER RESOURCES

Resource	MW	Term
Morgan Stanley Capital Group, Inc.	100	December 1, 2000 through February 28, 2001
City of Tallahassee	75	May 200 through November 30, 2001
City of Tallahassee	50	December 1, 2000 through March 31, 2001

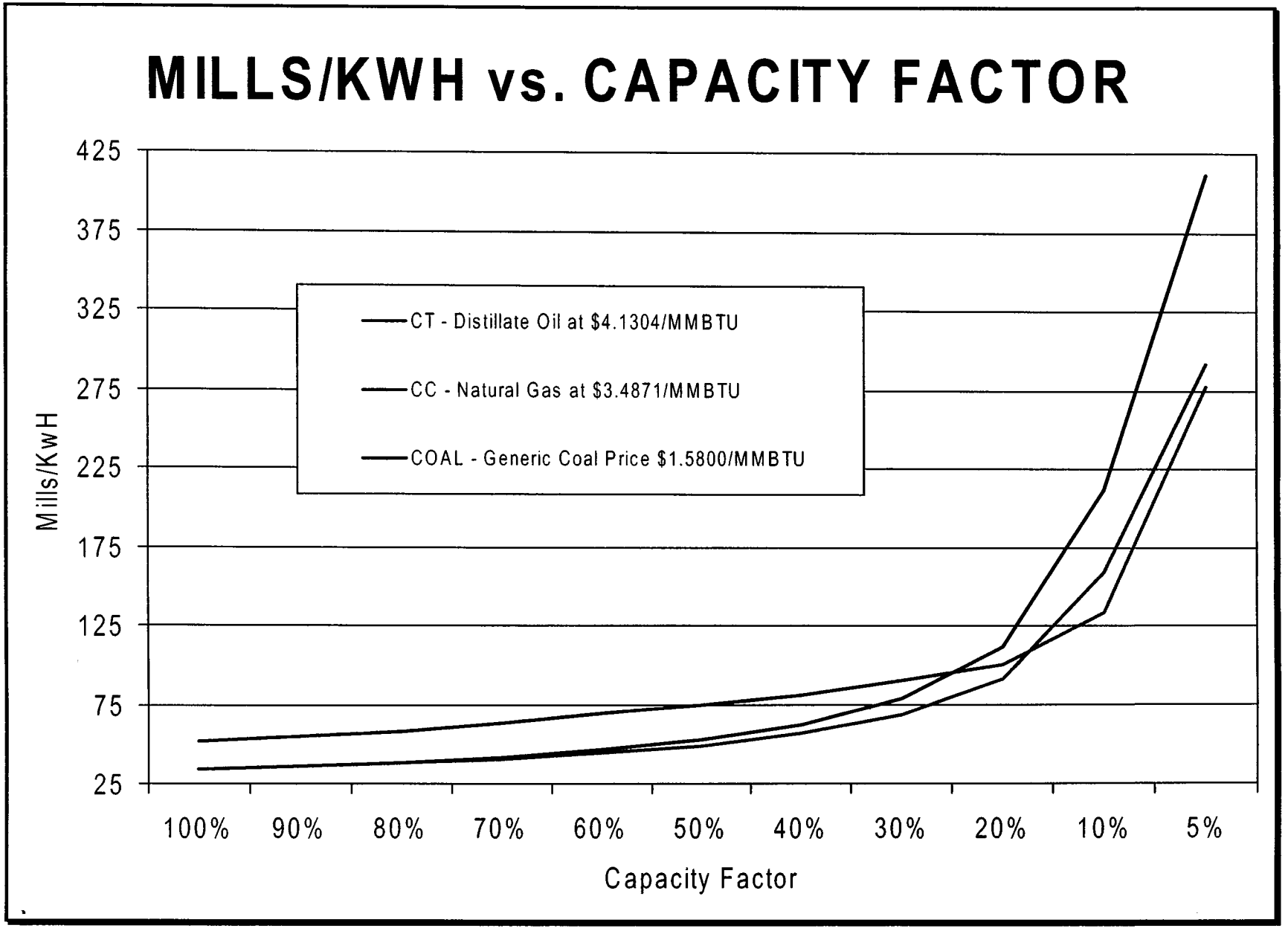
Docket No. _____
Witness: Garl S. Zimmerman
Exhibit No. ___ (GSZ-1)

Table 2

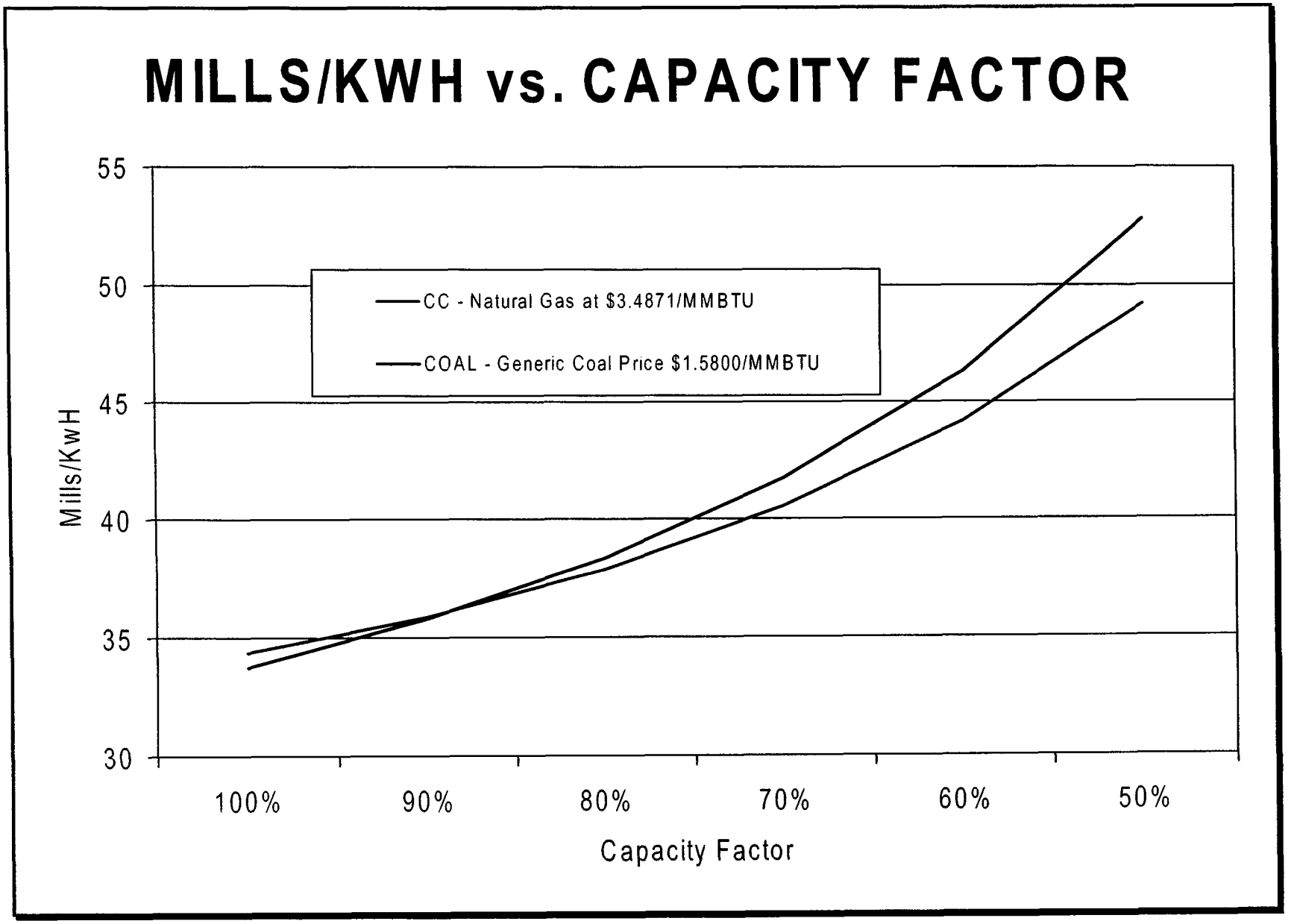
Summer Reserve Margin (No Addition)

Year	Capacity (MW)	Demand (MW)	Reserve Margin (%)
2004	2897	2596	11.6
2005	2897	2682	8.0
2006	2897	2738	5.8
2007	2591	2838	-8.7
2008	2591	2942	-11.9
2009	2591	3045	-14.9

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001748-EC EXHIBIT NO 2
COMPANY/
WITNESS: Zimmerman / Demoracle
DATE 2-12-01



Docket No. _____
Witness: Garl S. Zimmerman
Exhibit No. ____ (GSZ-2)
Page 1of 2



Docket No. _____
Witness: Garl S. Zimmerman
Exhibit No. ____ (GSZ-2)
Page 2 of 2

Seminole Electric
COOPERATIVE, INC.
IN PARTNERSHIP WITH THOSE WE SERVE

July 6, 2000

RFP No. IP 2004 - Request for Firm Year-Round Intermediate and Peaking Capacity

Purpose

Seminole Electric Cooperative, Inc. is seeking proposals from qualified and eligible bidders to meet portions of its power supply requirements, beginning in **2004.** Proposals for intermediate and peaking capacity will be considered. Proposals providing demand side options will also be considered for evaluation. Seminole favors short-term proposals in the range of two (2) to five (5) years' duration but will consider attractive longer-term proposals. Joint ownership proposals will also be considered. Seminole is primarily interested in proposals that will allow maximum control and the flexibility to use resources for any purpose.

Proposals must offer "firm" capacity from identified generating resources. This RFP is open to all parties, including, but not limited to: independent power producers, exempt wholesale generators, qualifying facilities (under PURPA), power marketers, and utilities.

Description of Capacity Requirements

Seminole has a **minimum** need of 160 MW of intermediate type capacity, beginning May 1, 2004. In addition, Seminole will evaluate an **additional** 440 MW of capacity to potentially displace existing power supply arrangements, beginning January 1, 2004. In total, Seminole is seeking proposals for intermediate and peaking capacity needs, in the following amounts, not to exceed a total of 600 MW:

Between 160 and 400 MW of intermediate type capacity
Up to 350 MW of peaking type capacity.

Proposals may be for less than the amounts shown above. Offers of capacity and energy may be from one or more resources. Such resources must be suitable to meet Seminole's firm load and/or reserve obligations (i.e., Seminole must have first-call priority for shared resources).

Seminole will **not** consider proposals that describe non-firm capacity.

Scheduling

Preference will be given to proposals that maximize scheduling flexibility, including real-time control capability, such as automatic generation control (AGC).

Delivery to the Seminole System

Seminole currently serves portions of its load directly through its own transmission system or through the transmission systems of Florida Power Corporation (FPC) or Florida Power and Light Company (FPL). Therefore, Seminole will consider offers that deliver capacity and energy to the Seminole, FPC or FPL transmission systems. Wheeling and interconnection arrangements and costs to deliver the capacity and energy to the Seminole, FPC or FPL transmission system delivery points are the responsibility of the bidder. Prices quoted must be based upon net capacity delivered to the transmission tie. All proposals must identify any wheeling and interconnection agreements with third parties that are required to deliver the power and energy to Seminole. Seminole would expect transmission arrangements to deliver the offered capacity to be firm. If the bidder desires to achieve the equivalence of firm delivered capacity by other means, (e.g., alternative generating resources), then a thorough explanation of such alternative arrangements should be provided.

Pricing

All price quotes must be communicated on the attached forms. Capacity prices should be quoted in the form of a flat amount per month or nominal dollars per kilowatt-month ($/kW-month). If capacity price is quoted on the basis of $/kW-month, the kW to which the capacity price is applied must be stated. Non-fuel energy pricing should be bid in nominal dollars or mills per kilowatt-hour. The proposal shall specify the methodology for determining fuel billings.

Prices quoted must include all costs that Seminole would be expected to pay for the capacity and energy proposed.

Other Terms and Conditions

Each proposal must comply with all applicable federal and state laws. All permits, licenses, fees, emissions allowances, and environmental requirements are the responsibility of the bidder for the entire term of each proposal. Proposals must include detailed descriptions of guarantees and related remedies for failure to perform. Each proposal must provide guarantees for in-service dates, contract capacity, heat rates and availability. Operational characteristics such as (but not limited to) capacity limitations, ramp limitations, maximum or minimum run-times, maximum or minimum down-times, fuel limitations, etc., should also be specified. If a resource included in a proposal is not yet in service, a detailed milestone schedule describing major project activities leading up to the commencement date for commercial service should also be provided.

Seminole is currently engaged in negotiations relating to all or a portion of the needs identified in this RFP. Parties involved in those negotiations are not required to submit bids under this RFP and will receive written confirmation of such status. Those negotiations may continue on a parallel path with this bid solicitation.

Reservation of Rights

Seminole reserves the right, without qualification and at its sole discretion, to amend or withdraw this request for offers and to reject any or all proposals or portion of proposals received. Those who submit proposals to Seminole do so without recourse against Seminole for either rejections by Seminole or failure to execute a purchased power agreement for any reason. Seminole also reserves the right to request further information, as necessary, to complete its evaluation of the proposals received.

Procedures for Application

1. A copy of this Request for Proposals, together with supporting application forms, is on the Seminole Electric Cooperative, Inc. web site, "**www.seminole-electric.com**". The link to the Request for Proposals appears on the Seminole home page. The link to the application forms is in the **"Pricing"** section of this RFP.

2. Seminole requires that each bidder pay a non-refundable application fee of five hundred dollars ($500.00) for each proposal submitted. Respondents are requested to submit their proposals via e-mail to the e-mail address below. In addition, an **original proposal, signed by an authorized officer**, plus **four (4) copies** must be mailed. The mailing addresses are:

   By Courier:

   Seminole Electric Cooperative, Inc.
   Attention: Ms. Trudy Novak, Director of Pricing and Bulk Power Contracts
   16313 North Dale Mabry Highway
   Tampa, FL 33618

   By U.S. Mail:

   Seminole Electric Cooperative, Inc.
   Attention: Ms. Trudy Novak, Director of Pricing and Bulk Power Contracts
   P.O.Box 272000
   Tampa, FL 33688-2000

   By E-Mail:

   "rfpresponse@seminole-electric.com".

3. All proposals must arrive via e-mail by **August 31, 2000**. Paper copies must arrive at Seminole's Tampa offices by the same date. Seminole is not obliged to contact bidders concerning missing or incomplete forms. Only versions of the forms attached to this Request for Proposals may be used to submit proposals.

4. The bidder must designate a contact person with whom Seminole can communicate with questions about the proposal.

5. All offer packages should include any additional information required to support evaluation of the proposal, including a completed Credit Application, which form is included in the attached forms accompanying this RFP. Documents requested in support of the Credit Application must accompany the mailed versions of the proposals.

Confidentiality

Seminole recognizes that certain information contained in proposals submitted may be confidential and, as permitted by applicable law, will treat each proposal in its entirety as confidential. If Seminole is formally requested by any regulatory or judicial authority, including the Rural Utilities Service (RUS), to disclose information with regard to a proposal, Seminole may disclose such information.

Seminole also reserves the right to disclose any or all of the information submitted in response to this request to any consultant(s) retained by Seminole to assist with the various aspects of this process. Seminole will take reasonable steps to ensure that its consultant(s) will also treat information received from bidders as confidential; however, Seminole will not be liable for any failure of any consultants(s) to do so.

Communication

Seminole expects to identify a short list by **October 30, 2000**. Negotiations with those bidders on the short list are expected to be completed by **February 28, 2001**. Contracts detailing the terms and conditions of the completed capacity power purchase agreements are expected to be executed by **May 31, 2001**.

This RFP is available either on the Internet at **http://www.seminole-electric.com**, or by e-mail, fax or U.S. mail.

If interested parties have any questions or desire any additional information related to this request for offers, **such questions or requests should be made in writing and directed via fax at (813) 264-7906 or via e-mail (to the e-mail address above)** to Ms. Trudy S. Novak, Director of Pricing and Bulk Power Contracts.

GENERAL INFORMATION

The undersigned submits this proposal in response to Seminole's Request for Proposals for power supply in the Year 2004 (Submit separate forms for each proposal offered):

On Forms Provided Herein, Add Additional Rows As Needed

Guaranteed Capacity (MW) Delivered to the Transmission Tie:

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Commencement Date (mo/da/yr): [ ] **Termination Date (mo/da/yr):** [ ]

Please describe remedies for failure to deliver committed capacity and/or failure to attain in-service dates:

_____

_____

Complete Company Name of Bidder _____

Address _____

Telephone No. _____

Contact Person(s) _____

E-mail Address(es) _____

Fax Machine No. _____

Authorized Signature _____

Bidder's Business Classification (IOU, QF, Power Marketer, Merchant Plant, etc):

_____

Type of Resource Offered:

System Purchase(1); Unit Purchase, Existing(2); Unit Purchase, Proposed(3); Portfolio (4): [ ]

Please indicate here whether this proposal is for Seminole's Intermediate or Peaking need: _____

Please Identify the Company Responsible for Operating the Resource: _____

_____

For System Purchases:

Resources Included _____ (Entire System or Group of Units?)

Number of Units _____

Type (Base(1), Intermediate(2), Peaking(3), Combination(4)) [ ]

For Unit Purchases or Joint Ownership Proposals:

Current Status (In Operation (1), Under Construction (2), Proposed (3)): [ ]

In-service Date (mo/da/yr) under construction/proposed: [ ]

Generating Technology:

_____

Primary and Secondary Fuel Types:

_____

For Power Marketers:

Please attach a summary to describe your portfolio.

_____

_____

The following information is requested for proposals describing UNIT purchases or JOINT OWNERSHIP Proposals:

Facility Description and Geographic Location of Each Resource in Proposal:

Expected In-service Date(s) and Milestone Schedule for Units Under Construction:

Proximity of Each Resource (Miles) to Nearest Currently Existing Transmission Facilities: _____

Describe Transmission Facilities:

Identify Control Area They Are In:

If Transmission Facilities do not Currently Exist, Please Discuss Interconnection Plans:

The following information for proposals describing SYSTEM purchases:

Characteristics of System Purchase Proposed (i.e., describes Firm Capacity, Equivalent to Native Load, etc.):

Unit Purchases or Joint Ownership Proposals: Guaranteed Capacity Delivered to the Transmission Tie:

Please provide information requested below for each resource offered.

Unit/Resource Name _____

Proposed Unit: with or without evaporative cooler? _____

Capacity (MW):

	At 32 degrees:	At ISO:	At 95 degrees:
By Fuel Type: **OIL:**			
Minimum Load			
First Intermediate Load			
Second Intermediate Load			
Full Load			
Emergency			
Power Augmentation			
By Fuel Type: **GAS:**			
Minimum Load			
First Intermediate Load			
Second Intermediate Load			
Full Load			
Emergency			
Power Augmentation			
By Fuel Type: **OTHER:**			
Minimum Load			
First Intermediate Load			
Second Intermediate Load			
Full Load			
Emergency			
Power Augmentation			

Unit Purchases or Joint Ownership Proposals: Guaranteed Net Heat Rate (Btu/kWh HHV):

If heat rate curves and degradation data are available, please enclose.

Provide information requested below for each resource offered.

Unit/Resource Name _____

	At 32 degrees:	At ISO:	At 95 degrees:
By Fuel Type: **OIL:**			
Minimum Load			
First Intermediate Load			
Second Intermediate Load			
Full Load			
Emergency			
Power Augmentation			
By Fuel Type: **GAS:**			
Minimum Load			
First Intermediate Load			
Second Intermediate Load			
Full Load			
Emergency			
Power Augmentation			
By Fuel Type: **OTHER:**			
Minimum Load			
First Intermediate Load			
Second Intermediate Load			
Full Load			
Emergency			
Power Augmentation			

Discuss remedies for non-performance of heat rate guarantees:

_____

_____

Fixed Costs (Capacity-Related), Flat Monthly Amount or Nominal $/kW-month:

Please provide a full description of the capacity to which the fixed rate will be applied. For example, is this a guaranteed capacity rating? Nameplate rating? Does the capacity vary by season?

Discuss remedies for non-performance of guaranteed capacity commitments.

Provide information requested below for SYSTEM proposed or EACH UNIT offered.
For information dimensioned annually, add additional rows as needed.

System OR Unit/Resource _____

Capacity Charge (Indicate Monthly Amount or $/kW-month):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Describe Escalation: _____

If proposal is for joint ownership, indicate all-in installed cost (2004 $): _____
Would Seminole share in the cost of the entire facility or some portion? Please describe.

Seminole ownership share (%): _____

Fixed O&M (Indicate Monthly Amount or $/kW-month):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Describe Escalation: _____

If proposal is for joint ownership, describe sharing of fixed O&M costs:

Other Charges (Indicate Monthly Amount or $/kW-month):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Describe Escalation: _____

If proposal is for joint ownership, describe sharing of other charges:

Total Fixed Costs (Indicate Monthly Amount or $/kW-month):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Non-Fuel Variable Costs:

Provide information requested below for SYSTEM proposed or EACH UNIT offered. For information dimensioned annually, add additional rows as needed.

System OR Unit/Resource _____

Variable O & M (Nominal $/MWh or Nominal $ per Machine-Hour) :

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Describe Escalation _____

Other Variable Charges (i.e., Start Charges. Please Describe. Enter as Nominal $/MWh or $000):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Describe Escalation _____
Description of Cost Item _____

Please separately identify estimated costs (in nominal $000) and intervals of major maintenance items, such as hot gas path inspections and other major overhauls: _____

If proposal is for joint ownership, describe sharing of variable O&M costs:

_____
_____

Fuel Information (For Unit Purchases):

Describe fuel delivery logistics and on-site fuel storage facilities:

_____

Published fuel pricing index used, if applicable:

_____

If fuel is gas, please provide the following information:

Fuel supply arrangement (firm, relinquished, interruptible) _____
Name of supplier _____
Existing contract? _____
If applicable, describe firm gas transportation charges _____

_____

Fuel supply constraints that might prevent the resource from dispatching fully?

_____

If facility burns oil, are there environmental restrictions on the quantity of oil consumption?

_____

How many hours of full load operation of the facility will be supported with planned on-site fuel storage / inventory?

_____

Fuel Information (For SYSTEM purchases):

Describe billing procedures and reimbursement of fuel cost:

_____
_____
_____
_____
_____

Availability, Forced Outage, Planned Outage:

Please provide information requested below for EACH UNIT offered.
For information dimensioned annually, add additional rows as needed.

Unit/Resource Name _____

Guaranteed Availability (%):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-peak												
Off-peak												

Forced Outage (%):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-peak												
Off-peak												

Planned Outage (Hours or Days):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-peak												
Off-peak												

For purposes of clarification, define on and off-peak hours or days:

_____

_____

_____

Please provide availability for the whole term of the proposal to capture major maintenance (hot gas path inspections, etc.)

Discuss remedies for non-performance of unit availability guarantees:

_____

_____

_____

Information requested below for SYSTEM CAPACITY offered.

Guaranteed Availability (%):

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Discuss remedies for non-performance of system availability guarantees:

_____

_____

Operational Parameters:

Unit Name _____

	Input Here	
Minimum Run Time per Dispatch		Hours
Minimum Down Time Between Calls		Hours
Startup Energy, on peak		MMBtu
Startup Energy, off peak		MMBtu
Ramp Rate		MW / minute
Ramp Rate		minutes to full load
Number of Hot Starts per Year		Maximum
Number of Hot Starts per Year		Included in Bid Price
Cost of Additional Hot Starts		Dollars per Start
Number of Cold Starts per Year		Maximum
Number of Cold Starts per Year		Included in Bid Price
Cost of Additional Cold Starts		Dollars per Start
Quick Start Capability to First MW		Minutes
Quick Start Capability, # MW in Ten Minutes		MW
Start up Time from Cold Start		Minutes
Start up Cost from Cold Start		Dollars
Start up Time from Hot Start		Minutes
Start up Cost from Hot Start		Dollars
Automatic Generation Control (AGC) Capability?		Yes/No
Minimum sustained operating level (MW) of the facility (unit) when operating on each applicable fuel?		MW

SEMINOLE ELECTRIC COOPERATIVE, INC.
CREDIT APPLICATION

Name of Firm _____

Contact Name _____

Street Address _____

_____

Mailing Address _____

_____

Federal Tax ID No. _____

YEARS firm has been in active, full time business under present business name? _____

Is your firm currently involved in any litigation, the outcome of which could adversely affect your company's financial position? If so, please describe:

_____

_____

_____

Primary Bank Name _____
Contact Name _____
Address _____

_____

Phone No. _____ Fax No. _____

Account Numbers and Type of Account _____ , _____

_____ , _____

Name of Authorized Signer of Bank Account _____

CREDIT REFERENCES (Please provide the most recent credit information requested):

Company Name _____ Contact _____
Address _____ Fax _____
Phone _____

Company Name _____ Contact _____
Address _____ Fax _____
Phone _____

Company Name _____ Contact _____
Address _____ Fax _____
Phone _____

Company Name _____ Contact _____
Address _____ Fax _____
Phone _____

Company Name _____ Contact _____
Address _____ Fax _____
Phone _____

Please clarify relationships of any associated companies (Parent, subsidiaries, etc.) that relate to the financial position of your firm or your firm's capabilities to complete the proposed contracts/agreements.

Please provide a copy of your most recent Annual Report and financial statements (including last year's and interim reports).

Please sign this release (below):

_____ _____
Authorized Signature Date

Docket No. _____
Witness: Garl S. Zimmerman
Exhibit No. ___ (GSZ-4)

Table 9 **Ranking of Peaking Capacity Bids**	
Average Annual Cost (Nominal $/MWh)	Rank
$_____	1
$_____	2
$_____	3
$_____	4
$_____	5

Docket No. _____
Witness: Garl S. Zimmerman
Exhibit No. ___ (GSZ-5)

Table 11
Calpine Osprey : Savings (PVRR) when compared to:

Bidder	Period of Comparison	MW	Additional Costs
Bidder 2	2004 - 2008	350	$_____
Bidder 3	2004 - 2008	350	$_____
Bidder 4	2004 - 2008	350	$_____
Seminole self-build	2004-2008	350	$_____

Docket No.001748-EC
Witness: Garl S. Zimmerman
Exhibit No._____(GSZ-6)

Inflation and Discount Rates Used in Seminole's Analysis of Alternatives

Seminole used the Implicit Price Deflator (IPD) for the inflation rate which is forecast at 2.7 % decreasing and leveling off at 2.5 %. The discount rate used was 5.85 % which is the same as the levelized RUS guaranteed long term debt rate. The bids were compared on an annual dollar basis as well as present worth and the ranking did not change. Changing the inflation and discount rates to 3 % and 10 %, respectively would not change the rankings of the proposals. In fact, the effect of the higher discount rate would be offset somewhat by the higher inflation rate.

Docket No. _____
Witness:William T. Lawton
Exhibit No. ____ (WTL-1)

Exhibit WTL-1

Seminole Electric Cooperative, Inc.
2000 Power Requirements Study

FORECAST SUMMARY

	(GWH) Energy	Maximum Demand (MW) Winter	(MW) Summer	Maximum Load Management Reductions (MW) Winter	(MW) Summer	(%) Annual Load Factor	(%) Annual Purchases Growth	(%) Annual Peak Growth
1980	4,287	1,133	873	-	-	43.1	-	-
1981	4,593	1,217	978	-	-	43.1	7.1	7.4
1982	4,532	1,342	928	-	-	38.5	-1.3	10.3
1983	4,949	1,222	1,055	-	-	46.2	9.2	(9.0)
1984	5,148	1,436	1,075	-	-	40.8	4.0	17.5
1985	5,723	1,736	1,269	-	-	37.6	11.2	20.9
1986	6,006	1,717	1,276	-	-	39.9	4.9	(1.1)
1987	6,484	1,583	1,454	-	-	46.8	8.0	(7.8)
1988	7,031	1,873	1,474	-	-	42.7	8.4	18.3
1989	7,690	1,961	1,629	-	-	44.8	9.4	4.7
1990	7,833	2,270	1,714	-	-	39.4	1.9	15.7
1991	8,176	2,009	1,693	-	-	46.5	4.4	(11.5)
1992	8,434	2,245	1,860	-	-	42.8	3.2	11.8
1993	8,978	2,112	1,924	-	-	48.5	6.5	(6.0)
1994	9,218	2,291	1,877	-	-	45.9	2.7	8.5
1995	10,218	2,652	2,149	-	-	44.0	10.8	15.8
1996	10,579	3,079	2,205	-	-	39.1	3.5	16.1
1997	10,734	2,893	2,277	-	-	42.4	1.5	(6.1)
1998	11,682	2,380	2,560	-	-	52.1	8.8	(11.5)
1999	11,912	3,147	2,589	-	-	43.2	2.0	22.9
2000	12,503	3174*	2599*	293	236	44.9	5.0	0.8
2001	13,015	3,346	2,716	250	204	44.4	4.1	5.4
2002	13,495	3,473	2,812	250	204	44.4	3.7	3.8
2003	13,985	3,601	2,914	250	204	44.3	3.6	3.7
2004	14,523	3,731	3,015	250	204	44.3	3.8	3.6
2005	14,998	3,864	3,117	250	204	44.3	3.3	3.6
2006	15,539	4,003	3,225	250	204	44.3	3.6	3.6
2007	16,093	4,145	3,334	250	204	44.3	3.6	3.5
2008	16,704	4,290	3,446	250	204	44.3	3.8	3.5
2009	17,239	4,438	3,560	250	204	44.3	3.2	3.5
2010	17,833	4,589	3,677	250	204	44.4	3.4	3.4
2011	18,451	4,746	3,799	250	204	44.4	3.5	3.4
2012	19,134	4,906	3,923	250	204	44.4	3.7	3.4
2013	19,729	5,072	4,049	250	204	44.4	3.1	3.4
2014	20,390	5,238	4,178	250	204	44.4	3.4	3.3
2015	21,067	5,410	4,312	250	204	44.4	3.3	3.3
2016	21,833	5,587	4,450	250	204	44.5	3.6	3.3
2017	22,499	5,770	4,591	250	204	44.5	3.1	3.3
2018	23,241	5,958	4,734	250	204	44.5	3.3	3.3
2019	23,999	6,150	4,882	250	204	44.5	3.3	3.2
2020	24,840	6,348	5,035	250	204	44.5	3.5	3.2

* Actual winter peak 3137 MW, actual summer peak 2566 MW.
Reporting actual data through December 1999.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001748-EC EXHIBIT NO. 3
COMPANY/
WITNESS: Seminole / Lawton
DATE 3-12-01

WTL - 2

Seminole Electric Cooperative, Inc.
2000 Power Requirements Study

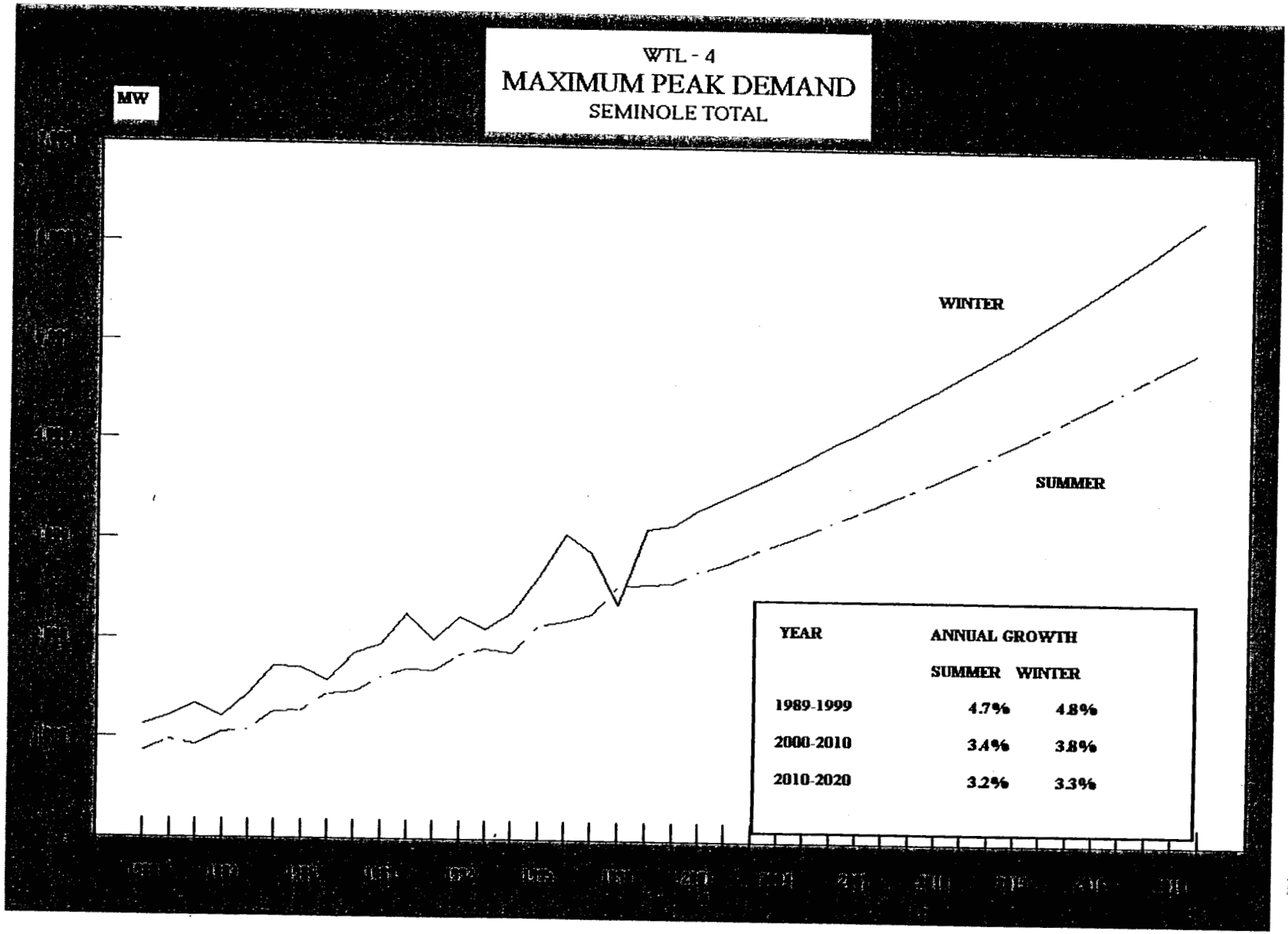
CONSUMER FORECASTS

	Residential	Percent Growth	Commercial	Percent Growth	Other	Percent Growth	Total	Percent Growth
1975	205,376	-	15,273	-	3,868	-	224,517	-
1976	215,880	5.11	16,405	7.41	3,874	0.16	236,159	5.19
1977	227,936	5.58	17,872	8.94	3,871	(0.08)	249,679	5.72
1978	243,272	6.73	19,375	8.41	3,574	(7.67)	266,221	6.63
1979	262,623	7.95	21,511	11.02	3,404	(4.76)	287,538	8.01
1980	283,276	7.86	23,584	9.64	2,812	(17.39)	309,672	7.70
1981	302,533	6.80	24,838	5.32	2,872	2.13	330,243	6.64
1982	318,591	5.31	26,040	4.84	2,922	1.74	347,553	5.24
1983	335,362	5.26	27,901	7.15	3,021	3.39	366,284	5.39
1984	353,131	5.30	29,924	7.25	3,112	3.01	386,167	5.43
1985	374,234	5.98	32,225	7.69	2,966	(4.69)	409,425	6.02
1986	394,049	5.29	35,060	8.80	2,810	(5.26)	431,919	5.49
1987	421,802	7.04	38,204	8.97	2,999	6.73	463,005	7.20
1988	442,571	4.92	40,977	7.26	3,165	5.54	486,713	5.12
1989	462,593	4.52	42,969	4.86	3,324	5.02	508,886	4.56
1990	481,195	4.02	43,968	2.32	3,353	0.87	528,516	3.86
1991	495,362	2.94	44,388	0.96	3,241	(3.34)	542,991	2.74
1992	506,754	2.30	47,327	6.62	3,248	0.22	557,329	2.64
1993	518,690	2.36	49,079	3.70	3,304	1.72	571,073	2.47
1994	531,680	2.50	50,743	3.39	3,341	1.12	585,764	2.57
1995	546,831	2.85	51,421	1.34	3,366	0.75	601,618	2.71
1996	561,981	2.77	53,223	3.50	3,349	(0.51)	618,553	2.81
1997	578,344	2.91	55,263	3.83	3,514	4.93	637,121	3.00
1998	595,967	3.05	57,012	3.16	3,586	2.05	656,565	3.05
1999	607,059	1.86	59,044	3.56	3,593	0.20	669,696	2.00
2000	624,729	2.91	61,026	3.36	3,671	2.17	689,426	2.95
2001	641,782	2.73	62,783	2.88	3,766	2.59	708,331	2.74
2002	658,087	2.54	64,279	2.38	3,855	2.36	726,221	2.53
2003	674,269	2.46	65,807	2.38	3,941	2.23	744,017	2.45
2004	690,494	2.41	67,355	2.35	4,024	2.11	761,873	2.40
2005	706,751	2.35	68,909	2.31	4,108	2.09	779,768	2.35
2006	722,711	2.26	70,457	2.25	4,192	2.04	797,360	2.26
2007	738,690	2.21	72,008	2.20	4,275	1.98	814,973	2.21
2008	754,681	2.16	73,564	2.16	4,358	1.94	832,603	2.16
2009	770,680	2.12	75,120	2.12	4,439	1.86	850,239	2.12
2010	786,687	2.08	76,681	2.08	4,523	1.89	867,891	2.08
2011	803,264	2.11	78,296	2.11	4,608	1.88	886,168	2.11
2012	819,844	2.06	79,911	2.06	4,694	1.87	904,449	2.06
2013	836,427	2.02	81,528	2.02	4,779	1.81	922,734	2.02
2014	853,013	1.98	83,142	1.98	4,864	1.78	941,019	1.98
2015	869,601	1.94	84,760	1.95	4,951	1.79	959,312	1.94
2016	886,949	1.99	86,449	1.99	5,040	1.80	978,438	1.99
2017	904,300	1.96	88,139	1.95	5,129	1.77	997,568	1.96
2018	921,653	1.92	89,830	1.92	5,219	1.75	1,016,702	1.92
2019	939,005	1.88	91,519	1.88	5,309	1.72	1,035,833	1.88
2020	956,361	1.85	93,210	1.85	5,397	1.66	1,054,968	1.85

Reporting actual data through December 1999.

Docket No. _____
Witness: William T. Lawton
Exhibit No. ____ (WTL-2)

Docket No. _____
Witness:William T. Lawton
Exhibit No. ____(WTL-3)



Docket No. _____
Witness: William T. Lawton
Exhibit No. ____ (WTL-4)

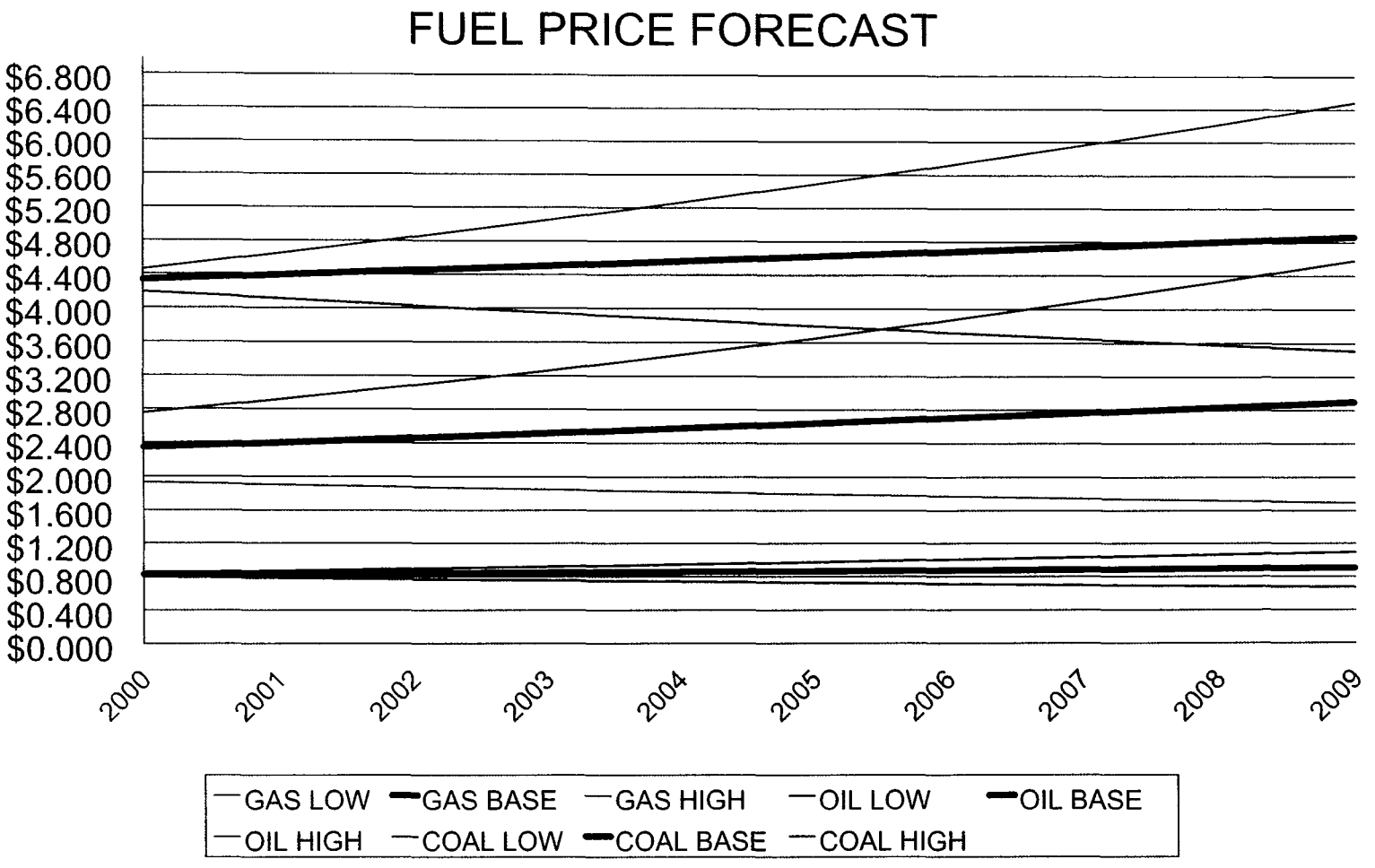
Docket No. _____
Witness: Robert L. Woodall
Exhibit No. ____ (RLW-1)

FUEL PRICE FORECAST

YEAR	WELLHEAD GAS U.S. GULF COAST PRICE NOMINAL $/MMBTU			DISTILLATE FUEL OIL U.S. GULF COAST PRICE NOMINALS/MMBTU		
	LOW RANGE	BASE CASE	HIGH RANGE	LOW RANGE	BASE CASE	HIGH RANGE
2000	$1.932	$2.341	$2.757	$4.193	$4.331	$4.457
2001	$1.904	$2.397	$2.917	$4.111	$4.388	$4.646
2002	$1.877	$2.454	$3.087	$4.031	$4.445	$4.844
2003	$1.850	$2.513	$3.266	$3.953	$4.502	$5.049
2004	$1.823	$2.573	$3.456	$3.876	$4.561	$5.264
2005	$1.796	$2.635	$3.657	$3.800	$4.620	$5.487
2006	$1.770	$2.699	$3.869	$3.726	$4.680	$5.720
2007	$1.745	$2.763	$4.094	$3.654	$4.741	$5.963
2008	$1.719	$2.830	$4.332	$3.583	$4.803	$6.216
2009	$1.694	$2.898	$4.584	$3.513	$4.865	$6.480

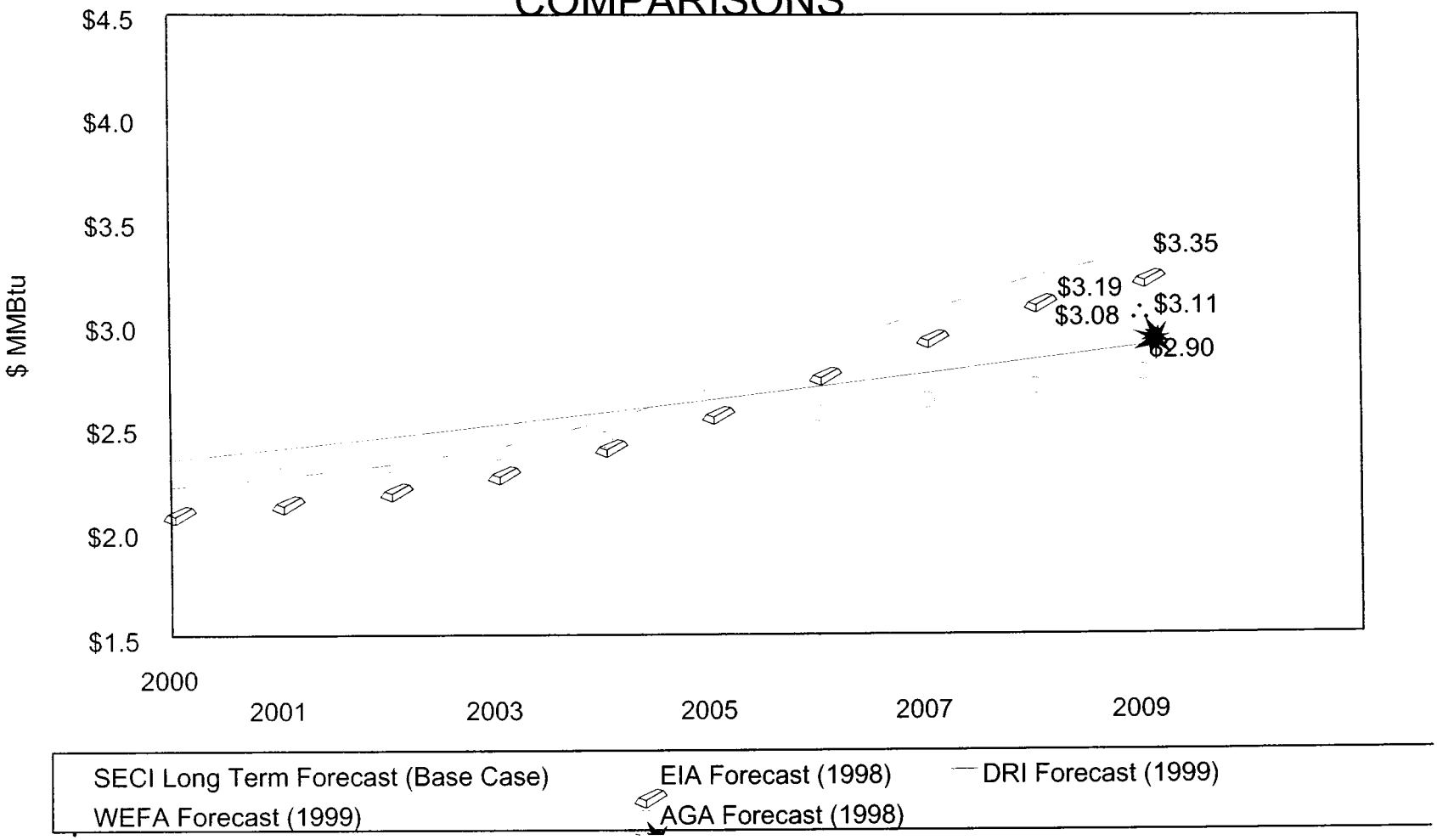
YEAR	HIGH SULFUR COAL MINE MOUTH PRICE NOMINAL $/MMBTU		
	LOW RANGE	BASE CASE	HIGH RANGE
2000	$0.804	$0.825	$0.844
2001	$0.788	$0.831	$0.868
2002	$0.773	$0.838	$0.893
2003	$0.758	$0.847	$0.919
2004	$0.743	$0.855	$0.946
2005	$0.729	$0.864	$0.973
2006	$0.715	$0.874	$1.002
2007	$0.701	$0.884	$1.031
2008	$0.687	$0.893	$1.061
2009	$0.674	$0.903	$1.091

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001748-EC EXHIBIT NO. 4
COMPANY/
WITNESS: Leonard Woodall
DATE: 2-12-01



Witness:Robert L. Woodall
Exhibit No. ___ (RLW-2)

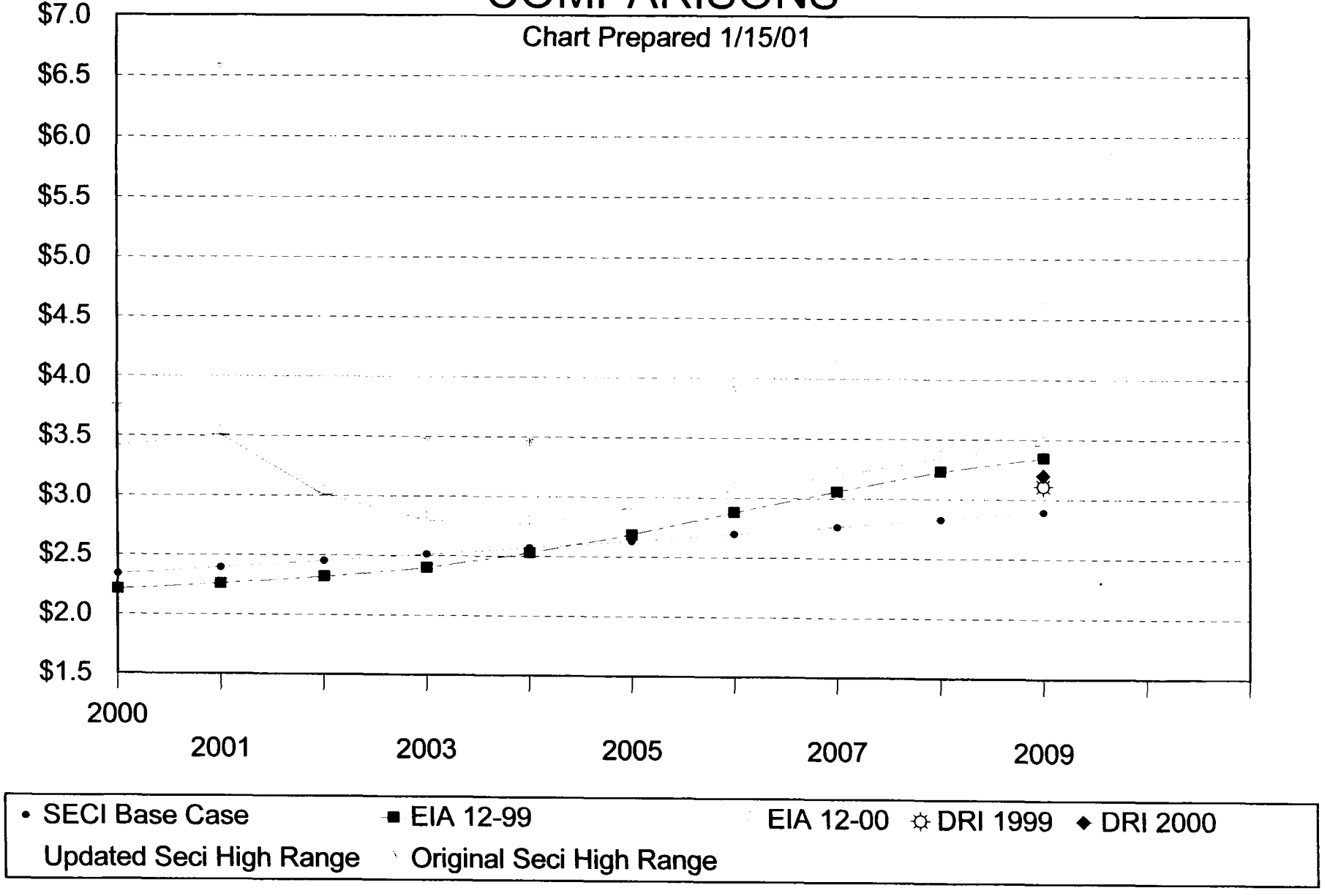
WELLHEAD NATURAL GAS FUEL PRICE FORECAST COMPARISONS



Docket No. _____
Witness:Robert L. Woodall
Exhibit No. ___(RLW-3)

Docket No. 001748-EC
Witness:Robert L. Woodall
Supplemental Exhibit No.____ (RLW-4)

WELLHEAD NATURAL GAS PRICE FORECAST COMPARISONS



TR 5f

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for the Osprey Energy Center in Polk County by Seminole Electric Cooperative, Inc. and Calpine Construction Finance Company, L.P.	)	**Docket No. 001748-EC**
	)	**Filed: January 10, 2001**

SEMINOLE ELECTRIC COOPERATIVE, INC.

REVISED EXHIBITS TO AMENDED JOINT PETITION

FOR DETERMINATION OF NEED FOR THE

OSPREY ENERGY CENTER

VOLUME 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001748-EC EXHIBIT NO. 5
COMPANY/ WITNESS: Seminole
DATE: 2-12-01

DOCUMENT NUMBER-DATE
00438 JAN 10 01
FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for the Osprey Energy Center in Polk County by Seminole Electric Cooperative, Inc. and Calpine Construction Finance Company, L.P.	)	Docket No. 001748-EC
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SEMINOLE ELECTRIC COOPERATIVE, INC.

REVISED EXHIBITS TO AMENDED JOINT PETITION

FOR DETERMINATION OF NEED FOR THE

OSPREY ENERGY CENTER

VOLUME 1

REVISED EXHIBITS TO AMENDED JOINT PETITION

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A. EXECUTIVE SUMMARY

Seminole Electric Cooperative, Inc., ("Seminole") an "electric cooperative" within the meaning of section 403.503 (13), Florida Statutes, was formed by the ten Member cooperatives it serves to negotiate power purchase contracts on their behalf and also to construct generation and transmission facilities with which to serve them. The Members' service areas are spread throughout all areas of Florida, and lie in three separate transmission control areas–those of Florida Power Corporation ("FPC"), Florida Power and Light Company ("FPL"), and Seminole's own Direct Sale Area. Through wholesale contracts with the Member cooperatives (which are owned, in turn, by their Members/customers), Seminole supplies all but 1% of the Members' capacity requirements.

Seminole meets the needs of its Members through a mixed portfolio of owned generation facilities and power purchase contracts. Seminole owns two large coal-fired generators, Seminole 1 and Seminole 2, and is in the process of constructing the Payne Creek unit, a 500 MW class combined cycle project for which the Commission issued a determination of need in 1994. Seminole is a party to numerous power purchase contracts, some of which will be expiring during its current planning horizon.

Seminole plans and maintains a system having capacity sufficient to meet summer and winter peak demands with a reserve margin of at least 15%. Seminole develops its load forecast with the active input of its Members. Based on the load forecast that was prepared for its 2000 Ten Year Site Plan, Seminole determined that it would fall short of the 15% minimum standard by 160 MW in 2004 unless it took appropriate action. It began the process of identifying the appropriate means of maintaining acceptable reliability.

Seminole's planning process is based on the objective of minimizing revenue requirements. Seminole uses the PROMOD IV production costing simulation model to calculate the revenue requirements of its system under assumed scenarios. Inputs to PROMOD IV include the load forecast and Seminole's fuel forecast, which is also developed in-house. To address its need, Seminole first simulated the system under projected 2004 conditions to assess the type of generating capacity--base, intermediate, or peaking--that would be the most appropriate addition. Based upon the results of the simulation and Seminole's knowledge of the range of capacity factors necessary to render a base-loaded, pulverized coal unit economically feasible, Seminole discarded that option at an early stage.

Having determined that it would require intermediate or peaking capacity in 2004, Seminole prepared a Request for Proposals ("RFP") and distributed it widely to potentially interested providers. Simultaneously, Seminole asked Black and Veatch to provide detailed costs of a combined cycle unit and of a peaking unit, to identify Seminole's self-build option. Based on strategic considerations, including the desire to balance the components of owned and purchased resources in its supply portfolio, Seminole preferred to address its 2004 need through a power purchase arrangement, but was prepared to pursue the self-build option in the event it offered material savings compared to the other options.

Seminole received five peaking proposals and eight combined cycle proposals to meet its 2004 need for capacity. These included Calpine's Osprey Energy Center ("Osprey Project" or "Project") proposal, which had been under discussion by the parties prior to the issuance of the RFP and which Seminole evaluated as part of the RFP process.

Seminole evaluated the proposals in stages. In the first stage, Seminole modeled its system

with a hypothetical, generic combustion turbine ("CT") to identify the manner in which a CT could be expected to operate. When performing the evaluation, Seminole incorporated an updated load forecast, the effect of which was to increase the amount of needed capacity to 201 MW, given Seminole's existing inventory of sources. Combining the indicated operating characteristics with bid data, Seminole developed an average annual cost per megawatt hour for each bid and ranked the bids on that basis. It compared the least expensive peaking proposal to the cost of additional partial requirements ("PR") service and to the least expensive combined cycle proposal. As the peaking proposal was more costly than either, the five peaking proposals were excluded from further consideration.

When evaluating the "intermediate" offers, Seminole first used a stand-alone screening approach to produce a short list of the four most attractive proposals available to meet its 2004 need. Calpine's Osprey Project received the highest ranking. At this point, Seminole determined that the offers of combined cycle capacity were more economical and cost-effective than an existing 150 MW contract with Florida Power Corporation that Seminole can adjust or terminate with three years' advance notice. To reflect the availability of this cost-effective option, and to increase the range of its strategic options, Seminole adjusted the identified amount of needed capacity to 350 MW.

Seminole then performed separate, detailed iterations of its production costing simulations in which it hypothetically added each of the short-listed bid proposals to the Seminole system. Seminole calculated the system revenue requirements of each "bid scenario" over the period 2004-2008. Under this more rigorous analysis, the Calpine Osprey Project continued to be the most cost-effective alternative, relative to the other top three RFP responses. The Calpine proposal is also more cost-effective than Seminole's self-build option.

Based upon Seminole's selection of Calpine's bid, Seminole and Calpine have negotiated comprehensive commercial terms and conditions, which are memorialized in a definitive Power Purchase Agreement. (Appendix I-C). The terms of the PPA provide both economic and strategic benefits to Seminole. Seminole will obtain 350 MW of firm capacity at pricing that reflects the economies of scale of an efficient, 500+ MW class combined cycle machine. The firm capacity will enable Seminole to meet or exceed its minimum reserve margin criterion in 2004. As Calpine intends to place the Osprey Project in service during the summer of 2003, the risk to Seminole that additional capacity may not be in place when needed to maintain an adequate reserve margin is reduced greatly. The purchase from Calpine will contribute to Seminole's efforts to minimize the system revenue requirements borne by its Members. Seminole will also be entitled to acquire optional firm capacity, for incremental periods of 12 months, in amounts up to the full capability of the Osprey Project, to the extent the capacity has not been committed to another party on a firm basis at the time Seminole wishes to exercise its option. Significantly, Seminole can renegotiate the terms of the agreement with Calpine at the end of each 60-month period, meaning that it will have the ability periodically to obtain market-based pricing or exit the contract. These provisions give Seminole a valuable degree of flexibility with which to respond to any changes in circumstances.

B. DESCRIPTION OF SEMINOLE

Seminole Electric Cooperative, Inc., is a corporation organized and existing under the laws of the State of Florida for the purpose of providing reliable electric power at the lowest feasible cost to its ten distribution Members' service areas, which comprise approximately one half of the land area of peninsular Florida. Seminole is an "electric cooperative" within the meaning of Section 403.503(13), Florida Statutes. Seminole fulfills its functions by generating, transmitting, purchasing, selling, and exchanging electric power and energy, and by constructing, owning, and/or leasing such facilities as are required for this purpose.

The Seminole Member cooperatives are:

- Central Florida Electric Cooperative, Inc.
  Chiefland, Florida
- Clay Electric Cooperative, Inc.
  Keystone Heights, Florida
- Glades Electric Cooperative, Inc.
  Moore Haven, Florida
- Lee County Electric Cooperative, Inc.
  North Fort Myers, Florida
- Peace River Electric Cooperative, Inc.
  Wauchula, Florida
- Sumter Electric Cooperative, Inc.
  Sumterville, Florida
- Suwannee Valley Electric Cooperative, Inc.
  Live Oak, Florida
- Talquin Electric Cooperative, Inc.
  Quincy, Florida

- Tri-County Electric Cooperative, Inc.
  Madison, Florida

- Withlacoochee River Electric Cooperative, Inc.
  Dade City, Florida

Seminole's load is located within three control areas: those of FPC, FPL, and Seminole's Direct Service Area ("SDS"). Within the FPL and SDS areas, Seminole is obligated to serve total Member system load. Under a long-term Partial Requirements Agreement with FPC, Seminole is obligated to supply its Members' aggregate load in the FPC control area up to a specified MW commitment level ("Capacity Commitment"). FPC is responsible for providing load following service for all loads in excess of the Capacity Commitment level.

Seminole owns 52 miles of 230 kilovolt ("kV") double circuit transmission line from the Seminole Plant to the Silver Springs North Switching Station, eight miles of 230 kV double circuit line from the Seminole Plant to FPL's Rice Substation, and nine miles of 230 kV double circuit line from the Hardee Power Station to FPC's Vandolah Substation. Seminole also owns 78 miles of 230 kV single circuit transmission line from the Hardee Power Station ("HPS") to Lee County Electric Cooperative's Lee Substation (which is also an interconnection with FPL), and 63 miles of 230 kV single circuit line from the Seminole Plant to an interconnection with JEA at the Clay-Duval County line. Seminole jointly owns, with FPC, two tie lines from Silver Springs North to FPC's Silver Springs Substation. Seminole also owns fourteen 69 kV transmission lines, which total 143.2 miles in length.

Seminole meets its power supply obligations through a combination of owned and purchased resources. Seminole Units 1 & 2, 600 MW class coal-fired units, went into commercial operation in 1984 and 1985, respectively. Seminole also owns a 14.5 MW share of FPC's Crystal River 3 ("CR3")

nuclear generating unit.

Seminole has contracts with the Jacksonville Electric Authority (JEA) for 53 MW of firm capacity through May 21, 2004. Seminole has also contracted with the Orlando Utilities Commission ("OUC") for 75 MW of firm capacity through 2004 and for an additional 50 MW of firm capacity through 2000. Further, Seminole has contracted with FPC for the following purchases: 450 MW of firm capacity through 2001; 150 MW of firm system intermediate capacity through 2013 (cancellable with 3 years' notice); 150 MW of firm system peaking capacity for the period 2000 through 2002; and an additional 150 MW of firm system peaking capacity for the period 2001 through 2002. Seminole purchases partial and/or full requirements power from FPC, the City of Gainesville, and Tampa Electric Company. Seminole has also contracted for the following: with Lee County Resource Recovery for approximately 35 MW of capacity through December 2014; with Morgan Stanley for 100 MW of firm winter capacity for the period December 2000 to February 2001; with the City of Tallahassee for firm capacity in the amount of 50 MW for the period December 2000 to March 2001; and with the City of Tallahassee for firm capacity in the amount of 75 MW for the period May 2000 to November 2001.

Through a contract with TECO Power Services ("TPS"), Seminole purchases 145 MW of capacity from the Big Bend 4 ("BB4") coal unit (a 488 MW unit) and a nominal 295 MW of first call reserve capacity from the HPS. Seminole has first priority use of BB4 capacity for any purpose, subject to an annual energy cap. Seminole has first priority use of the HPS as a reserve resource to cover a forced or scheduled outage or reduced capability of Seminole's coal-fired plant or CR3. The term of the contract is through 2012; however, the BB4 capacity reverts back to TPS in 2003.

Seminole's plans include the installation of Payne Creek Generating Station ("PCGS"), a 500 MW nominally rated gas-fired combined cycle unit. The Florida Public Service Commission issued its order approving the need for PCGS in 1994, and in 1995 Seminole received certification of the unit from the Florida Electrical Power Plant Siting Board pursuant to the Florida Electrical Power Plant Siting Act. Construction began on the PCGS in February 2000; the scheduled in-service date is January 2002.

Seminole recently entered into contracts for peaking capacity with Reliant Energy Osceola, LLC, and Oleander Power Project, Limited Partnership. Reliant will supply 300 MW for the period December 2001 through December 2006. Oleander will supply 300 MW beginning in December 2002 and increasing to 450 MW in May 2003 through December 2009.

C. SEMINOLE'S NEED STUDY

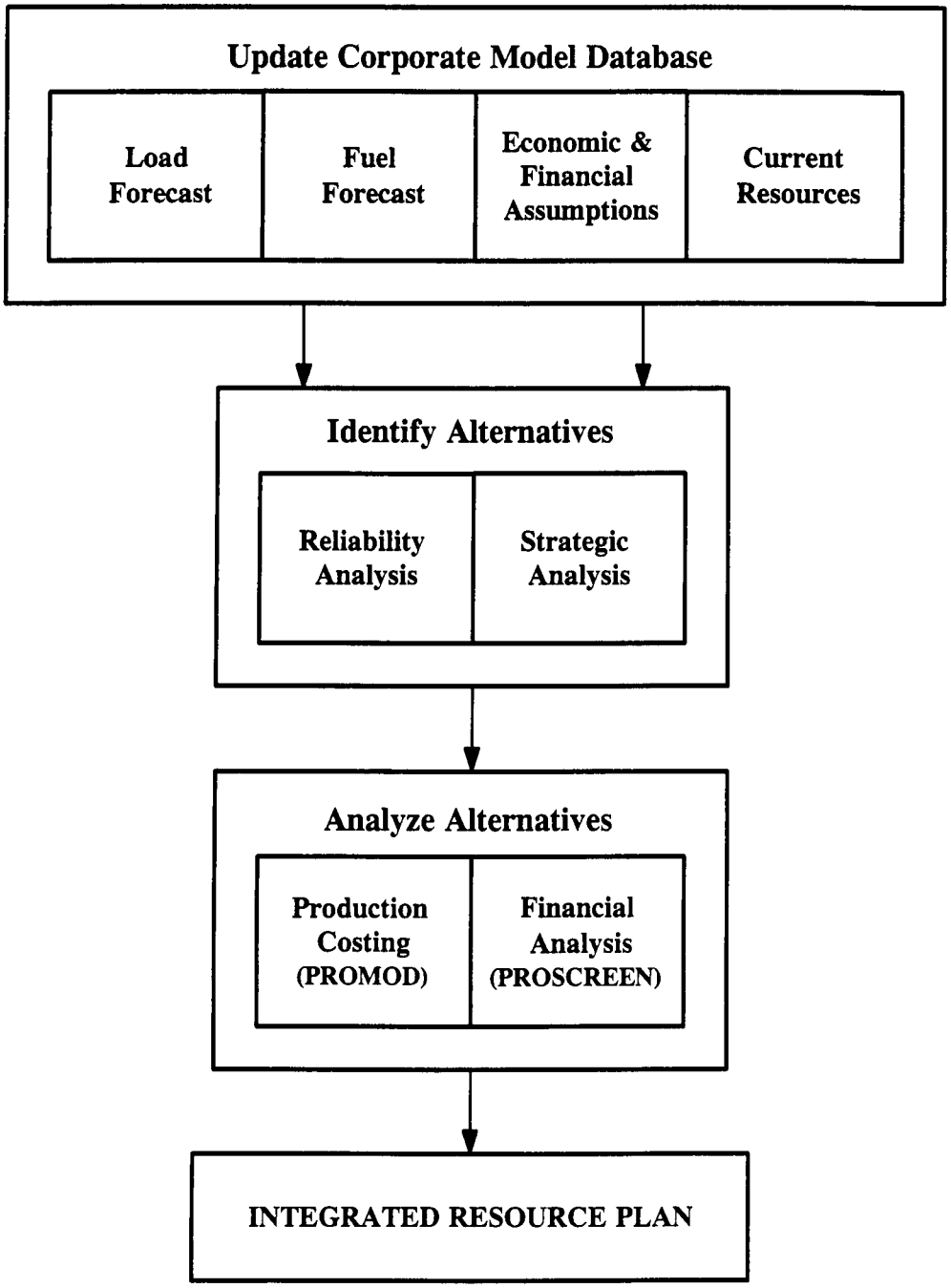
1. THE PLANNING PROCESS

Seminole's primary planning goal is to develop the most cost-effective way to meet its Members' load requirements while maintaining high system reliability. Seminole regularly updates its power supply plan to determine: (1) future reserve requirements--both installed reserves and operating reserves, (2) requirements to replace expiring contracts, (3) the optimal mix of base, intermediate and peaking capacity (4) the economic feasibility of displacing PR service with more economical sources, and/or (5) exercising options within existing purchase power contracts.

Seminole's process for optimizing the selection of resources is based primarily on measuring and minimizing the total cost of revenue requirements. Inasmuch as Seminole is a not-for-profit cooperative, revenue requirements translate directly into rates to the Member Distribution Cooperatives. The plan with the lowest revenue requirements is generally selected, assuming that other factors, such as impact on reliability, initial rate impact, and strategic considerations, do not override economics. A flow chart of Seminole's planning process is shown in the following figure.

Figure 1

Resource Planning Process



a. Optimization of Partial Requirements Service

As part of its routine planning process, Seminole compares the economics of PR purchases from FPC with those of acquiring peaking capacity, whether owned or purchased for the system. Seminole's PR contract provides Seminole the ability to make annual adjustments to the Capacity Commitment. An optimization analysis identifies the most economical annual level of PR achievable under contract constraints and the associated Capacity Commitment. This commitment level defines the amount of firm capacity that Seminole must supply in the FPC control area.

b. Reliability Criteria

Seminole presently uses a minimum 15% system peak reserve margin (as that minimum figure may be increased by specific operating reserve requirements allocated to Seminole by the FRCC at a given point in time) as its primary criterion of reliability. To meet this criterion, supply plans include adequate firm resources having a total capacity 15% greater than Seminole's annual maximum summer and winter peak demands. Since the mid-80s, Seminole has also planned to meet a criterion of no more than 1% Expected Unserved Energy (EUE). At first, the EUE target resulted in a reserve margin higher than the 15% minimum requirement. As Seminole's system and resources have grown and diversified, the two criteria have approached each other and crossed over such that reserve margin is now the determinative criterion.

c. Effect of Conservation and Load Managment Measures on Capacity Requirements.

Seminole's future demand is defined by the sum of the forecasted coincident demands in the FPL control area and the Direct Service Area, and the Capacity Commitment level in the FPC control area. As the forecast of demand is developed in close cooperation with the Member cooperatives, the forecast takes into account the impact of Members' conservation/load management programs. While

Seminole has no direct conservation program, it has adopted a rate structure designed to send proper price signals to Members that will encourage the use of cost-effective load management measures.

d. Determination of Type of Capacity Needed

Once total demand is identified, the need for capacity is determined by comparing demand with available resources. The need for capacity is further analyzed to determine the most economic level of base, intermediate and peaking capacity with which to serve Seminole's future demand. The costs of peaking and intermediate capacity, both owned and purchased, together with the energy pricing of each is analyzed to identify the optimal breakpoints for the intermediate and peaking portions of the supply portfolio.

2. CAPACITY NEEDS

a. Timing of Need

In its 2000 power supply study, Seminole compared the ability of system resources to maintain a 15% reserve margin during peak periods over time, given the duration of existing purchased power contracts and the forecast of the growth of Members' requirements. The analysis revealed that, absent action by Seminole, the reserve margin would fall below 15% in the year 2004 and would deteriorate thereafter. The projected reserve margin over time, assuming no capacity additions, is shown in the following tables.

Table 1

Winter Reserve Margin (No Addition)

Year	Capacity (MW)	Demand (MW)	Reserve Margin (%)
2004	3362	2807	19.8
2005	3224	2902	11.1
2006	3224	2966	8.7
2007	2860	3074	-7.0
2008	2860	3186	-10.2
2009	2860	3298	-13.3

Table 2

Summer Reserve Margin (No Addition)

Year	Capacity (MW)	Demand (MW)	Reserve Margin (%)
2004	2897	2596	11.6
2005	2897	2682	8.0
2006	2897	2738	5.8
2007	2591	2838	-8.7
2008	2591	2942	-11.9
2009	2591	3045	-14.9

b. Quantity of Capacity Needed

Having determined when reserves would fall below its planning criterion, Seminole next measured the amount of capacity that would be needed to restore reserve margin to the minimum

acceptable level. This quantification was made without regard to the sizes in which increments of capacity would be available. (The quantification was first based on the load forecast which underlies Seminole's 2000 Ten-Year Site Plan. It was subsequently revised to reflect an updated load forecast made in July 2000. The updated load forecast is detailed in Section E and Appendix I-A of this volume.)

The table below lists the number of megawatts of capacity needed to restore the 15% reserve margin, on a seasonal basis, for the years 2004 through 2009. These needs take into account Capacity Commitment optimization, incorporation of the most recent load forecast, and expiring purchase power contracts.

Table 3

Future Capacity Needs

Year	Current Winter Need			Current Summer Need		
	Intermediate	Peaking	Total	Intermediate	Peaking	Total
2004	0	0	0	201	0	201
2005	173	0	173	287	0	287
2006	242	0	242	343	0	343
2007	450	273	723	450	299	749
2008	550	294	844	550	303	853
2009	600	365	965	600	356	956

c. Capacity Expansion Plan

The above capacity needs are expressed in terms of the bare minimum necessary to maintain the planning criterion. Seminole translated these needs into a capacity expansion plan. To determine the type of generation that should be incorporated in the plan Seminole used PROMOD IV, a

production costing simulation model, to quantify the amount of energy usage and to identify the hours over which the usage would occur. Seminole regarded proven technologies for base, intermediate capacity, and peaking capacity, generation as potential candidates. For base-loaded capacity, Seminole evaluated a conventional pulverized coal unit; for intermediate, gas-fired combined cycle technology; and for peaking, gas- or oil-fired combustion turbines. Each of these technologies has a proven track record and has been demonstrated to be technically viable and reliable.

Seminole has developed screening criteria, in the form of breakpoint capacity factors, designed to identify whether each of these technologies is an economically viable candidate for a given application. Under Seminole's current screening criteria, a pulverized coal unit must operate at a capacity factor of 87% or higher to be an economic choice. Based on simulations of the system, which indicated that a lower capacity factor would be achieved, Seminole discarded the pulverized coal unit option early in its analysis.

The simulations indicated that the intermediate generation technology would be the most economic choice. Seminole constructed a generation expansion plan by matching commercially available increments of combustion turbines and "one-on-one" combined cycle units (i.e., a configuration employing a single combustion turbine and a single heat recovery steam generator) to the required capacity as closely as possible. This plan, shown in Table 4, is Seminole's minimum self-build or "back-stop" plan.

Table 4

Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Construction Start Mo/Yr	Comm'l In-Service Mo/Yr	Expected Retirement Mo/Yr	Maximum Nameplate (kW)	Summer (MW)	Winter (MW)	Status
				Pri	Alt	Pri	Alt							
Payne Creek Gen. Station	1	Hardee County S1,T33S, R24E	CC	NG	FO2	PL	TK	01/2000	01/2002	Unk	587,000	488	572	U
Unk	1	Unk	CC	NG	FO2	PL	TK	06/2002	06/2004	Unk	290	244	286	P
Unk	1	Unk	GT	FO2		TK		06/2003	06/2005	Unk	193	153	182	P
Unk	1	Unk	CC	NG	FO2	PL	TK	01/2005	01/2007	Unk	290	244	286	P
Unk	1	Unk	GT	FO2		TK		06/2005	06/2007	Unk	193	153	182	P
Unk	1	Unk	GT	FO2		TK		06/2006	06/2008	Unk	193	153	182	P
Total												1,435	1,690	

Notes:

Payne Creek Generating Station capacity will replace purchased capacity beginning 01/01/2002 and is being counted for reserve purposes in 2002.

Unk:	Unknown
U:	Regulatory approval received. Under construction.
P:	Planned, but not authorized by utility.

Seminole then incorporated the "self-build" additions into an overall system formulation. Tables 5 and 6 list Seminole's projected demand and planned capacity for the period 2000 through 2009. These tables encompass the addition of 572 MW of Combined Cycle capacity for the period 2004 through 2008 at unknown sites, and 546 MW of peaking capacity.

Table 5

Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak

	Total Installed Capacity	Firm Capacity Import (Less PR/FR)[1]	Firm Capacity Import (PR/FR)	Firm Capacity Export	QF[2]	Total Capacity Available	Total Capacity Available Less PR/FR	System Firm Summer Peak Demand	System Firm Summer Obligation[3]	Reserve Margin Before Maintenance[4]		Scheduled Maintenance	Reserve Margin After Maintenance[4]	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(% of Pk)	(MW)	(MW)	(% of Pk)
2000	1,331	1,182	332	0	298	3,143	2,811	2,651	2,319	492	26.4%	0	492	26.4%
2001	1,331	1,314	279	0	298	3,222	2,943	2,770	2,491	452	24.0%	0	452	24.0%
2002	1,819	1,058	257	0	298	3,432	3,175	2,868	2,611	564	26.1%	0	564	26.1%
2003	1,819	1,058	299	0	298	3,474	3,175	2,972	2,673	502	19.9%	0	502	19.9%
2004	2,063	930	328	0	298	3,619	3,291	3,074	2,746	545	21.0%	0	545	21.0%
2005	2,216	930	347	0	298	3,791	3,444	3,179	2,832	612	22.8%	0	612	22.8%
2006	2,216	930	400	0	298	3,844	3,444	3,288	2,888	556	20.3%	0	556	20.3%
2007	2,613	624	412	0	298	3,947	3,535	3,400	2,988	547	19.3%	0	547	19.3%
2008	2,766	624	422	0	298	4,110	3,688	3,514	3,092	596	20.3%	0	596	20.3%
2009	2,766	624	435	0	298	4,123	3,688	3,630	3,195	493	16.2%	0	493	16.2%

1	Firm capacity includes partial requirements (PR) and full requirements (FR) purchases and purchases from other supplier.
2	The capacity shown under QF represents a contract with TECO Power Services for first-call capacity from the Hardee Power Station to backup 1240 MW of generation from Seminole Units 1 and 2 and CR#3.
3	Seminole's firm obligation demand does not include PR and FR purchases.
4	Percent reserves are calculated on Seminole's obligation since Seminole is not responsible for supplying reserves for FR and PR purchases. Seminole's reserve capacity does not include FPC peaking and intermediate purchases.

Table 6

Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak

	Total Installed Capacity	Firm Capacity Import (Less PR/FR)[1]	Firm Capacity Import (PR/FR)	Firm Capacity Export	QF[2]	Total Capacity Available	Total Capacity Available Less PR/FR	System Firm Winter Peak Demand	System Firm Winter Obligation[3]	Reserve Margin Before Maintenance[4]		Scheduled Maintenance	Reserve Margin After Maintenance[4]	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(% of Pk)	(MW)	(MW)	(% of Pk)
2000	1,345	1,273	745	0	362	3,725	2,980	3,237	2,492	488	24.0%	0	488	24.0%
2001	1,345	1,448	735	0	362	3,890	3,155	3,413	2,678	477	23.0%	0	477	23.0%
2002	1,917	1,132	734	0	362	4,145	3,411	3,542	2,808	603	25.6%	0	603	25.6%
2003	1,917	1,078	796	0	362	4,153	3,357	3,672	2,876	481	17.6%	0	481	17.6%
2004	1,917	1,233	848	0	362	4,360	3,512	3,805	2,957	555	19.8%	0	555	19.8%
2005	2,203	1,095	889	0	362	4,549	3,660	3,941	3,052	608	21.0%	0	608	21.0%
2006	2,385	1,095	967	0	362	4,809	3,842	4,083	3,116	726	24.5%	0	726	24.5%
2007	2,671	731	1,004	0	362	4,768	3,764	4,228	3,224	540	17.6%	0	540	17.6%
2008	2,853	731	1,040	0	362	4,986	3,946	4,376	3,336	610	19.1%	0	610	19.1%
2009	3,035	731	1,079	0	362	5,207	4,128	4,527	3,448	680	20.6%	0	680	20.6%

1	Firm capacity includes partial requirements (PR) and full requirements (FR) purchases and purchases from other supplier.
2	The capacity shown under QF represents a contract with TECO Power Services for first-call capacity from the Hardee Power Station to backup 1240 MW of generation from Seminole Units 1 and 2 and CR#3.
3	Seminole's firm obligation demand does not include PR and FR purchases.
4	Percent reserves are calculated on Seminole's obligation since Seminole is not responsible for supplying reserves for FR and PR purchases. Seminole's reserve capacity does not include FPC peaking and intermediate purchases.

3. REQUEST FOR PROPOSALS

a. Description of RFP

Having identified the amount of capacity needed to maintain the minimum 15% reserve margin, and having developed the "self-build" expansion plan, Seminole initiated a competitive procurement process designed to identify and obtain the most cost-effective solution to its projected reserve margin shortfall. Seminole issued a Request for Proposals (RFP), No. IP2004, on July 6, 2000. (Appendix I-B). Its purpose was to solicit bids for intermediate and peaking capacity, beginning in 2004. Seminole solicited proposals to satisfy a minimum need of 160 MW of intermediate type capacity beginning May 1, 2004. Seminole also solicited up to 440 MW of additional capacity to potentially displace existing power supply arrangements, beginning January 1, 2004. (The minimum capacity requirement of 160 MW was based upon the load forecast prepared for the 2000 Ten-Year Site Plan. The load forecast was updated shortly following the release of the RFP.) Based upon Seminole's latest load forecast, the details of which are contained in Section E of this volume of the Exhibits, and given the resources presently in place, Seminole measured the minimum intermediate capacity requirements beginning in 2004 to be approximately 200 MW at the outset of the analysis of responses. The parameters of the procurement process were sufficient to accommodate the impact of the revised load forecast: in the RFP, Seminole sought proposals of between 160 and 400 MW of intermediate type capacity and up to 350 MW of peaking type capacity.

Seminole solicited proposals from a wide variety of potential bidders, including independent power producers, exempt wholesale generators, qualifying facilities (under PURPA), power marketers, and utilities. Although the RFP stated that Seminole favored short-term proposals, it also stated that Seminole would consider attractive longer-term bids, as well as proposals describing joint

ownership. The RFP stated that bids offering demand side options would also be accepted and considered.

b. Issuance of the RFP

The RFP was issued in two main sections. The first section described the purpose of the RFP, identified capacity requirements, and addressed scheduling, delivery, pricing, terms and conditions, and instructions for completing and submitting the application. The second section contained a series of application forms that each bidder was required to complete. In the application forms, the bidder was asked to describe the type of capacity offered, the quantity offered (in megawatts), pricing information (fixed and variable), the length of the term, description of the facilities (proposed or existing), fuel information, and detailed operational information. A credit application was also included.

c. Announcement of the RFP

Three methods were employed to announce the RFP : direct communications with potentially interested organizations, a press release, and publication of the RFP on the home page of Seminole's web site. The direct announcements were faxed to over forty entities. Seminole sent the press release to a number of media outlets. The home page of the Seminole web site advertised the RFP until August 31, 2000, the due date for submission of bids.

d. Responses to the RFP

Seminole received a total of fourteen proposals from nine bidders, all of which described purchased power proposals. (These included proposals from entities who had begun discussions with Seminole prior to the issuance of the RFP, including Calpine. Seminole rolled such proposals into the RFP process and evaluated them using the same criteria that were applied to RFP respondents.)

No demand-side measures were proposed in the responses. Seminole received five peaking bids from five separate bidders, four of which described essentially the same type of gas-fired combustion turbine. The peaking capacity offers ranged from 170 MW to 320 MW.

Seminole received nine proposals describing intermediate-type capacity purchases from seven of the nine bidders. One was a system purchase, backed up by a proposed combined cycle facility. One was a repowered facility. Another was a capacity purchase from an integrated gasification combined cycle facility ("IGCC"). The remaining five offers described purchases of varying capacity from combined cycle facilities at proposed plants within Florida. Tables 7 and 8 below summarize the proposals.

Table 7

Peaking Capacity Offers

Capacity Type	Capacity (MW)	Term
GE 7FA CTs	314	2004 - 2008
GE 7FA CTs	170	2004 - 2008
GE 7EA CTs	320	2004 - 2009
GE 7FA CTs	300	2004 - 2008
GE 7FA CTs	300	2004 - 2008

Table 8 Intermediate Capacity Offers		
Capacity Type	Capacity (MW)	Term
Unit Purchase Westinghouse 2x1 501F CC	300-534	2004 - 2008 (options to extend to 20 years)
GE 2x1 7FA CC	475	2004 - 2008
GE 1x1 7FA CC	240	2004 - 2008
GE 1x1 7FA CC	240	2004 - 2008
GE 3x3 7FA CC with Integrated Gasification	100-400	2004 - 2014
System Purchase	200	2004 - 2008
Combined Cycle	200	2004 - 2008
GE 2x1 7FA CC	500	2004 - 2011
GE 3x3 7F CC	50-100	2004 - 2008

4. SELF-BUILD OPTION

In parallel with the RFP process, Seminole retained Black and Veatch to prepare an engineers' estimate of the turnkey costs for a combustion turbine, a one-on-one combined cycle unit, and a two-on-one combined cycle unit. For strategic reasons -- primarily the objective of a balanced mix of owned and purchased resources -- Seminole preferred a short-term purchase power agreement to fill its capacity need; however, if the turnkey self-build option had appeared to provide significant savings over the most economical purchase power proposal, Seminole was prepared to consider it.

5. EVALUATION OF PROPOSALS

a. Methodology and Overview

The System Planning Department, in conjunction with the Strategic Services Department, was given the responsibility for evaluating the bids. First, Seminole reviewed the bids for completeness and responsiveness. As a result of this preliminary screening, all of the bids except the IGCC were accepted (although some of the bidders were contacted for additional information or clarification). The bidder proposing the IGCC unit specified an in-service date later than Seminole's 2004 summer seasonal requirements. In subsequent discussions, the IGCC bidder revised its projected in-service date to May 1, 2005, which was even farther removed from the time when Seminole would first need capacity. Therefore, this proposal was not regarded as a candidate to satisfy the 2004 need. However, the proposal was retained for later consideration, as Seminole must meet needs occurring beyond 2004. Once all of the information necessary for analysis and comparison was available, the bids were separated by capacity type for evaluation.

To compare and evaluate the capacity offers, Seminole used production costing software to simulate its system over the time period 2004 to 2008 -- Seminole's preferred contract term. Production costing software allocates available resources to meet load demands so as to minimize energy costs. For this purpose Seminole uses PROMOD IV, a simulation software which is licensed from NewEnergy Associates, and PROSCREEN, the companion financial software package that calculates system fixed costs. Seminole's Corporate Model links the output from these software tools and generates total system costs. A key input to the computer model is the assumption regarding fuel prices. The fuel forecast contained in Section D of this volume of the Exhibits was the source of the prices that were incorporated in the need analysis.

Peaking - Peaking capacity bids were evaluated in three stages. First, the bids were compared against each other in order to rank the offers based on overall cost. To derive the utilization characteristics necessary to the analysis, Seminole simulated the addition of a combustion turbine to Seminole's resources for the period June, 2004 - December, 2008. The operational parameters for a GE 7 FA unit were used in the simulation, as all but one of the respondents based their proposals on this unit. (The other bidder offered capacity from GE 7EA turbines, which are very similar to the 7FA in operation.) Fuel costs were considered to be a pass-through. The quoted demand costs ($/MW) proved to be the critical variable for peaking capacity, as other variables -- fuel costs, hours of operation, start-up costs were equal or substantially similar. Using demand costs plus fixed values for energy, service hours, and the number of unit starts for each bid, Seminole calculated an average annual cost in nominal dollars per megawatt hour. The results of this analysis are shown in the Table 9.

Table 9

Ranking of Peaking Capacity Bids

Average Annual Cost (Nominal $/MWh)	Rank
$_____	1
$_____	2
$_____	3
$_____	4
$_____	5

Next, the bid ranked No. 1 was compared to the cost of equivalent additional PR purchases. This analysis indicated that the least cost bid was not economically superior to the existing PR contract.

In the final stage of the analysis of the peaking bids, Seminole compared the top-ranking bid to the least cost intermediate capacity offer. The comparison confirmed that intermediate capacity is the appropriate and most economic choice to fill Seminole's projected need. Production costing simulations for identical amounts of peaking and intermediate capacity showed that the least-cost peaking bid was not economically competitive with the least-cost intermediate offer. The simulations also exhibited a level of projected usage that supported the need for intermediate capacity. As a result of the analysis of the peaking offers, none of these bids were retained for further evaluation.

Intermediate - Of the nine offers received, five were for capacity from GE 7 FA combined cycle units in various configurations; one was for a similar Westinghouse unit; and one was for a system energy purchase. Another bid did not specify a unit type; characteristics provided in the bid document indicated that it, too, was operationally similar to the GE and Westinghouse combined cycle units. These eight bids contained either energy costs or operational characteristics, including energy output and heat rates, which enabled Seminole to compare the offers directly. The ninth bid offered time-of-day pricing. Seminole converted this proposal to its corresponding average energy cost so that it could be included in the economic screening.

The evaluation of the intermediate proposals consisted of two phases: an initial screening to identify the four most economical choices, followed by a far more rigorous development of the impact of each of the four best alternatives on overall system costs. In the first phase of the evaluation of intermediate capacity proposals, Seminole used its production costing software to model the addition of a generic combined cycle unit to its system resources for the period 2004 through 2008. Operational parameters for a GE 7FA combined cycle unit with a two-on-one configuration were used to produce utilization characteristics which defined the unit's performance. To estimate the financial impact of implementing each of the offers, the total stand-alone cost of each proposal to Seminole

was calculated based on these utilization characteristics, bid criteria and estimated costs. The total cost of each offer included fixed demand costs, fuel and fuel transportation costs, and variable operation and maintenance costs. The costs of offers for units other than the 7FA were adjusted according to unit performance information provided in the proposals. The offers were compared and ranked by overall least cost of energy, which allowed a direct comparison of offers for varying capacity amounts.

b. Detailed Evaluation of Power Supply Contract Options

Once the least-cost bid was identified in the preliminary screening analysis, a production costing analysis was performed to compare this bid to a long-term 150 MW intermediate capacity contract with FPC that Seminole can adjust with proper notice. The bid was determined to be more economical than the FPC contract. To recognize Seminole's ability to substitute capacity from the intermediate offer for the existing power purchase contract on an economic basis, Seminole revised its capacity needs from the amount shown in Table 1 to 350 MW, as shown in Table 10.

Table 10

Revised Future Capacity Needs

Year	Current Winter Need			Current Summer Need		
	Intermediate	Peaking	Total	Intermediate	Peaking	Total
2004	0	0	0	351	0	351
2005	323	0	323	437	0	437
2006	392	0	392	493	0	493
2007	600	273	873	600	299	899
2008	700	294	994	700	303	1003
2009	750	365	1115	750	356	1106

The second and more detailed phase of the evaluation process was designed to scrutinize and compare the top four bidders more closely. Again, production costing simulations were employed. However, instead of using a generic unit to obtain performance characteristics in a stand-alone comparison, in the second phase each specific bid was "added to the system." Seminole then modeled the entire system over time and quantified the total system revenue requirements associated with each scenario. This enabled Seminole to evaluate the proposals based on overall system costs, rather than dollars paid to the developer. Production cost simulations were developed to compare the highest ranked proposal with the bids ranked by the previous analysis as two through four. The No. 1 bid provided flexibility in amount of capacity offered. This aspect enabled Seminole to compare this bid directly to the other offers, which varied in the amounts of capacity offered from 100 MW to 475 MW. In the second phase, demand costs were included in the PROMOD IV studies, so that further processing through the financial software and corporate model was unnecessary.

The first study compared 100 MW from the No. 1 ranked bid to the bids ranked No. 3 and No.

4. These results confirmed the economic advantage of the No. 1 bid, which produced total system revenue requirements that were lower than Bids No. 3 and No. 4, by $_____ and $_____ respectively (in 2004 dollars). Seminole also concluded from these studies that the No. 2 ranked bid was economically superior to Bids No. 3 and No. 4. The last study compared the No. 1 ranked bid to the No. 2 ranked bid with 350 MW of capacity. The comparison showed that bid No. 1 would save Seminole $_____ ($_____ per 100 MW) in system revenue requirements over the 4-1/2 year period, as compared to the No.2 bid.

As a result of this second phase evaluation process, the No. 1 ranked bid was confirmed as the least-cost intermediate capacity alternative. The next three bids retained their original positions as No. 2, No. 3 and No. 4.

Finally, Seminole compared the costs of the No. 1 ranked bidder to the turnkey self-build engineers' estimates prepared by Black and Veatch. Seminole analyzed the self-build alternatives under several forecasts of future financial conditions. The financing options included Rural Utilities Services ("RUS") guaranteed financing at 6% interest with a 30-year loan period; RUS guaranteed financing at 6% with a 17-year loan period (the time remaining on the Seminole-Member Wholesale Power Contract); and non-RUS guaranteed financing at 7% interest. When comparing the costs of the self-build option with the power purchase option, Seminole assumed that purchasing power instead of constructing a unit would have no effect on Seminole's cost of capital. It has been Seminole's experience that RUS, Seminole's principal source of financing, does not regard the purchase option as more risky than the self-build option. Unit cost averages for the first five years of ownership and over the loan terms were compared with the costs of the No. 1 ranked purchase power offer. The results of the analysis are summarized in Table 11.

Table 11 Calpine Osprey : Savings (PVRR) when compared to:			
Bidder	Period of Comparison	MW	Additional Costs
Bidder 2	2004 - 2008	350	$_____
Bidder 3	2004 - 2008	350	$_____
Bidder 4	2004 - 2008	350	$_____
Seminole self-build	2004-2008	350	$_____

Note: The above self-build cost assumes that the capacity not needed by Seminole could be sold for the time period not needed. For purposes of the comparison, costs were based on the assumption that each bidder would offer 350MW.

After taking comparative costs and strategic concerns into account, the No. 1 ranked bid, submitted by Calpine, was selected as the preferred Seminole option to fulfill the 2004 need.

6. POWER PURCHASE AGREEMENT

Based on the results of the evaluation of competing proposals, Seminole and Calpine negotiated comprehensive commercial terms, which are reflected in the Power Purchase Agreement, a copy of which is included as Appendix I-C to Volume 1 of Revised Exhibits to the Amended Joint Petition. (The public version has been redacted to protect confidential, commercially sensitive terms.)

The terms to which Seminole and Calpine have agreed provide significant benefits to Seminole. While Seminole is acquiring 350MW of firm capacity, the pricing provisions in the PPA reflect the efficiencies and economies of scale that are associated with a 500+ MW class unit. Seminole's ability to purchase optional firm capacity (to the extent it has not been firmly committed to others) enhances its strategic flexibility. Because Calpine intends to bring the unit on line prior to

the time when Seminole would experience a capacity shortfall, the risk that capacity may not be available when needed for reliability is diminished. The reopener provisions to which the parties have agreed ensure that Seminole will not find itself with a long term commitment to above-market costs.

7. CONSEQUENCES OF DELAY

Through a competitive bidding and negotiation process, Seminole has determined that the purchase from Calpine of combined cycle generating capacity beginning in mid-2004 is the most cost-effective method of meeting its Members' power supply needs reliably. If Seminole's need determination is not granted, it will be forced to seek power purchases from other sources, if available, or to add shorter lead-time combustion turbines to maintain acceptable system reliability. Either of these alternatives would be only a temporary solution and would result in increased costs to Seminole's Members.

D. FUEL PRICE FORECAST

This section summarizes Seminole's Fuel Price Forecast. This forecast was used in the economic evaluations of available alternatives to meet Seminole's need which led Seminole to identify the Osprey Project proposed by Calpine as its most cost-effective choice. The forecast encompasses the prices of gas, oil and coal for the period from 2000 through 2009. Seminole's fuel forecast is similar to other published forecasts covering the same time period.

1. LONG TERM TRENDS VS. SHORT TERM ABERRATIONS

Seminole prepared this forecast before oil and gas prices spiked during the past few months. Seminole believes the current prices are a response to OPEC, international limitations on oil production, and a short term imbalance in natural gas production. Current market prices for oil and natural gas, which are described below, illustrate just how volatile the pricing of these fuels can be in the short term. Seminole believes the underlying economic fundamentals relating to oil and natural

gas have not changed from the time we made our long term price forecast. Seminole fully expects prices to return to the forecast range in the not too distant future.

2. FORECAST METHODOLOGY

Seminole forecasts the price for each fuel at its source. The U.S. Gulf Coast was considered the source for gas and oil. For coal, this forecast covers high-sulfur coal mined in the Illinois Basin and the Pittsburgh # 8 coal seam in West Virginia. All prices are stated in nominal dollars.

3. NATURAL GAS MARKET OUTLOOK

Seminole forecasts the wellhead price of natural gas to increase at a moderate rate somewhat slower than the rate of economic inflation. The primary sources of natural gas for the USA are domestic on-shore wells and Gulf of Mexico wells. A small but increasing quantity of natural gas comes from Canadian wells and imported liquified natural gas. The federal Energy Information Administration projects a 50% increase in consumption of natural gas over the next two decades. This increase is due, in large measure, to the construction of new gas-fired combined cycle power plants. The natural gas production industry has a remarkable record of technological advances, which lower the cost of producing gas from new wells, enable the economic recovery of gas from previously inaccessible reserves, and lead to the discovery of previously unknown reserves. Experts predict this trend will continue and that the industry will expand production to meet demand with only modest increases in the wellhead price of natural gas. Seminole's forecast of wellhead gas price is slightly below the range of forecasts published by gas industry associations and national economic forecasting organizations.

The high gas price case assumes that technological developments do not keep pace and new production becomes more expensive.

The low gas price case could occur if unforseen technological developments reduce the cost of new production and/or lead to discovery of new, low cost reserves.

4. OIL MARKET OUTLOOK

The price forecast for oil assumes that the long-term historic market trends will continue. Consumption will continue to rise while domestic production declines and imports of oil continue to increase. The base case also assumes there are no international conflicts which cause a long-term disruption in oil imports. This is of particular importance, since world oil prices are strongly influenced by OPEC, as opposed to economic factors. These assumptions lead us to forecast a steady growth in the price of oil consistent with the underlying historic trend.

The high oil price case assumes that OPEC strengthens its influence over its Members so that production quotas are honored, production is limited, and prices increase. Conversely, the low oil price case foresees a relatively weak OPEC, with Member and non-Member nations maintaining a high production rate which would reduce the price of oil over time.

5. COAL MARKET OUTLOOK

Coal prices are forecast in terms of dollars per ton ($/ton) at the producing mine. During the study period, prices are forecast to increase at a very moderate rate. Several factors combine to limit the rate of price increases for coal. There are abundant reserves of coal, which will support all needed new production. Overall industry production is expected to remain in close balance with consumer demand. Technological advances and improvements in efficiency are expected to continue their historic contributions to productivity gains. These factors are expected to have a moderating effect on the rate of increase in coal prices.

The high case pricing scenario contemplates more stringent environmental regulation of mining which constrains the growth of production, the cessation of improvements in productivity, and

an increasing demand for low sulfur coal. The low case pricing scenario contemplates additional technological advances which increase productivity and contribute to an over-supply of coal.

6. FORECAST RESULTS

Natural gas, distillate oil, and coal price projections are shown in Table 12 and Figure 2. Table 12 contains a table showing the base case, high range and low range forecast. Figure 2 is a graph of this data. The Seminole base case gas price forecast is compared to other forecasts in the graph contained in Figure 3.

TABLE 12
FUEL PRICE FORECAST

YEAR	WELLHEAD GAS U.S. GULF COAST PRICE NOMINAL $/MMBTU			DISTILLATE FUEL OIL U.S. GULF COAST PRICE NOMINAL$/MMBTU		
	LOW RANGE	BASE CASE	HIGH RANGE	LOW RANGE	BASE CASE	HIGH RANGE
2000	$1.932	$2.341	$2.757	$4.193	$4.331	$4.457
2001	$1.904	$2.397	$2.917	$4.111	$4.388	$4.646
2002	$1.877	$2.454	$3.087	$4.031	$4.445	$4.844
2003	$1.850	$2.513	$3.266	$3.953	$4.502	$5.049
2004	$1.823	$2.573	$3.456	$3.876	$4.561	$5.264
2005	$1.796	$2.635	$3.657	$3.800	$4.620	$5.487
2006	$1.770	$2.699	$3.869	$3.726	$4.680	$5.720
2007	$1.745	$2.763	$4.094	$3.654	$4.741	$5.963
2008	$1.719	$2.830	$4.332	$3.583	$4.803	$6.216
2009	$1.694	$2.898	$4.584	$3.513	$4.865	$6.480

YEAR	HIGH SULFUR COAL MINE MOUTH PRICE NOMINAL $/MMBTU		
	LOW RANGE	BASE CASE	HIGH RANGE
2000	$0.804	$0.825	$0.844
2001	$0.788	$0.831	$0.868
2002	$0.773	$0.838	$0.893
2003	$0.758	$0.847	$0.919
2004	$0.743	$0.855	$0.946
2005	$0.729	$0.864	$0.973
2006	$0.715	$0.874	$1.002
2007	$0.701	$0.884	$1.031
2008	$0.687	$0.893	$1.061
2009	$0.674	$0.903	$1.091

E. LOAD FORECAST

1. BACKGROUND

The analysis of Seminole's need for capacity was initiated with the use of the load forecast that supported Seminole's April 2000 Ten-Year Site Plan. As described in Section C, the analysis was altered and the indicated capacity need was increased based on an updated load forecast that was completed in July 2000. The information in this Section E relates to the updated, July 2000 forecast that is the basis for Seminole's conclusions regarding the reliability of its system.

The 2000 Power Requirements Study (PRS) update was conducted in accordance with a work plan, which was approved by Seminole's Board of Trustees in May 1998 and by the Rural Utilities Service (RUS) in September 1998. The work plan calls for triennial revision of the PRS with annual updates in the interim. The plan also calls for close coordination among the staffs of Seminole, its ten distribution cooperative Members, and the RUS. The purpose of this study is to arrive at forecasts which project future electricity sales and peak demand for Seminole and its Members.

2. METHODOLOGY

Projections for the Seminole system are the result of an aggregation of the Member-level forecasts. Detailed forecasts are prepared for each Member system. Both econometric and end-use modeling are used to produce the final Member-level forecasts. Trends in population, consumers, usage, peak demand, and weather and their interactions are analyzed for each Member system's service area. The 2000 PRS also incorporates the results of the 1997 Residential Survey that was completed in May 1997. This survey analyzed the demographic information, housing stock, and appliance saturations of the residential consumers served by Seminole Members. Seminole has been compiling residential surveys since 1980. Throughout the study, close interaction with Member

systems is maintained in the form of data exchanges, written correspondences, e-mail, and phone consultations. The interactions promote mutual understanding and cooperation between the Member systems, Seminole, and the RUS through exchange of information affecting future sales and demand, discussion of the process and the methodology in the development of the load forecast, and review of the results at each major step of the process. Appendix I-A discusses Seminole's forecasting methodology in greater detail.

3. SERVICE AREA AND ECONOMY

Seminole's Member cooperatives provide electricity to an area approximately 400 miles long, from the northern border to southwestern parts of Florida. The variety of geographic and weather conditions provides a diverse mix of economic activity and demographic characteristics.

The northern region shares many physical and cultural characteristics with the two states to the north, Georgia and Alabama. Agriculture, mining, and manufacturing are important industries in the region. This region has experienced moderate, but continued growth in population and economic activities.

The southwest coastal region relies heavily on the construction and service industries for its economic growth. In addition, many of its new residents are relatively affluent retirees, leading the state in per capita income growth and stability.

The interior peninsular region is quite diverse, both with respect to population and the economy. As the coastal areas become more populated, the interior regions are expected to experience stronger growth.

4. FORECAST RESULTS

During the 1980s, Seminole system retail sales grew at rates exceeding 6% annually while Florida retail sales increased at rates exceeding 4% annually. During the 1990s, these growth rates have slowed to 4.8% and 3.3% respectively. Continuing this pattern, growth rates for the Seminole system are expected to remain higher than the Florida average during the forecast period, but both Florida and Seminole system are projected to grow at slower rates. The retail sales growth during the 1980s was influenced by the robust growth in population. Population growth in the 1990s has slowed, lowering the growth in retail sales. The tables on the following two pages summarize the historical and forecast growth rates of key variables for Seminole and Florida and Seminole's projections of Net Energy for Load and Net Firm Demands. Appendix I-A describes the forecast results in greater detail.

Historical and Forecast Growth Rates (%/Yr)

	1990-1999		2000-2009	
	Seminole	**Florida**	**Seminole**	**Florida**
Residential				
Consumers	2.6	2.5	2.4	1.7
Sales	4.6	3.4	3.7	2.0
Commercial/Industrial[2]				
Consumers	3.3	2.8	2.3	1.8
Sales	5.1	3.8	3.6	2.6
Retail Sales	4.8	3.3	3.6	2.2
Peak Demand				
Winter	3.7	5.4	3.8	2.1
Summer	4.7	3.6	3.6	2.2

SOURCE: Florida data is from "2000 Regional Load & Resource Plan," by Florida Reliability Coordinating Council.

[2] Florida data includes commercial sector only; Seminole's data includes the industrial sector also.

Seminole Electric Cooperative, Inc.

FORECAST SUMMARY

	(GWH) Net Energy for Load	Net Firm Demand (MW) Winter	(MW) Summer	(%) Annual Energy Growth	(%) Annual Peak Growth
1990	8,156	2,270	1,714	-	-
1991	8,552	2,009	1,693	4.9	-11.5
1992	8,807	2,245	1,860	3.0	11.7
1993	9,326	2,112	1,924	5.9	-5.9
1994	9,649	2,384	1,933	3.5	12.9
1995	10,624	2,666	2,217	10.1	11.8
1996	10,822	2,731	2,252	1.9	2.4
1997	10,998	2,912	2,320	1.6	6.6
1998	12,033	2,414	2,606	9.4	-10.5
1999	12,168	3,085	2,627	1.1	27.8
2000	12,755	3,237	2,651	4.8	4.9
2001	13,276	3,413	2,770	4.1	5.4
2002	13,766	3,542	2,868	3.7	3.8
2003	14,265	3,673	2,972	3.6	3.7
2004	14,814	3,805	3,074	3.8	3.6
2005	15,298	3,941	3,179	3.3	3.6
2006	15,850	4,083	3,288	3.6	3.6
2007	16,414	4,228	3,400	3.6	3.6
2008	17,038	4,376	3,514	3.8	3.5
2009	17,583	4,527	3,630	3.2	3.5
2010	18,189	4,681	3,749	3.4	3.4
2011	18,819	4,841	3,874	3.5	3.4
2012	19,516	5,005	4,001	3.7	3.4
2013	20,123	5,173	4,129	3.1	3.4
2014	20,796	5,343	4,261	3.3	3.3
2015	21,487	5,519	4,397	3.3	3.3
2016	22,268	5,699	4,538	3.6	3.3
2017	22,947	5,886	4,682	3.0	3.3
2018	23,703	6,077	4,828	3.3	3.2
2019	24,476	6,273	4,979	3.3	3.2
2020	25,334	6,475	5,134	3.5	3.2

Reporting actual data through December 1999

F. APPENDIX 1-A

APPENDIX TO LOAD FORECAST

Population

In projecting the growth rate for its Members' service areas, Seminole relies on county-level population growth projections from the University of Florida's Bureau of Economic and Business Research (BEBR), as well as its own historical experience. The projected population growth rates in the Members' service areas are only slightly higher than BEBR's medium forecast at county levels. The higher growth rates for the Members' service areas are consistent with the fact that these service areas are less populated and have grown faster than the average rates for counties in which they are located.

As has been the case in the past, population in the counties most representative of the Members' service areas is projected to grow faster than the overall Florida population. Those counties which have experienced high growth rates in the past are projected to continue to show strong growth in the future, but at lower rates. Among the counties projected to grow rapidly in the next decade are those in the Fort Myers and Naples area (Collier, Lee), central west coast (Citrus, Dixie, Gilchrist, and Hernando), central inland area (Clay, Lake, Marion and Sumter) and northern area (Hamilton, Lafayette, and Suwannee).

Seminole's Members supply electricity to significant portions of those areas that are generally less urbanized, but are located adjacent to metropolitan areas. It is therefore reasonable to expect higher consumer growth rates for Seminole's Members than for Florida as a whole to continue, as population overflows into Member territory. However, as the Members' service areas become more urbanized, this disparity in growth rates between Seminole and Florida is expected to decline.

The historical and forecasted population for Seminole's Members' service area is shown in

Table A-1-17. The service area population experienced an annual growth rate of 3.9% during the 1980s and dropped to an average of 2.3 % during the 1990s. In 1999, total population in the service area was estimated to be approximately 1.5 million. It is projected to grow to 2.2 million by 2020 at an annual growth rate of 1.9%, reflecting the lower growth rate experienced in the 1990s. Several factors contributed to the robust population growth of the 1980s. The 1981-1982 recession ended with a construction recovery coupled with pent-up demand. This placed Florida ahead of the rest of the nation in job creation. Florida also avoided the rolling recessions that most of the country experienced in the 1980s. This created a higher migration into the state. Finally, the demographic pool of new retirees and young workers willing to relocate was high during the 1980s. However, like the rest of the country, Florida was affected by the recession of the early 1990s. This slowed job creation and migration into Florida to levels that demographers consider to be more normal and sustainable. Finally, the demographic pool of new retirees and younger workers is much smaller in the 1990s. These trends experienced in the 1990s are projected to continue throughout the forecast period.

Consumers

Residential consumers have increased at an average annual rate of approximately 14,000 consumers per year or 2.6% since 1990. Residential consumers are projected to grow at an average annual rate of approximately 16,200 consumer per year or 2.3% between 2000 and 2010. The rate of growth decreases to 2.0% between 2010 and 2020. The average number of residential consumers in 2000 is estimated to be approximately 625,000. That number is projected to reach approximately 956,000 in 2020. The forecasts of residential consumers and energy sales are shown in table A-1-13.

The number of commercial consumers grew faster than residential consumers during the 1980s, due to factors such as rapid population growth, the strength of the Florida economy, and the

continued urbanization of the Members' service areas. During the period 1989 through 1992, commercial consumer growth rates dropped off sharply and fell below those of residential consumers. This was due primarily to the recession of the early 1990s. In 1992, a few Members had little or negative growth in commercial consumers. Since 1993, as the economy recovered from the recession, commercial consumer growth rates have surpassed those of the residential class.

Since 1993, commercial consumers in the service area have increased at an average annual rate of 3.1%. Commercial consumers are projected to grow from approximately 61,000 in 2000 to 77,000 in 2010, at an average annual rate of 2.3%. This will decrease to a 2.0% growth rate from 2010-2020. The forecasts of commercial consumers and energy sales are shown in table A-1-14.

Seminole Members' consumers are projected to continue growing faster than Florida utilities in the next decade: 2.4 % vs. 1.7 % for residential, 2.3% vs. 1.8% for commercial.

Usage per Consumer

Between 1990 and 1999, residential usage per consumer in Seminole Members' service areas increased at an average annual rate of 1.9 % as compared to the State average of 0.9%. The continued growth in average usage is consistent with the Residential Appliance Survey results, which shows steady increases in appliance saturations and larger homes during the last decade.

Homes and Electric Appliance Saturations (%)

	1986	1997
Single Family Homes	59	64
Homes>2000 ft^2	13	20
Homes<2000 ft^2	42	25
Primary Space-heating	55	81
Air-conditioning	82	95
Water Heater	89	92
Refrigerator	99	99
TV	98	99
Electric Range	70	78
Microwave Oven	53	93
Dishwasher	40	62
Clothes Dryer	58	84
Clothes Washer	81	92
Pool Pump	10	15

SOURCE: "Residential Survey," Seminole Electric Cooperative, Inc., 1986 and 1997

Between 1986 and 1997, the percentage of homes having 2000 square feet and larger increased to 20.2% from 12.5%. This is in contrast to decreases in the percentage of homes having1200 square feet or less, from 41.5 % to 25.2 %. In addition, appliance saturations steadily increased during the 10-year period. Saturations of space-conditioning appliances, which are weather sensitive, made substantial increases; primary electric heating made noticeable increases to 80.9 % from 55.4 %; electric air-conditioning increased to 94.8 % from 82.0 %; water heaters to 92.2 % from 88.6 %. Other electric appliances also made steady increases, including dishwashers, electric clothes washers, electric dryers, microwave ovens, and home computers.

Also noteworthy is the fact that electricity prices in nominal terms have declined over the last decade, which means real prices (prices adjusted for inflation) have declined even more. The decline

in real electricity prices is presumed to be an additional contributing factor for the increased energy usage per consumer.

As the result of continued increases in residential usage per consumer, the average residential usage in the Seminole system surpassed the average of Florida as a whole for the first time. The 1999 annual average residential usage of Seminole Members was 13,166 KWh, compared to the state's average of 13,099 KWh.

However, Florida's average residential usage is projected to be higher than Seminole's system average for the next few years. Florida's average residential usage is projected to increase at 0.3% annually through 2009, while the Seminole system average is expected to grow at 1.3% during the same time period. The continued trend toward larger homes, continued increases in appliance saturations, and stable or lower electricity prices will all contribute to higher energy consumption levels in the future.

Commercial/industrial usage per consumer is much lower on the Seminole system than in Florida as a whole: 52,654 KWh versus 77,270 KWh in 1999. Seminole Members' commercial usage also includes industrial consumers, whereas the Florida average does not. Commercial/industrial usage per consumer is projected to grow from 54,220 KWh in 2000 to 60,497 KWh in 2009, at an average annual growth rate of 1.2 %. This compares with the Florida forecast, which projects usage per consumer to grow from 79,907 KWh in 2000 to 85,434 KWh in 2009, or an average annual growth rate of 0.8%.

Energy Sales and Purchases

Since 1990, residential energy sales have increased at an average annual rate of 4.6%. They are projected to grow at an annual rate of 3.5% between 2000 and 2020, reaching 16,684 GWH in 2020.

The forecast methodology is designed to incorporate any increases in energy savings due to additional load management programs of Seminole Members. At this time most of Seminole's Members do not plan to expand their load management programs. Some are evaluating the economic feasibility of maintaining their current programs into the future. As a result, Seminole projects that there will be no growth in the load management program over the forecast period.

Commercial energy sales have increased at an average annual rate of 5.1 % since 1990. They are projected to grow at an average annual rate of 3.4 %, reaching 6,480 GWH in 2020.

Combined with an annual growth rate of 2.1 % in other energy sales, total retail energy sales are projected to be 11,759 GWH in 2000 and 23,348 GWH in 2020, growing at an average annual rate of 3.5 %. Over the same period, Members' total purchases from Seminole are projected to grow from 12,503 GWH in 2000 to 24,840 GWH in 2020, increasing at an average annual rate of 3.5 %. The forecasts of sales and purchases are shown in table A-1-12.

Peak Demand

Seminole's winter peak demand is projected to increase to 6,348 MW in 2020, representing an annual growth rate of 3.5 % over the next 20 years. Summer peak demand is expected to increase at an annual rate of 3.4 %, from 2,599 MW in 2000 to 5,035 MW in 2020.

Seminole's system and most of its Members' systems are expected to continue to be winter peaking. For the Seminole system, winter peaks are expected to be approximately 25 % higher than summer peaks. Florida is generally winter peaking as well; however, the summer and winter peaks do not have as much diversity as the Seminole system.

The continued winter-peaking nature of the Seminole system is due primarily to increases in electric space-heating appliance saturations during the 1990s. Some Members in the northern part of the service area, where saturations of electric heating systems had been relatively low due to

higher saturations of gas heating appliances, have shown significant increases in saturations of electric heating systems in the 1990s.

The peak demand forecasts also reflect no additional load management. The annual load factor for the Seminole system is expected to remain relatively constant at a level of 44.4 % during the forecast period, which is consistent with the historical average of 44.4 % during the 1990-1999 period. The forecasts of peak demands are shown in table A-1-15.

Load Forecast Methodology

a. **Economic and Demographic Data**

Seminole's economic and demographic data base has three principal sources: (1) population and income data from the Florida Economic Data Base furnished by the Bureau of Economic and Business Research (BEBR) at the University of Florida, (2) electricity price data from Seminole's Member cooperatives' "Financial and Statistical Reports" (RUS Form 7), and (3) appliance and housing data from the Residential Appliance Surveys conducted by Seminole and its Member systems since 1980.

b. **Population**

Seminole obtains historical data on population and personal income by county for the 45 counties served by Seminole Member systems. To convert the county specific data to Member cooperative level, the counties are combined using the Member's share of each county's total consumers as of December 1999. Table A-1-1 shows the distribution of population among the counties in which the Member systems serve.

Population is the main explanatory variable in the residential and commercial/industrial consumer models. BEBR provides medium, low, and high population forecast scenarios for each county: The county medium, low and high forecasts are weighted and combined to yield a base

population forecast for each Member.

c. **Income**

The commercial/industrial energy usage model uses real per capita income ("RPCI") as an explanatory variable. The Consumer Price Index for All Urban Consumers ("CPI-U") published by the U.S. Bureau of Labor Statistics is used to convert nominal income to real values. Both variables are re-created using a 12-month moving-average method. This is done because the inherent cyclical fluctuations of both data cannot precisely explain the more stable electricity demand or consumption from one month to another. The increased statistical significance of the moving-average variables justifies the new method.

Forecasts of RPCI are taken from "The Florida Long-Term Economic Forecast 1999." These forecast growth rates for each of Seminole's Members are shown in Table A-1-2.

d. **Price of Electricity**

The real price of electricity is used in the residential and commercial/industrial energy models. The real price is calculated by dividing KWh sales for each consumer class by the corresponding revenue and then deflating the result by the CPI-U. This price is transformed using a 12-month moving-average method for the same reason as the income data explained before. Statistical significance improved markedly with the transformed price variable.

For the forecast, the real price of electricity is assumed to decline in the future at an average annual rate of .989 %. This rate is based on system-wide historical reductions in retail rates.

e. **Appliance Saturations and Housing Shares**

Appliance saturations and housing data are obtained from the Residential Appliance Survey conducted by Seminole and its Member systems since 1980. The three housing types distinguished in the survey are single-family homes, mobile homes, and multi-family homes. Homes are also segregated into three age groups: less than 5 years old, between 5 and 15 years old, and more than 15 years old. For each category of home type and age combination, the appliance saturations include room air-conditioners, central air-conditioners, electric space-heating appliances, and electric water heaters.

The information from the surveys is combined with the residential consumer forecast to produce weighted appliance stock variables for space-conditioning appliances which are used in the residential energy usage model and the peak demand load factor model.

f. **Weather Data**

Seminole obtains hourly weather data from the National Oceanic and Atmospheric Administration ("NOAA") for six weather stations located in or around Seminole's Members' service area: Jacksonville, Gainesville, Tallahassee, Orlando, Tampa, and Ft. Myers. The data includes dry and wet bulb temperature, humidity, wind speed, cloud cover, and dew point. The data begins in 1970, except for Tallahassee (for which data starts in 1976) and Gainesville (for which data starts in 1984). To better reflect weather conditions in each Member's service territory, different weather stations are assigned to individual Member systems based on geographic proximity. Table A-1-3 shows the assigned weights of weather stations to individual Members.

Two types of weather variables are created: one for billing month and the other for calendar month. Calendar month weather is developed for each calendar month; billing month weather contains data from the middle of the previous month to the middle of the current month. A statistical

analysis showed that billing month weather more realistically measures the relationship between billing month sales and weather for the majority of Members. Talquin is unique, in that it lets consumers read their own meters and report the readings in their monthly bills. This unique arrangement makes the two previous calendar months a better explainer of Talquin's billing sales. Both billing and calendar month variables are used in the residential and commercial/industrial energy usage models as "best fit." In addition, heating and cooling degree hours ("HDH", "CDH") on Seminole's peak day are used in the peak demand model.

An extensive analysis of the relationship between hourly loads and hourly weather revealed that air-conditioning demand generally begins in the summer when the outdoor temperature reaches 72°F for residential load and 67°F for commercial load. Space-heating was found to have two different cut-off points in the winter: 61°F for residential and 56°F for commercial, in the service areas of the northern Members, and 63°F for residential and 58°F for commercial in the southern regions. Monthly cooling degree variables are computed by subtracting 24 times the cut-off temperature from the sum of the 24 hourly temperatures, while heating degree variables are created by reversing the order, i.e., subtracting the sum of the 24 hourly temperatures from 24 times the cut-off temperature. These weather variables have been proved effective in explaining weather-neutral temperature ranges for space-conditioning appliances and lagging weather effects within a period of time.

g. **Sales and Hourly Load Data**

Member systems have furnished monthly operating statistics to Seminole, beginning with 1970. Included in this data are statistics by class on number of consumers, KWh sales, revenue, and others. This data is the basis for consumer and energy usage models.

Hourly loads for each Member and the Seminole system, as well as the Members' monthly total energy purchases are collected from over 160 delivery points, covering the period from January

1979 to the present. This data is a basis for modeling peak demand and hourly load profile forecasts and for load management implementation.

h. **Integrated Forecasting System**

Seminole's Integrated Forecasting System consists of the following sub-models:

(1) Residential Consumer Model

(2) Appliance Model

(3) Commercial/Industrial Consumer Model

(4) Other Class Consumers Model

(5) Residential Energy Usage Model

(6) Commercial/Industrial Energy Usage Model

(7) Other Class Energy Usage Model

(8) Peak Demand Load Factor Model

(9) Hourly Load Profiles and Load Management

Each model consists of ten sub-models, since each Member system is modeled and forecast separately. Figure 1 shows the Integrated Forecasting System and Table A-1-4 presents definitions of explanatory variables used in the model.

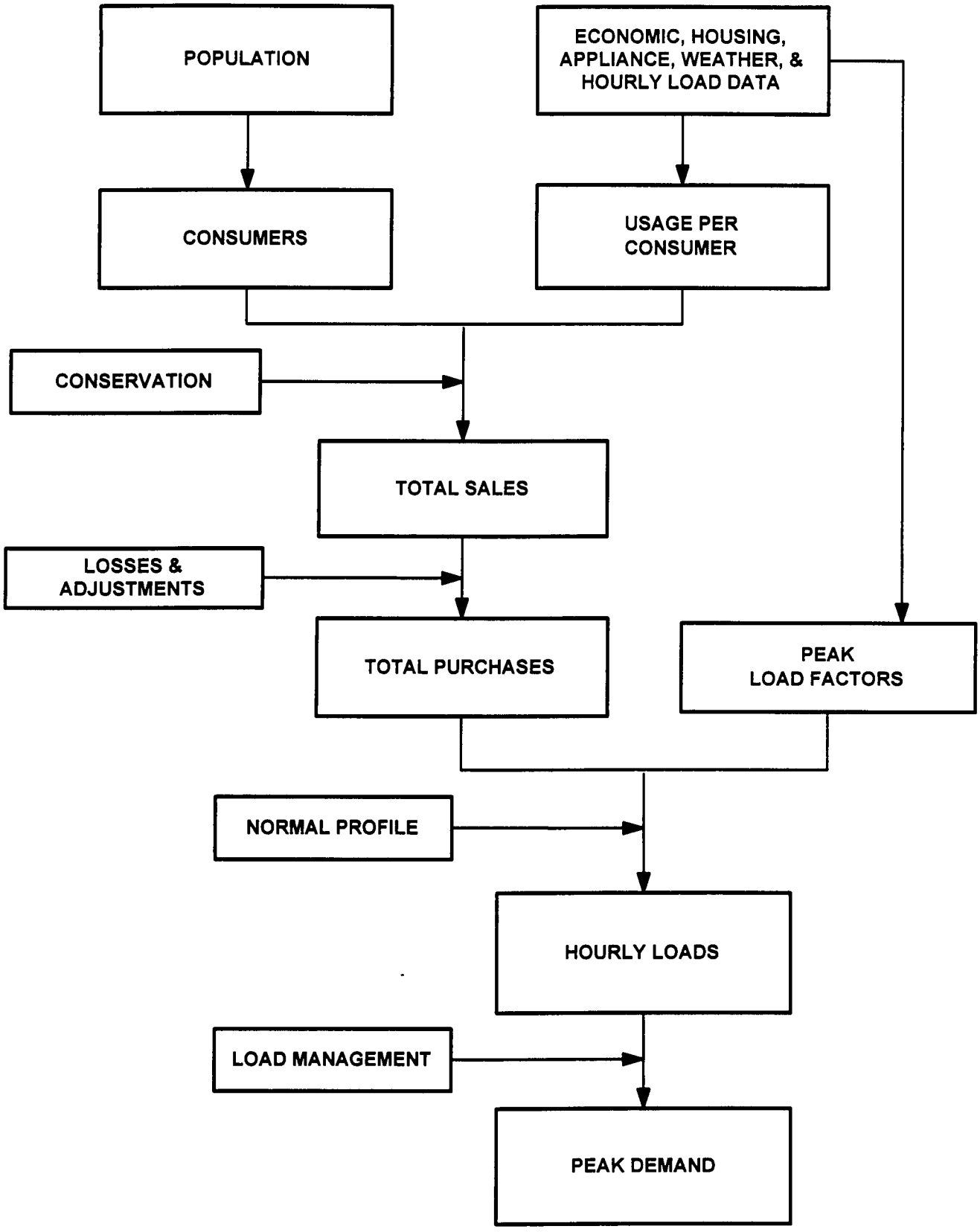
i. **High and Low Scenarios**

Two sets of scenarios are developed in addition to the base case: one for economic scenarios and the other for weather. In lieu of economic scenarios, population (which is the main driving force behind Seminole's load growth) is tested, and high and low population growth scenarios are developed for each Member system based on BEBR's alternative scenarios.

Severe and mild weather scenarios are developed for the energy usage and load factor models using data obtained by averaging the three highest or lowest weather data in each month during the past 20 years.

Figure 1

INTEGRATED FORECASTING SYSTEM



Residential Consumer Model

For each Member, the historical relationship between annual residential consumers and Members' service area population is statistically determined using an ordinary least squares technique, with a first-order auto-regressive correction when necessary. Some Members require dummy variables as a way of explaining abrupt, external changes due to consumer re-classification, accounting changes, or territorial and consumer transfers.

The estimated equations are shown in Table A-1-7. For all ten Members, the high t-ratios and R^2-statistics indicate that service area population is a highly reliable predictor of residential consumers. The estimated equations are applied to the population forecasts to generate annual forecasts of residential consumers. Forecasts are benchmarked using the 1999 actual data. The annual consumer forecasts are converted to monthly forecasts, through linear interpolation between successive values. Then the monthly forecasts are adjusted to reflect seasonal fluctuations using average historical seasonal factors.

Appliance Model

The Appliance model combines the results of the Residential Consumer Model with data from the Residential Appliance Survey to yield forecasts of space-heating and air-conditioning stock variables, which are used in the Residential Energy Usage Model and the Peak Demand Load Factor Model.

First, annual forecasts of the shares of each home type are produced: single-family homes, mobile homes, and multi-family homes. Shares in the final year of the forecast (target shares) are derived by developing an average of the housing type mix for existing consumers and the projected housing type mix for the additional consumers expected to be added to the system during the forecast period. The housing type mix for new consumers is assumed to be the same as that of homes less than 5 years old, based on the two most recent Residential Appliance Surveys. The shares by type for the

forecast period are calculated with linear regression of saturations against time between the historical housing type shares and the target shares for the forecast period.

Next, annual forecasts of space-conditioning saturations are created. Air-conditioning and space-heating saturations are forecast by fitting a logistic curve to the historical saturations and a target saturation for the forecast period. The target is derived by combining the relevant saturations among existing and future consumers. Room air-conditioning saturations are fit with a quadratic curve because they have been declining, reversing the trend of the 1970s. Subsequently, the forecast of room air-conditioning saturations are converted to central air-conditioning equivalents and combined with the central air-conditioning saturations to produce a composite central air-conditioning saturation. Finally, the air-conditioning saturations and the space-heating saturations are combined with housing type share information, resulting in weather-sensitive stock variables for heating and cooling.

Commercial/Industrial Consumer Model

Commercial/industrial consumer forecasts follow basically the same method as explained in the Residential Consumer Model Section for the statistical model specifications. Again, dummy variables are used for abrupt and external historical changes in consumers and adjustments to model specification or forecast results, the conversion of annual consumers to monthly, etc.

Whenever Members expect new large commercial consumers in the near future, the information is implemented in the forecasts as explained in detail in the PRS report. The estimated equations are shown in Table A-I-6.

Other Class Consumer Model

Other classes generally include irrigation, street and highway lighting, public buildings, and sales for resale, which represent less than 2 % of Seminole's Members' total energy sales. Some Member systems include some of these classes in the commercial/industrial sector.

Annual consumer forecasts for Central Florida, Clay, Lee, Sumter and Talquin were projected

using regression analysis against population. For other Members who have experienced slow but stable historical consumer growth patterns, a trending technique is used. The equations for the other classes' consumer model are shown in Table A-1-9.

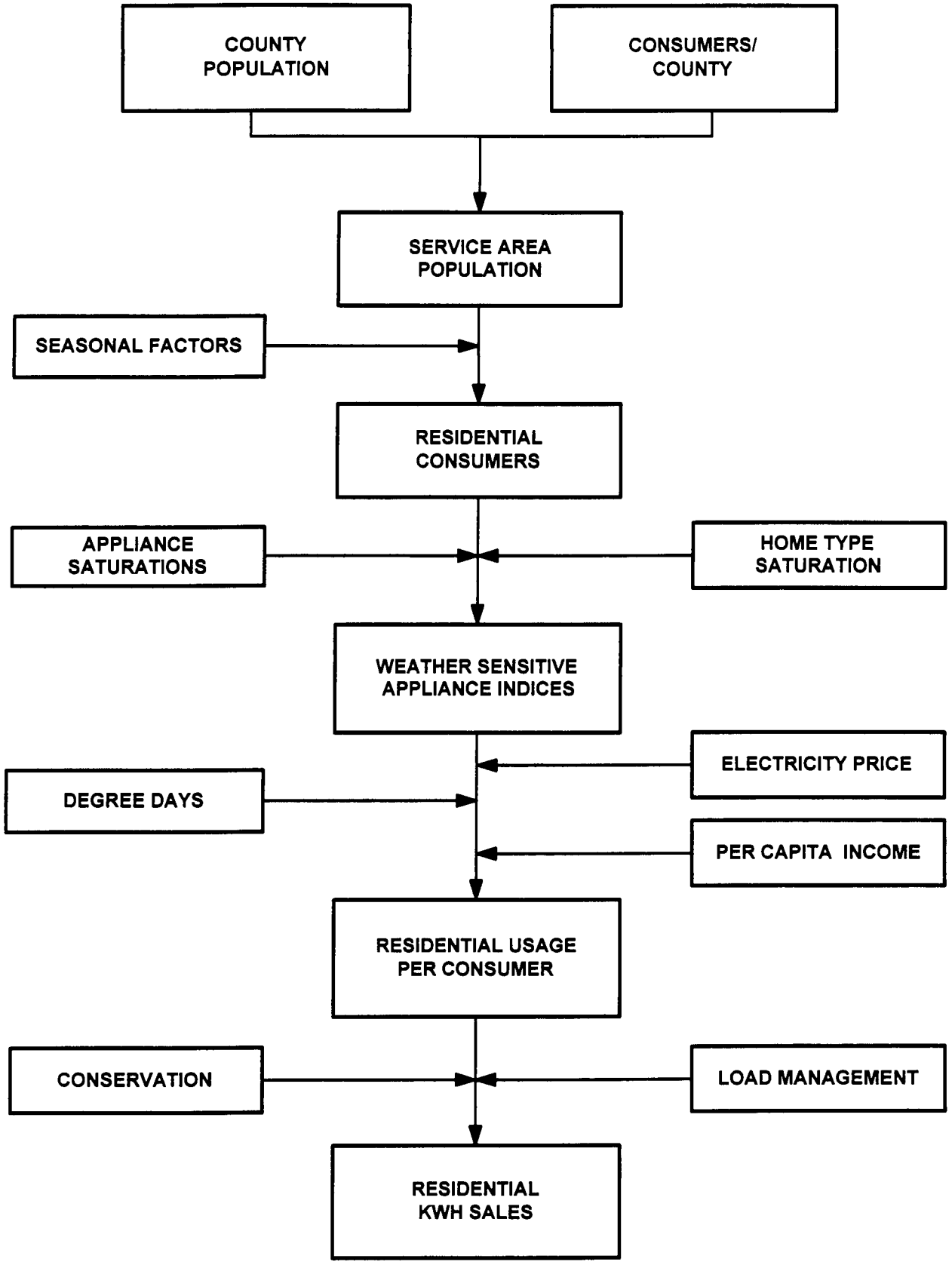
Residential Energy Usage Model

The overall structure of the Residential Energy Usage Model, a combination of econometric and end-use methods, is shown in Figure 2. For each Member system, monthly residential usage is modeled as a function of explanatory variables using ordinary least squares. The explanatory variables include heating and cooling degree variables weighted with space-conditioning appliances, real price of electricity and real per capita income. As previously explained, billing cycle weather is used for most of Members. To explain varying relationships between consumption and weather during the primary heating and cooling months, individual coefficients for those months are also estimated. Table A-I-7 shows the estimated equations and statistical results.

The monthly forecasts are benchmarked against weather-normalized energy in the last year of the analysis period. Then the monthly usage per consumer forecasts are multiplied by the monthly residential consumer forecasts to produce monthly residential energy sales forecasts.

Figure 2

RESIDENTIAL ENERGY USAGE MODEL



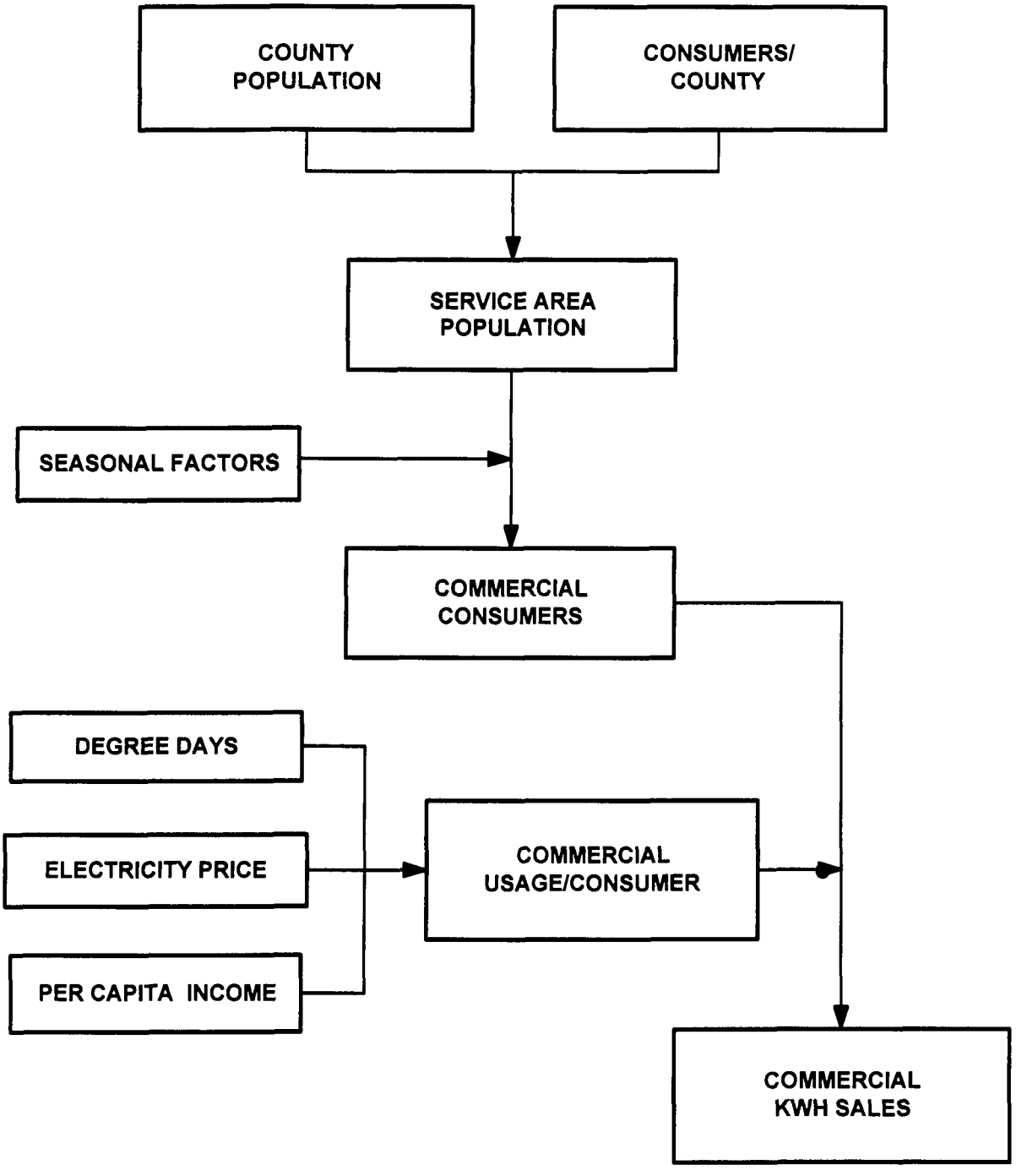
Commercial/Industrial Energy Usage Model

Figure 3 shows the structure of the Commercial/Industrial Energy Usage Model. For each Member system, monthly commercial/industrial usage per consumer is modeled as a function of several explanatory variables, which include monthly heating and cooling degree variables, real price of electricity, real per capita income, and dummy variables for some Member systems to explain abrupt or external changes. Lagged weather variables which reflect the billing cycles are also used in the equations as explained in the Residential Energy Usage Model Section. The models for Glades Electric and Peace River use monthly precipitation variables because irrigation consumers are included in this classification. Ordinary least squares methodology with a first order auto-regressive correction is used. Table A-1-8 shows the equations and statistical results.

Next, the monthly energy usage per consumer forecasts are adjusted for the last year of the historical period. Then the forecasts are combined with the consumer forecasts to produce monthly commercial/industrial KWh sales forecasts.

Whenever Members expect new large commercial consumers in the near future, the information is implemented in the forecasts.

Figure 3
COMMERCIAL ENERGY USAGE MODEL



Other Class Energy Usage Model

Energy usage of other classes for Peace River and Talquin are forecast through a trending method. The remaining Members' historical patterns of energy usage are quite stable and their usage are held constant for the forecast period. Table A-I-9 shows the estimated equations and statistical results.

Total Sales and Purchases

The sales forecasts for Residential, Commercial/Industrial and Other classes are summed up for a total sales forecast by month for each Member system. The sales forecast is converted to Member purchases at delivery point levels using historical averages of the ratio of calendar month purchases to billing cycle sales for each Member. Therefore, these adjustment factors represent both energy losses and the difference between the billing cycle sales and calendar month purchases; the latter, as a function primarily of weather and billing days, often changes unpredictably.

Peak Demand Load Factor Model

The Peak Demand Load Factor Model relates monthly peak load factors to a set of explanatory variables including heating and cooling degree variables, precipitation, air-conditioning and space-heating saturations, and heating and cooling degree hours at the time of the Member's peak demand. In most cases, weather variable coefficients unique to each month are estimated because an analysis indicated that system responses differ for these months. For several Members, dummy variables are used to capture the effect of non-weekday peak demands, which tend to be lower.

Two seasonal equations for each Member system are developed: one for the winter months (November through March) and the other for the summer months (April through October). The monthly load factor forecasts were combined with the purchases forecasts to produce projections of monthly peaks by Member. As explained in the Commercial/Industrial Energy Usage Model Section, new large commercial consumers expected in the near future have been additionally implemented also

in the peak demand projections.

Hourly demand forecasts are created through a calibration procedure which transforms the normal profiles[1] in such a way that maximum peak, monthly minimum, and monthly energy match up the monthly forecasts generated from the forecasting process explained above. This calibration procedure produces hourly profile forecasts by month and by Member, an aggregation of which then constitutes hourly profiles for Seminole's system.

The structure of the model is shown in Figure 4. The models and their statistical properties are presented in Tables A-I-1 and A-I-11. Tables A-1-12 through A-1-17 present historical data and the forecast results in greater detail.

[1] The normal hourly profiles are selected from the historical hourly load data. The criteria used in the selection include weather (monthly degree days, degree hours on peak day), peak demand hour, diversity factors, load factors, and the actual load shapes, etc. The normal months are selected based on the Seminole system level data. Because of weather variations across the Seminole system, however, in some cases individual Members may demonstrate unusual and diverse profiles. Then adjustments are made for the unusual diversity by estimating normal profiles under normal weather.

Figure 4

PEAK DEMAND LOAD FACTOR MODEL

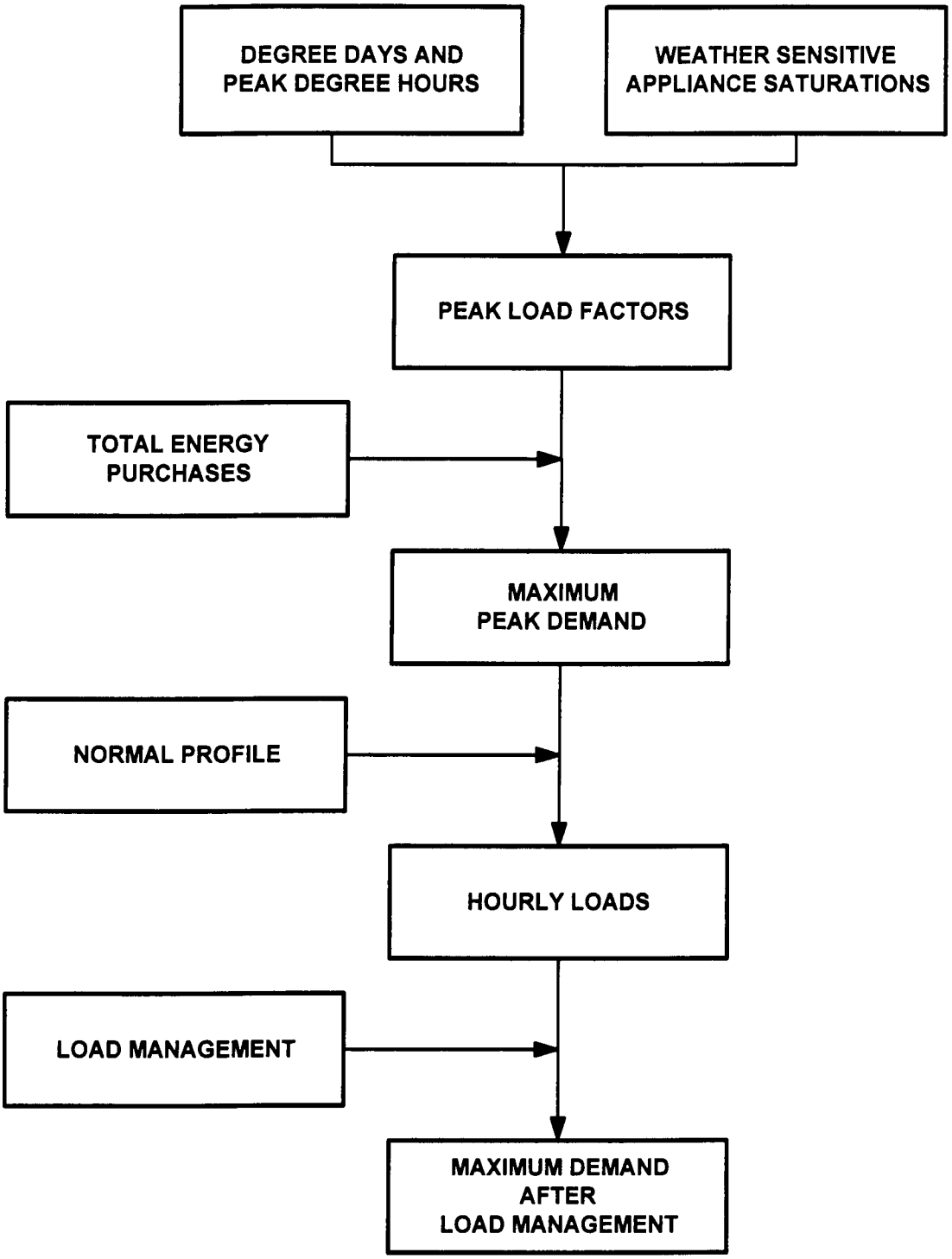


Table A-1-1

COUNTY DISTRIBUTION BY MEMBER SYSTEM (As of 12/31/99)

Member	County	Share (%)	
CENTRAL FLORIDA	Alachua	0.8	
	Dixie	100.0	
	Gilchrist	100.0	
	Levy	100.0	
CLAY	Alachua	17.6	
	Bradford	46.6	
	Clay	96.6	
	Columbia	56.0	
	Duval	0.2	
	Lake	2.5	
	Levy	4.3	
	Marion	13.5	
	Putnam	60.3	
	Union	50.0	
	Volusia	0.8	
GLADES	Glades	47.5	
	Hendry		12.4
	Highlands	13.7	
	Okeechobee	8.8	
LEE COUNTY	Charlotte	0.8	
	Collier	24.1	
	Hendry		3.4
	Lee	57.0	
PEACE RIVER	DeSoto		8.6
	Hardee	63.3	
	Highlands	0.6	
	Hillsborough	0.2	
	Indian River	0.3	
	Manatee	7.4	
	Osceola	1.3	
	Polk	2.4	
SUMTER	Citrus	25.2	
	Hernando	0.2	
	Lake	39.5	
	Levy	6.8	
	Marion	30.3	

	Sumter	81.3
SUWANNEE VALLEY	Columbia	6.1
	Hamilton	46.6
	Lafayette	79.3
	Suwannee	86.9
TALQUIN	Gadsden	61.0
	Leon	23.6
	Liberty	79.1
	Wakulla	68.8
TRI-COUNTY	Dixie	6.6
	Jefferson	55.3
	Lafayette	1.7
	Madison	74.4
	Taylor	67.5
WITHLACOOCHEE	Citrus	36.1
	Hernando	100.0
	Pasco	46.5
	Polk	0.2
	Sumter	4.8

Table A-1-2

PROJECTED REAL PER CAPITA INCOME
GROWTH RATES (%)

Member	Annual Growth Rate *
CENTRAL FLORIDA	0.55
CLAY	0.97
GLADES	1.17
LEE	1.07
PEACE RIVER	1.2
SUMTER	0.73
SUWANNEE VALLEY	0.44
TALQUIN	1.28
TRI-COUNTY	0.68
WITHLACOOCHEE	0.58

* Based on the period 1987-1996.

Table A-1-3

WEATHER STATION ASSIGNMENTS

	Weather Station Weights (%)				
	Ft. Myers	Jacksonville	Orlando	Tallahassee	Tampa
CENTRAL FLORIDA		50.0			50.0
CLAY		66.7	33.3		
GLADES	75.0				25.0
LEE COUNTY	100.0				
PEACE RIVER	20.0		40.0		40.0
SUMTER			66.7		33.3
SUWANNEE VALLEY		66.7		33.3	
TALQUIN				100.0	
TRI-COUNTY				100.0	
WITHLACOOCHEE			25.0		75.0

Table A-1-4

VARIABLE DEFINITIONS

Consumer Models

POP	Member service area population
D79	Dummy variable for Glades' commercial consumer reclassification
D86	Dummy variable for residential consumer reclassifications for Glades and Suwannee Valley, for commercial consumer reclassification for Clay, and for residential billing change for Peace River
D87	Dummy variable for Peace River and Suwannee Valley commercial consumers reclassified due to commercial accounting changes.
D88	Dummy variable for residential consumer billing change for Sumter and commercial consumer reclassification for Lee County
D89	Dummy variable for commercial billing change for Sumter
D90	Dummy variable for Suwannee Valley's residential consumer accounting change
D92	Dummy variable for residential and commercial consumer reclassification for Clay

Usage Models

RESIDENTIAL

CDDZA	Monthly cooling degree days weighted with air conditioning stock index (also used lagged by one and two months as L1CDDZA and L2CDDZA)
SUMMER	CDDZA in August, September and October for Talquin; in June, July and August for Suwannee Valley and Tri-County; and in July, August and September for Central, Glades, Lee County and Withlacoochee River
HDDZH	Monthly heating degree days weighted with space heating stock index (also used lagged by one and two months as L1HDDZH AND L2CDDZA)
WINTER	HDDZH in February and March for Talquin, and for December and January for all other member systems
INCPR	Real per capita income ($) / real price of electricity (cents/KWH)
DSEASON	Dummy variable for Lee for increased usage by seasonal consumers

COMMERCIAL/INDUSTRIAL

CDD	Monthly cooling degree days (also used lagged one and two months as L1CDD and L2CDD
SUMMER	CDD in July and August for Peace River; in July, August and September for Sumter; in June and July for Suwannee Valley; and in August and September for Tri-County
HDD	Monthly heating degree days (also used lagged one and two months as L1HDD and L2HDD)
WINTER	HDD in December for Sumter, in January for Suwannee Valley and Withlacoochee River, and in February for Talquin.
INCPR	Real per capita income ($) / real price of electricity (cents/KWH)
PRECIP	Monthly rainfall in Member service area, lagged one month
D869	Dummy variable for Central's consumer reclassification (9/85)
D859	Dummy variable for Clay's consumer reclassification (8/85)
D921	Dummy variable for Clay's consumer reclassification (1/92)
D8711	Dummy variable for Lee's consumer reclassification (10/87)
D91	Dummy variable for Withlacoochee River's consumer reclassification
D856	Dummy variable for Suwannee Valley's consumer reclassification (5/85)

OTHER CLASSES

TRND	Time variable equal to 1 in the first year of the estimation period
DUM	Dummy variable for Talquin's consumer reclassification in 1987

Load Factor Models:

ACSAT	Air conditioning appliance saturation
SPH	Space heating appliance saturation
PRECIP	Monthly rainfall in Member service area
WKEND	Dummy variable for weekend and holiday peak demand
CDD	Monthly cooling degree days
JANHDD	Heating degree days in January
FEBHDD	Heating degree days in February
NOVHDD	Heating degree days in November
DECHDD	Heating degree days in December
MAYCDD	Cooling degree days in May
JUNCDD	Cooling degree days in June
JULCDD	Cooling degree days in July
AUGCDD	Cooling degree days in August
SEPCDD	Cooling degree days in September
OCTCDD	Cooling degree days in October
JANPKDH	Heating degree hours at the time of maximum demand in January
FEBPKDH	Heating degree hours at the time of maximum demand in February
MARPKDH	Heating degree hours at the time of maximum demand in March
NOVPKDH	Heating degree hours at the time of maximum demand in November
DECPKDH	Heating degree hours at the time of maximum demand in December
APRPKDH	Cooling degree hours at the time of maximum demand in April
MAYPKDH	Cooling degree hours at the time of maximum demand in May
JUNPKDH	Cooling degree hours at the time of maximum demand in June
JULPKDH	Cooling degree hours at the time of maximum demand in July
AUGPKDH	Cooling degree hours at the time of maximum demand in August
SEPPKDH	Cooling degree hours at the time of maximum demand in September
OCTPKDH	Cooling degree hours at the time of maximum demand in October

Table A-1-5

RESIDENTIAL CONSUMER MODEL

Coefficients and Statistics

Member	Estimation Period	Intercept	Population	Auto-regressive Term	Dummy Variable	R^2	Durbin-Watson
CENTRAL FLORIDA	1977-1999	-5143.04 (-21.20)	0.491 (95.21)	-0.466 (-2.35)	--	0.997	--
CLAY	1977-1999	-32146.00 (-21.09)	0.491 (91.99)	-0.324 (-1.49)	2153.83 (-4.49)	0.999	--
GLADES	1977-1999	-3793.72 (-8.48)	0.538 (29.16)	-0.416 (-1.99)	1011.54 (6.91)	0.991	--
LEE	1977-1999	-8197.75 (-6.27)	0.44 (84.77)	--	--	0.997	0.808
PEACE RIVER	1977-1999	-7622.53 (-7.23)	0.51 (22.94)	-0.61 (-3.42)	-845.33 (3.22)	0.991	--
SUMTER	1977-1999	-23051.00 (-12.52)	0.508 (48.67)	-0.81 (-6.16)	-2932.68 (-3.83)	0.995	--
SUWANNEE VALLEY	1977-1999	-3505.52 (-5.20)	0.47 (29.14)	-0.505 (-2.55)	-963.74 (-5.31)	0.995	--
TALQUIN	1977-1999	-16535.00 (-11.75)	0.572 (34.59)	-0.66 (-3.76)	--	0.984	--
TRI-COUNTY	1977-1999	-7326.33 (-5.52)	0.56 (13.29)	-0.883 (-8.45)	--	0.893	--
WITHLACOOCHEE	1977-1999	-20782.00 (-28.05)	0.492 (164.53)	0.607 (-3.41)	--	0.999	--

Notes: (1) t-values shown in parentheses

(2) Dummy Variables:

Clay	D92=1 1977-1991 (consumer reclassification)
Glades	D86=1 1977-1985 (consumer reclassification)
Peace River	D86=1 1977-1985 (change to year-round billing)
Sumter	D88=1 1979-1987 (change to year-round billing)
Suwannee	D90=1 1977-1989 (accounting change)

Table A-1-6

COMMERCIAL CONSUMER MODEL
Coefficients and Statistics

Member	Estimation Period	Intercept	Population	Auto-regressive Term	Dummy Variable	R^2	Durbin-Watson
CENTRAL FLORIDA	1977-1999	-636.54 (-20.71)	0.039 (60.12)	-0.468 (-2.37)	--	0.994	--
CLAY	1977-1999	-2798.77 (-4.84)	0.046 (22.81)	-0.529 (-2.72)	-2385.55 (-12.80)	0.994	--
GLADES	1977-1999	495.57 (2.91)	0.109 (12.97)	-0.736 (-4.74)	-539.576 (-4.36)	0.934	--
LEE	1981-1999	3306.87 (4.07)	0.028 (9.64)	-0.509 (-2.583)	-1602.12 (-4.77)	0.978	--
PEACE RIVER	1977-1999	-1888.66 (-12.66)	0.108 (28.51)	-0.364 (-1.74)	--	0.974	--
SUMTER	1977-1999	132.075 (0.82)	0.037 (34.39)	--	349.96 (2.65)	0.982	0.961
SUWANNEE VALLEY	1977-1999	-1171.05 (-9.03)	0.049 (14.48)	-0.62 (-3.44)	--	0.912	--
TALQUIN	1977-1999	-2125.17 (-7.28)	0.044 (14.40)	-0.564 (-2.90)	--	0.916	--
TRI-COUNTY	1977-1999	-1099.14 (-12.061)	0.068 (24.23)	-0.475 (-2.41)	--	0.965	--
WITHLACOOCHEE	1977-1999	-4341.9 (-15.71)	0.051 (46.14)	-0.574 (-3.13)	--	0.9902	--

Notes: (1) t-values shown in parentheses
(2) Dummy Variables:

Clay	D86=1 1977-1985 (consumer reclassification)
Lee	D92=1 1977-1991 (consumer reclassification)
Glades	D79=1 1977-1978 (consumer reclassification)
Lee	D88=1 1981-1987 (consumer reclassification)
Peace River	D87=1 1985-1986 (accounting change)
Sumter	D89=1 1987-1989 (billing change)
Suwannee	D87=1 1987-1988 (accounting change)

Table A-1-7

RESIDENTIAL USAGE MODEL
Coefficients and Statistics

	Intercept	HDDZH	LHDDZH	Winter	CDDZA	LCDDZA	Summer	IncPr	DSeason	R^2	Durbin-Watson
CENTRAL FLORIDA											
	173.95	2.204	0.866	3.685	1.982	0.12	2.277	0.069	--	0.94	1.44
	(9.46)	(9.53)	(2.72)	(20.99)	(18.56)	(2.0)	(26.80)	(22.64)			
CLAY											
	495.64	1.751	--	4.41	1.331	--	1.71	0.03	--	0.82	1.56
	(14.77)	(3.84)		(11.88)	(10.80)		(22.15)	(7.27)			
GLADES											
	217.02	6.76	1.81	5.22	0.77	0.35	1.08	0.21	--	0.84	1.58
	(6.03)	(7.28)	(3.15)	(8.71)	(8.18)	(3.98)	(12.24)	(11.98)			
LEE											
	430.91	2.21	0.99	--	1.6	--	1.94	0.075	61.57	0.92	1.69
	(22.15)	(12.23)	(3.01)		(22.84)		(38.19)	(16.28)	(4.7)		
PEACE RIVER											
	186.293	4.93	1.05	6.43	1.2	0.088	--	0.22	--	0.81	1.69
	(5.32)	(6.97)	(2.034)	(11.145)	(13.40)	(0.99)		(12.68)			
SUMTER											
	381.73	3.96	--	6.22	1.94	--	--	0.06	--	0.67	1.77
	(9.80)	(4.84)		(8.99)	(14.60)			(8.20)			
SUWANNEE											
	308.23	0.99	0.87	2.49	3.28	0.2	3.53	0.08	--	0.93	1.7
	(10.75)	(4.14)	(3.04)	(15.19)	(16.68)	(2.27)	(29.07)	(13.72)			
TALQUIN											
	538.07	3.64	--	3.16	1.47	--	1.72	0.05	--	0.9	1.83
	(22.51)	(11.63)		(19.56)	(16.41)		(32.40)	(11.31)			
TRI-COUNTY											
	372.54	1.32	0.41	2.02	2.49	0.35	2.73	0.04	--	0.95	2.25
	(27.51)	(8.80)	(2.39)	(20.04)	(20.23)	(6.15)	(34.40)	(12.81)			
WITHLACOOCHEE											
	253.436	2.77	1.85	4.15	1.82	--	2.23	0.08	--	0.9	1.95
	(8.79)	(11.42)	(5.15)	(20.26)	(17.89)		(32.78)	(15.41)			

Notes:
(1) t-values in parentheses
(2) Estimation period = 1/85-12/99
(3) Central, Lee, Suwannee, Tri-County and Withlacoochee use billing month weather with calendar month lag. Talquin uses calendar month weather lagged once for CDD/HDD and twice for LCDD/LHDD. All other members use calendar month weather with calendar month lag.
(4) Refer to Table A-III-6 for definitions of Summer, Winter, DSeason, and IncPr variables

Table A-1-8

COMMERCIAL USAGE MODEL
Coefficients and Statistics

	Intercept	HDD	LHDD	Winter	CDD	LCDD	Summer	IncPr	Precip	Dummy Variable	R^2	Durbin-Watson
CENTRAL FLORIDA	615.57	0.53	-	-	2.40	0.47	-	0.29	-	389.52	0.86	1.92
	(6.96)	(2.02)	-	-	(10.02)	(2.98)	-	(23.38)	-	(4.54)		
CLAY	2946.47	-	-	-	2.59	-	-	0.05	-	1163.11	0.73	2.00
	(12.39)	-	-	-	(13.48)	-	-	(2.61)	-	(11.35)		
GLADES	61.07	0.73	-	-	-	-	-	1.26	-37.87	-	0.76	0.72
	(0.53)	(1.08)	-	-	-	-	-	(22.29)	(-5.21)	-		
LEE	2180.05	-	-	-	1.85	-	-	0.55	-	826.75	0.65	2.24
	(12.55)	-	-	-	(7.89)	-	-	(14.72)	-	(7.42)		
PEACE RIVER	747.39	1.28	-	-	1.07	-	0.88	0.41	-42.12	-	0.61	0.90
	(10.11)	(1.89)	-	-	(7.05)	-	(5.58)	(13.57)	(-6.33)	-		
SUMTER	348.71	-	-	10.03	1.20	-	1.26	0.43	-	-	0.82	1.54
	(3.66)	-	-	(3.46)	(7.03)	-	(10.56)	(25.21)	-	-		
SUWANNEE	3160.82	-	-	1.70	3.74	0.61	4.88	-	-	-	0.60	0.53
	(63.58)	-	-	(4.13)	(5.77)	(1.72)	(9.42)	-	-	-		
TALQUIN	3594.78	-	-	0.73	3.07	-	-	0.22	-	-	0.88	1.17
	(53.81)	-	-	(2.53)	(28.15)	-	-	(18.84)	-	-		
TRI-COUNTY	1681.42	-	-	-	2.45	0.47	2.83	0.21	-	-	0.87	2.06
	(21.29)	-	-	-	(10.50)	(3.40)	(11.89)	(13.12)	-	-		
WITHLACOOCHEE	3075.05	-	-	1.70	2.94	0.27	-	0.17	-	-699.10	0.91	1.37
	(27.98)	-	-	(3.98)	(12.55)	(1.66)	-	(10.57)	-	(-13.73)		

NOTES: (1)t-values in parentheses
(2)Estimation period = 1/85-12/99.
(3)Central, Lee , Suwannee, Tri-County and Withlacoochee use billing month weather with calendar month lag. Talquin uses calendar month weather lagged once for CDD/HDD and twice for LCDD/LHDD. All other members use calendar month weather with calendar month lag.
(4)Refer to Table A-III-6 for definitions of Summer, Winter, and IncPr variables

Table A-1-9
OTHER CLASSES CONSUMER MODEL
Coefficients and Statistics

Member	Estimation Period	Intercept	Population	Auto-regressiv Term	Dummy Variable	R^2	Durbin Watson
CENTRAL FLORIDA	1977-1999	-30.78 (-7.26)	-0.001 (20.78)	-0.57 (-3.03)	-4.05 (-1.98)	0.97	--
CLAY	1978-1999	-5.14 (-0.68)	0.0001 (6.17)	-0.77 (-5.29)	--	0.65	--
LEE	1974-1999	358.94 (7.94)	0.001 (5.53)	-0.82 (-7.03)	--	0.56	--
SUMTER	1978-1999	-88.89 (-1.32)	0.008 (19.52)	-0.46 (-2.304)	--	0.95	--
TALQUIN	1974-1999	102.586 (4.65)	0.006 (23.52)	-0.543 (-3.089)	--	0.95	--

NOTES:
t-values shown in parentheses
(2) Dummy Variable for Central = 1 1977-1980 (consumer reclassification)
(3) Forecasts for the other distribution members are based on periodic increases or are held constant

OTHER CLASSES ENERGY USAGE MODEL
Coefficients and Statistics

Member	Estimation Period	Intercept	Trend	Auto-regressiv Term	Dummy Variable	R^2	Durbin Watson
PEACE RIVER	1977-1999	1000965 (18.689)	10246 (2.292)	-0.56 (-2.959)	-77755 (-0.883)	0.21	--
TALQUIN	1978-1999	5944.05 (2.786)	1181.014 (8.29)	-0.43 (-1.97)	23542/-7587.82 (15.052)/(-5.206)	0.95	--

Notes:
(1) t-values shown in parentheses
(2) Dummy Variable for Peace River = 1 1997
(3) Dummy Variable for Talquin = 1 1978-1986 (consumer reclassification)
(4) Dummy Variable for Talquin = 1 1997
(5) Forecasts for the other distribution members are held constant

Table A-1-10

LOAD FACTOR MODEL - WINTER SEASON (JANUARY-MARCH & NOVEMBER-DECEMBER)
Coefficients and Statistics

	Central	Clay	Glades	Lee	Peace River	Sumter	Suwannee Valley	Talquin	Tri-County	Withlacoochee River
INTERCEPT	0.84 (61.68)	0.78 (46.99)	0.71 (13.09)	0.82 (52.79)	0.78 (19.84)	0.69 (32.17)	0.85 (57.68)	0.77 (40.55)	0.90 (55.79)	0.67 (67.98)
SPH	-0.29 (-13.52)	-0.012 (-0.59)	0.13 (1.95)	- -	0.02 (0.44)	-0.03 (-1.48)	-0.27 (-13.47)	-0.20 (-7.96)	-0.39 (-16.06)	- -
JANHDD	0.0005 (6.22)	0.0005 (7.25)	0.0002 (0.79)	-0.0004 (-0.97)	0.0003 (2.41)	0.0008 (6.43)	0.0003 (5.18)	0.0002 (4.27)	0.0001 (2.36)	0.001 (5.17)
FEBHDD	0.0004 (3.97)	0.0004 (4.02)	- -	- -	0.0002 (1.03)	0.0006 (3.58)	0.0004 (4.97)	0.0003 (3.50)	0.0002 (2.37)	0.001 (3.78)
NOVHDD	- -	- -	- -	- -	- -	- -	- -	0.000005 0.05	- -	- -
DECHDD	0.0006 (8.75)	0.0005 (7.10)	0.0003 (1.27)	0.0001 (0.56)	0.0004 (3.16)	0.008 (7.26)	0.0004 (7.30)	0.0005 (7.85)	0.0003 (4.59)	0.0008 (6.03)
JANPKDH	-0.003 (-16.05)	-0.004 (-19.65)	-0.004 (-10.94)	-0.004 (-9.51)	-0.005 (17.21)	-0.004 (-15.66)	-0.002 (-13.77)	-0.002 (-10.81)	-0.0001 (2.36)	-0.004 (-12.98)
FEBPKDH	-0.003 (-16.16)	-0.003 (-18.58)	-0.004 (-16.10)	-0.005 (-17.04)	-0.004 (-17.11)	-0.003 (-15.41)	-0.002 (-14.98)	-0.002 (-10.94)	-0.002 (-10.11)	-0.004 (-15.89)
MARPKDH	-0.002 (-17.80)	-0.003 (-22.82)	-0.004 (-13.18)	-0.004 (-13.74)	-0.004 (-19.85)	-0.003 (-17.52)	-0.002 (-15.82)	-0.002 (-14.45)	-0.0016 (-10.99)	-0.004 (-15.72)
NOVPKDH	-0.002 (-15.08)	-0.003 (-19.65)	-0.004 (-8.75)	-0.005 (-6.71)	-0.004 (-15.14)	-0.002 (-13.19)	-0.002 (-14.22)	-0.002 (-7.33)	-0.001 (-9.81)	-0.003 (11.27)
DECPKDH	-0.003 (-17.40)	-0.003 (-19.24)	-0.004 (-10.24)	-0.004 (-10.09)	-0.004 (-15.74)	-0.003 (-15.94)	-0.002 (-14.59)	-0.003 (-12.60)	-0.002 (-10.03)	-0.004 (-15.16)
WKEND	0.007 (2.11)	0.02 (6.03)	0.016 (1.80)	0.0002 (0.03)	0.01 (2.50)	0.015 (3.06)	0.005 (1.48)	0.031 (5.43)	0.024 (4.07)	0.17 (2.99)
R^2	0.81	0.81	0.71	0.72	0.82	0.76	0.76	0.68	0.71	0.75
D.W.	1.97	1.83	1.43	1.60	1.37	1.50	2.02	1.38	1.78	1.62

Notes: (1) t-values in parentheses
(2) Estimation period is 1/85-12/99

Table A-1-11

LOAD FACTOR MODEL - SUMMER SEASON (APRIL-OCTOBER)
Coefficients and Statistics

	Central	Clay	Glades	Lee	Peace River	Sumter	Suwannee Valley	Talquin	Tri-County	Withlacoochee River
Intercept	0.76	0.708	0.74	0.68	0.653	0.8	0.67	0.69	0.71	0.682
	(55.11)	(44.79)	(26.89)	(84.92)	(46.64)	(41.69)	(125.2)	(55.27)	(69.89)	(23.32
AC	-0.09	-0.04	0.01	-	0.0723	-0.099	-	-0.43	-0.021	0.025
	(-6.11)	(-2.16)	(0.32)	-	(4.67)	(-4.9)	-	(-2.8)	(-1.3)	(0.82
PRECIP	-0.002	-0.001	-0.002	-	-	-0.004	-0.0016	0.0005	-	-0.001
	(-3.81)	(-3.84)	(-2.31)	-	-	(-4.77)	(-3.27)	(1.65)	-	(-2.35
MAYCDD	0.0002	0.005	0.0002	0.0002	0.0004	0.0006	-	-	0.0002	0.0005
	(1.75)	(5.25)	(1.45)	(3.05)	(4.16)	(4.24)	-	-	(2.08)	(4.56
JUNCDD	-	0.0007	-	0.0007	0.0005	-	0.0004	0.0007	0.0005	-
	-	(7.46)	-	(5.4)	(5.15)	-	(4.97)	(9.59)	(5.86)	-
JULCDD	0.0002	.0004	-	0.0005	0.0002	0.0003	0.0003	0.0004	0.0004	0.0003
	(1.62)	(3.59)	-	(4.15)	(1.82)	(2.11)	(2.95)	(3.54)	(4.22)	(2.26
AUGCDD	-	0.0001	0.0004	0.0004	-	-	0.0001	0.0004	0.0002	0.0003
	-	(1.45)	(2.27)	(2.92)	-	-	(1.27)	(4.73)	(2.8)	(2.07
SEPCDD	0.0003	0.008	0.0006	0.0005	0.0004	0.0004	0.0006	0.0007	0.0005	0.0003
	(2.22)	(6.11)	(2.53)	(2.65)	(3.44)	(2.34)	(4.24)	(5.24)	(4.32)	(2.037
OCTCDD	0.0004	0.0003	0.0003	0.0006	0.00009	0.0003	-	-	-	0.0006
	(2.17)	(1.76)	(1.78)	(6.02)	(0.82)	(2.57)	-	-	-	(4.75
APRPKDH	-0.0008	-0.009	-0.0007	-0.0003	-0.0007	-0.001	-0.00089	-0.0006	-0.0004	-0.0008
	(-9.75)	(-13.98)	(-5.53)	(-4.71)	(-9.77)	(-12.19)	(-13.08)	(-10.47)	(-6.92)	(-8.38
MAYPKDH	-0.0008	-0.001	-0.0008	-0.0005	-0.0007	-0.001	-0.0007	-0.0005	-0.0005	-0.001
	(-7.52.)	(-12.28)	(-4.04)	(-6.13)	(-7.02)	(-9.56)	(-15.009)	(-14.4)	(-7.54)	(-0.001
JUNPKDH	-0.00035	-0.001	-0.0002	-0.0009	-0.0009	-0.0005	-0.0007	-0.001	-0.0007	-0.0004
	(-7.46)	(-10.28)	(-2.67)	(-6.04)	(-6.91)	(-8.77)	(-7.88)	(-13.32)	(-8.6)	(-7.81
JULPKDH	-0.0005	-0.009	-0.0002	-0.0008	-0.0005	-0.0008	-0.0005	-0.0007	-0.0006	-0.0008
	(-3.02)	(-4.67)	(-2.85)	(-4.93)	(-3.01)	(-3.83)	(-3.78)	(-5.42)	(-5.66)	(-4.14
AUGPKDH	-0.0002	-0.0004	-0.0007	-0.0006	-0.0001	-0.0003	-0.0004	-0.0006	-0.0004	-0.0008
	(-5.06)	(-2.59)	(-3.086)	(-3.45)	(-4.154)	(-6.41)	(-2.68)	(-7.16)	(-4.62)	(-3.72
SEPPKDH	-0.0008	-0.001	-0.001	-0.0007	-0.00074	-0.001	-0.001	-0.001	-0.0008	-0.0008
	(-4.63)	(-8.3)	(-3.42)	(-3.09)	(-4.64)	(-4.64)	(-7.753)	(-8.35)	(-7.35)	(-4.85
OCTPKDH	-0.001	-0.0009	-0.0008	-0.0009	-0.0005	-0.001	-0.0009	-0.0006	-0.0006	-0.0001
	(8.03)	(-8.01)	(-3.72)	(-8.35)	(-5.12)	(-9.17)	(-14.75)	(-11.47)	(-12.83)	(-10.62
WKEND	-	-	0.016	0.005	-0.00004	-	-	-0.003	0.0005	-
	-	-	(2.63)	(1.65)	(-0.019)	-	-	(-1.24)	(0.18)	-
R^2	0.51	0.7	0.4	0.53	0.58	0.53	0.69	0.65	0.58	0.54
D.W.	1.30	1.34	1.26	1.33	1.41	1.18	1.6	1.51	1.9	1.15

Notes: (1) t-values in parentheses
(2) Estimation period is 4/85-10/99

Seminole Electric Cooperative, Inc.
2000 Power Requirements Study

HISTORY AND FORECAST OF SALES AND PURCHAS

	MWH Residential Sales	Change	(%) Growt	MWH Commercial Sales	Change	(%) Growt	MWH Other Sales	(%) Growt	MW Total Sales	Adjustment Facto	MWH Purchases	(%) Growt
1975	1,808,343	-	-	572,982	-	-	129,934	-	2,511,258	0.123	2,819,385	-
1976	1,962,238	153,895	8.5	648,212	75,230	13.1	137,111	5.5	2,747,561	0.131	3,106,226	10.2
1977	2,194,733	232,495	11.8	730,524	82,312	12.7	144,169	5.1	3,069,426	0.125	3,452,228	11.1
1978	2,408,602	213,869	9.7	812,290	81,766	11.2	137,937	(4.3)	3,358,828	0.127	3,785,576	9.7
1979	2,523,004	114,402	4.7	881,632	69,342	8.5	138,330	0.3	3,542,966	0.111	3,934,498	3.9
1980	2,755,782	232,778	9.2	959,773	78,141	8.9	142,440	3.0	3,857,995	0.111	4,286,536	8.9
1981	2,991,266	235,484	8.5	1,044,568	84,795	8.8	95,114	(33.2)	4,130,948	0.112	4,593,435	7.2
1982	2,949,831	(41,435)	(1.4)	1,070,081	25,513	2.4	76,657	(19.4)	4,096,569	0.106	4,531,676	(1.3)
1983	3,198,058	248,227	8.4	1,156,318	86,237	8.1	75,972	(0.9)	4,430,347	0.117	4,949,498	9.2
1984	3,398,711	200,653	6.3	1,263,900	107,582	9.3	80,983	6.6	4,743,594	0.085	5,148,099	4.0
1985	3,691,619	292,908	8.6	1,412,278	148,378	11.7	90,714	12.0	5,194,611	0.102	5,723,399	11.2
1986	3,931,782	240,163	6.5	1,491,027	78,749	5.6	86,655	(4.5)	5,509,464	0.090	6,005,786	4.9
1987	4,357,087	425,305	10.8	1,597,572	106,545	7.1	89,808	3.6	6,044,467	0.073	6,484,170	8.0
1988	4,723,379	366,292	8.4	1,733,971	136,399	8.5	94,571	5.3	6,551,920	0.073	7,030,533	8.4
1989	5,076,789	353,410	7.5	1,921,868	187,897	10.8	136,505	44.3	7,135,163	0.078	7,690,356	9.4
1990	5,340,035	263,246	5.2	1,985,420	63,552	3.3	60,533	(55.7)	7,385,988	0.061	7,833,006	1.9
1991	5,525,440	185,405	3.5	2,031,051	45,631	2.3	90,897	50.2	7,647,388	0.069	8,176,133	4.4
1992	5,698,277	172,837	3.1	2,122,532	91,481	4.5	108,860	19.8	7,929,669	0.064	8,433,673	3.1
1993	5,999,095	300,818	5.3	2,261,094	138,562	6.5	102,461	(5.9)	8,362,649	0.074	8,977,911	6.5
1994	6,250,041	250,946	4.2	2,399,466	138,372	6.1	86,248	(15.8)	8,735,755	0.055	9,218,228	2.7
1995	6,906,619	656,578	10.5	2,564,149	164,683	6.9	101,426	17.6	9,572,195	0.068	10,218,400	10.8
1996	7,266,364	359,745	5.2	2,681,324	117,175	4.6	105,411	3.9	10,053,100	0.052	10,578,597	3.5
1997	7,238,240	(28,124)	(0.4)	2,808,825	127,501	4.8	123,161	16.8	10,170,226	0.055	10,734,384	1.5
1998	7,974,604	736,364	10.2	3,011,899	203,074	7.2	117,290	(4.8)	11,103,794	0.052	11,682,226	8.8
1999	7,992,818	18,214	0.2	3,108,882	96,983	3.2	126,775	8.1	11,228,474	0.061	11,912,382	2.0
2000	8,328,660	335,842	4.2	3,308,840	199,958	6.4	121,411	(4.2)	11,758,911	0.063	12,502,873	5.0
2001	8,645,010	316,350	3.8	3,467,842	159,002	4.8	125,064	3.0	12,237,916	0.063	13,014,763	4.1
2002	8,973,972	328,962	3.8	3,587,003	119,161	3.4	128,014	2.4	12,688,990	0.064	13,494,837	3.7
2003	9,307,610	333,638	3.7	3,710,871	123,868	3.5	130,906	2.3	13,149,388	0.064	13,984,718	3.6
2004	9,674,540	366,930	3.9	3,848,573	137,702	3.7	134,128	2.5	13,657,241	0.063	14,522,701	3.8
2005	9,995,925	321,385	3.3	3,968,592	120,019	3.1	136,637	1.9	14,101,154	0.064	14,997,521	3.3
2006	10,361,661	365,736	3.7	4,107,344	138,752	3.5	140,540	2.9	14,609,544	0.064	15,538,760	3.6
2007	10,736,798	375,137	3.6	4,249,624	142,280	3.5	143,377	2.0	15,129,799	0.064	16,092,598	3.6
2008	11,152,617	415,819	3.9	4,407,268	157,644	3.7	146,636	2.3	15,706,520	0.063	16,703,735	3.8
2009	11,512,837	360,220	3.2	4,544,551	137,283	3.1	149,053	1.6	16,206,440	0.064	17,238,749	3.2
2010	11,916,082	403,245	3.5	4,696,517	151,966	3.3	151,955	1.9	16,764,554	0.064	17,832,986	3.4
2011	12,333,746	417,664	3.5	4,855,104	158,587	3.4	155,867	2.6	17,344,718	0.064	18,450,714	3.5
2012	12,799,544	465,798	3.8	5,031,069	175,965	3.6	159,242	2.2	17,989,855	0.064	19,134,395	3.7
2013	13,201,927	402,383	3.1	5,181,839	150,770	3.0	161,706	1.5	18,545,471	0.064	19,729,264	3.1
2014	13,649,849	447,922	3.4	5,351,618	169,779	3.3	164,685	1.8	19,166,151	0.064	20,390,148	3.3
2015	14,110,681	460,832	3.4	5,523,279	171,661	3.2	167,704	1.8	19,801,664	0.064	21,066,959	3.3
2016	14,634,395	523,714	3.7	5,719,022	195,743	3.5	171,221	2.1	20,524,638	0.064	21,833,201	3.6
2017	15,085,567	451,172	3.1	5,886,823	167,801	2.9	173,858	1.5	21,146,248	0.064	22,498,983	3.0
2018	15,590,270	504,703	3.3	6,075,818	188,995	3.2	176,980	1.8	21,843,068	0.064	23,241,085	3.3
2019	16,107,364	517,094	3.3	6,267,019	191,201	3.1	180,123	1.8	22,554,506	0.064	23,998,853	3.3
2020	16,683,905	576,541	3.6	6,480,288	213,269	3.4	183,730	2.0	23,347,923	0.064	24,839,849	3.5

The two terms, Sales and Purchases are defined as follows. Purchases represent electricity purchases fromSeminole by its members at the delivery point level; sales represent consumption at the retail consumer level.
Reporting actual data through December 1999.

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Seminole Electric Cooperative, Inc.
2000 Power Requirements Stud

RESIDENTIAL CONSUMERS AND ENERGY SALE

	Average Consumers	Change	(%) Growth	KWH/ Consumer	Change	(%) Growth	MWH Sales	Change	(%) Growth
1976	215,880	-	-	9,089	-	-	1,962,238	-	-
1977	227,936	12,056	5.58	9,629	540	5.94	2,194,733	232,495	11.85
1978	243,271	15,335	6.73	9,901	272	2.82	2,408,602	213,869	9.74
1979	262,622	19,351	7.95	9,607	(294)	(2.97)	2,523,004	114,402	4.75
1980	283,276	20,654	7.86	9,728	121	1.26	2,755,782	232,778	9.23
1981	302,533	19,257	6.80	9,887	159	1.63	2,991,266	235,484	8.55
1982	318,592	16,059	5.31	9,259	(628)	(6.35)	2,949,831	(41,435)	(1.39)
1983	335,363	16,771	5.26	9,536	277	2.99	3,198,058	248,227	8.41
1984	353,131	17,768	5.30	9,625	89	0.93	3,398,711	200,653	6.27
1985	374,234	21,103	5.98	9,864	239	2.48	3,691,619	292,908	8.62
1986	394,047	19,813	5.29	9,978	114	1.16	3,931,782	240,163	6.51
1987	421,801	27,754	7.04	10,330	352	3.53	4,357,087	425,305	10.82
1988	442,569	20,768	4.92	10,673	343	3.32	4,723,379	366,292	8.41
1989	462,593	20,024	4.52	10,975	302	2.83	5,076,789	353,410	7.48
1990	481,194	18,601	4.02	11,097	122	1.11	5,340,035	263,246	5.19
1991	495,363	14,169	2.94	11,154	57	0.51	5,525,440	185,405	3.47
1992	506,754	11,391	2.30	11,245	91	0.82	5,698,277	172,837	3.13
1993	518,687	11,933	2.35	11,566	321	2.85	5,999,095	300,818	5.28
1994	531,032	12,345	2.38	11,770	204	1.76	6,250,041	250,946	4.18
1995	546,832	15,800	2.98	12,630	860	7.31	6,906,619	656,578	10.51
1996	561,981	15,149	2.77	12,930	300	2.38	7,266,364	359,745	5.21
1997	578,345	16,364	2.91	12,515	(415)	(3.21)	7,238,240	(28,124)	(0.39)
1998	592,441	14,096	2.44	13,461	946	7.56	7,974,604	736,364	10.17
1999	607,059	14,618	2.47	13,166	(295)	(2.19)	7,992,818	18,214	0.23
2000	624,729	17,670	2.91	13,332	166	1.26	8,328,660	335,842	4.20
2001	641,782	17,053	2.73	13,470	138	1.04	8,645,010	316,350	3.80
2002	658,087	16,305	2.54	13,636	166	1.23	8,973,972	328,962	3.81
2003	674,269	16,182	2.46	13,804	168	1.23	9,307,610	333,638	3.72
2004	690,494	16,225	2.41	14,011	207	1.50	9,674,540	366,930	3.94
2005	706,751	16,257	2.35	14,143	132	0.94	9,995,925	321,385	3.32
2006	722,711	15,960	2.26	14,337	194	1.37	10,361,661	365,736	3.66
2007	738,690	15,979	2.21	14,535	198	1.38	10,736,798	375,137	3.62
2008	754,681	15,991	2.16	14,778	243	1.67	11,152,617	415,819	3.87
2009	770,680	15,999	2.12	14,939	161	1.09	11,512,837	360,220	3.23
2010	786,687	16,007	2.08	15,147	208	1.39	11,916,082	403,245	3.50
2011	803,264	16,577	2.11	15,355	208	1.37	12,333,746	417,664	3.51
2012	819,844	16,580	2.06	15,612	257	1.67	12,799,544	465,798	3.78
2013	836,427	16,583	2.02	15,784	172	1.10	13,201,927	402,383	3.14
2014	853,013	16,586	1.98	16,002	218	1.38	13,649,849	447,922	3.39
2015	869,601	16,588	1.94	16,227	225	1.41	14,110,681	460,832	3.38
2016	886,949	17,348	1.99	16,500	273	1.68	14,634,395	523,714	3.71
2017	904,300	17,351	1.96	16,682	182	1.10	15,085,567	451,172	3.08
2018	921,653	17,353	1.92	16,916	234	1.40	15,590,270	504,703	3.35
2019	939,005	17,352	1.88	17,154	238	1.41	16,107,364	517,094	3.32
2020	956,361	17,356	1.85	17,445	291	1.70	16,683,905	576,541	3.58

Reporting actual data through December 1999.

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Seminole Electric Cooperative, Inc.
2000 Power Requirements Study

COMMERCIAL CONSUMERS AND ENERGY SALES

	Average Consumers	Change	(%) Growth	KWH/ Consumer	Change	(%) Growth	MWH Sales	Change	(%) Growth
1976	16,405	-	-	39,513	-	-	648,212	-	-
1977	17,872	1,467	8.94	40,875	1,362	3.45	730,524	82,312	12.70
1978	19,375	1,503	8.41	41,925	1,049	2.57	812,290	81,766	11.19
1979	21,511	2,136	11.02	40,985	(939)	(2.24)	881,633	69,343	8.54
1980	23,584	2,073	9.64	40,696	(289)	(0.71)	959,773	78,140	8.86
1981	24,838	1,254	5.32	42,055	1,359	3.34	1,044,567	84,794	8.83
1982	26,040	1,202	4.84	41,094	(961)	(2.29)	1,070,081	25,514	2.44
1983	27,901	1,861	7.15	41,444	350	0.85	1,156,317	86,236	8.06
1984	29,924	2,023	7.25	42,237	793	1.91	1,263,900	107,583	9.30
1985	32,225	2,301	7.69	43,826	1,589	3.76	1,412,278	148,378	11.74
1986	35,060	2,835	8.80	42,528	(1,298)	(2.96)	1,491,024	78,746	5.58
1987	38,204	3,144	8.97	41,564	(964)	(2.27)	1,587,911	96,887	6.50
1988	40,977	2,773	7.26	42,320	756	1.82	1,734,158	146,247	9.21
1989	42,969	1,992	4.86	44,710	2,390	5.65	1,921,156	186,998	10.78
1990	43,968	999	2.32	45,144	434	0.97	1,984,905	63,749	3.32
1991	44,388	420	0.96	45,785	640	1.42	2,032,295	47,390	2.39
1992	47,327	2,939	6.62	44,845	(940)	(2.05)	2,122,383	90,088	4.43
1993	49,079	1,752	3.70	46,048	1,203	2.68	2,259,982	137,599	6.48
1994	50,743	1,664	3.39	47,319	1,271	2.76	2,401,098	141,116	6.24
1995	51,421	678	1.34	49,828	2,509	5.30	2,562,211	161,113	6.71
1996	53,223	1,802	3.50	50,353	525	1.05	2,679,957	117,746	4.60
1997	55,263	2,040	3.83	50,806	452	0.90	2,807,667	127,710	4.77
1998	57,012	1,749	3.16	52,967	2,161	4.25	3,019,727	212,060	7.55
1999	59,044	2,032	3.56	52,654	(313)	(0.59)	3,108,882	89,155	2.95
2000	61,026	1,982	3.36	54,220	1,567	2.98	3,308,840	199,958	6.43
2001	62,783	1,757	2.88	55,235	1,015	1.87	3,467,842	159,002	4.81
2002	64,279	1,496	2.38	55,804	568	1.03	3,587,003	119,161	3.44
2003	65,807	1,528	2.38	56,390	587	1.05	3,710,871	123,868	3.45
2004	67,355	1,548	2.35	57,139	748	1.33	3,848,573	137,702	3.71
2005	68,909	1,554	2.31	57,592	453	0.79	3,968,592	120,019	3.12
2006	70,457	1,548	2.25	58,296	704	1.22	4,107,344	138,752	3.50
2007	72,008	1,551	2.20	59,016	720	1.24	4,249,624	142,280	3.46
2008	73,564	1,556	2.16	59,911	895	1.52	4,407,268	157,644	3.71
2009	75,120	1,556	2.12	60,497	587	0.98	4,544,551	137,283	3.11
2010	76,681	1,561	2.08	61,247	750	1.24	4,696,517	151,966	3.34
2011	78,296	1,615	2.11	62,010	762	1.24	4,855,104	158,587	3.38
2012	79,911	1,615	2.06	62,958	949	1.53	5,031,069	175,965	3.62
2013	81,528	1,617	2.02	63,559	601	0.95	5,181,839	150,770	3.00
2014	83,142	1,614	1.98	64,367	808	1.27	5,351,618	169,779	3.28
2015	84,760	1,618	1.95	65,164	797	1.24	5,523,279	171,661	3.21
2016	86,449	1,689	1.99	66,155	991	1.52	5,719,022	195,743	3.54
2017	88,139	1,690	1.95	66,790	635	0.96	5,886,823	167,801	2.93
2018	89,830	1,691	1.92	67,637	847	1.27	6,075,818	188,995	3.21
2019	91,519	1,689	1.88	68,478	841	1.24	6,267,019	191,201	3.15
2020	93,210	1,691	1.85	69,524	1,046	1.53	6,480,288	213,269	3.40

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Seminole Electric Cooperative, Inc.
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MAXIMUM DEMAND (KW)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	WINTER	SUMMER
1980	866,000	1,030,000	1,133,000	572,000	695,000	830,000	873,000	861,000	803,000	619,000	682,000	849,000	1,133,000	873,000
1981	1,217,000	1,159,000	731,000	635,000	744,000	978,000	895,000	849,000	862,000	714,000	884,000	1,212,000	1,217,000	978,000
1982	1,342,000	779,000	854,000	695,000	789,000	918,000	891,000	928,000	907,000	761,000	752,000	996,000	1,342,000	928,000
1983	1,221,765	1,153,567	961,067	663,487	801,852	860,188	1,021,263	1,055,147	1,017,326	790,246	932,202	1,435,536	1,221,765	1,055,147
1984	1,267,794	1,324,650	1,223,860	760,955	947,390	962,064	986,120	1,074,806	1,014,355	823,079	996,997	1,190,221	1,435,536	1,074,806
1985	1,735,927	1,320,651	1,028,433	778,717	1,015,007	1,269,247	1,148,917	1,081,455	1,068,113	1,000,222	847,045	1,528,525	1,735,927	1,269,247
1986	1,717,359	1,379,188	1,327,793	846,669	1,104,821	1,157,111	1,276,258	1,250,274	1,181,038	1,194,134	966,467	984,611	1,717,359	1,276,258
1987	1,565,707	1,583,237	1,099,023	1,243,669	1,088,325	1,309,091	1,358,813	1,454,485	1,345,345	924,322	1,144,332	1,506,329	1,583,237	1,454,485
1988	1,873,079	1,719,077	1,500,041	1,037,255	1,216,437	1,385,079	1,450,098	1,473,819	1,428,412	1,218,872	1,157,695	1,831,703	1,873,079	1,473,819
1989	1,373,228	1,961,040	1,492,153	1,134,672	1,517,715	1,571,806	1,575,214	1,629,046	1,482,262	1,366,876	1,172,367	2,269,776	1,961,040	1,629,046
1990	1,621,803	1,328,968	1,264,485	1,277,552	1,482,646	1,700,672	1,714,057	1,681,135	1,651,224	1,496,100	1,149,416	1,599,248	2,269,776	1,714,057
1991	1,664,519	2,008,526	1,614,626	1,570,955	1,570,091	1,639,888	1,645,639	1,676,834	1,692,532	1,349,172	1,735,126	1,716,938	2,008,526	1,692,532
1992	2,245,411	1,809,094	1,388,818	1,255,034	1,457,553	1,707,289	1,859,530	1,688,825	1,681,010	1,258,974	1,699,433	1,743,770	2,245,411	1,859,530
1993	1,846,919	1,940,714	2,111,649	1,266,985	1,417,620	1,844,452	1,902,599	1,924,457	1,768,343	1,504,806	1,620,777	2,111,711	2,111,649	1,924,457
1994	2,125,384	2,290,599	1,504,141	1,454,479	1,732,385	1,876,848	1,860,927	1,871,014	1,833,162	1,594,958	1,389,167	1,553,964	2,290,599	1,876,848
1995	2,277,450	2,652,449	1,633,484	1,683,768	2,012,558	2,084,309	2,063,363	2,149,148	1,966,777	1,760,523	1,787,524	2,419,802	2,652,449	2,149,148
1996	2,863,376	3,079,347	2,417,943	1,654,082	2,003,434	2,118,641	2,204,505	2,013,863	2,040,778	1,614,168	1,631,238	2,468,084	3,079,347	2,204,505
1997	2,892,524	1,989,016	1,518,786	1,561,977	1,960,686	2,124,762	2,276,526	2,271,808	2,171,831	1,827,371	1,754,973	2,114,674	2,892,524	2,276,526
1998	2,167,873	2,086,826	2,379,827	1,714,381	2,238,200	2,560,160	2,411,648	2,480,415	2,177,460	2,120,299	1,600,625	2,097,402	2,379,827	2,560,160
1999	3,147,316	2,441,486	2,132,497	2,153,310	2,157,637	2,246,203	2,545,417	2,588,851	2,411,916	2,123,705	1,900,966	2,543,323	3,147,316	2,588,851
2000	3,173,527	2,992,986	2,423,886	1,889,787	2,263,411	2,478,268	2,542,729	2,599,032	2,427,522	2,112,438	2,061,872	2,829,244	3,173,527	2,599,032
2001	3,345,976	3,138,375	2,561,338	1,971,000	2,357,596	2,596,009	2,666,387	2,716,391	2,545,230	2,197,356	2,147,810	2,980,951	3,345,976	2,716,391
2002	3,472,677	3,260,843	2,661,258	2,048,314	2,447,619	2,690,395	2,761,179	2,811,937	2,635,373	2,277,856	2,230,017	3,093,764	3,472,677	2,811,937
2003	3,600,805	3,383,353	2,762,617	2,127,007	2,538,616	2,787,701	2,858,194	2,914,364	2,728,253	2,361,152	2,315,867	3,210,036	3,600,805	2,914,364
2004	3,730,663	3,506,705	2,833,859	2,207,170	2,632,039	2,886,118	2,957,125	3,014,557	2,822,998	2,446,514	2,403,462	3,328,527	3,730,663	3,014,557
2005	3,864,049	3,636,338	2,971,225	2,289,283	2,727,183	2,986,769	3,057,928	3,117,097	2,920,344	2,534,814	2,493,909	3,452,772	3,864,049	3,117,097
2006	4,002,966	3,770,938	3,082,808	2,376,617	2,829,645	3,093,738	3,164,072	3,224,717	3,021,711	2,627,128	2,589,989	3,582,479	4,002,966	3,224,717
2007	4,144,552	3,909,484	3,197,726	2,466,677	2,933,761	3,202,737	3,272,803	3,334,201	3,125,757	2,721,515	2,688,032	3,713,882	4,144,552	3,334,201
2008	4,289,784	4,048,636	3,282,237	2,558,867	3,041,279	3,314,576	3,383,696	3,446,260	3,232,038	2,818,456	2,787,330	3,849,973	4,289,784	3,446,260
2009	4,438,023	4,195,689	3,435,285	2,653,454	3,149,881	3,428,716	3,496,241	3,560,053	3,339,477	2,917,073	2,890,983	3,989,014	4,438,023	3,560,053
2010	4,588,969	4,343,080	3,558,671	2,750,451	3,261,681	3,545,019	3,612,309	3,676,870	3,450,091	3,018,866	2,996,774	4,132,731	4,588,969	3,676,870
2011	4,746,218	4,496,277	3,686,292	2,851,471	3,378,810	3,666,567	3,732,281	3,799,140	3,565,131	3,124,692	3,106,930	4,280,801	4,746,218	3,799,140
2012	4,906,392	4,650,920	3,786,450	2,956,157	3,498,647	3,790,668	3,854,193	3,923,116	3,682,958	3,232,840	3,219,136	4,434,974	4,906,392	3,923,116
2013	5,071,892	4,814,718	3,952,365	3,061,697	3,621,978	3,917,818	3,979,794	4,049,309	3,802,360	3,342,637	3,334,401	4,588,511	5,071,892	4,049,309
2014	5,238,235	4,979,402	4,090,101	3,170,430	3,746,767	4,049,106	4,107,767	4,178,140	3,925,160	3,455,746	3,451,572	4,748,087	5,238,235	4,178,140
2015	5,410,428	5,149,348	4,230,280	3,282,317	3,875,326	4,180,331	4,237,591	4,312,014	4,049,460	3,571,174	3,573,374	4,911,076	5,410,428	4,312,014
2016	5,586,830	5,303,654	4,345,369	3,399,568	4,011,027	4,319,600	4,374,689	4,449,838	4,181,555	3,692,645	3,700,775	5,081,624	5,586,830	4,449,838
2017	5,770,477	5,499,711	4,528,181	3,518,544	4,147,675	4,462,267	4,514,361	4,591,218	4,314,782	3,816,722	3,830,082	5,256,122	5,770,477	4,591,218
2018	5,958,111	5,684,994	4,683,757	3,641,337	4,288,839	4,607,571	4,657,294	4,734,474	4,452,613	3,943,336	3,962,698	5,434,491	5,958,111	4,734,474
2019	6,149,921	5,873,543	4,841,454	3,766,509	4,434,267	4,756,425	4,803,179	4,882,302	4,591,075	4,073,750	4,098,849	5,616,454	6,149,921	4,882,302
2020	6,347,995	5,895,543	4,972,508	3,896,086	4,584,367	4,910,060	4,953,422	5,034,623	4,733,681	4,208,337	4,239,464	5,803,518	6,347,995	5,034,623

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Seminole Electric Cooperative, Inc.
2000 Power Requirements Study

PURCHASES (MWH)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
1983	450,794	380,647	376,095	325,109	379,165	418,075	497,944	504,751	416,371	378,078	357,511	464,959	4,949,499
1984	489,060	401,485	396,505	359,303	416,204	450,614	474,504	518,644	434,391	402,979	398,657	405,751	5,148,097
1985	557,997	427,310	394,729	381,983	462,923	533,087	534,976	537,496	475,903	483,861	404,716	528,418	5,723,399
1986	525,610	409,239	461,771	400,817	477,293	543,614	608,663	588,596	568,629	498,095	453,432	470,028	6,005,787
1987	568,245	458,688	464,827	455,365	508,775	614,128	665,905	707,514	601,597	448,918	461,735	528,473	6,484,170
1988	646,197	568,426	518,754	477,150	528,924	624,554	689,709	708,218	668,800	508,146	490,095	601,562	7,030,535
1989	534,324	553,257	568,829	524,974	633,688	704,993	761,326	777,799	701,560	609,038	536,451	784,120	7,690,359
1990	594,820	510,273	555,311	538,617	695,670	757,493	796,657	814,717	748,700	663,423	543,202	614,121	7,833,004
1991	620,330	571,214	600,650	613,737	740,196	754,465	809,211	835,851	766,263	605,790	610,624	647,797	8,176,128
1992	744,802	609,514	605,449	578,145	649,592	792,932	919,350	826,203	782,292	606,897	638,861	679,634	8,433,671
1993	657,834	647,355	670,669	575,341	691,813	850,778	939,916	954,417	847,219	689,837	650,013	802,711	8,977,903
1994	803,401	633,858	683,828	699,926	807,261	880,552	895,900	895,124	810,120	726,093	658,540	723,626	9,218,229
1995	836,311	738,435	681,119	699,251	944,245	899,025	1,021,767	1,034,052	920,655	818,251	733,648	891,639	10,218,398
1996	917,006	835,551	841,887	713,816	927,798	942,575	1,085,327	1,014,523	949,619	773,932	727,719	848,845	10,578,598
1997	878,465	714,818	781,324	730,160	892,535	972,673	1,107,660	1,109,932	1,019,421	848,613	753,078	925,706	10,734,385
1998	866,857	800,395	867,655	791,263	1,020,613	1,248,260	1,222,318	1,194,747	1,042,768	964,620	795,855	866,876	11,682,227
1999	934,422	803,881	840,509	924,375	1,003,031	1,061,484	1,247,300	1,278,756	1,083,699	948,577	807,320	979,027	11,912,381
2000	1,026,095	949,770	914,988	880,922	1,048,788	1,139,409	1,255,535	1,271,625	1,136,742	985,639	856,117	1,037,241	12,502,871
2001	1,078,179	958,941	956,857	921,098	1,094,784	1,187,600	1,307,160	1,323,625	1,183,675	1,027,318	893,628	1,081,905	13,014,770
2002	1,119,346	995,743	993,597	956,595	1,136,219	1,230,553	1,353,561	1,370,121	1,225,496	1,064,530	926,749	1,122,333	13,494,843
2003	1,160,203	1,032,571	1,030,861	992,735	1,178,067	1,274,799	1,401,031	1,417,539	1,268,522	1,103,015	961,380	1,163,996	13,984,719
2004	1,201,633	1,108,390	1,068,891	1,029,539	1,221,014	1,319,607	1,449,450	1,466,207	1,312,457	1,142,407	996,704	1,206,403	14,522,702
2005	1,244,170	1,108,662	1,107,631	1,067,256	1,264,749	1,365,367	1,498,795	1,516,051	1,357,595	1,183,084	1,033,178	1,250,983	14,997,521
2006	1,288,536	1,149,173	1,148,757	1,107,377	1,311,868	1,414,106	1,550,807	1,568,368	1,404,574	1,225,699	1,071,918	1,297,577	15,538,760
2007	1,334,259	1,190,947	1,191,183	1,148,746	1,359,787	1,463,701	1,604,067	1,621,631	1,452,816	1,269,186	1,111,500	1,344,779	16,092,602
2008	1,381,032	1,277,604	1,234,209	1,191,065	1,409,281	1,514,642	1,658,431	1,676,148	1,502,089	1,313,905	1,151,664	1,393,671	16,703,741
2009	1,428,631	1,277,333	1,278,865	1,234,542	1,459,289	1,566,599	1,713,577	1,731,482	1,551,925	1,359,355	1,193,526	1,443,628	17,238,752
2010	1,477,132	1,321,872	1,324,525	1,279,129	1,510,751	1,619,554	1,770,490	1,788,313	1,603,245	1,406,333	1,236,362	1,495,277	17,832,983
2011	1,527,627	1,368,085	1,371,730	1,325,499	1,564,668	1,674,926	1,829,313	1,847,802	1,656,551	1,455,111	1,280,877	1,548,525	18,450,714
2012	1,579,134	1,466,218	1,420,578	1,373,586	1,619,822	1,731,380	1,889,080	1,908,104	1,711,231	1,504,978	1,326,320	1,603,963	19,134,394
2013	1,632,360	1,464,344	1,470,118	1,422,032	1,676,596	1,789,304	1,950,668	1,969,508	1,766,614	1,555,622	1,372,908	1,659,196	19,729,270
2014	1,685,883	1,514,215	1,521,055	1,472,009	1,734,081	1,849,103	2,013,422	2,032,195	1,823,577	1,607,730	1,420,324	1,716,559	20,390,153
2015	1,741,294	1,565,060	1,573,054	1,523,354	1,793,290	1,908,890	2,077,128	2,097,369	1,881,242	1,660,971	1,469,641	1,775,663	21,066,956
2016	1,798,071	1,675,671	1,627,501	1,577,172	1,855,727	1,972,253	2,144,338	2,164,398	1,942,490	1,716,892	1,521,280	1,837,404	21,833,197
2017	1,857,238	1,671,955	1,683,389	1,631,820	1,918,674	2,037,254	2,212,865	2,233,193	2,004,286	1,774,067	1,573,578	1,900,669	22,498,988
2018	1,917,741	1,728,371	1,741,068	1,688,141	1,983,694	2,103,424	2,282,984	2,302,925	2,068,206	1,832,390	1,627,229	1,964,909	23,241,082
2019	1,979,492	1,785,393	1,799,503	1,745,556	2,050,650	2,171,208	2,354,559	2,374,822	2,132,415	1,892,490	1,682,364	2,030,394	23,998,846
2020	2,042,605	1,909,653	1,859,396	1,804,738	2,119,382	2,240,584	2,427,705	2,448,171	2,197,881	1,953,887	1,738,676	2,097,180	24,839,858

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Seminole Electric Cooperative, Inc.
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POPULATION

	History/ Base	Change	(%) Growth	High Growth	Change	(%) Growth	Low Growth	Change	(%) Growth
1975	674,886	-	-	-	-	-	-	-	-
1976	694,375	19,489	2.9	-	-	-	-	-	-
1977	720,212	25,837	3.7	-	-	-	-	-	-
1978	752,943	32,731	4.5	-	-	-	-	-	-
1979	790,447	37,504	5.0	-	-	-	-	-	-
1980	829,810	39,363	5.0	-	-	-	-	-	-
1981	862,358	32,548	3.9	-	-	-	-	-	-
1982	893,395	31,037	3.6	-	-	-	-	-	-
1983	925,242	31,847	3.6	-	-	-	-	-	-
1984	964,908	39,666	4.3	-	-	-	-	-	-
1985	1,005,711	40,803	4.2	-	-	-	-	-	-
1986	1,047,614	41,903	4.2	-	-	-	-	-	-
1987	1,092,090	44,476	4.2	-	-	-	-	-	-
1988	1,133,939	41,849	3.8	-	-	-	-	-	-
1989	1,176,313	42,374	3.7	-	-	-	-	-	-
1990	1,212,130	35,817	3.0	-	-	-	-	-	-
1991	1,243,672	31,542	2.6	-	-	-	-	-	-
1992	1,274,812	31,140	2.5	-	-	-	-	-	-
1993	1,303,073	28,261	2.2	-	-	-	-	-	-
1994	1,322,944	19,871	1.5	-	-	-	-	-	-
1995	1,345,740	22,796	1.7	-	-	-	-	-	-
1996	1,380,657	34,917	2.6	-	-	-	-	-	-
1997	1,416,857	36,200	2.6	-	-	-	-	-	-
1998	1,435,487	18,630	1.3	-	-	-	-	-	-
1999	1,493,001	57,514	4.0	-	-	-	-	-	-
2000	1,531,672	38,671	2.6	1,584,201	-	-	1,476,773	-	-
2001	1,565,190	33,518	2.2	1,643,543	59,342	3.7	1,485,735	8,962	0.6
2002	1,598,709	33,519	2.1	1,702,886	59,343	3.6	1,494,699	8,964	0.6
2003	1,632,226	33,517	2.1	1,762,225	59,339	3.5	1,503,664	8,965	0.6
2004	1,665,745	33,519	2.1	1,821,569	59,344	3.4	1,512,629	8,965	0.6
2005	1,699,263	33,518	2.0	1,880,911	59,342	3.3	1,521,592	8,963	0.6
2006	1,732,113	32,850	1.9	1,944,972	64,061	3.4	1,525,430	3,838	0.3
2007	1,764,961	32,848	1.9	2,009,033	64,061	3.3	1,529,265	3,835	0.3
2008	1,797,807	32,846	1.9	2,073,092	64,059	3.2	1,533,104	3,839	0.3
2009	1,830,656	32,849	1.8	2,137,153	64,061	3.1	1,536,941	3,837	0.3
2010	1,863,504	32,848	1.8	2,201,215	64,062	3.0	1,540,779	3,838	0.2
2011	1,897,496	33,992	1.8	2,270,955	69,740	3.2	1,540,190	(589)	(0.0)
2012	1,931,488	33,992	1.8	2,340,697	69,742	3.1	1,539,600	(590)	(0.0)
2013	1,965,479	33,991	1.8	2,410,437	69,740	3.0	1,539,010	(590)	(0.0)
2014	1,999,469	33,990	1.7	2,480,179	69,742	2.9	1,538,422	(588)	(0.0)
2015	2,033,460	33,991	1.7	2,549,920	69,741	2.8	1,537,831	(591)	(0.0)
2016	2,068,987	35,527	1.7	2,625,722	75,802	3.0	1,532,813	(5,018)	(0.3)
2017	2,104,514	35,527	1.7	2,701,527	75,805	2.9	1,527,795	(5,018)	(0.3)
2018	2,140,043	35,529	1.7	2,777,330	75,803	2.8	1,522,772	(5,023)	(0.3)
2019	2,175,570	35,527	1.7	2,853,135	75,805	2.7	1,517,754	(5,018)	(0.3)
2020	2,211,096	35,526	1.6	2,928,937	75,802	2.7	1,512,734	(5,020)	(0.3)

Reporting actual data through 1999.

G. APPENDIX I-B

REQUEST FOR PROPOSALS

H. APPENDIX I-C

POWER PURCHASE AGREEMENT

CONFIDENTIAL

POWER PURCHASE AGREEMENT

By and Between

CALPINE ENERGY SERVICES L.P.

and

SEMINOLE ELECTRIC COOPERATIVE, INC.

Dated as of December 14, 2000

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INTRODUCTION

THIS POWER PURCHASE AGREEMENT (the "Agreement") is entered into as of December 14, 2000 (the "Agreement Date"), by and between CALPINE ENERGY SERVICES, L.P., a Delaware limited partnership ("Seller"), and SEMINOLE ELECTRIC COOPERATIVE, INC. ("Buyer"), a Florida corporation. Buyer and Seller may be individually referred to herein as a "Party" and, collectively, as the "Parties."

RECITALS

WHEREAS, Buyer is a cooperative corporation organized and existing pursuant to the laws of the State of Florida; and

WHEREAS, Buyer provides wholesale electric capacity and energy to its distribution cooperative members' electric utility systems, which in turn provide that electric capacity and energy to their retail member-consumers within Florida; and

WHEREAS, Seller is a Delaware limited partnership engaged in the business of marketing wholesale electric capacity and energy in the United States; and

WHEREAS, Calpine Construction Finance Company, L.P. or its successor ("CCFC"), an affiliate of Seller, is presently developing the Osprey Energy Center, a natural gas fired, combined cycle power plant in Auburndale, Polk County, Florida (the "Plant"), which through a contractual arrangement Seller provides fuel to and receives all of the electric capacity and energy from the Plant for sale at wholesale in Florida; and

WHEREAS, Buyer needs additional firm generating capacity and energy resources to meet the future needs of its distribution cooperative members' electric utility systems; and

WHEREAS, pursuant to this Agreement the full output of the Plant will be committed on a firm (i.e., unit contingent) basis, as provided herein, to Buyer for the benefit of Buyer, Buyer's member systems, and the retail member-consumers of Buyer's member systems.

NOW, THEREFORE, in view of the foregoing premises and in consideration of the mutual benefits to be gained by Buyer and Seller, the Parties hereby agree to the following:

Section 1. Definitions

In addition to terms defined in the Introduction and Recitals, the following terms shall have the meanings set forth below.

"Affiliate" means any Person that directly or indirectly Controls or is Controlled by or is under common Control with, the Person in question.

"Agreement" has the meaning set forth in the Introduction.

"Agreement Date" has the meaning set forth in the Introduction.

"Alternate Delivery Point" means a point of delivery for Requested Energy, which has been mutually agreed to by the Parties, other than the Delivery

"Ancillary Services" means those services necessary to support the transmission of Energy from resources to loads as defined in Tampa Electric Company's or its successor's open access transmission tariff, as amended from time to time.

"Applicable Law" has the meaning set forth in the Section 14.

"Attributable Start" has the meaning set for in Section 4.4.

"Breaching Party" has the meaning set forth in Subsection 21.3.

"Business Day or "Business Daily" means any day which is not a Saturday, Sunday or a day which is a NERC holiday .

"Buyer" has the meaning set forth in the Introduction.

"Buyer's Natural Gas Transportation Entitlement" means the firm transportation allotment to which Buyer is entitled on the applicable Interstate Pipeline as defined by the following formula:

[Firm Capacity/534]

"Capacity Charge" has the meaning set forth in Subsection 4.1.

"CCFC" has the meaning set forth in the Recitals.

"Claims" means all claims or actions threatened or filed by a person other than a Party, and whether groundless, false or fraudulent, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorney's fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

"Commencement Date" has the meaning set forth in Subsection 3.1.

"Commercial Operation Date" means the date on which Seller provides notice to Buyer

that the Plant, in accordance with Good Utility Practice, is capable of providing Firm Capacity and Energy for sale to Buyer at the Delivery Point pursuant to the terms and conditions of this Agreement, which date shall be no earlier than the date on which the Plant successfully completes the Commercial Operation Tests.

"Commercial Operation Tests" means: a twenty-four (24) hour demonstration test during which the Plant must operate during each hour at an output of a minimum of 350 MW at ISO Conditions. The output of the Plant shall be corrected to ISO Conditions through the utilization of the OEMs' standard performance correction curves, and by measuring the ambient conditions of temperature, relative humidity and atmospheric pressure at the Plant site. Such test shall not be deemed successful unless the twenty-four (24) hour demonstration test shows that the Plant can operate meeting all Permit requirements. Seller shall provide Buyer ten (10) Business Days prior written notification of the Commercial Operation Test, and Buyer shall have the right to be present at such testing. Buyer shall pay its avoided cost for test Energy produced during the demonstration and performance tests, if after reasonable notice by Seller to Buyer, Buyer agrees to take and purchase the test Energy from Seller. Otherwise, Seller may at its own discretion sell all of such test Energy to a third party.

"Confidential Information" has the meaning set forth in Section 11.

"Continuation" has the meaning set forth in Section 16.

"Contract Price" means collectively, the Capacity Charges, Requested Energy Charges, and Start-Up Charges, as set forth in Section 4.

"Contract Year" means (i) for the first Contract Year, the period commencing on the Commencement Date and ending on May 31, 2005, and (ii) for each 12-month period thereafter through the Termination Date, the Contract Year shall be each 12-month period ending May 31, unless the Termination Date is prior to a May 31, in which case the last Contract Year shall end on such Termination Date.

"Controls or Controlled" means the possession, directly or indirectly, through one or more intermediaries, of the following: (a) in the case of a corporation, 50% or more of the outstanding voting securities thereof; (b) in the case of a limited liability company, partnership, limited partnership or venture, the right to 50% or more of the distributions therefrom (including liquidating distributions); (c) in the case of a trust or estate, 50% or more of the beneficial interest therein; (d) in the case of any other entity, 50% or more of the economic or beneficial interest therein; or (e) in the case of any entity, the power or authority, through the ownership of voting securities, by contract or otherwise, to direct the management, activities or policies of the entity.

"Costs" means, with respect to a Party, brokerage fees, commissions and other similar transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or in entering into new arrangements which replace this Agreement and attorneys' fees, if any, incurred in connection with enforcing its rights under this Agreement.

"CPI-U" means the U.S. Consumer Price Index for All Urban Consumers published by the Bureau of Labor Statistics of the U.S. Department of Labor, or any successor

"Defaulting Party" has the meaning set forth in Subsection 21.1.

"Delivered Energy" means, pursuant to a Request for Energy, the amount of (i) metered Requested Energy expressed in MWh produced at the Plant and delivered at the Delivery Point, and (ii) Requested Energy provided as Substitute Energy and Replacement Energy pursuant to Subsections 3.3 and 3.4, respectively. Delivered Energy in any hour shall not exceed the Request for Energy for such hour. Seller shall be responsible for all costs related to generation scheduling imbalances related to the provision of Delivered Energy.

"Delivery Point" means the high side of the transformer at the interconnection between the Plant and Tampa Electric Company's or its successor's transmission system.

"Designated Network Resources" means those generating resources designated by the Buyer and accepted by the transmission provider as eligible to provide Energy to serve Buyer's load.

"Early Termination Date" means any date earlier than May 31, 2020 on which either Party, pursuant to the terms of this Agreement, terminates this Agreement.

"Eastern Standard Time" means the time prevailing in the Eastern United States time zone.

"Energy" means electric energy having characteristics commonly known as three phase alternating current, with a nominal frequency of sixty (60) Hertz, a nominal voltage equivalent to that of Tampa Electric Company's or its successor's transmission system, and measured in KWh or MWh.

"Event of Default" has the meaning set forth in Subsection 21.1.

"FERC" means the Federal Energy Regulatory Commission or its successor.

"Firm Capacity" has the meaning set forth in Subsection 3.1 as may be adjusted pursuant to Subsection 3.5.

"First Call Priority" means (i) as to system purchases, a priority equivalent to native load, and (ii) as to unit contingent purchases, a priority equal to all other firm customers sharing the unit (e.g., deratings will be accomplished on a pro-rata basis between or among all firm customers).

"Force Majeure" has the meaning set forth in Section 13.

"Fuel Charge" has the meaning set forth in Subsection 4.2.

"Fuel Index Price" has the meaning set forth in Subsection 4.5.

"Fuel Transportation Charge" has the meaning set forth in Subsection 4.1.

"Fuel Transportation Price" means

"GAAP" means generally accepted accounting principles.

"Gains" means,

"Gas Day" means the 24 hour period of time as defined in the applicable Interstate Pipeline's FERC approved transportation tariff as a "day."

"Good Utility Practice" means, at a particular time, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry prior to such time, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result(s) at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts expected to accomplish the desired results, having due regard for, among other things, manufacturers' warranties, Applicable Law, Permits, NERC guides, and applicable safety and maintenance codes.

"High Demand Season" has the meaning set forth in Subsection 7.1.

"Impaired Capacity" has the meaning set forth in Subsection 3.4.

"Initial Firm Capacity" has the meaning set forth in Subsection 4.1.

"Interstate Pipeline" means Gulfstream Natural Gas System, L.L.C. or such other interstate pipeline which Seller utilizes to transport natural gas to the Plant. or its successor pipeline.

"ISO Conditions" means the standard temperature, atmospheric pressure and relative humidity conditions of 59° F, atmospheric pressure at sea level, and 60% relative humidity, as established by International Standards Organization.

"kW" means kilowatt.

"kWh" means kilowatt-hour.

"Late Payment Rate" means a per annum rate of interest equal to the Prime Rate plus two percent (2%); provided, the Late Payment Rate shall never exceed the maximum lawful rate permitted by applicable law.

"Losses" shall mean,

"Low Demand Season" has the meaning set forth in Subsection 7.1.

"Minor Maintenance Days" has the meaning set forth in Subsection 6.2.

"MMBtu" means one million British thermal units.

"MW" means a megawatt. One MW is equal to 1,000 kW.

"MWh" means a megawatt-hour. One MWh is equal to 1,000 kWh.

"Negotiation Period" has the meaning set forth in Section 9.

"NERC" means the North American Electric Reliability Council, or its successor.

"Non-Defaulting Party" has the meaning set forth in Subsection 21.1.

"Non-Performing Party" has the meaning set forth in Section 13(A).

"OEM" means the original manufacturer of the Plant's equipment or components thereof.

"Outage" has the meaning set forth in Section 6.

"Party" has the meaning set forth in the Introduction.

"Permit" or "Permits" means the specific governmental permits applicable to the operation of the Plant.

"Person" means an individual, partnership, corporation, limited liability company, association, trust, unincorporated organization, or a government authority or agency or political subdivision thereof.

"Plant" has the meaning set forth in the Recitals, and as further described in Attachment 5.

"Prime Rate" means the prime lending rate as may from time to time be published in the *Wall Street Journal* under "money rates" or a successor heading, provided that if more than one rate is published under such heading, the Prime Rate shall be the average of such rates so published.

"Projection Period" has the meaning set forth in Section 5.

"Replacement Power" has the meaning set forth in Subsection 3.4.

"Request for Energy" means the request by Buyer for the delivery of Energy, including changes thereto, in accordance with the applicable provisions of Section 5.

"Requested Energy" has the meaning set forth in Subsection 3.2.

"Requested Energy Charge" has the meaning set forth in Subsection 4.2.

"Requested Energy Notice Requirements" means the advance notice requirements required to issue a Request for Energy specified in Table A-1 under Subsection 4.1 and Section 5.

"Reserved Firm Capacity" has the meaning set forth in Subsection 3.5.

"RUS" means the Rural Utilities Service.

"Sales Price" has the meaning set forth in Subsection 7.2.

"SCA" has the meaning set forth in Section 9.

"Scheduled Outage" means any reduction or outage of the Plant or a major component thereof, which is necessary, as commercially reasonably determined by Seller, to maintain or repair the Plant in accordance with Good Utility Practice and which has been scheduled in accordance with Subsection 6.2; provided, however, that Scheduled Outage excludes any outage of the Plant as a result of any Unscheduled Outage.

"Seasonal On-Peak Hours" has the meaning set forth in Subsection 7.1.

"Seller" has the meaning set forth in the Introduction.

"Security Coordinator" means the applicable security coordinator authorized by and under the Florida Reliability Coordinating Council or its successor for the Plant.

"Start-Up Charge" means the aggregate of the Start-Up Maintenance Charge and Start-Up Fuel Charge.

"Start-Up Fuel Charge" has the meaning set forth in Subsection 4.4.

"Start-Up Maintenance Charge" has the meaning set forth in Subsection 4.4.

"Substitute Energy" has the meaning set forth in Subsection 3.3.

"Term" has the meaning set forth in Section 2.

"Termination Date" means May 31, 2020, unless this Agreement is terminated earlier in accordance with the provisions of this Agreement, in which case the Termination Date means such earlier date on which this Agreement is terminated.

"Unscheduled Energy" has the meaning set forth in Subsection 3.6.

"Unscheduled Outage" means any reduction or outage of the Plant or a major component thereof, which is necessary, as commercially reasonably determined by Seller, to (i) maintain or repair the Plant in accordance with Good Utility Practice and was not reasonably foreseeable by Seller in time to perform as scheduled or routine maintenance, (ii) prevent significant harm or damage to the Plant, (iii) prevent harm or damage to life or property of others, or (iv) respond to any Force Majeure event; provided, however, that Unscheduled Outage excludes any outage of the Plant as a result of any scheduled or routine maintenance.

"Variable O&M Charge" has the meaning set forth in the in Subsection 4.2.

Section 2. Duration

This Agreement shall become effective as of the Agreement Date, upon signing by both Parties. This Agreement shall continue in effect through May 31, 2020, unless terminated early pursuant to the terms hereof (the "Term").

Section 3. Scope

Subsection 3.1 Firm Capacity

Beginning with the later of the Commercial Operation Date of the Plant and June 1, 2004 ("Commencement Date"), for the remainder of the Term, Seller shall provide and Buyer shall purchase the firm (i.e., unit contingent) electric capacity from the Plant at the Delivery Point, in the amounts identified in the monthly firm capacity schedule attached hereto as Attachment 1. Such amounts, as may be increased in accordance with Subsection 3.5, shall be defined as "Firm Capacity"

Subsection 3.2 Requested Energy

For the period between the Commencement Date and the end of the Term, Seller shall be obligated to sell and deliver at the Delivery Point, and Buyer shall be obligated to purchase and receive, the amount of Energy for each hour, requested by Buyer under a Request for Energy, up to the number of MWh that corresponds to the MW of Firm Capacity, subject to a minimum take by Buyer of enough MWs, in combination with Seller's use of its share of the Plant, so that the Plant is not going to operate at less than 250 MW per hour ("Requested Energy").

Subsection 3.3 Substitute Energy

Subsection 3.4 Replacement Power

Subsection 3.5 Reserved Firm Capacity

In addition to the Firm Capacity specified in Subsection 3.1 above, for the period between the Commercial Operation Date and the end of the Term, Seller shall provide Buyer, on a reserved firm capacity option basis, the right to call upon,

up to the difference between (i) Buyer's then committed Firm Capacity amount and (ii) the then-full MW capability of the Plant as adjusted for seasonal variability and projected degradation (such seasonal variability and projected degradation of the then-full MW capability of the Plant to be provided by Seller to Buyer upon written request) (said difference hereinafter being defined as "Reserved Firm Capacity");

If Buyer calls upon all or a portion of the Reserved Firm Capacity as provided for above, such called upon portion of Reserved Firm Capacity shall be considered Firm Capacity.

Subsection 3.6 Exclusivity

For the period between the Commencement Date and the end of the Term, the Plant shall be dedicated to providing Firm Capacity and Requested Energy as described herein to Buyer, except during those periods when Seller is performing testing and operational maintenance as

provided herein. Buyer is not obligated to pay the Start-Up Charges associated with the Plant during such testing or maintenance. For the period between the Commencement Date and the end of the Term,

Subsection 3.7 Title, Risk of Loss and Indemnity with Respect to Requested Energy

As between the Parties, Seller shall be deemed to be in exclusive control (and responsible for any damages or injury caused thereby) of the Requested Energy up to the Delivery Point or Alternate Delivery Point, and Buyer shall be deemed to be in exclusive control (and responsible for any damages or injury caused thereby) of the Requested Energy from the Delivery Point or Alternate Delivery Point. Seller warrants that the Requested Energy delivered by Seller shall be free and clear of all liens, claims and encumbrances at the Delivery Point or Alternate Delivery Point. Title to and risk of loss related to the Requested Energy shall transfer from Seller to Buyer upon delivery of the Requested Energy at the Delivery Point or Alternate Delivery Point.

Section 4. Price

Subsection 4.1 Capacity Charge.

The monthly capacity charge ("Capacity Charge") shall be :

The Capacity Charge shall be applied to the Firm Capacity for the then applicable month for the purpose of invoicing.

Subsection 4.2 Requested Energy Charge

The monthly Requested Energy charge shall be comprised of a fuel charge and a variable O&M charge component ("Requested Energy Charge"). The fuel charge shall be calculated by multiplying the Delivered Energy (MWh) during the applicable billing month by a $/MWh rate, which rate shall be calculated by

The variable O&M charge shall be calculated by applying a monthly Variable O&M Price per MWh ($/MWh) to all Delivered Energy purchased

Subsection 4.3 Firm Capacity and Requested Energy

Six months prior to the end of each calendar year of the Term, Buyer

Subsection 4.4 Start-Up Charges

If Seller, in response to a Request for Energy is required to start either of the two (2) combustion turbines at the Plant, such start shall be considered a start attributable to Buyer on a whole basis and if Seller, in response to a Request for Energy is required to start either of the two (2) combustion turbines at the Plant, such start shall be considered a start attributable to Buyer

Subsection 4.5 Fuel Index Price Procedure

Section 5. Scheduling

(a) Seller shall provide to Buyer through electronic telemetering equipment the allowable operating limits for the Plant. These operating limits will be established through the utilization of the OEMs' standard performance test curves for the ambient conditions existing at the Plant. Buyer shall pay for such telemetering equipment and the installation thereof. Buyer shall pay for a dedicated telephone line capable of supporting said telemetering equipment, the installation thereof and any phone charges associated therewith. The installation of the telemetering equipment and the phone line shall be subject to the review and approval of Seller. Seller shall, at its expense, provide the necessary interconnection to its Plant control system and operate and maintain its Plant control system in a manner consistent with such telemetering.

(b) Seller shall provide Buyer the upper and lower operating limits, maximum allowable ramp rate and real and reactive power output for the Plant via an electronic interface made available to Buyer at the common point of interface in the Plant switchyard. The upper and lower operating limits for the Plant will be established in accordance with the OEMs' performance correction curves by measuring the ambient temperature, barometric pressure and humidity at the Plant. This information will be calculated at a minimum of once every five minutes and telemetered to the dispatcher.

(c) Seller shall provide Buyer an advance projection of expected capacity available and expected operation of the Plant if any, for each hour of the twenty-four (24) hour period for the next Gas Day ("Projection Period") (If the next Gas Day is a weekend or a holiday, such projection shall include the applicable weekend and holiday days). The advance projection shall be communicated on a Business Daily basis before 7:00 a.m. Eastern Prevailing Time, by telephone and confirmed in writing. In addition, if Buyer, on or before 8:00 am Eastern Prevailing Time, requests an advance projection of expected capacity available s, for each hour of the twenty-four (24) hour period for the next Gas Day, Seller shall provide Buyer such information along with any scheduling flexibility limitations by 9:00 am Eastern Prevailing Time by telephone and confirmed in writing on the date of such request.

(d) Seller shall be entitled to make changes to such before 7:00 a.m. Eastern Prevailing Time advance projection, communicated per Subsection 5(c) above, after 7:00 a.m. Eastern Prevailing Time, subject to Good Utility Practice, the technical limits (Seller shall not use the technical limits as an excuse to not provide Requested Energy between the loads of 250 MW to the Firm Capacity), applicable laws and applicable Permits. Seller shall advise Buyer promptly of any change in condition that materially alters Seller's expectation as to the availability of Firm Capacity from the Plant.

(e) Seller's advance projection of capacity and changes thereto (including telephone requests and written confirmations) shall clearly specify

(f) Requests for Energy scheduled shall be communicated by telephone and confirmed by Buyer in writing on a Business Daily basis before 10:00 a.m. Eastern Prevailing Time one Gas Day ahead for each hour of the twenty-four (24) hour period for the next Gas Day.

(i) For Attributable Starts of the Plant, and for increases or reductions in Requested Energy, Buyer shall be required to, pursuant to its Request for Energy, schedule as Requested Energy the Energy produced to ramp the Plant up or down to the ultimate Requested Energy level.

Section 6. Outages

Subsection 6.1 Outages

An "Outage" of the Plant shall mean the unavailability of the Plant, either in whole or in part, caused by either a Scheduled Outage or an Unscheduled Outage.

Subsection 6.2 Scheduled Outages

At least sixty (60) days before the beginning of each calendar year, Seller shall provide Buyer with a proposed schedule of Scheduled Outages of the Plant for the next calendar year. Such schedule shall be based on Good Utility Practice and OEMs' recommendations. Seller shall make good faith efforts to coordinate Scheduled Outages with Buyer so as to take account of scheduled outages of one or more of Buyer's generating units. If Buyer reasonably objects to

the Scheduled Outage schedule proposed by Seller, Buyer shall notify Seller thereof within thirty (30) days after receipt of Seller's proposed schedule, stating in detail the reasons for its objection and a proposed alternative Scheduled Outage schedule. Seller shall consider Buyer's objections and proposed alternative schedule reasonably and in good faith, and shall develop a revised Scheduled Outage schedule. Seller may revise the Scheduled Outage schedule during a calendar year, subject to Buyer's approval, such approval to not be unreasonably withheld taking into consideration Good Utility Practice, OEMs' recommendations, and scheduled outages of one or more of Buyer's generating units. Under no circumstances, however, may a Scheduled Outage take place during the On Peak Hours during the months of except, however, Buyer shall provide, with ten (10) Business Days notice to Seller, two (2) consecutive days in each quarter of each calendar year for the purpose of Seller performing minor maintenance ("Minor Maintenance Days"), and said Minor Maintenance Days shall not be deemed as having violated the aforementioned On-Peak Scheduled Outage restriction. During each Scheduled Outage, Seller shall keep Buyer apprised of the status of the Plant and the expected duration of the Scheduled Outage.

Subsection 6.3 Unscheduled Outages

Seller shall provide Buyer with a good faith oral best estimate (followed by written confirmation) of the cause, duration and scope of each Unscheduled Outage as soon as practical after the occurrence thereof.

Section 7. Failure To Provide or Receive Requested Energy

Subsection 7.1 Failure of Seller To Provide Requested Energy

(a) Unless excused by Buyer's failure to perform, Seller shall in the months of ("High Demand Season") during the Term maintain an Equivalent Availability Factor of

(b) Unless excused by Buyer's failure to perform, Seller shall in the months of ("Low Demand Season") during the Term maintain an Equivalent Availability Factor of

Subsection 7.2 Failure of Buyer To Receive Requested Energy

If pursuant to a Request for Energy, Seller has incurred an obligation to take and pay for gas supply under this Agreement, unless excused by Force Majeure or Seller's failure to perform, and Buyer fails to receive or otherwise take the Requested Energy, then

Section 8. Commercial Operation Date Delay

Subsection 8.1 Commercial Operation Date Delay

In the event that the Commercial Operation Date of the Plant shall occur later than the expected in-service date of June 1, 2004, for reasons other than Force Majeure

Section 9. Termination for Convenience/Conditions Subsequent

Subsection 9.1 Conditions Subsequent

If any of the following conditions subsequent are not satisfied, Buyer may terminate this Agreement for its convenience by written notice to Seller:

Section 10. Dispute Resolution

The dispute resolution procedures set forth in this Section 10 shall govern the resolution of any dispute, controversy or claim arising out of, under, or relating to this Agreement (a "Dispute") unless mutually agreed to by the Parties. The Parties agree to first negotiate in good faith to attempt to resolve any Dispute that arises under this Agreement. In the event that the Parties are unsuccessful in resolving a Dispute through such negotiations, the controversy may be submitted to binding arbitration as provided below.

(A) Good-Faith Negotiations.

The process of "good-faith negotiations" requires that each Party set out in writing to the other its reason(s) for adopting a specific conclusion or for selecting a particular course of action, together with the sequence of subordinate facts leading to the conclusion or course of action. The Parties shall attempt to agree on a mutually agreeable resolution of the Dispute. Upon request, each Party shall promptly make available to the other such information, including existing studies and raw data, to the extent related to the Dispute. The related information to be made available must include both studies and raw data that support the position advocated and existing studies and raw data that are related to, but do not support, the position advocated. A Party shall not be required as part of these negotiations to provide any information which is confidential or proprietary in nature unless it is satisfied in its discretion that the other Party will maintain the confidentiality of and will not misuse such information or any information subject to attorney-client or other privilege under applicable law regarding discovery and production of documents.

Additionally, where one Party possesses the exclusive capability of collecting additional raw data or making additional studies related to the Dispute, it shall accommodate reasonable requests from the other Party requesting such data or studies, subject to limitations on disclosure

of confidential, proprietary or privileged information. The Party requesting such data shall reimburse the other Party for the cost incurred to provide the data. The negotiation process shall include at least two meetings to discuss any Dispute prior to invoking arbitration rights. Unless otherwise mutually agreed, the first meeting shall take place within ten (10) Business Days after either Party has received notice from the other of the desire to commence formal negotiations concerning the Dispute. Unless otherwise mutually agreed, the second meeting shall take place no more than ten (10) Business Days later. In the event a Party refuses to attend a negotiation meeting, either Party may proceed immediately to binding arbitration concerning the Dispute.

(B) Binding Arbitration.

Binding arbitration may be initiated at any time by either Party following Good Faith Negotiations (the "Binding Arbitration Notice"). The Binding Arbitration Notice shall specify the issue(s) to be submitted to binding arbitration, including a summary of the complaining Party's position with respect thereto and a proposed resolution. The Party receiving the Binding Arbitration Notice shall have the right to rebut the issue(s) set forth in the Binding Arbitration Notice. The Parties shall by mutual agreement appoint an arbitrator within thirty (30) days after receipt of the Binding Arbitration Notice giving preferred consideration to former US Circuit Court Judges with training or experience to address the issue in controversy. In the event the Parties are unable to agree upon an arbitrator within such time frame, either Party may request the American Arbitration Association to designate three potential arbitrators, each of whom (1) shall have agreed to arbitrate the Dispute, (2) shall have never been affiliated with either Party or its affiliate(s), (3) shall be qualified by training or experience to address the issue in controversy and (4) shall be available to fulfill the responsibilities of binding arbitration in a timely manner. Each Party shall be provided relevant information related to each potential arbitrator, including applicable fees; and each shall designate its first, second and third choices among the potential arbitrator, with the designated choice receiving four, three and one point(s), respectively. In the event a Party fails to designate an order of choice, each potential arbitrator shall receive one point. The potential arbitrator receiving the most points shall be the arbitrator. Unless otherwise mutually agreed, binding arbitration shall commence two (2) weeks after the selection of the arbitrator. The arbitration shall proceed in accordance with the rules for commercial arbitration established by the American Arbitration Association absent the contrary agreement of the Parties. Any recommendation or decision by the arbitrator shall be binding on the Parties. The fees and expenses of the arbitrator shall be shared equally by the Parties, and each Party shall bear its own costs.

(C) Confidentiality and Non-Admissibility of Statements Made in, and Evidence Specifically Prepared for, Good Faith Negotiations and Binding Arbitration.

Each Party hereby agrees that all statements made in the course of good faith negotiations, as contemplated in Section 10(A), and in binding arbitration, as contemplated in Section 10(B), shall be confidential, and shall not be disclosed to or shared with any third parties (other than the arbitrator, potential arbitrators or any other person whose presence is necessary to facilitate the negotiation and/or binding arbitration process). Furthermore, each Party agrees that any documents or data specifically prepared for use in good faith negotiations and/or binding arbitration shall not be disclosed to any third party, except those parties whose presence is necessary to facilitate the binding arbitration process. Each Party agrees and acknowledges that no statements made in or evidence specifically prepared for good faith negotiations, under

Section 10(A) shall be admissible for any purpose in any subsequent binding arbitration.

Section 11. Confidentiality of Shared Information

Neither Party shall disclose or otherwise make available to any other party any information of a technical, commercial or business nature regarding the Plant or this Agreement ("Confidential Information") without the prior written consent of the other Party, except that Seller may provide Confidential Information to its lenders. Confidential Information shall not include information which (i) the receiving Party can demonstrate was known to it prior to its disclosure by the other Party, (ii) is, or later becomes, public knowledge without breach of this Agreement by the receiving Party, (iii) was received by the receiving Party from a third party without obligation of confidentiality, or (iv) is developed by the receiving Party independently from Confidential Information received from the other Party, as evidenced by appropriate documentation. In the event that disclosure is required by court order or a Governmental Body, the Party subject to such requirement may disclose Confidential Information to the extent so required, but shall promptly notify the other Party and shall use reasonable efforts to obtain protective orders or similar restraints with respect to such disclosure. Notwithstanding the above, either Party may disclose information required pursuant to regulation by a Governmental Body, on a non-confidential basis if necessary, but only to such extent necessary, in connection with a regulatory filing contemplated hereunder or as otherwise required pursuant to this Agreement.

Section 12. Buyer's Support for Need Determination of the Plant

Buyer shall provide such support for the petition for determination of need for Seller's Plant as the Parties mutually agree is necessary to facilitate and expedite the permitting and construction of the Plant. Buyer's support shall include becoming a co-applicant for the requisite determination of need for the Plant.

Section 13. Force Majeure

(A) Force Majeure Excuse. Neither Party shall be responsible or liable for or deemed in breach of this Agreement for any delay or failure in the performance of its respective obligations under this Agreement to the extent such delay or failure is due to circumstances beyond the reasonable control of the Party experiencing such delay or failure (such Party referred to herein as the "Non-Performing Party"), and such circumstances are limited to: (i) types of events such as acts of God, drought, flood, landslide, earthquake, hurricane, tornado, storm, or other such unusually severe weather conditions, fire, lightning, epidemic, war, blockade, riot, civil disturbance, famine, sabotage, explosions, theft, embargo, and injunction, (ii) labor strikes or slowdowns of the Non-Performing Party's employees to the extent that such strikes or slowdowns also affect employers in addition to the Non-Performing Party.

In the event of Force Majeure:

1. the Non-Performing Party shall give the other Party notice within forty-eight (48) hours (or as soon as practicable) after learning of the Force Majeure, with details further describing the particulars of the occurrence to be supplied within ten (10) Business Days after learning of the Force Majeure; if such notice is given within the required time period, the Non-Performing Party shall be relieved of its obligations from the commencement of the Force Majeure; if such notice is given later than the required time period, the Non-Performing Party shall be relieved of its obligations from the time of giving such notice; if no notice is given, then the obligations of the Parties shall continue without regard to the Force Majeure event;

2. the suspension of performance shall be of no greater scope and of no longer duration than is reasonably attributable to the Force Majeure;

3. the Non-Performing Party shall use its reasonable commercial efforts to remedy its inability to perform;

4. when the Non-Performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party notice to that effect; and

(B) Non-Force Majeure Examples. Examples of circumstances which the term Force Majeure does not include are as follows: (1) changes in market conditions that affect the cost of a Party's supply of fuel or any alternate supplies of fuel, (2) any negligent or intentional acts, errors or omissions, or failure to comply with any Applicable Law, or any breach of or default under this Agreement, or any other agreement, by the Non-Performing Party or its contractors, (3) the inability to obtain any Permits required to construct and operate the Plant, (4) changes in market conditions that affect the cost of producing or making available Requested Energy or Firm Capacity or any necessary wheeling or transmission arrangements, (5) any damage to or failure of necessary equipment comprising the Plant caused by a defect in design, manufacturing or construction of the Plant or any component thereof, (6) any damage to or failure of the Plant or any component thereof caused by normal wear and tear, and (7) inability of Seller to enter into a firm gas transportation agreement with an Interstate Pipeline. These examples are not intended to be exclusive or exhaustive.

Section 14. Applicable Law

This Agreement shall be made under and shall be governed by and construed in accordance with the laws of the State of Florida, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction ("Applicable Law"). The Parties agree to submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Middle District of Florida, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Circuit Court of the State of Florida sitting in Hillsborough County, Florida, and the Parties further agree to waive any right they may have to a jury trial with respect thereto.

Section 15.

Section 16. Reopener

The Parties will engage in good faith negotiations concerning the price, terms and conditions under which this Agreement will continue beyond May 31, 2009 ("Continuation"). If the Continuation is not executed by July 31, 2005, then Seller shall promptly thereafter notify Buyer in writing that unless either Party within sixty (60) days of such written notice from Seller elects to terminate this Agreement for its convenience as of May 31, 2009, that this Agreement shall be deemed continued as written for another sixty (60) month increment, with the exception that all references to "May 31, 2009" in this Section shall be modified to reflect the date sixty (60) months thereafter and all references to "July 31, 2005" in this Section shall be modified to reflect the date forty-six (46) months prior to such sixty (60) months thereafter date. Within sixty (60) days of such notice from Seller, either Party, based on its sole judgment, will be free to terminate this Agreement as of May 31, 2009 for its convenience.

If the Continuation is not executed by July 31, 2005, and neither Party, within sixty (60) days of such notice from Seller terminates this Agreement for its convenience, pursuant to the preceding sentence, then this Agreement shall be deemed continued consistent with the terms hereof. The Parties agree that, unless otherwise agreed to by the Parties, Continuations to this Agreement's term shall be in sixty (60) month increments and that similar reopener provisions to that contained herein shall be part of any such Continuation.

Section 17. Ancillary Services

Section 18. Metering

Subsection 18.1 Meter Reading

The Parties will cause meters to be read monthly at times agreed upon. Metering records shall be available at all reasonable times to authorized representatives and employees of the Parties.

Subsection 18.2 Billing, Meters and Associated Transformers

Seller will, own, operate, and maintain the billing meters and associated transformers at the Delivery Point. Seller's records of data collected from such meters shall be available at all reasonable times to the duly authorized representatives of Buyer.

Subsection 18.3 Meter Tests

Each meter used hereunder shall, by comparison with accuracy standards as provided for in Subsection 18.4, be tested and calibrated by Seller or its agent at approximate intervals of twelve (12) months or as otherwise agreed to by both Parties. If a meter is found not registering accurately, it shall be restored to an accurate condition or it shall be replaced by an accurate meter. Seller shall provide Buyer prior written notification of any such testing and calibration, and Buyer shall have the right to be present at such testing and calibration.

Subsection 18.4 Meter Accuracy

Each Party shall have the right to request that a special test of metering equipment be made at any time. If any test made at Buyer's request discloses that the metering equipment tested is registering within one-half percent (+ or - 0.5%) accuracy, Buyer shall bear the expense of the test. The expense of all other such tests shall be borne by Seller.

Subsection 18.5 Meter Adjustments

The results of all meter tests and calibrations shall be open to examination by Buyer. Any meter tested and found to be within one-half percent (+ or - 0.5%) accuracy shall be considered to be accurate. If, as a result of any test, any meter is found to register not within plus or minus one-half percent accuracy, the readings of such meter previously taken shall be corrected according to the percentage of inaccuracy so found for the most recent one-half of the time period since the date the meter was last tested, and the applicable invoices shall be adjusted to reflect such corrected meter readings; provided, however, that the time period for which the meter readings are adjusted shall not exceed six months. If any metering equipment fails to register, or if the meter registration is erratic, the Energy delivered shall be determined first by

reference to backup meters, if any. If no backup meters exist, or if the backup meters are not accurate, the Energy delivered shall be determined by mutual agreement of the Parties.

Section 19. Representation and Warranties

Subsection 19.1 Representations and Warranties

As a material inducement to entering into this Agreement, each Party, with respect to itself, hereby represents and warrants to the other Party as of the Agreement Date as follows:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation and is qualified to conduct its business in those jurisdictions necessary to perform this Agreement;

(b) it has all regulatory authorizations necessary for it to legally perform its obligations under this Agreement, except for those which Seller is to obtain as conditions subsequent pursuant to Subsection 9.1 and except for the regulatory approval from the Administrator of the RUS pursuant to Subsection 9.1;

(c) the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms or conditions in its governing documents or any contract to which it is a party or any law, rule, regulation, order, writ, judgment, decree or other legal or regulatory determination applicable to it;

(d) this Agreement constitutes a legal, valid and binding obligation of such Party enforceable against it in accordance with its terms, subject to bankruptcy, insolvency, reorganization and other laws affecting creditor's rights generally, and with regard to equitable remedies, to the discretion of the court before which proceedings to obtain same may be pending;

(e) there are no bankruptcy, insolvency, reorganization, receivership or other arrangement proceedings pending or being contemplated by it, or to its knowledge threatened against it; and

(f) there are no suits, proceedings, judgments, rulings or orders by or before any court or any governmental authority that could reasonably be expected to materially adversely affect its ability to perform this Agreement.

Subsection 19.2 No Other Representations and Warranties

Each Party acknowledges that it has entered into this Agreement based solely upon the express representations and warranties set forth in this Agreement.

Section 20. Additional Covenants

Subsection 20.1 Remaking of Representations and Warranties

Each Party covenants that it will cause its respective representations and warranties in Subsection 19.1, except for suits and proceedings under Subsection 19.1(f), to remain true and correct throughout the Term.

Subsection 20.2 Financial Information

Each Party shall cause to be delivered to the other Party such financial information as is reasonably requested by the other Party, including annual audited financial statements

Section 21. Events of Default and Remedies

Subsection 21.1 Event of Default

An "Event of Default" shall mean, with respect to a Party alleged to have taken or been affected by any of the actions set forth below in this Subsection 21.1 (the "Defaulting Party"):

(a) the failure of the Defaulting Party to make, when due, any payment required under this Agreement if such failure is not remedied within ten (10) Business Days after written notice of such failure is given to the Defaulting Party by the other Party ("Non-Defaulting Party") and *provided* the payment is not the subject of a good faith dispute as described in the billing and payment provisions under Subsection 22.1; or

(b) any representation or warranty made by the Defaulting Party in this Agreement shall prove to have been false or misleading in any material respect when made, or ceases to remain true and not cured within thirty (30) days of receipt of written notice from the other Party that such representation or warranty has ceased to be true, during the Term, except for suits and proceedings under Subsection 19.1(f); or

(c) the failure by the Defaulting Party to perform any material covenant set forth in this Agreement (other than the events that are otherwise specifically covered in this Subsection 21.1 as a separate Event of Default or its obligations to deliver or receive Requested Energy, a remedy for good faith failure of which is provided in Subsections 7.1 and 7.2), and such failure is not excused by Force Majeure or cured within ten (10) Business Days after written notice thereof to the Defaulting Party or if the breach or default is not of the type that can be reasonably cured by the payment of money within ten (10) Business Days, within a reasonable period not longer than thirty (30) days so long as (i) the Defaulting Party has commenced to cure the breach or default within such ten (10) Business Day period and thereafter diligently pursues such cure to

completion, (ii) the Defaulting Party continues to perform all other obligations under this Agreement; or

(d) the Defaulting Party shall:

(i) make an assignment or any general arrangement for the benefit of creditors;

(ii) file a petition or otherwise commence, authorize or acquiesce in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or have such petition filed against it and such petition is not withdrawn or dismissed for thirty (30) days after such filing;

(iii) otherwise become bankrupt or insolvent (however evidenced); or

(iv) be unable to pay its debts as they fall due.

Subsection 21.2 Remedies Upon an Event of Default

Subsection 21.3 Effects of Regulation

In the event that either Party is regulated by a federal, state or local regulatory body, and such body shall disallow all or any portion of any costs incurred or yet to be incurred by such regulated Party under any provision of this Agreement, such action shall not operate to excuse such regulated Party from performance of any obligation, nor shall such action give rise to any right of such regulated Party to any refund or retroactive adjustment of the Contract Price. Notwithstanding the foregoing, if a Party's activities hereunder become subject to regulation of any kind whatsoever under any law to a greater or different extent than that existing on the Agreement Date and such regulation either (a) renders this Agreement illegal or unenforceable or (b) materially adversely affects the business of a Party, with respect to its financial position or otherwise, then in the case of (a) above, either Party, and in the case of (b) above, only the Party affected (the "Breaching Party"), shall at such time have the right to

Section 22. Billing and Payment

Subsection 22.1 Billing and Payment

Seller shall render to Buyer (by regular mail, facsimile or other acceptable means pursuant to Subsection 27.8) for each calendar month during the Term a statement setting forth the total Capacity Charges for the month, the Requested Energy Charges for that month, Start-Up Charges for that month, and any other charges due Seller or Buyer. On or before fifteen (15) Business Days after receipt of Seller's statement, Buyer or Seller, as the case may be, shall pay, by wire transfer, the amount set forth on such statement. to the other Party. Wire transfers to Seller shall be to Seller's account as Seller directs on its statement. Any payment determined to be due to Buyer by Seller under this Agreement shall be rendered by Seller to Buyer by wire transfer to Buyer's account as specified by Buyer in a notice to Seller. Overdue payments shall accrue interest from, and including, the due date to, but excluding, the date of payment at the Late Payment Rate. If either Party, in good faith, disputes a statement, such Party shall provide a written explanation specifying in detail the basis for the dispute and pay the portion of such statement conceded to be correct no later than the due date. If any amount disputed by such Party is determined to be due to the other Party, it shall be paid within fifteen (15) Business Days of such determination, along with interest accrued at the Late Payment Rate until the date paid.

Subsection 22.2 Netting

If Buyer and Seller are each required to pay an amount in the same month, then such amounts with respect to each Party may be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount shall pay to the other Party the difference between the amounts owed. Each Party reserves to itself all rights, counterclaims and other remedies and defenses consistent with this Section 22 (to the extent not expressly herein waived or denied) which such Party has or may be entitled to arising from or out of this Agreement.

Subsection 22.3 Audit

Each Party (and its representatives) has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If requested, a Party shall provide to the other Party statements evidencing the quantities of Requested Energy delivered at the Delivery Point or mutually agreed to alternate delivery point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be promptly made and shall bear interest calculated at the Late Payment Rate from the date the overpayment or underpayment was made until paid; *provided, however*, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of from the end of the year in which the statement was rendered; and *provided further* that this Subsection 22.3 will survive any termination of this Agreement for a period of from the date of such termination for the purpose of such statement and payment objections.

Section 23. Assignment

Subsection 23.1 Assignment

Neither Party shall assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, either Party may, without the need for consent from the other Party (and without relieving itself from liability hereunder), (a) transfer, sell, mortgage, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements directly related to the construction of the Plant, including lease back arrangements relating to the Plant; (b) transfer or assign this Agreement to an Affiliate of such Party; or (c) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets of such Party; *provided, however*, that in each such case any such assignee shall agree in writing to be bound by the terms and conditions hereof. Notwithstanding the above, Buyer's interest in this Agreement may be assigned, transferred, mortgaged or pledged by Buyer without Seller's consent for the purpose of creating a security interest for the benefit of the United States of America, acting through the RUS (and thereafter the RUS, without the approval of Seller or its Lenders, may cause the RUS's interest in this Agreement to be sold, assigned transferred or otherwise disposed of to a third party.). To the extent this Agreement is transferred, sold, mortgaged, pledged, encumbered or

assigned in connection with any financing or other financial arrangements related to the construction of the Plant or to the RUS, the non-assigning Party shall cooperate with the assigning Party by providing reasonably requested documentation (i.e., consents and acknowledgements).

Subsection 23.2 Binding Effect

This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns. No assignment or transfer permitted hereunder shall relieve Seller or Buyer of any of its respective obligations under this Agreement, except those assignments permitted hereunder or consented to by the non-assigning Party.

Section 24. Indemnification, Limitation of Liability and Insurance

Subsection 24.1 Seller Indemnification

Seller hereby agrees to indemnify, defend and hold harmless Buyer, its agents, servants, partners, officers, directors, trustees, affiliates, and employees of each (collectively, "Buyer's Indemnitees"), from and against any and all losses, claims, damages and liabilities to third parties

arising out of the fraud, negligence or willful misconduct of Seller relating to power delivered under this Agreement before or at such time as the power has been delivered to Buyer at the Delivery Point or mutually agreed to alternative delivery point including, without limitation, the loss or claims for loss or damage to property, except to the extent caused by the fraud, negligence or the willful misconduct or breach of obligation under this Agreement of Buyer's Indemnitees and provided that Seller shall be promptly notified in writing of any such claim or suit brought against any such Buyer Indemnitee and shall be permitted to manage at its cost and expense reasonably acceptable to Buyer a defense against or negotiate a settlement (other than any settlement involving criminal liability or admission of guilt or responsibility by such Buyer Indemnitee) of such claim or suit through counsel. The foregoing notwithstanding, Seller's obligations under this Agreement towards any Buyer Indemnitee are conditioned upon such Buyer Indemnitee providing at Seller's expense such cooperation as Seller may reasonably request in connection with its defense or settlement of the claim or suit against such Buyer Indemnitee.

Subsection 24.2 Buyer's Indemnification

Buyer hereby agrees to indemnify, defend and hold harmless Seller, its agents, servants, partners, officers, directors, trustees, affiliates and employees of each (collectively, "Seller's Indemnitees"), from and against any and all losses, claims, damages or liabilities to third parties

arising out of the fraud, negligence or willful misconduct of Buyer relating to power delivered under this Agreement after such power has been delivered to Seller at the Delivery Point or mutually agreed to alternative delivery point, including, without limitation, the loss or

claims for loss or damage to property, except to the extent caused by the fraud, negligence or the willful misconduct or breach of obligation under this Agreement of Seller's Indemnitees and provided that Buyer shall be promptly notified in writing of any such claim or suit brought against any such Seller Indemnitee and shall be permitted to manage at its cost and expense reasonably acceptable to Seller a defense against or negotiate a settlement (other than any settlement involving criminal liability or admission of guilt or responsibility by such Seller Indemnitee) of such claim or suit through counsel. The foregoing notwithstanding, Buyer's obligations under this Agreement towards any Seller Indemnitee are conditioned upon such Seller Indemnitee providing at Buyer's expense such cooperation as Buyer may reasonably request in connection with its defense or settlement of the claim or suit against such Seller Indemnitee.

Subsection 24.3

Subsection 24.4 Duty To Mitigate

Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Subsection 24.5 Florida Uniform Commercial Code

Except as otherwise provided for in this Agreement, the provisions of the Florida Uniform Commercial Code shall govern this Agreement and shall be deemed to apply to this

Agreement. Requested Energy shall be deemed to be a "good" for purposes of the Florida Uniform Commercial Code.

Subsection 24.6 Insurance

Within thirty (30) days after execution of this Agreement, each Party shall provide the other Party certificates of insurance demonstrating that it has adequate liability insurance pursuant to its corporate policies for any liability arising out of its activities undertaken pursuant to this Agreement. Each Party agrees to provide at least thirty (30) days' notice to the other Party prior to cancellation of its liability insurance policy.

Section 25. Taxes

Subsection 25.1 General

Buyer and Seller shall each use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with their intent to minimize taxes, so long as neither Party is materially adversely affected by such efforts. Either Party, upon written request of the other, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if either Party is exempt from taxes, and shall use reasonable efforts to obtain and cooperate with obtaining any exemption from or reduction of tax. Either Party with knowledge of a tax on the purchase or sale of the capacity or Energy, that may be applicable to the Firm Capacity or Requested Energy sold hereunder, shall notify the other Party, in advance, of the applicability of such tax and shall also notify the other Party of any proposal to implement a new tax or apply an existing tax to the purchase, sale, delivery, or receipt of Firm Capacity or Requested Energy hereunder.

Subsection 25.2 Applicable Taxes

Seller shall be responsible for all existing and any new sales, use, excise, ad valorem, and any other similar taxes, imposed or levied by any federal, state or local governmental agency on the Requested Energy to be sold and delivered hereunder prior to the transfer of title. Buyer shall be responsible for all existing and any new sales, use, excise, ad valorem, and any other similar taxes, imposed or levied by any federal, state or local governmental agency on the Capacity sold hereunder, the Requested Energy sold and delivered hereunder and imposed or levied on the Delivered Energy after transfer of title thereto. If either Party is required to pay any tax that under the provisions hereof is the responsibility of the other Party, the paying Party shall be reimbursed by the other Party. Neither Party is required to pay, or cause to be paid, any taxes measured by the income of the other Party. Each Party shall indemnify (to the extent permitted by law), release, defend and hold harmless the other Party from and against any and all liability for (i) taxes measured by the income of the other Party and (ii) taxes imposed or assessed by any taxing authority with respect to the Firm Capacity and Requested Energy sold, delivered and received hereunder that are not the responsibility of such other Party pursuant to this Subsection 25.2.

Section 26. Construction Schedule and Access Rights

Seller shall submit an integrated project schedule to Buyer within ninety (90) days from the execution of this Agreement. This schedule shall identify key licensing, permitting, construction, performance testing and operating milestone dates and activities. Seller shall notify Buyer of any material changes in such schedule within ten (10) Business Days after such changes are determined. Seller shall provide monthly progress reports to Buyer, which shall report in detail on the status of the Plant, and in addition will report promptly any adverse events that are reasonably likely to delay the achievement of milestone dates.

Seller shall arrange through its affiliate CCFC to provide Buyer and its authorized experts, representatives and/or agents with access to the Plant upon reasonable prior notice (in light of the circumstances) and subject to CCFC's safety and operating rules and regulations of general applicability, in connection with the design, construction and operation of the Plant. Such access shall include access to CCFC's maintenance records during normal business hours upon at least thirty (30) Business Days' prior notice to Seller by Buyer. Any information provided to Buyer by Seller or by CCFC on behalf of Seller in accordance with this Section shall constitute confidential information and be treated by Buyer in accordance with Section 11. Buyer's access shall not interfere with Seller's or CCFC's normal business operations.

Section 27. Miscellaneous

Subsection 27.1 Entirety

This Agreement and its Attachments, which are incorporated by reference, constitute the entire agreement between the Parties. There are no prior or contemporaneous agreements or representations affecting the same subject matter other than those herein expressed. Except for any matters that, in accordance with the express provisions of this Agreement, may be resolved

by verbal agreement between the Parties, no amendment, modification or change herein shall be enforceable unless reduced to writing and executed by both Parties.

Subsection 27.2 Non-Waiver

No waiver by any Party of any one or more defaults by the other Party in the performance of any of the provisions of this Agreement shall be construed as a waiver of any other default or defaults whether of a like kind or different nature.

Subsection 27.3 Severability

Except as otherwise stated herein, any provision or article declared or rendered unlawful by a court of law or regulatory agency having jurisdiction over the Parties, or deemed unlawful because of a statutory change, will not otherwise affect the lawful obligations that arise under this Agreement.

Subsection 27.4 Headings: Attachments

The headings used for the sections and subsections herein are for convenience and reference purposes only and shall in no way affect the meaning or interpretation of the provisions of this Agreement. References in this Agreement to sections and subsections shall be deemed a reference to this Agreement, unless otherwise indicated. Any and all Attachments referred to in this Agreement are, by such reference, incorporated herein and made a part hereof for all purposes.

Subsection 27.5 Winding Up Arrangements

All indemnity, limitation of liability and audit rights shall survive the termination of this Agreement. All obligations provided in this Agreement shall remain in effect for the purpose of complying herewith.

Subsection 27.6 No Third Party Beneficiaries

Nothing in this Agreement shall provide any benefit to any third party or entitle any third party to any claim, cause of action, remedy or right of any kind, it being the intent of the Parties that this Agreement shall not be construed as a third party beneficiary contract.

Subsection 27.7 Counterparts

This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument.

Subsection 27.8 Notices

All notices, requests, or statements shall be made as follows. Notices required to be in writing shall be delivered by letter, facsimile or other documentary form. Notice by facsimile or hand delivery shall be deemed to have been received by the close of the Business Day on which it was transmitted or hand delivered (unless transmitted or hand delivered after close in which case it shall be deemed received at the close of the next Business Day). Notice by overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent. A Party may change its address by providing notice of same in accordance herewith.

If to Buyer: Seminole Electric Cooperative, Inc.
Attention: Director of Pricing and Bulk Power Contracts
16313 North Dale Mabry Highway
Tampa, FL 33618
Phone: (813) 963-0994
Fax: (813) 264-7906

If to Seller: Calpine Energy Services, L.P.
Attention: Director, Contracts and Administration
The Pilot House, Second Floor
Lewis Wharf
Boston, MA 02110
Phone:
Fax:

Each Party shall have the right to change the place to which notices shall be sent or delivered or to specify one additional address to which copies of notices may be sent, in either case by similar notice sent or delivered in like manner to the other Party.

EXECUTION

By the signatures of their authorized representatives below, Buyer and Seller enter into this Agreement. This Agreement may be executed in any number of counterparts, such counterparts may be transmitted by either Party to the other Party by facsimile transmission, and each executed counterpart or facsimile transmission thereof shall have the same force and effect as an original instrument.

CALPINE ENERGY SERVICES, L.P.
a Delaware limited partnership

By: _____
Name: Robert K. Alff
Title: Senior Vice President

SEMINOLE ELECTRIC COOPERATIVE, INC.
a Florida corporation

By: _____
Name: Richard J. Midulla
Title: Executive Vice President and General Manager

ATTACHMENT 1
MONTHLY FIRM CAPACITY SCHEDULE

Month	Firm Capacity
January	360
February	360
March	354
April	350
May	346
June	341
July	340
August	340
September	342
October	347
November	355
December	360

ATTACHMENT 2

ATTACHMENT 3
DEGRADATION

Contract Year	Degradation Factor	Heat Rate for Compensation (MMBTU/MWhr-HHV)
1		
2		
3		
4		
5		

ATTACHMENT 4
START-UP FUEL

Startup Energy, Hot Start	1 2
Startup Energy, Cold Start	3 4

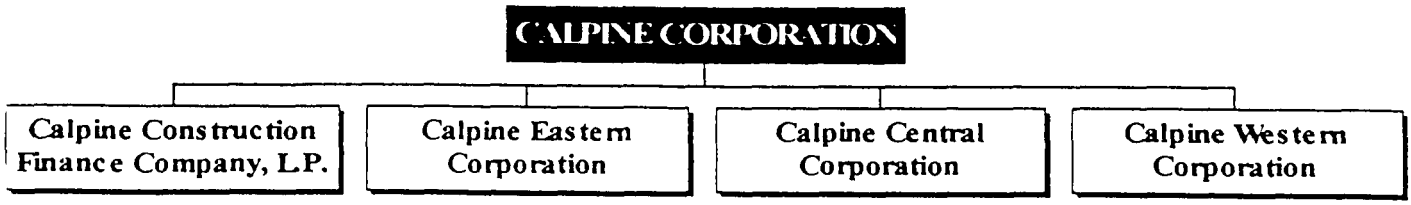
ATTACHMENT 5
PLANT DESCRIPTION

The Osprey Energy Center is located in Auburndale, Florida. The Plant will tie into a number of existing facilities, including potable water, reclaimed water and wastewater pipelines, a paved road, and Tampa Electric Company's Recker Substation, which has 230-kV transmission lines adjacent to the Plant.

The Plant will consist of a nominal 534-MW combined-cycle power plant and associated facilities. The Plant will include two nominal 170-MW Westinghouse "F" Class combustion turbines (CTs) and associated triple pressure heat recovery steam generators (HSRGs). The CTs will be equipped with dry low-nitrogen oxides combustors to reduce NOx emissions from the CTs. The HRSGs will be equipped with Selective Catalytic Reduction systems to further reduce NOx emissions. The CT units will have a combined generating capacity of nominally 340-MW (net), when operating under average ambient conditions (74^0 F), excluding power augmentation. The HRSGs will supply steam to a steam turbine electric generator, which will have a nominal generating capacity of 200-MW under average ambient conditions, excluding duct firing. The Plant will have a total generating capacity of nominally 534-MW (average ambient). The Plant will be fired exclusively with natural gas and is expected to be operated in a combined-cycle mode.

Electric energy from the Plant will have characteristics commonly known as three-phase alternating current, with a nominal frequency of sixty (60) Hertz, a nominal voltage equivalent to that of the transmission system into which the energy is delivered.

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.
OWNERSHIP STRUCTURE



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001748-EC EXHIBIT NO 6
COMPANY/
WITNESS: Calpine/Eves
DATE: 7-12-01

Calpine Corporation Portfolio
of Generating Assets

Calpine

Operating Gas Fired Power Plants	Baseload Capacity (megawatts)	Calpine Interest Percentage	Calpine Net Interest (megawatts)
Agnews San Jose, CA	26.5	100%	26.5
Auburndale Auburndale, FL	143.0	100%	143.0
Bayonne Bayonne, NJ	158.0	7.5%	11.9
Bethpage Hicksville, NY	52.0	100%	52.0
Clear Lake Pasadena, TX	335.0	100%	335.0
Dighton Dighton, MA	162.0	50%	81.0
Gilroy Gilroy, CA	112.0	100%	112.0
Gordonsville Gordonsville, VA	233.0	50%	116.5
Grays Ferry Philadelphia, PA	143.0	40%	57.2
Greenleaf 1 Yuba City, CA	50.0	100%	50.0
Greenleaf 2 Yuba City, CA	50.0	100%	50.0
Hidalgo Edinburg, TX	502.0	78.5%	394.1
Kennedy Jamaica, NY	95.0	100%	95.0
King City King City, CA	103.0	100%	103.0
Lockport Lockport, NY	177.0	11.36%	20.1
Morris Morris, IL	155.0	86.45%	134.0
Newark Newark, NJ	47.0	80%	37.6
Parlin Parlin, NJ	89.0	80%	71.2

Pasadena Pasadena, TX	231.0	100%	231.0
Pasadena Expansion Pasadena, TX	520.0	100%	520.0
Philadelphia Philadelphia, PA	22.0	66.4%	14.6
Pittsburg Pittsburg, CA	64.0	100%	64.0
Pryor Pryor, OK	109.0	80%	87.2
Stony Brook Stony Brook, NY	36.0	100%	36.0
Sumas Sumas, WA	120.0	70%	84.0
Texas City Texas City, TX	465.0	100%	465.0
Tiverton Tiverton, RI	240.0	62.8%	150.7
Watsonville Watsonville, CA	29.0	100%	29.0

Operating Geothermal Power Plants	Baseload Capacity (megawatts)	Calpine Interest Percentage	Calpine Net Interest (megawatts)
Aidlin Middletown, CA	20.0	100%	20.0
Bear Canyon Middletown, CA	20.0	100%	20.0
Calistoga Middletown, CA	73.0	100%	73.0
Lake County (2 power plants) Middletown, CA	145.0	100%	145.0
Sonoma Middletown, CA	53.0	100%	53.0
Sonoma County (12 power plants) Middletown, CA	512.0	100%	512.0
West Ford Flat Middletown, CA	27.0	100%	27.0

Under Construction	Baseload Capacity (megawatts)	Calpine Interest Percentage	Calpine Net Interest (megawatts)

Acadia Eunice, LA	1,080.0	50%	540.0
Aries Pleasant Hill, MO	516.0	50%	258.0
Baytown Baytown, TX	704.0	100%	704.0
Channel Houston, TX	519.0	100%	519.0
Decatur Decatur, AL	659.0	100%	659.0
Delta Pittsburg, CA	798.0	50%	399.0
Freestone Freestone County, TX	1,002.8	100%	1,002.8
Hermiston Hermiston, OR	530.0	100%	530.0
Los Medanos Pittsburg, CA	493.0	100%	493.0
Lost Pines I Austin, TX	522.0	50%	261.0
Magic Valley Edinburg, TX	687.0	100%	687.0
Morgan Decatur, AL	660.0	100%	660.0
Oneta Coweta, OK	960.3	100%	960.3
Ontelaunee Ontelaunee, PA	511.0	100%	511.0
Rumford Rumford, ME	237.0	66.7%	158.1
South Point Bullhead City, AZ	526.0	100%	526.0
Sutter Yuba City, CA	516.0	100%	516.0
Westbrook Westbrook, ME	487.0	100%	487.0

Under Development	**Baseload Capacity (megawatts)**	**Calpine Interest Percentage**	**Calpine Net Interest (megawatts)**
Blue Heron Indian River County, FL	1,080.0	100%	1,080.0
Calgary Energy Centre Calgary, Alberta	198.0	100%	198.0

Fremont Fremont, Ohio	500.0	100%	500.0
Haywood Haywood County, TN	763.0	100%	763.0
Hillabee Tallapoosa County, AL	700.0	100%	700.0
Lawrence Hamilton Township, OH	850.0	100%	850.0
Lone Oak Lowndes County, MS	763.0	100%	763.0
Metcalf San Jose, CA	533.0	50%	266.5
Osprey Auburndale, FL	540.0	100%	540.0
Teayawa Thermal, CA	530.0	100%	530.0
Towantic Oxford, CT	508.0	100%	508.0
Wawayanda Middletown, NY	530.0	100%	530.0
West Phoenix Phoenix, AZ	511.0	50%	255.5

Last updated: 12/20/00 2:08:43 PM

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USE OF THIS SITE CONSTITUTES AGREEMENT
TO THE FOLLOWING TERMS AND CONDITIONS

90 FERC ¶ 61,164

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

February 23, 2000

Docket Nos. ER00-939-000
ER00-1049-000
ER00-1115-000

Skadden, Arps, Slate, Meagher & Flom LLP
ATTN: Victor A. Contract, Esq.
Attorney for Lake Worth Generation L.L.C.
1440 New York Avenue, N.W.
Washington, D.C. 20005

Dynegy Inc.
ATTN: Daniel A. King, Esq
Attorney for Calcasieu Power, LLC
Suite 510-A
805 15th Street, N.W.
Washington, D.C. 20005-2207

Davis Wright Tremaine LLP
ATTN: Steven F. Greenwald, Esq.
Attorney for Calpine Construction Finance Company, L.P.
Suite 600
One Embarcadero Center
San Francisco, California 94111-3834

Dear Sirs:

You submitted for filing with the Commission rate schedules under which applicants will engage in wholesale electric power and energy transactions at market-based rates. Your submittals, as modified below, comply with the Commission's requirements for market-based rates and are accepted for filing. They are designated and made effective as indicated in Appendix A to this order.

Calpine Construction Finance Company, L.P. (Calpine) requests authority to engage in the sale of certain ancillary services (listed in its proposed rate schedule) at market-based rates into the markets administered by the California ISO, the New England Power Pool markets administered by ISO New England, Inc., the New York Power Pool markets administered by the New York Independent System Operator, and into the

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FEB 23 2000

ER00-939-000 2-23-00 1

Pennsylvania-New Jersey-Maryland Interchange Energy Market. [1] We will grant this request. [2]

Any waivers or authorizations requested by the applicants are granted to the extent specified in Appendix B to this order. Waiver of the prior or advance notice requirements, if requested, is granted to the extent specified in Appendix A. The applicants must comply with the reporting requirements and other requirements specified in Appendix B to this order. [3]

The codes of conduct submitted by the applicants are accepted if consistent with Appendix C, which reflects requirements adopted in previous Commission orders. Any code of conduct inconsistent with Appendix C is rejected and in such case Appendix C has been designated as the applicant's code of conduct. The codes of conduct submitted by the applicants covered by this order are consistent with Appendix C.

Calcasieu Power, L.L.C.'s (Calcasieu) proposed rate schedule fails to include a prohibition on power sales to affiliates, absent prior Commission approval under section

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[1]Calpine also proposes to provide Replacement Reserve service at market-based rates. The Commission has determined that Replacement Reserve service is not an ancillary service, and the granting of market-based rate authority for sales of energy and capacity includes the granting of market-based rate authority for Replacement Reserve service. See, e.g., AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 at 61,452, 61,464 (1998), order on reh'g, 87 FERC ¶ 61,208 (1999) (AES).

[2]See AES; New England Power Pool, 85 FERC ¶ 61,379 (1998), reh'g pending; Central Hudson Gas & Electric Corporation, et al., 86 FERC ¶ 61,062, order on reh'g, 88 FERC ¶ 61,138 (1999); Atlantic City Electric Company, et al., 86 FERC ¶ 61,248, clarified, 86 FERC ¶ 61,310 (1999).

[3]On May 27, 1999, the Commission issued an order in which it modified the reporting requirements for long-term transactions applicable to public utilities without ownership or control over generation or transmission facilities that are authorized to sell power at market-based rates (power marketers). Southern Company Services, et al., 87 FERC ¶ 61,214 (1999), reh'g pending (Southern). Specifically, with respect to any long-term transaction agreed to by a power marketer after 30 days from the date of issuance of a final order in the Southern case, the power marketer must file a service agreement with the Commission within 30 days after service commences, rather than reporting transactions thereunder in its quarterly transaction summaries.

205 of the Federal Power Act (FPA), 16 U.S.C. § 824d (1994). Calcasieu is directed, within 30 days of the date of this order, to revise its rate schedule accordingly.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1999), an entity's filing of a timely notice of intervention or a timely, unopposed motion to intervene in a proceeding makes it a party to that proceeding.

Should an applicant or any of its affiliates deny, delay, or require unreasonable terms, conditions, or rates for natural gas fuel or services to a potential electric competitor in bulk power markets, then that electric competitor may file a complaint with the Commission that could result in the applicant's or its affiliate's authority to sell power at market-based rates being suspended. [4]

Sales of accounts receivable are not dispositions of jurisdictional facilities and are not within the scope of section 203 of the FPA. To the extent an applicant seeks a case-specific finding on this or any related point, it may file a petition for a declaratory order with the Commission.

Calcasieu and Lake Worth Generation L.L.C. (Lake Worth) seek Commission approval to reassign transmission capacity. We find their requests to be consistent with our requirements.

Lake Worth and Calcasieu must inform the Commission of the dates service commences.

By direction of the Commission.

Linwood A. Watson, Jr.,
Acting Secretary.

[4] See, e.g., Louisville Gas & Electric Co., 62 FERC ¶ 61,016 at 61,148 (1993).

APPENDIX A

Applicants are hereby informed of the following rate schedule designations:

Lake Worth Generation L.L.C.
Docket No. ER00-939-000
Rate Schedule Designation
Effective Date: Date Service Commences

Designation	Description
FERC Electric Tariff, Original Volume No. 1, Original Sheet No. 1	Market-Based Rate Tariff

Calcasieu Power, LLC
Docket No. ER00-1049-000
Rate Schedule Designations
Effective Date: Date Service Commences

Designation	Description
FERC Electric Tariff, Original Volume No. 1 Original Sheet Nos. 1-2	Market-Based Rate Tariff and Code of Conduct

Calpine Construction Finance Company, L.P.
Docket No. ER00-1115-000
Rate Schedule Designation
Effective Date: March 14, 2000

Designation	Description
FERC Electric Tariff, Original Volume No. 1 Original Sheet Nos. 1-2	Market-Based Rate Tariff

APPENDIX B

(1) If requested, waiver of Parts 41, 101, and 141 of the Commission's regulations, with the exception of 18 C.F.R. §§ 141.14, .15 (1999), is granted. Licensees remain obligated to file the Form No. 80 and the Annual Conveyance Report.

(2) Within 30 days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liabilities by those applicants who have sought such approval should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214.

(3) Absent a request to be heard within the period set forth in Paragraph (2) above, if the applicants have requested such authorization, the applicants are hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the applicants, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

(4) If requested, until further order of this Commission, the full requirements of Part 45 of the Commission's regulations, except as noted below, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate involving the applicants. Any such person instead shall file a sworn application providing the following information:

(a) full name and business address; and

(b) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(5) The Commission reserves the right to modify this order to require a further showing that neither the public nor private interests will be adversely affected by continued Commission approval of the applicants' issuances of securities or assumptions of liabilities, or by the continued holding of any affected interlocks.

(6) If requested, waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15 and 35.16, is granted for transactions under the rate schedules at issue here.

(7) (a) Applicants who own generating facilities may file umbrella service agreements for short-term power sales (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales (including risk management transactions if they result in actual delivery of electricity). For long-term transactions (longer than one year), applicants must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service. To ensure the clear identification of filings, and in order to facilitate the orderly maintenance of the Commission's files and public access to documents, long-term transaction service agreements should not be filed together with short-term transaction summaries. For applicants who own, control or operate facilities used for the transmission of electric energy in interstate commerce, prices for generation, transmission and ancillary services must be stated separately in the quarterly reports and long-term service agreements.

(b) Applicants who do not own generating facilities must file quarterly reports detailing the purchase and sale transactions undertaken in the prior quarter (including risk management transactions if they result in actual delivery of electricity). Applicants who are power marketers should include in their quarterly reports only those risk management transactions that result in the actual delivery of electricity.

(8) The first quarterly report filed by an applicant in response to Paragraph (7) above will be due within 30 days of the end of the quarter in which the rate schedule is made effective.

(9) Each applicant must file an updated market analysis within three years of the date of this order, and every three years thereafter. The Commission reserves the right to require such an analysis at any time. The applicants must also inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These include, but are not limited to: (a) ownership of generation or transmission supplies; or (b) affiliation with any entity not disclosed in the applicants' filing that owns generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area. Alternatively, the applicants may elect to report such changes in conjunction with the updated market analysis required above. Each applicant must notify the Commission of which option it elects in the first quarterly report filed pursuant to Paragraph (7) above.

APPENDIX C

[APPLICANT]
SUPPLEMENT NO. _ TO RATE SCHEDULE NO. _

STATEMENT OF POLICY
AND CODE OF CONDUCT
WITH RESPECT TO THE RELATIONSHIP BETWEEN
[POWER MARKETER] AND [PUBLIC UTILITY]

Marketing of Power

1. To the maximum extent practical, the employees of [Power Marketer] will operate separately from the employees of [Public Utility].

2. All market information shared between [Public Utility] and [Power Marketer] will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.

3. Sales of any non-power goods or services by [Public Utility], including sales made through its affiliated EWG's or QF's, to [Power Marketer] will be at the higher of cost or market price.

4. Sales of any non-power goods or services by the [Power Marketer] to [Public Utility] will not be at a price above market.

Brokering of Power

To the extent [Power Marketer] seeks to broker power for [Public Utility]:

5. [Power Marketer] will offer [Public Utility's] power first.

6. The arrangement between [Power Marketer] and [Public Utility] is non-exclusive.

7. [Power Marketer] will not accept any fees in conjunction with any Brokering services it performs for [Public Utility].

OSPREY ENERGY CENTER
GENERATING ALTERNATIVES EVALUATED

GENERATING TECHNOLOGIES CONSIDERED

COMBUSTION TURBINE-OIL

COMBUSTION TURBINE-GAS

COMBINED CYCLE-GAS

COMBINED CYCLE-OIL

PULVERIZED COAL STEAM

CONVENTIONAL GAS STEAM

COAL GASIFICATION-COMBINED CYCLE

NUCLEAR STEAM

RENEWABLE ENERGY

OSPREY ENERGY CENTER
COST-EFFECTIVENESS ANALYSES OF ALTERNATIVE GENERATION TECHNOLOGIES

Comparison of Generation Alternatives

Technology Type	Levelized Life-Cycle Cost at Assumed Capacity Factor (2000 $/MWh)		
	Peaking Operation (10% CF)	Intermediate Oper. (50% CF)	Base Load Oper. (90% CF)
Combined Cycle - Gas Fired	$ 98 - 118	$ 37 - 45	$ 30 - 37
Combined Cycle - Oil Fired	111 - 134	50 - 61	43 - 53
Simple Cycle - Gas Fired	85 - 116	52 - 73	45 - 68
Simple Cycle - Oil Fired	110 - 144	71 - 101	64 - 97
Steam - Coal	200 - 220	52 - 59	35 - 42
Steam - Gas	124	53	45
Steam - Nuclear	283	61	36
IGCC Technology	196 - 245	49 - 61	32 - 40
Renewable Energy	121 - 1072	67 - 240	47 - 147

Source: R. W. Beck and Associates.

TED S. BALDWIN
Calpine Corporation
Two Urban Center
4890 W. Kennedy Blvd., Suite 600
Tampa, FL 33609

JOB EXPERIENCE:

REGIONAL ENGINEER, Calpine Corporation, Tampa, FL, May 2000 to present.

- Responsible for technical support of all business development activities in the Southeastern United States. Project locations include Florida, Alabama, Mississippi, and Kentucky.

  Tasks managed include due diligence on existing facilities, conceptualization of project technical configuration, preparation of project heat balances, site selection and site development (including environmental permits), preparation of capital cost estimates, participation in the negotiation of power purchase agreements and tolling agreements, development and negotiation of engineering and construction contracts, review of fuel supply contracts and other project documents, and interface with financing parties regarding technical aspects of the projects.

DIRECTOR OF ENGINEERING AND CONSTRUCTION, Nations Energy Corporation (Independent Power Subsidiary of Tucson Electric Power), Winter Park, Fl., May 1995 to present.

- Involved in the startup of a new energy development company. Responsibilities include managing all technical aspects of developing domestic and international energy projects, including acquisitions and greenfield/brownfield projects. Successfully closed two projects and carried two other projects through advanced stages of development with closings expected in 1999 and 2000.

  Tasks managed include due diligence on existing facilities, conceptualization of project technical configuration, site selection and site development (including environmental permits), preparation of capital cost estimates, preparation of operation and maintenance (O&M) estimates, participation in the negotiation of power purchase agreements and tolling agreements, development and negotiation of engineer, procurement, and construction (EPC) contracts and O&M agreements, review of fuel supply contracts and other project documents, and interface with financing parties regarding technical aspects of the projects. Also manage the implementation of one international EPC contract by providing direction to project manager directly responsible for the project.

  Country involvement includes U.S.A. (Colorado, Florida, and Louisiana), Mexico, Panama, Honduras, Netherlands Antilles, and Czech Republic. Fuel technologies include gas, pulverized coal, waste coal, biomass, diesel, residual oil, and refinery byproducts such as refinery gas and asphalt. Projects often involve the integration of existing facilities with new facilities and the supply of power, steam, and other utilities to industrial complexes such as refineries and breweries.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001748-EC EXHIBIT NO. 7
COMPANY/ WITNESS: Calpine / Baldwin
DATE: 3-12-01

Resume of
TED S. BALDWIN
Page 2 of 3

APPLICATION ENGINEERING MANAGER, Power Generation Business Unit, Westinghouse Electric Corp., Orlando, Fl., April 1992-April 1995.

- Managed a multi-disciplined group of twenty-three engineers and technicians including thermal design, mechanical design, controls, and electrical engineers. The group was responsible for the technical content of bids and the technical negotiation of all new construction orders within the business unit, including combustion turbine and steam turbine equipment, extended scope thermal island (combined cycle and conventional steam), and extended scope turnkey (simple cycle and combined cycle) projects. Annual sales in 1994 significantly in excess of one billion dollars. Responsible for technical negotiation of EPC contracts and risk management of all technical related warranties including plant performance, emissions, availability, reliability, etc. Oversaw transformation of organization into regional business teams with application engineering personnel stationed at four different locations throughout the world.

THERMAL CYCLE SYSTEM GROUP MANAGER, Power Generation Projects Division, Westinghouse Electric Corp., Orlando, Fl., April 1990-March 1992.

- Responsible for the implementation of combined cycle power projects from contract signing to completion of plant performance testing. Managed a group of ten engineers and technicians responsible for thermal cycle design, preparation of plant mass and material balances, and specification/evaluation of major thermal equipment (heat recovery steam generator, steam turbine, condenser, deaerator, cooling tower, auxiliary boiler, etc.) within the power plant. The group was also responsible for performance testing of the power plant after commissioning.

THERMAL CYCLE SYSTEMS ENGINEER, Power Generation Projects Division, Westinghouse Electric Corp., Orlando, Fl., May 1987-March 1990.

- Responsible for application support and implementation support of combined cycle power projects, mostly in the domestic market. Prepared preliminary and final cycle design, final plant mass and material balances, major equipment specifications for heat recovery steam generators, condensers, deaerators, etc. Participated in the evaluation and vendor negotiations for these pieces of equipment.

BOILER ENGINEER, Machinery Technology Division, Westinghouse Electric Corp., Pittsburgh, Pa., December 1985-April 1987.

- Provided thermal design engineering support to the U.S. Navy in the field of marine propulsion boilers.

Resume of
TED S. BALDWIN

EQUIPMENT ENGINEER/ANALYTICAL ENGINEER, Machinery Division/Furnace Division, The M.W. Kellogg Company, Houston, Texas, June 1982-November 1985.

- Responsible for preparation of equipment specifications, evaluation of vendors' bids, requisition preparation, technical follow-up, drawing review, and performance testing on major power generation equipment items including package boilers, gas turbine waste heat recovery units, and associated auxiliaries.

EDUCATION:

Masters of Science in Mechanical Engineering, 1982. The University of Michigan, Ann Arbor. Graduate Fellowship Program. Curriculum emphasis in the thermal sciences.

Bachelor of Science in Mechanical Engineering, 1981. The University of Texas, Austin. Scholarship Program.

TABLE 2

OSPREY ENERGY CENTER
PROJECT PROFILE

Expected Plant Capacity:

a.	Average ambient rating (74°F, 80% R.H.):	529 MW
b.	Summer (95°F, 80% R.H.):	496 MW
	With Duct-firing & Power Augmentation:	575 MW
c.	Winter (32°F, 60% R.H.):	578 MW
	With Duct-firing & Power Augmentation:	666 MW
d.	ISO (59°F, 60% R.H.):	545 MW

Project Energy Production: Approximately 4,300,000 MWH/year (not including duct-firing or power augmentation)

Technology Type: Two Siemens-Westinghouse 501F advanced firing temperature technology combustion turbines, two heat recovery steam generators, and one steam turbine generator in combined cycle configuration

Anticipated Construction Schedule:

a.	Engineering release date:	February 2001
b.	Construction mobilization date:	June 2001
c.	Commercial in-service date:	2nd quarter 2003

Fuel Use: Approximately 86 million Standard Cubic Feet of natural gas/day, annual average conditions (74°F, 80% R.H.), full load

Air Pollution Control Strategy: Dry low-NOx burners and SCR

Cooling Method: Wet Cooling Tower

Total Site Area: 19.5 acres (approximate)

Construction Status: Planned

Certification Status: Need Determination Petition and Site Certification Application filed.

Status with Federal Agencies: FERC has issued its order granting Calpine market-based rate authority.

TABLE 2

OSPREY ENERGY CENTER
PROJECT PROFILE
(CONTINUED)

Projected Unit Performance Data:

Planned Outage Factor (POF):	3.5%
Forced Outage Factor (FOF):	2.0%
Equivalent Availability Factor (EAF):	94.5%
Estimated Annual Average Capacity Factor (%):	91.0%

Average Net Operating Heat Rate (ANOHR): 6800 Btu/kWh (HHV) (74°F, 80°R.H.) expected

Project Unit Financial Data (per Calpine Corporation):

Book Life (years):	35 years
Direct Construction Cost:	Approx. $194.8 million
AFUDC Amount:	Not applicable
Escalation ($/kW):	Not applicable
Fixed O&M ($/kW per year):	Proprietary
Variable O&M (4/MWH):	Proprietary
K-Factor:	Not applicable
Project Life:	35 years

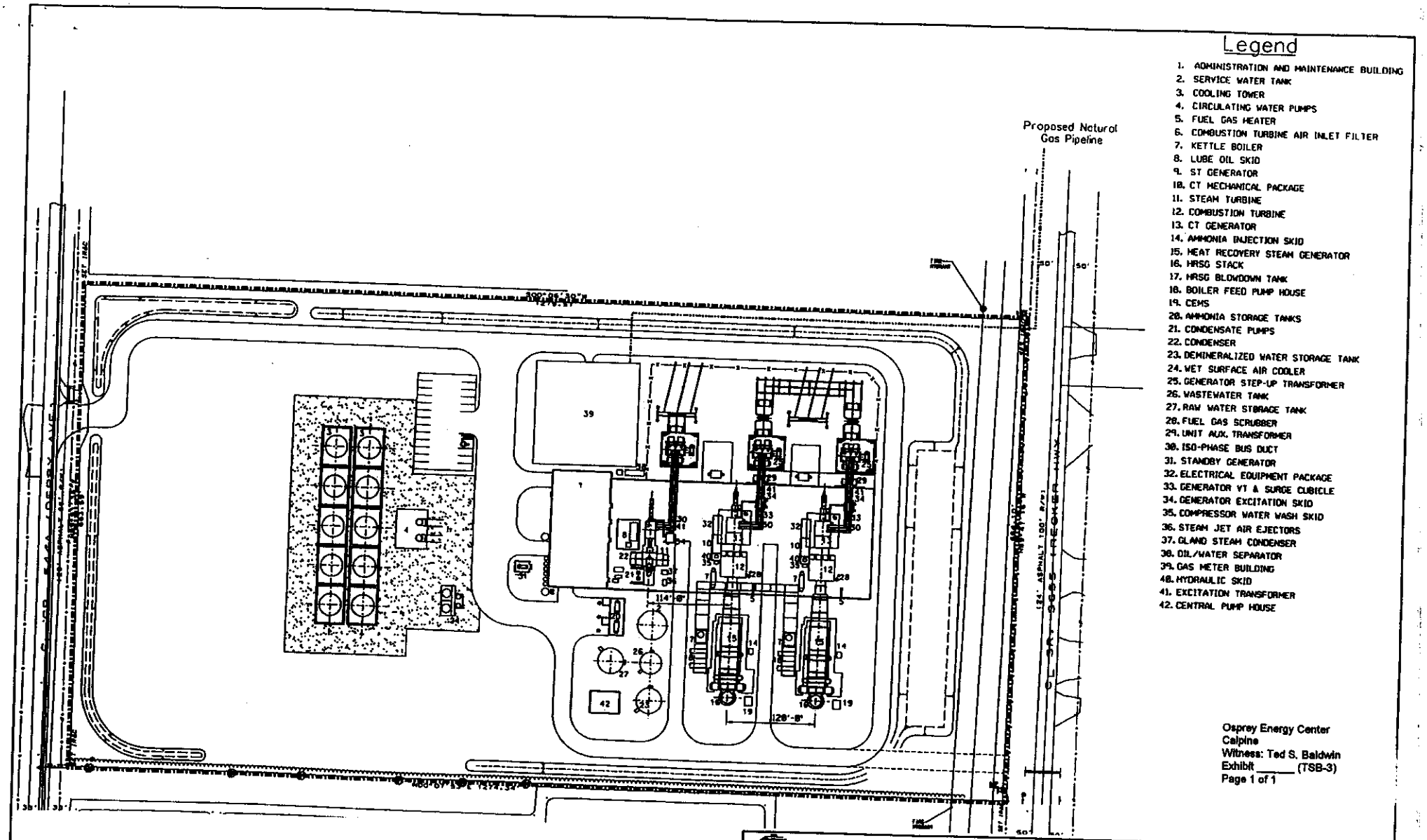
Expected Plant Air Emissions:
NO_x: 3.5 ppmvd @15% O_2
SO_2: 20.8 lbs/hour
CO: 10 ppm

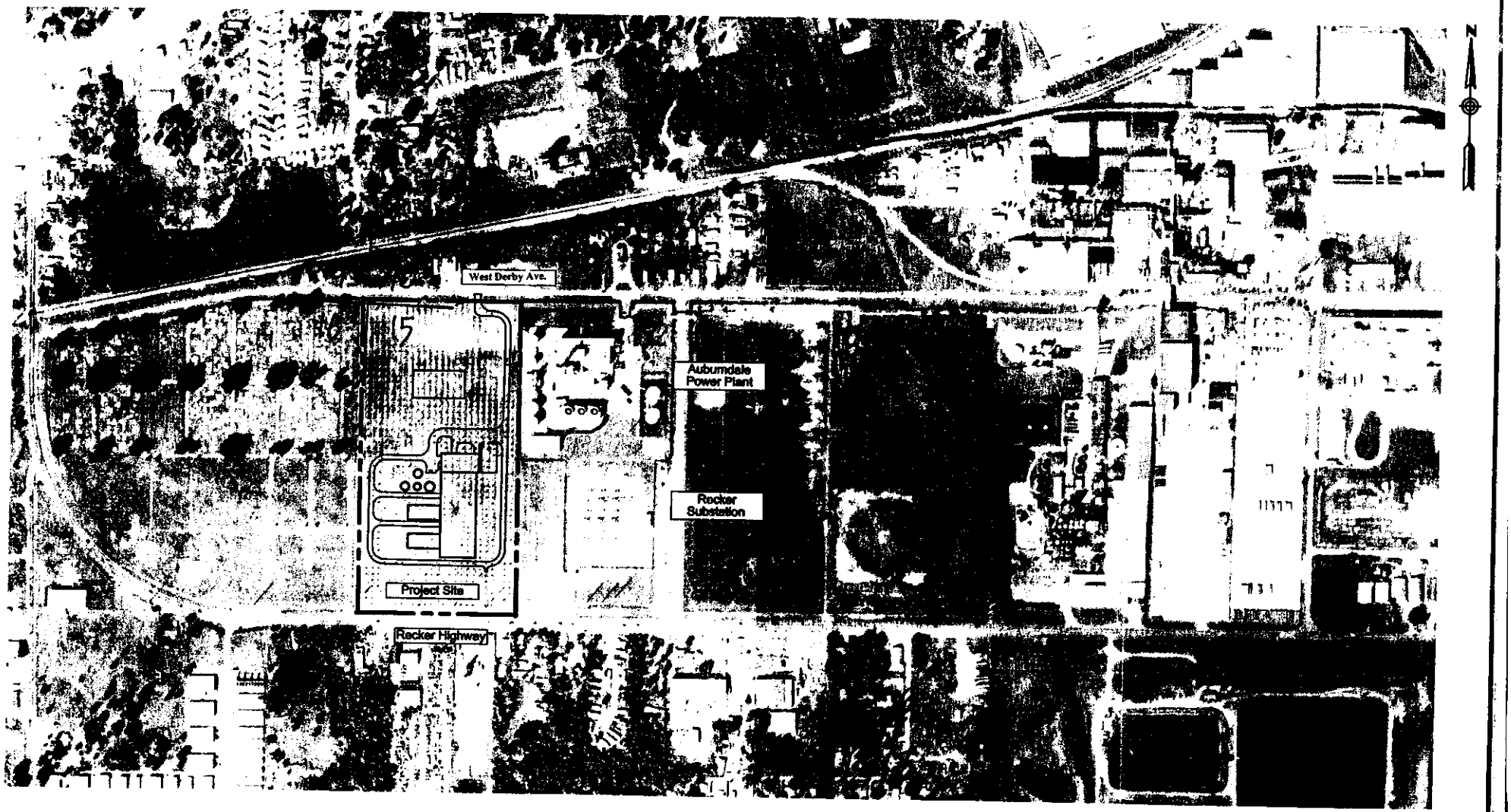
New Transmission Lines Required: None

Gas Pipeline Required: None

Water Requirements:
(Including Reclaimed Water)
Approx. 4.79 MGD, summer peak Conditions (95°F, 80 R.H.), (with power augmentation and duct-firing)
Approx. 3.55 MGD average (74°F, 80 R.H.), (without power augmentation or duct-firing)

Wastewater Discharge:
Approx. 1.26 MGD. summer peak conditions (with power augmentation and duct-firing)
Approx. 0.62 MGD, average conditions (3.9 cycles of concentration without power augmentation and duct-firing)


Proposed Natural Gas Pipeline
Legend
1. ADMINISTRATION AND MAINTENANCE BUILDING
2. SERVICE WATER TANK
3. COOLING TOWER
4. CIRCULATING WATER PUMPS
5. FUEL GAS HEATER
6. COMBUSTION TURBINE AIR INLET FILTER
7. KETTLE BOILER
8. LUBE OIL SKID
9. ST GENERATOR
10. CT MECHANICAL PACKAGE
11. STEAM TURBINE
12. COMBUSTION TURBINE
13. CT GENERATOR
14. AMMONIA INJECTION SKID
15. HEAT RECOVERY STEAM GENERATOR
16. HRSG STACK
17. HRSG BLOWDOWN TANK
18. BOILER FEED PUMP HOUSE
19. CEMS
20. AMMONIA STORAGE TANKS
21. CONDENSATE PUMPS
22. CONDENSER
23. DEMINERALIZED WATER STORAGE TANK
24. WET SURFACE AIR COOLER
25. GENERATOR STEP-UP TRANSFORMER
26. WASTEWATER TANK
27. RAW WATER STORAGE TANK
28. FUEL GAS SCRUBBER
29. UNIT AUX. TRANSFORMER
30. ISO-PHASE BUS DUCT
31. STANDBY GENERATOR
32. ELECTRICAL EQUIPMENT PACKAGE
33. GENERATOR VT & SURGE CUBICLE
34. GENERATOR EXCITATION SKID
35. COMPRESSOR WATER WASH SKID
36. STEAM JET AIR EJECTORS
37. GLAND STEAM CONDENSER
38. OIL/WATER SEPARATOR
39. GAS METER BUILDING
40. HYDRAULIC SKID
41. EXCITATION TRANSFORMER
42. CENTRAL PUMP HOUSE
Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-3)
Page 1 of 1
Golder Associates
Tampa, Florida
Client / Project
Calpine Construction Finance Company, L.P.
Osprey Energy Center
Site Plan
CAD BY: CDT
CHK BY: HGB
REV BY: —
SCALE: 1"=120'
DATE: 08/11/00
FILE No.: fig3_2_0-2.dwg
Job No. 993-9570
FIGURE Revision 1
3.2.0-2



Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-4)
Page 1 of 1

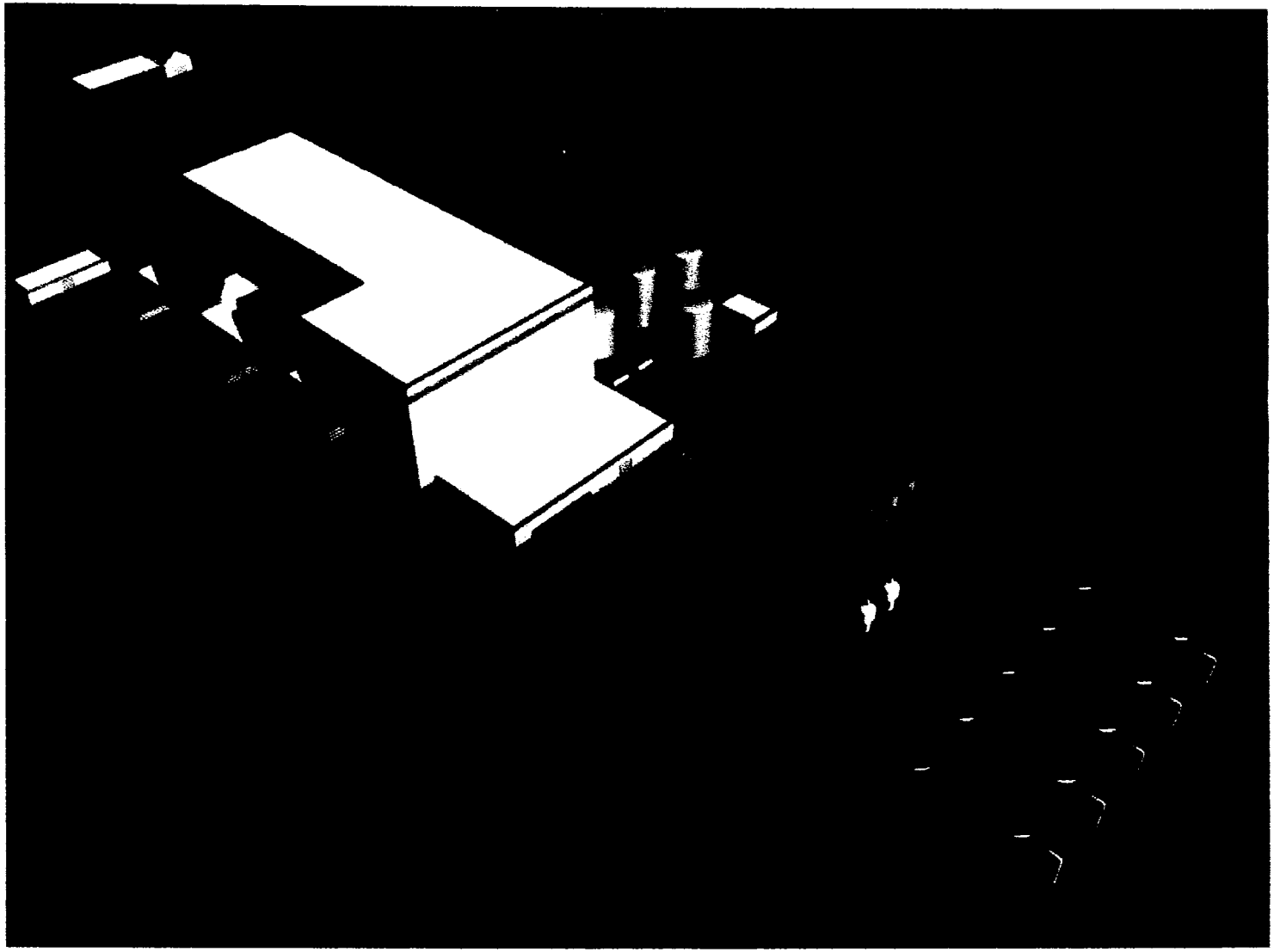
400' 0 400'
scale feet

PLOT PLAN

Golder Associates
Tampa, Florida

Client / Project
Calpine Construction Finance Copany, L.P.
Osprey Energy Center

CAD BY: CDT	SCALE: 1"=400'	Job No. 993-8570
CHK BY: RAZ	DATE: 03/02/00	FIGURE
REV BY: --	FILE No.: plot-plan.dwg	



Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-5)
Page 1 of 1

Golder Associates

Tampa, Florida

PERSPECTIVE RENDITION

Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

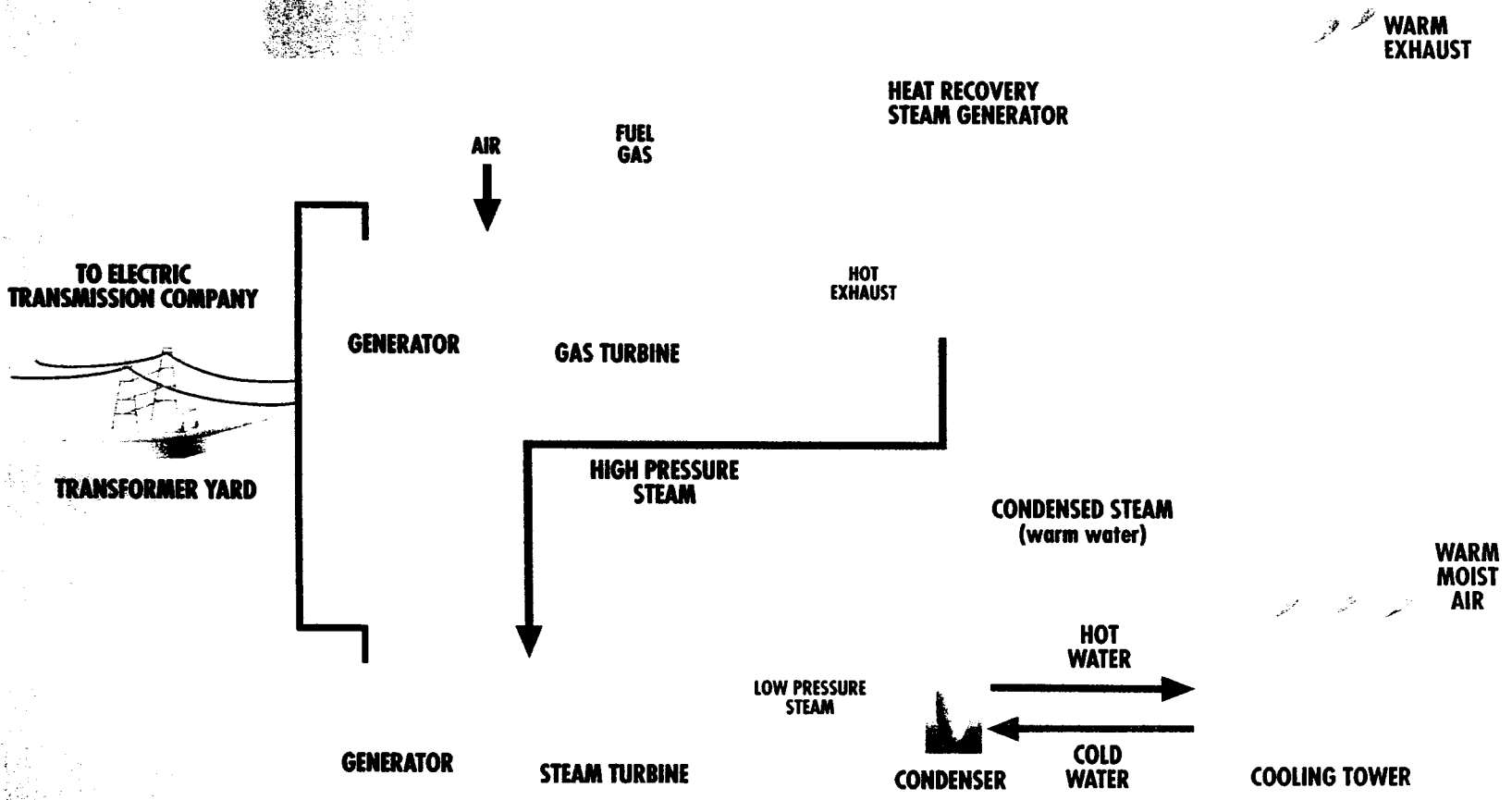
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CHK BY:	RAZ	DATE:	03/04/00	FIGURE	
REV BY:	–	FILE No.:	fig1_3_3-1.dwg		

TABLE 2
OSPREY ENERGY CENTER
Estimated Plant Performance and Emissions Data

Percent Load		100%	100%	100%	100%	70%	70%	70%	70%	60%	60%	60%	60%	100%
Ambient Temperature	F	95	74	59	32	95	74	59	32	95	74	59	32	95
Ambient Relative Humidity	%	80%	80%	60%	60%	80%	80%	60%	60%	80%	80%	60%	60%	80%
Gas Turbine Power	MW	324	347	362	390	222	240	253	272	190	205	216	233	357
Steam Turbine Power	MW	185	195	197	203	145	153	152	154	135	143	149	148	233
Net Cycle Power	MW	496	529	545	578	358	383	395	416	317	339	356	371	575
Net Cycle LHV Heat Rate	BTU/kW-hr	6,187	6,122	6,125	6,137	6,497	6,430	6,359	6,373	6,599	6,529	6,478	6,457	6,576
Net Cycle LHV Efficiency	%	55.2%	55.7%	55.7%	55.6%	52.5%	53.1%	53.7%	53.5%	51.7%	52.3%	52.7%	52.9%	51.9%
Net Cycle HHV Heat Rate	BTU/kW-hr	6,871	6,798	6,802	6,815	7,215	7,140	7,062	7,077	7,329	7,251	7,193	7,170	7,303
CTG fuel flow (lb/h)- total for two CTGs	lb/hr	146,325	154,237	159,099	168,918	110,864	117,346	119,634	126,212	99,806	105,621	109,911	114,296	155,858
CTG heat input, HHV basis (mmBtu/h)- total for two CTGs	MMBtu/hr	3,409	3,594	3,707	3,936	2,583	2,734	2,787	2,941	2,325	2,461	2,561	2,663	3,631
Duct burner fuel flow (lb/h)- total for two burners	lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	24,308
Duct burner heat input, HHV basis (mmBtu/h)- two burners	MMBtu/hr	0	0	0	0	0	0	0	0	0	0	0	0	566
CTG exhaust gas flow (lb/h)- total for two CTGs (two duct burners when on)	lb/hr	6,630,800	6,973,469	7,218,232	7,578,580	5,692,996	5,888,867	6,028,774	6,258,506	5,081,836	5,240,757	5,354,272	5,539,920	6,655,108
CTG exhaust gas composition (% by volume)														
Nitrogen	%	72.64	73.47	74.37	74.82	72.93	73.82	74.63	75.07	72.93	73.77	74.56	75.04	68.31
Argon	%	0.91	0.92	0.93	0.94	0.92	0.09	0.94	0.94	0.92	0.93	0.94	0.94	0.86
Oxygen	%	12.13	12.28	12.51	12.53	13.00	13.11	13.26	13.26	12.99	12.97	13.07	13.15	9.85
Carbon dioxide	%	3.70	3.74	3.74	3.79	3.31	3.37	3.40	3.47	3.31	3.43	3.49	3.52	4.26
Water	%	10.62	9.59	8.44	7.92	9.85	8.77	7.77	7.26	9.86	8.90	7.94	7.36	16.73
NOx as NO2 (lb/h)- total for two stacks	lb/hr	44.1	46.3	48.6	51.5	34.2	35.4	36.7	38.9	30.4	32.0	33.5	34.8	55.0
based on ppmvd @ 15% O2	ppm	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
CO (lb/h)- total for two stacks	lb/hr	78	82	86	90	60	62	64	68	266	279	292	304	279
based on ppmvd @ 15% O2	ppm	10	10	10	10	10	10	10	10	50	50	50	50	29
VOC as CH4 (lb/h)- total for two stacks	lb/hr	9.9	10.4	10.9	11.5	14.1	14.7	15.3	16.0	12.7	13.3	14.0	14.5	24.8
based on ppmvd @ 15% O2	ppm	2.3	2.3	2.3	2.3	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.6
SO2 (lb/h)- total for two stacks	lb/hr	18.8	19.8	20.7	22.0	14.4	15.0	15.6	16.4	13.0	13.7	14.3	14.9	23.9
Particulates as PM10 (lb/h)- total for two stacks	lb/hr	38.0	40.1	42.2	44.5	32.1	33.4	34.6	36.1	28.7	29.8	30.9	32.1	45.6

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Page 1 of 1

FIGURE 6
COMBINED-CYCLE GENERATION
SCHEMATIC DIAGRAM









CALPINE EASTERN

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Page 1 of 1

OSPREY ENERGY CENTER

DESIGN BASIS

INTRODUCTION

The Osprey Project is a highly efficient combined cycle electric power plant that will be fueled by natural gas. The Project will be nominally rated to produce 545 MW at ISO temperature and relative humidity, and 529 MW at average ambient site conditions. This Design Basis describes the Project and its supporting systems.

PROJECT LOCATION

The Osprey Project site will be located in the City of Auburndale, in Polk County, Florida, on approximately 19.5 acres situated approximately 1.5 miles southwest of downtown Auburndale and approximately 37 miles east of Tampa Bay. The site is a non-producing citrus grove zoned "Light Industry" and is currently unused. Land uses adjacent to the site include the TECO Recker Substation and 230 kV transmission line; the existing Auburndale Power Plant, which is a 150 MW natural gas-fired (with oil backup fuel) cogeneration plant owned by Auburndale Power Partners; two small residential enclaves; a cemetery; and commercial and industrial businesses. Access to the site will be from West Derby Avenue, a two-lane county collector road.

OVERVIEW

The proposed Project will consist of two gas-fired advanced technology, dry low-NO_x combustion turbine generators ("CTGs") with the capability to use power augmentation to increase the CTGs' power output, two heat recovery steam generators (HRSGs) that include duct-firing capability to increase the steam generation capability of the HRSGs, and one steam turbine generator ("STG") rated for the full steam production capacity (including duct-firing) of the HRSGs. The CTGs will generate approximately 65 percent of the Project's output and the STG will generate approximately 35 percent of the Project's output. Thermal energy will be recovered from the hot combustion gases exiting the CTGs to generate steam in the HRSGs. Steam from the HRSGs will be expanded through an STG which will produce the remaining balance of the Project's output. This process of utilizing both the power generated in the combustion turbines as well as that generated by the STG is commonly referred to as "combined cycle" generation. To enhance power output during peak demand periods, the HRSGs are equipped with duct burners which burn additional natural gas inside the HRSGs to produce additional steam that is then used in the STG to produce additional power. Further peaking power can also be provided by extracting steam from the STG and injecting it into the CTGs. These two methods of providing peaking power will be utilized primarily during the summer months. Cooling water will be used in conjunction with cooling towers to condense steam back to water for reuse in the HRSGs. The

Project's water supply will be a combination of reclaimed water and well water.

The Project will emit nitrogen oxides (NO_x), carbon monoxide (CO), non-methane hydrocarbons, small quantities of particulate matter (PM_{10}), and sulfur oxides (SO_x). The Project will be designed to control NO_x using an advanced dry low-NO_x combustion system and a selective catalytic reduction (SCR) system. This represents state-of-the-art emissions control technology, capable of achieving approximately 3.5 ppmvd NO_x levels. Only trace amounts of SO_2 will be emitted when burning natural gas. CO and non-methane hydrocarbon emissions will be minimized through the use of good combustion practice.

PROJECT DESCRIPTION

Project Structures and Buildings

The Osprey Project will include the following structures and buildings:

- A common control room, warehouse and administration building which will contain a workshop, a maintenance area, and offices.
- Each HRSG will be located adjacent to its CTG and will connect to an approximate 135 foot high emission stack. There will be one stack for each unit.
- Mechanical induced draft evaporative cooling towers.
- Water storage tanks.
- An electrical switchyard.

Combustion Turbine Generators

The Project will employ Siemens-Westinghouse 501F industrial frame advanced technology CTGs equipped with dry low-NO_x combustors. The CTGs will be housed in an enclosure which provides thermal insulation, acoustical attenuation, and fire extinguishing media containment. The enclosure will allow access for routine inspections and maintenance.

Heat Recovery Steam Generators

One of the significant features of a combined cycle plant is the utilization of the hot exhaust gas from the CTGs to produce steam which, in turn, is expanded in a STG to drive an electric generator and produce electricity. The HRSGs are the key pieces of equipment necessary to the production of this steam. The HRSGs will be multiple-pressure, reheat units. The various pressure sections will each consist of economizer, evaporator and superheater sections. The HRSGs will also be equipped with a reheater to further improve cycle efficiency.

Steam Turbine

The STG will be a multiple admission, reheat, condensing turbine designed for sliding pressure operation. The high pressure portion of the STG receives high pressure superheated steam from the HRSG and then exhausts steam into the reheat section of the

HRSG. Reheated steam from the HRSG is supplied to the intermediate pressure turbine, and the intermediate pressure turbine exhausts into the low pressure turbine. The low pressure turbine receives low pressure superheated steam from the HRSG and exhausts steam into the condenser.

Stacks

CTG combustion gases will discharge through two approximate 19 foot diameter, 135 foot high carbon steel stacks. The stacks will be designed to minimize the potential for aerodynamic down wash of stack emissions.

Cooling System

After the steam passes through the STG, it is condensed in a shell and tube heat exchanger (surface condenser) utilizing cooling water from the cooling tower. Each condenser will include a shell, tubes, a water box, and hot well. Condensed water in the hot well is pumped back to the HRSG to begin the thermal cycle again.

Cooling water for the condensers will be provided from evaporative (wet) induced draft cooling towers. Fans at the top of the cooling tower maintain a draft within the cooling tower. The water will be cooled by evaporation as it falls through baffles from the top of the cooling tower to a basin at the bottom of the tower where it is again pumped back through the condenser. Cooling tower components will include a basin, fans, fan decks,

drift eliminators, fill material (baffles), and other necessary components. Average water usage will be approximately 3.55 million gallons per day when operating at full load, but without duct-firing or power augmentation, at average site conditions. Maximum water usage will be approximately 4.79 million gallons per day when operating at 95° F, 80% relative humidity while using both power augmentation and duct-firing.

Fuel Supply and Storage Systems

Natural gas will be the primary fuel for the Project. The Project's gaseous fuel system will interconnect to the Gulfstream gas metering station located on the site. The gas fuel system will also include fuel gas heaters, meters, and an isolation system in accordance with governing engineering codes.

Condensate and Feedwater Systems

The condensate system will deliver de-aerated water from the condenser hotwell to the HRSG. The condensate system will also provide water to other Project subsystems. The feedwater system will provide feedwater to the economizer sections of the HRSG. The feedwater system will also supply water to interstage desuperheaters.

Demineralized Water System

The demineralizer plant will consist of a permanently installed demineralizer system to

produce demineralized water for the Project from the raw water source. The product water from the demineralizer system will be stored in a demineralized water storage tank for use as steam cycle makeup water.

The tank will be constructed of lined carbon steel. Demineralizer system wastewater treatment will be done on-site and then discharged to the City of Auburndale's wastewater treatment plants.

Boiler Feedwater Treatment System

The boiler feedwater treatment system would likely consist of hydrazine (or a suitable substitute) for oxygen scavenging (injected into condensate system); phosphate for boiler water solids control (utilized in the HRSG steam drums); and neutralizing amine for pH control (fed into condensate).

Wastewater Treatment System

The process waste streams will be combined, collected, and disposed of separately or in combination, depending on the type of treatment required and the ultimate discharge point. Plant wastewater that could potentially contain small quantities of oil (including wastewater from the plant area washdown floor drains, equipment and sample drains) will be treated in an oil/water separator, from which the clean effluent may be recycled for use as cooling tower makeup. Oil and sludge collected in the oil/water separator will

be disposed of off-site. Wastewater grab sample points will be provided in accordance with the requirements of all applicable permits.

Sanitary waste will be discharged to the local wastewater treatment plant for disposal. Approximately 2,880 gallons of sanitary waste will be generated per day.

HRSG blowdown will be collected in a dedicated sump and recycled to a small wastewater cooling tower before being discharged to the City of Auburndale's Allred Wastewater Treatment Plant. Cooling tower blowdown will also be routed to the Allred Wastewater Treatment Plant.

Spill prevention and control measures will include dikes around acid tanks and other chemical tanks. The dikes will be sized to contain a volume larger than that of the enclosed tank or tanks. Curbed enclosures will be provided for boiler feedwater treatment chemicals and water pretreatment chemicals.

Oil-filled transformers will be located in a sump. Storm water that collects in the sumps will drain to a common corner sump.

Compressed Air System

The compressed air system will be designed to provide dry, oil-free, control air for plant instrumentation, controls and maintenance activities.

The primary source of plant compressed air will be from permanently installed air compressors. The instrument air supply will be oil-filtered and dried. The system will

also include a compressed air receiver.

The system will be complete with piping, valves, locally mounted instrumentation, and controls.

Fire Protection System

An on-site fire protection system will be provided for the plant. The water supply for the fire protection system will be stored on-site in either the raw water tank or cooling tower basin. A main underground fire header will be provided to serve strategically placed yard hydrants and sprinkler/deluge systems for the Project.

The fire water distribution system will incorporate sectionalizing valves so that a failure in any part of the system can be isolated while allowing the remainder of the system to function properly.

The fire protection system will also include:

- An extinguishing system for the gas turbine/generator set;
- A dry pipe, automatic sprinkler system to envelop, as required, oil piping and equipment associated with the steam turbine lubrication oil system;
- Wet pipe sprinkler systems for the turbine building and warehouse storage area; and
- A protective signaling system with main panel in the control room.

Control System

Each unit will have a state-of-the-art, integrated microprocessor-based control system for plant control, data acquisition, and data analysis. The plant control system will provide for startup, shutdown, and control of plant operation within limits and for protection of equipment.

Electric Power System

The electric output of each of the Project's generators will be connected to main step-up transformers. The output from the main step-up transformers will be connected to the Project's on-site switchyard.

Emissions Monitoring

A continuous emissions monitoring system for airborne pollutants will be installed to provide monitoring and alarming of NO_x and CO concentrations in the HRSG exhaust systems. The emissions monitoring system will provide input signals to the microprocessor-based data acquisition system and will meet all the requirements of the Florida Department of Environmental Protection (FDEP) for monitoring and reporting.

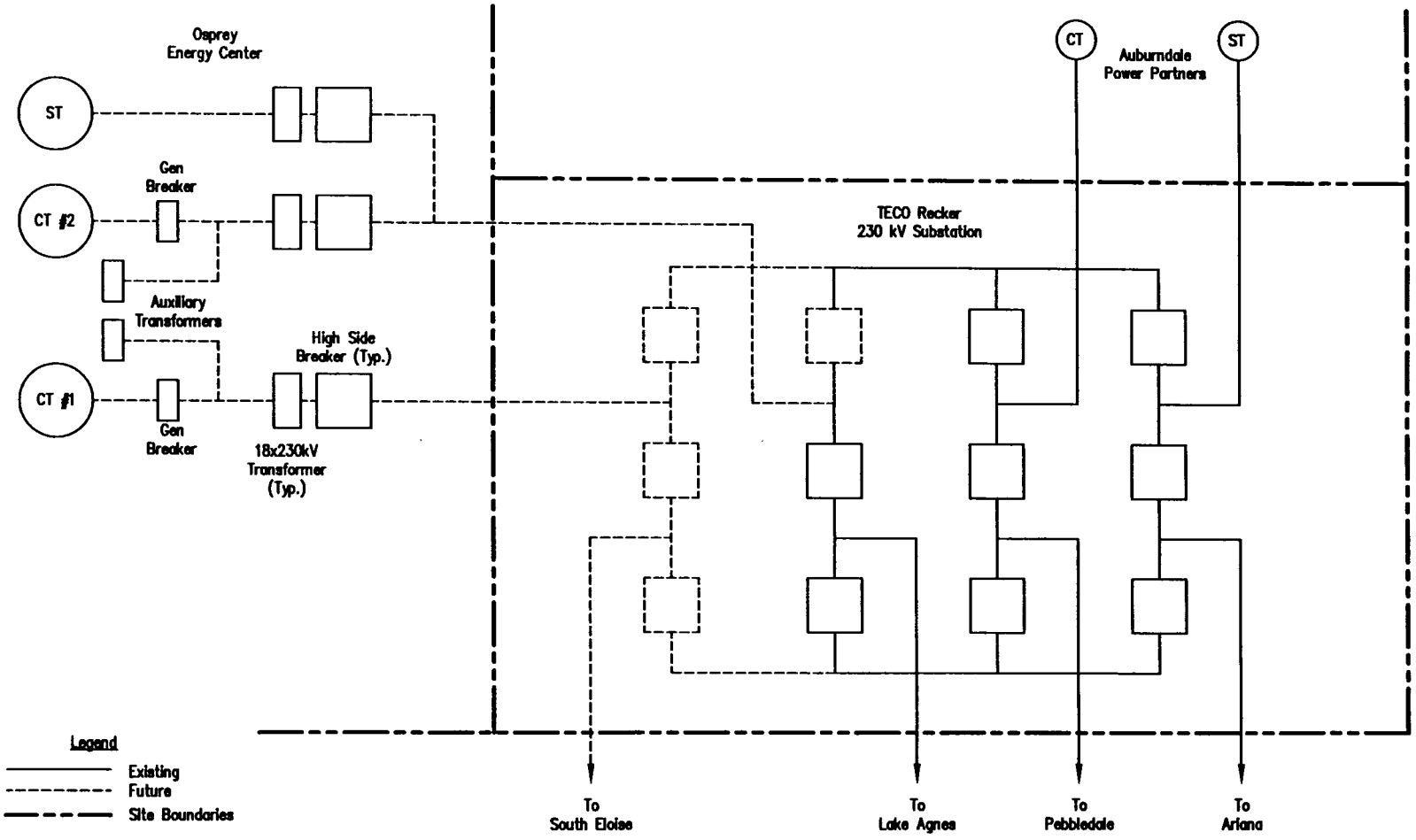
Stormwater Drainage

A permanent stormwater management basin will be provided to collect stormwater from

the Project. Stormwater will be collected by a system of drains and catch basins which will connect to underground piping and swales to provide a gravity drain system. The basin will be sized to allow collected sediment to settle out before it is discharged, as well as to ensure that peak runoff rates are not increased.

Associated Facilities

No linear facilities are being permitted in connection with the proposed Osprey Project. Natural gas will be provided to the Project from a natural gas pipeline and lateral to be constructed by Gulfstream.



Notes:
1. Switchyard breaker ratings are 2000 amp/40 Ka typical

Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-9)
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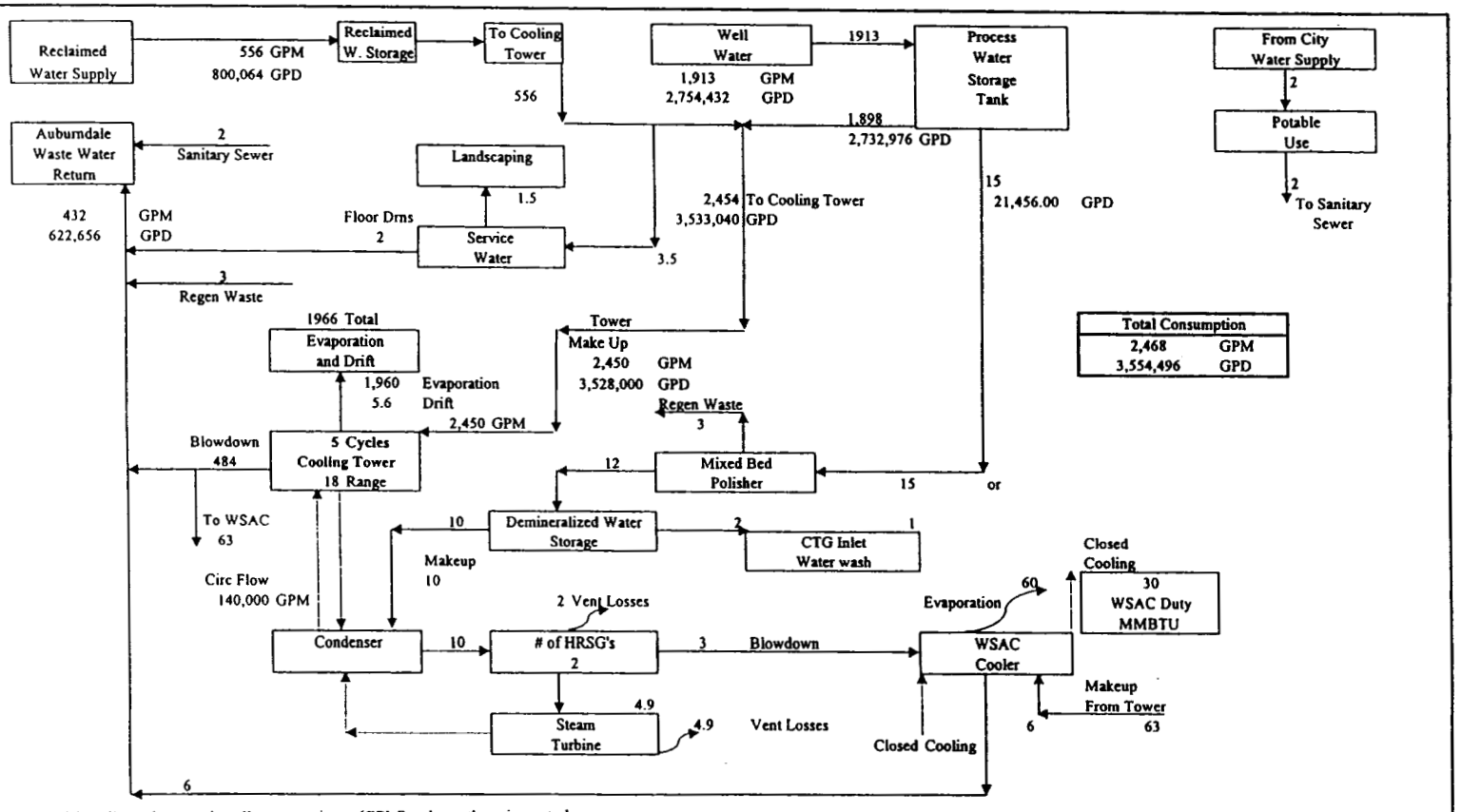
Tampa, Florida

Station One-Line
Electrical Diagram

Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

CAD BY:	CDT	SCALE:	NTS	Job No.	993-9570
CHK BY:	RAZ	DATE:	08/10/00	FIGURE	Revision 01
REV BY:	–	FILE No.:	fig3_1_0-3.dwg		3.1.0-3



Note: (1) All numbers are in gallons per minute (GPM) unless otherwise noted.
(2) GPD = gallons per day.
(3) Water use estimates are based on 5 cycles of concentration.
(4) Excludes duct-firing, fogging and power augmentation.

Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-10)
Page 1 of 1

Golder Associates

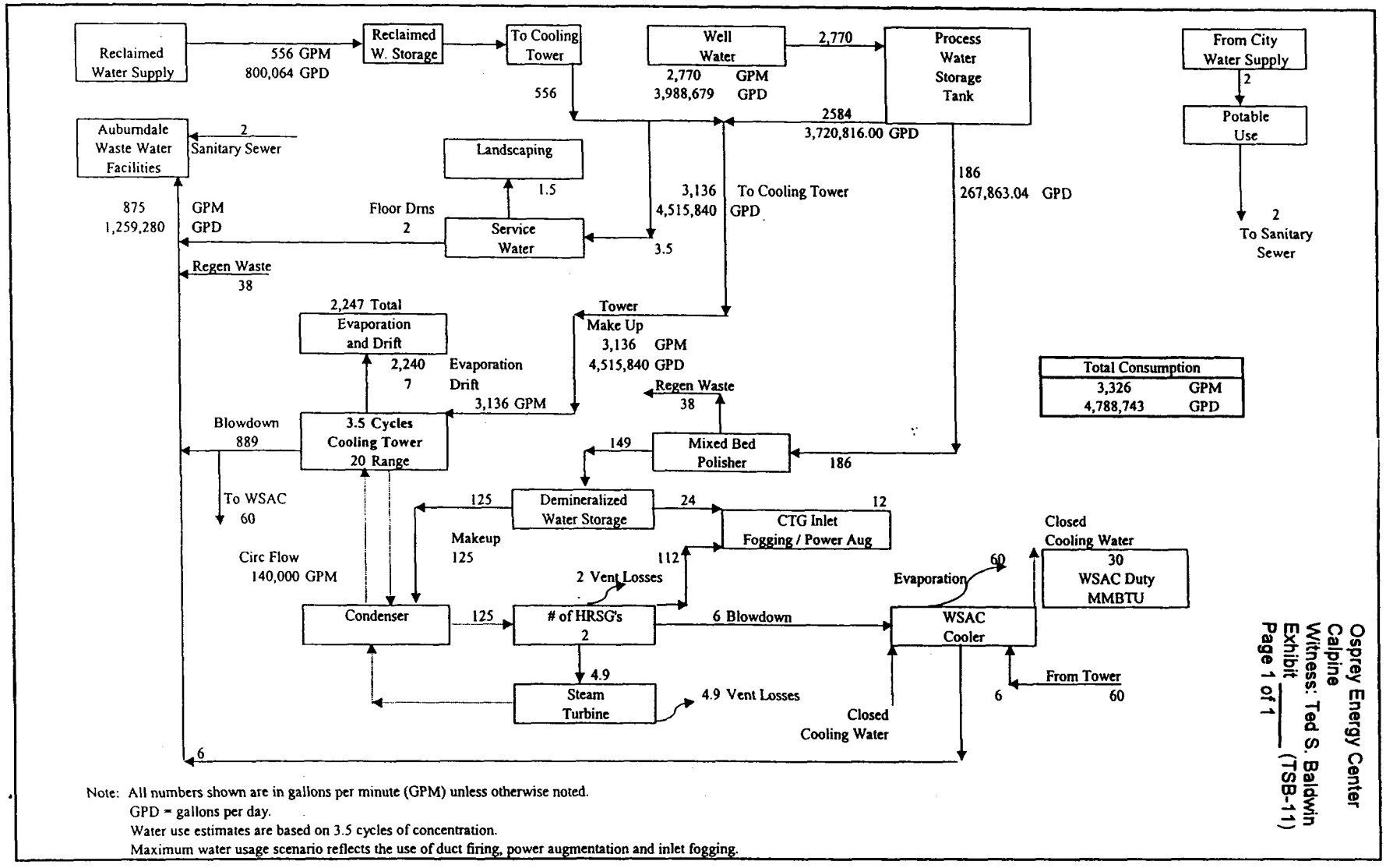
Tampa, Florida

Average Annual Daily Water Balance Diagram

Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

CAD BY:	CDT	SCALE:	NTS	Job No.	993-9570
CHK BY:	RAZ	DATE:	11/29/00		
REV BY:	–	FILE No.:	fig3_5_0-1.dwg		



Note: All numbers shown are in gallons per minute (GPM) unless otherwise noted.
GPD = gallons per day.
Water use estimates are based on 3.5 cycles of concentration.
Maximum water usage scenario reflects the use of duct firing, power augmentation and inlet fogging.

Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-11)
Page 1 of 1

Golder Associates

Tampa, Florida

Peak Month Daily Water Balance Diagram

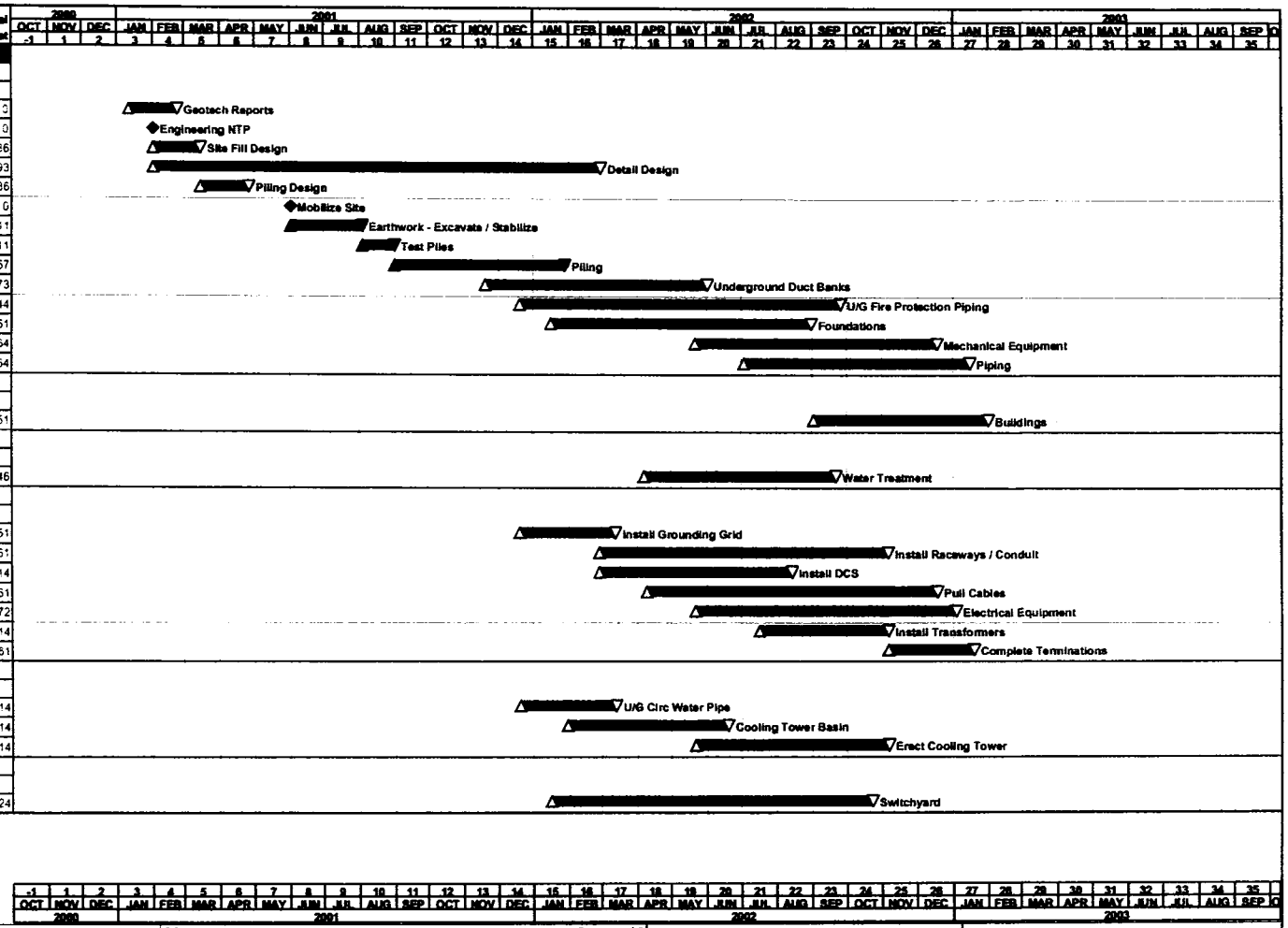
Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

CAD BY:	CDT	SCALE:	NTS	Job No.	993-9570
CHK BY:	RAZ	DATE:	11/29/00		
REV BY:	–	FILE No.:	fig3_5_0-2.dwg		

OSPREY ENERGY CENTER
PRELIMINARY PROJECT SCHEDULE

Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	Total Float
Balance of Plant					
Balance of Plant					
0900	Geotech Reports	11JAN01*	21FEB01	30	0
1000	Engineering NTP	01FEB01*		0	0
1010	Site Fill Design	01FEB01	14MAR01	30	36
1030	Detail Design	01FEB01	27FEB02	280	393
1020	Piling Design	15MAR01	25APR01	30	36
1200	Mobilize Site	01JUN01*		0	0
1210	Earthwork - Excavate / Stabilize	01JUN01	02AUG01	45	111
1220	Test Piles	03AUG01	30AUG01	20	111
1230	Piling	31AUG01	27JAN02	150	157
1240	Underground Duct Banks	19NOV01	31MAY02	140	173
1260	U/G Fire Protection Piping	19DEC01	24SEP02	200	244
1250	Foundations	16JAN02	30AUG02	163	151
1260	Mechanical Equipment	22MAY02	17DEC02	150	164
1270	Piping	03JUL02	14JAN03	140	164
Buildings					
Balance of Plant					
1300	Buildings	02SEP02	31JAN03	110	151
Chemical / Water Treatment					
Balance of Plant					
1400	Water Treatment	08APR02	20SEP02	120	246
Instrument & Electrical					
Balance of Plant					
1500	Install Grounding Grid	19DEC01	12MAR02	60	151
1510	Install Raceways / Conduit	27FEB02	05NOV02	160	161
1520	Install DCS	27FEB02	13AUG02	120	214
1540	Pull Cables	10APR02	17DEC02	160	161
1530	Electrical Equipment	22MAY02	02JAN03	162	172
1560	Install Transformers	17JUL02	05NOV02	80	214
1550	Complete Terminations	06NOV02	17JAN03	53	161
Cooling Tower					
Balance of Plant					
1600	U/G Circ Water Pipe	19DEC01	12MAR02	60	214
1610	Cooling Tower Basin	30JAN02	18JUN02	100	214
1620	Erect Cooling Tower	22MAY02	05NOV02	120	214
Switchyard					
Balance of Plant					
1800	Switchyard	16JAN02	22OCT02	200	224



Start Date	01JAN99
Finish Date	28MAR03
Data Date	30JAN00
Run Date	07MAR00 14:33

Early Bar
Progress Bar
Critical Activity

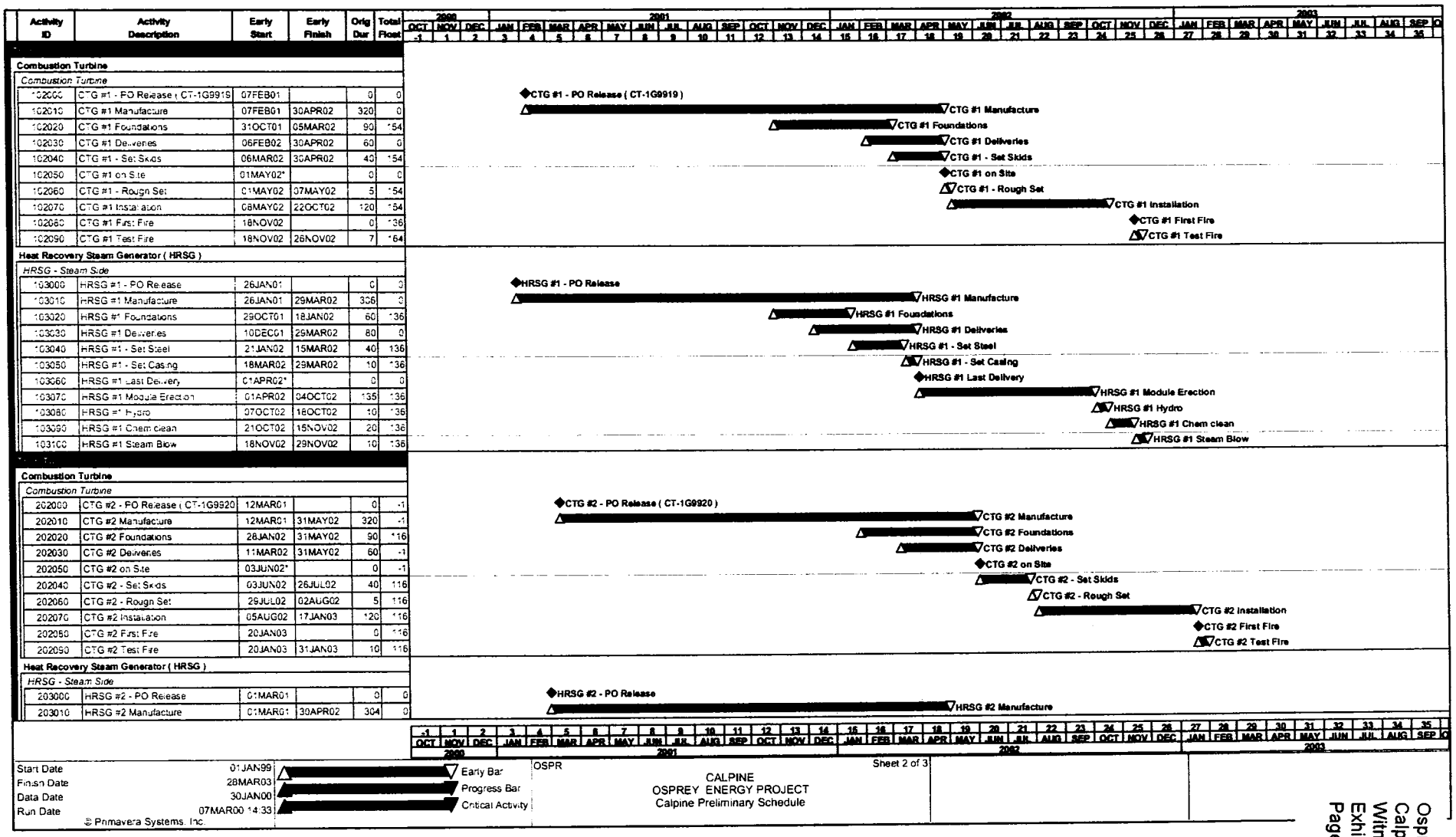
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OSPR | Sheet 1 of 3

CALPINE
OSPREY ENERGY PROJECT
Calpine Preliminary Schedule

Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-12)
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OSPREY ENERGY CENTER
PRELIMINARY PROJECT SCHEDULE
(continued)



Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	Total Float
Combustion Turbine					
Combustion Turbine					
102000	CTG #1 - PO Release (CT-1G9919	07FEB01		0	0
102010	CTG #1 Manufacture	07FEB01	30APR02	320	0
102020	CTG #1 Foundations	31OCT01	05MAR02	90	154
102030	CTG #1 Deliveries	06FEB02	30APR02	60	0
102040	CTG #1 - Set Skids	06MAR02	30APR02	40	154
102050	CTG #1 on Site	01MAY02*		0	0
102060	CTG #1 - Rough Set	01MAY02	07MAY02	5	154
102070	CTG #1 Installation	08MAY02	22OCT02	120	154
102080	CTG #1 First Fire	18NOV02		0	136
102090	CTG #1 Test Fire	18NOV02	26NOV02	7	164
Heat Recovery Steam Generator (HRSG)					
HRSG - Steam Side					
103000	HRSG #1 - PO Release	26JAN01		0	0
103010	HRSG #1 Manufacture	26JAN01	29MAR02	305	0
103020	HRSG #1 Foundations	29OCT01	18JAN02	60	136
103030	HRSG #1 Deliveries	10DEC01	29MAR02	80	0
103040	HRSG #1 - Set Steel	21JAN02	15MAR02	40	136
103050	HRSG #1 - Set Casing	18MAR02	29MAR02	10	136
103060	HRSG #1 Last Delivery	01APR02*		0	0
103070	HRSG #1 Module Erection	01APR02	04OCT02	135	136
103080	HRSG #1 Hydro	07OCT02	18OCT02	10	136
103090	HRSG #1 Chem clean	21OCT02	15NOV02	20	136
103100	HRSG #1 Steam Blow	18NOV02	29NOV02	10	136
Combustion Turbine					
Combustion Turbine					
202000	CTG #2 - PO Release (CT-1G9920	12MAR01		0	-1
202010	CTG #2 Manufacture	12MAR01	31MAY02	320	-1
202020	CTG #2 Foundations	28JAN02	31MAY02	90	116
202030	CTG #2 Deliveries	11MAR02	31MAY02	60	-1
202050	CTG #2 on Site	03JUN02*		0	-1
202040	CTG #2 - Set Skids	03JUN02	26JUL02	40	116
202060	CTG #2 - Rough Set	29JUL02	02AUG02	5	116
202070	CTG #2 Installation	05AUG02	17JAN03	120	116
202080	CTG #2 First Fire	20JAN03		0	116
202090	CTG #2 Test Fire	20JAN03	31JAN03	10	116
Heat Recovery Steam Generator (HRSG)					
HRSG - Steam Side					
203000	HRSG #2 - PO Release	01MAR01		0	0
203010	HRSG #2 Manufacture	01MAR01	30APR02	304	0

Start Date 01JAN99
Finish Date 28MAR03
Data Date 30JAN00
Run Date 07MAR00 14:33

Early Bar
Progress Bar
Critical Activity

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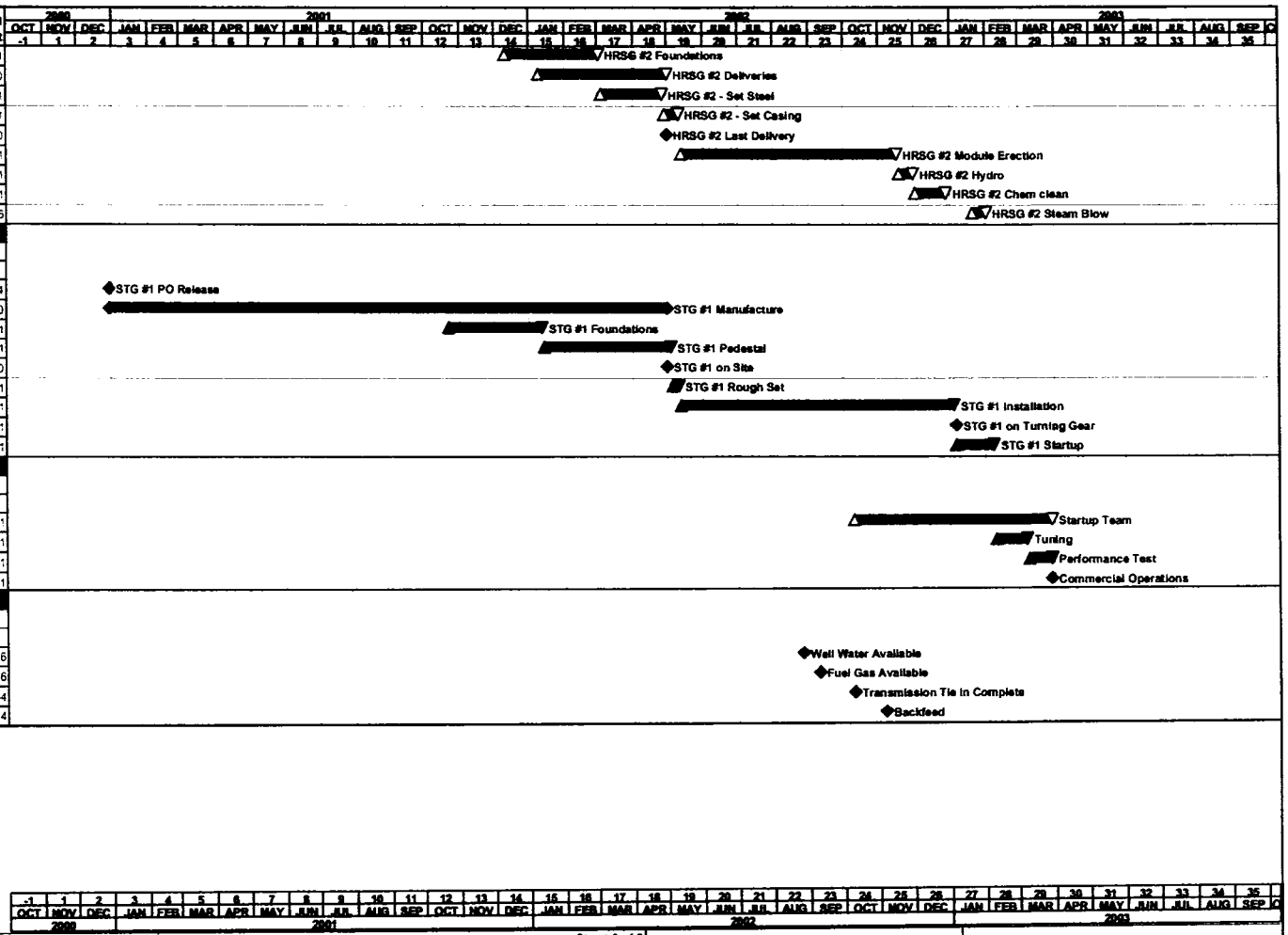
OSPR

CALPINE
OSPREY ENERGY PROJECT
Calpine Preliminary Schedule

Osprey Energy Center
Calpine
Witness: Ted S. Baldwin
Exhibit _____ (TSB-12)
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OSPREY ENERGY CENTER
PRELIMINARY PROJECT SCHEDULE
(continued)

Activity ID	Activity Description	Early Start	Early Finish	Orig Dur	Total Float
203020	HRSG #2 Foundations	10DEC01	01MAR02	60	131
203030	HRSG #2 Deliveries	09JAN02	30APR02	80	0
203040	HRSG #2 - Set Steel	04MAR02	26APR02	40	131
203050	HRSG #2 - Set Casing	29APR02	10MAY02	10	131
203060	HRSG #2 Last Delivery	01MAY02*		0	0
203070	HRSG #2 Module Erection	13MAY02	15NOV02	135	131
203080	HRSG #2 Hydro	18NOV02	29NOV02	10	131
203090	HRSG #2 Chem clean	02DEC02	27DEC02	20	131
203100	HRSG #2 Steam Blow	20JAN03	31JAN03	10	116
Steam Turbine					
Steam Turbine					
104000	STG #1 PO Release	29DEC00*		0	-164
104010	STG #1 Manufacture	29DEC00	30APR02	348	0
104020	STG #1 Foundations	22OCT01	11JAN02	60	111
104030	STG #1 Pedestal	14JAN02	03MAY02	80	111
104040	STG #1 on Site	01MAY02*		0	0
104050	STG #1 Rough Set	06MAY02	10MAY02	5	111
104060	STG #1 Installation	13MAY02	03JAN03	170	111
104070	STG #1 on Turning Gear	06JAN03		0	111
104080	STG #1 Startup	06JAN03	07FEB03	25	111
Balance of Plant					
Balance of Plant					
5000	Startup Team	09OCT02	28MAR03	123*	111
5010	Tuning	10FEB03	07MAR03	20	111
5020	Performance Test	10MAR03	28MAR03	15	111
5030	Commercial Operations		28MAR03	0	111
Linears					
Balance of Plant					
1710	Well Water Available	26AUG02		0	266
1700	Fuel Gas Available	09SEP02		0	256
1720	Transmission Tie In Complete	09OCT02		0	234
1730	Backfeed	06NOV02		0	214



Start Date 01JAN99
Finish Date 28MAR03
Data Date 30JAN00
Run Date 07MAR00 14:33

Early Bar
Progress Bar
Critical Activity

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CALPINE
OSPREY ENERGY PROJECT
Calpine Preliminary Schedule

Sheet 3 of 3

Osprey Energy Center
Calpine
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Exhibit ____ (TSB-1
Page 3 of 3

Technical Qualifications
and
Professional Experience

Kenneth John Slater

EDUCATION

B.Sc.,	Pure Mathematics and Physics,	Sydney University, 1960
B.E.,	Electrical Engineering,	Sydney University, 1962
M.A.Sc.,	Management Sciences,	University of Waterloo, 1974

PROFESSIONAL AFFILIATIONS

Association of Professional Engineers of Ontario
- Registered Professional Engineer

Institute of Electrical and Electronic Engineers
- Member of Power Engineering Society
- Past member of Power System Engineering Committee
- Past member of System Economics subcommittee and working group

EXPERIENCE

1957-62 Mr. Slater was a Junior Professional Officer at the Electricity Commission of New South Wales attending university and undergoing on-the-job training in power station and substation design, construction, protection, maintenance, and operation.

1962-67 Mr. Slater was a Professional Engineer Grades 1 and 2 at The Electricity Commission of New South Wales, engaged in a variety of functions within the areas of Power Station Construction, Generation Planning, System Operation and Load Dispatch.

1967-69 As Assistant Engineer Area Operations/Sydney West (Professional Engineer, Grade 3) with the Electricity Commission of New South Wales, Mr. Slater was responsible for the day-to-day operation of the Sydney West Area (approximately 20% of the State System).

He supervised the day-to-day work of more than 18 operators as they provided safe working conditions for Commission staff and others on system apparatus, and as they provided safe, secure, reliable and economic operation of this portion of the State System.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001748-EC EXHIBIT NO. 8
COMPANY/ WITNESS: Calpine / Slater
DATE 9-12-01

He performed the liaison function with head office staff, other divisions and customers on all operating activities, directed the performance of complicated operating procedures and trained both regular and emergency operators.

While he was in this and his previous position, Mr. Slater was responsible for the design and manufacture of the live line testing devices used by the Commissions' operators and linemen.

As well, he assumed responsibility for the preparation and execution of "black start" exercises and for the arrangement and detailing of complicated switching for major rearrangements and commissionings on the State System. He also developed original computer applications.

1969-74 As Engineer, and then Senior Engineer, heading the Production Development Section of Ontario Hydro's Operating Department, Mr. Slater was engaged in developing computational procedures and computer programs for Production Economics and Resource Management.

Major contributions included (1) the development and implementation of the computer program which, for more than 20 years, produced the daily generation schedule for the Ontario Hydro System, (2) the formulation of a Stochastic System Model to coordinate and optimize the production planning, maintenance planning, interchange planning and resource management of the Ontario Hydro System, and (3) the development of PROMOD, a Probabilistic Production Cost and Reliability model, the first version of the "core" of the Stochastic Model in (2) above.

As a member of the project group implementing the Operating Department's Data Acquisition and Computer System, he headed a work unit responsible for providing the application programs related to generation scheduling, power interchange and resource management. Also, he held responsibilities in the areas of policy determination, analytical techniques and the planning of future applications.

1974-75 As Manager of Engineering at the Ontario Energy Board, Mr. Slater was heavily involved in public hearings into Ontario Hydro's System Expansion Plans and Financial Policies, and into Ontario Hydro's Bulk Power Rates.

During this time, he provided much of the power system engineering input necessary for the start-up and formulation of the public hearing process related to Ontario Hydro. He also provided the engineering input for the regulation of Ontario's three major investor owned gas utilities.

1975-76 For 12 months, Mr. Slater was a private consultant contracted to the Royal Commission on Electric Power Planning, in Ontario, as its Research Director. During this time, he directed and participated in various studies of different aspects of electricity supply. He was also a member of the panel of expert examiners in a number of the Royal Commission's public hearings.

1976-83 As President of Slater Energy Consultants, Inc., in Toronto, Mr. Slater performed or made major contributions to a number of important assignments at the forefront of the electrical energy industry. These included:

- The Export of Electrical Power
  .... a study for the Ontario Ministry of Industry and Tourism.

- Load Management Studies
  .... for the Detroit Edison Company.

- California Utilities Increased Integration Study
  .... for San Diego Gas & Electric Company, Southern California Edison Company, Los Angeles Department of Water and Power, and Pacific Gas and Electric Company.

- Bradley-Milton 500 kV Transmission Lines
  .... a study for the Ontario Ministry of Energy and the Interested Citizens Group (Halton Hills).

- Solar Energy and the Conventional Energy Industries
  .... a study for the Canadian Ministry of Energy, Mines and Resources.

- The Expert Examiner for the Ontario Royal Commission on Electric Power Planning during hearings into Priority Projects.

- Various Studies into Unconventional Electrical Resources
  .... for the P.E.I. Institute of Man and Resources and the P.E.I Energy Corporation.

- Analysis and Expert Testimony in Support of Lower Demand Rates for Lake Ontario Steel Company Limited, Ivaco Industries Limited and Atlas Steels.

- Claims for Consequential Damages of the Roseton Boiler Implosions
  .... for Consolidated Edison Company, Central Hudson Power Company and Niagara Mohawk Power Corporation.

- A study of the Potential for Megawatt Scale Wind Power Plants in Electrical Utilities
  .... for the Canadian Ministry of Energy, Mines and Resources.

These studies have included the need to create special and unique power system models and solution techniques and have addressed significant issues of major importance in the electricity supply industry. Mr. Slater also has carried out assignments for the following clients;

Nova Scotia Power Corporation.
The Government of Prince Edward Island.
The New Brunswick Electric Power Commission.
Ontario Energy Corporation.
Ontario Energy Board.
Go-Home Lake Cottagers Associations.
Saskatchewan Power Corporation.
FMC Corporation.
FMC of Canada Limited.
ERCO Industries Limited.
Canadian Occidental Petroleum Ltd.
State Energy Commission (Western Australia).
Toronto District Heating Corporation.

In connection with his consulting activities, Mr. Slater gave expert testimony in the state of Idaho and in the provinces of Ontario and Prince Edward Island.

Mr. Slater also was a principal developer of PROMOD III, a proprietary electric utility production cost and reliability model owned by Energy Management Associates, Inc.. This model was used by over seventy utilities in Canada, the United States, Japan and Australia. Its wide acceptance made it the "Industry Standard" in the U.S..

1983-90 As Vice President and Chief Engineer for Energy Management Associates, Inc., Mr. Slater was responsible for giving technical direction for the development and maintenance of Energy Management Associates, Inc., state-of-the-art software products. As Senior Vice President and Chief Engineer, Mr. Slater was head of the Energy Management Associates, Inc.'s utility consulting practice. He led or made significant contributions to a number of important consulting engagements, including:

- Study and regulatory testimony concerning the value to the Idaho Power Company system of the interruptibility provisions in F.M.C.'s supply contract.

- Generation planning studies for Cincinnati Gas and Electric Company, San Diego Gas & Electric Company and the City of Austin Electric Utility Department.

- Assistance to legal counsel during regulatory litigation regarding the hostile takeover of a major Canadian gas utility holding company (Union Enterprises), including definition and examination of issues, selection of witnesses, and analysis of the opposing case.

- Development and demonstration of a method for the allocation of the Inland Power Pool's operating reserve requirement among its members.

- Analysis of replacement power costs during the outage of Niagara Mohawk Power Corporation's Nine Mile Point #1 nuclear unit.

- Reserve margin assessments for Public Service Company of Indiana, Allegheny Power System Inc., Iowa Electric Light & Power Company, San Diego Gas & Electric Company, and El Paso Electric Company.

- Examination of the gas supply situation in Southern California and regulatory testimony regarding the "unbundling" of storage service.

- Evaluation of the operational, planning and financial impacts of merging two large Eastern U.S. electric utilities.

- Study and regulatory testimony regarding the value and appropriate level of interruptible demand for the Union Gas system.

- Evaluation of the benefits of increased operational integration of a group of electric utilities.

- Assistance for Tucson Electric Power Co. and its legal counsel during arbitration of its dispute with San Diego Gas and Electric Company regarding the operation of a large power sale agreement.

- Analysis of the economics of a third A/C transmission line linking California and Oregon.

- A seminar on "Power Pooling and Inter-Utility Interconnections" for the management of the Central Electricity Generating Board and other parties involved in U.K. privatisation.

- Determination of the benefits of pool membership for two electric utilities in the Northeast U.S..

- Assistance for Riley Stoker Corporation and its legal counsel with the arbitration of direct and consequential damages arising out of the late completion and early poor performance of two major coal-fired generating units. The work included case examination and development, detailed reconstruction of events, analysis of all financial and economic consequences of project delay and performance with separation of fault, analysis of opponent's case and assistance with cross-examination, direct and rebuttal testimony, and assistance with oral and written argument.

Mr. Slater's consulting assignments included the areas of power system planning, operations, reliability, economics, ratemaking and assessment of the worth of unconventional resources. He appeared as an expert witness in regulatory hearings in Idaho, Iowa, Indiana, Florida, California, Texas, Ontario and Nova Scotia and in civil arbitration proceedings in Louisiana and Pennsylvania.

Mr. Slater continued to contribute to the development of E.M.A.'a utility software products. His contributions included being a principal developer of SENDOUT, E.M.A.'s proprietary supply model for gas utilities.

1990- In August 1990, Mr. Slater returned to working in his own practice, in Atlanta, where he heads a small corporation, Slater Consulting, which provides consulting services and expert testimony for various different participants in the utility industry.

Slater Consulting assignments, led by Mr. Slater, have included:

- Assistance to legal council for creditors of a bankrupt utility.
- Analysis and testimony for Texas - New Mexico Power Company regarding prudent alternatives to their decision to build TNP ONE Unit 2.
- Assistance and analysis for a utility and its legal counsel during litigation regarding damages sustained because of interference in a proposed merger of that utility with another utility.
- Analyses and testimony before the New York PSC for Sithe Energies, Inc., in certification proceedings and in numerous avoided cost and buy-back rate proceedings.
- Analyses and testimony for the Independent Power Producers of New York in QF curtailment, buy-back rate and back-up rate proceedings before the New York PSC.
- Analysis and testimony for Southwestern Public Service Co. at FERC and before the New Mexico Public Service Commission regarding the lack of production cost savings from the proposed merger of Central & South West Utilities with El Paso Electric Company.
- Analyses and testimony before the Public Service Commission for Independent Power Producers in Florida regarding QF curtailment.

- Analyses and testimony in Civil Court cases for Independent Power Producers in Florida regarding the correct implementation of contractual dispatchability provisions.

- Testimony before regulatory commissions in New York, Pennsylvania, Texas, Florida and Louisiana regarding various aspects of emerging competition.

- Analyses and testimony before the Georgia Public Service Commission on behalf of Mid-Geogia Co-gen and others regarding avoided costs on the Georgia Power / Southern Company system.

- Analysis and testimony before the Georgia Public Service Commission on behalf of Georgia Power Company regarding the Prudence of Georgia Power's 1978-1980 investment in the Rocky Mountain pumped storage plant.

- Testimony before the regulatory commissions of Texas, Virginia and Wisconsin regarding the fair allocation of utility revenue requirements to individual customer classes.

- Testimony before the United States Bankruptcy Court regarding the value of the non-nuclear assets of Cajun Electric Power Co-operative, Inc.

- Analyses for Sithe Energies, Inc. of the future dispatch and associated energy revenues for numerous generating resources in the Northeast United States.

- Operational planning analyses for Sithe Energies, Inc. regarding numerous existing and new generating resources in the Northeast United States.

- Analyses and testimony in Courts and before arbitrators for the non-operating owners of the South Texas Nuclear Project, the Cooper nuclear unit in Nebraska, and the Millstone 3 nuclear unit in Connecticut concerning the replacement power costs during extended outages.

In connection with these and other assignments, Mr. Slater has appeared as an expert in regulatory proceedings in Florida, Georgia, Louisiana, New Mexico, New York, Pennsylvania, South Carolina, Virginia, Wisconsin and Texas, and at the Federal Energy Regulatory Commission. He has also appeared in Federal Bankrupty Court, state courts in Virginia, Nebraska, Texas and Florida, and civil arbitration proceedings in Nevada and Pennsylvania.

PUBLICATIONS & PRESENTATIONS

"Meeting System Demand"
Canada-USSR Electric Power Working Group Electrical Seminar, Montreal, March, 1973.

"Stochastic Model for Use in Determining Optimal Power System Operating Strategies."
Power Devices and Systems Group, Electrical Engineering Department. University of Toronto - 1973.

"Economy-Security Functions in Power System Operations"
IEEE Power System Economic Subcommittee Work Group Paper
IEEE Special Publication 75 CH0960-6-PWR-1975.

"Economy-Security Functions in Power System Operations - A Summary Introduction."
IEEE Power System Economics Subcommittee Working Group Paper
IEEE T.P.A.S. Sept/Oct 1975 p. 1618.

"A Large Hydro-Thermal Scheduling Model"
TIMS/ORSA
Miami, November 1976.

"Generation System Modeling for Planning and Operations"
Atlantic Regional Thermal Conference
Charlottetown, June 1978.

"The Feasibility of Electricity Export from CANDU Nuclear Generation"
Canadian Nuclear Association
Ottawa, June 1978.

"Evaluation of the Worth of System Scale Wind Generation to the Prince Edward Island Electrical Grid."
IEEE Canadian Conference
Toronto, October 1979.

"The Results of a Study Examining The Possible Impact of Solar Space Heating on the Electrical Utility in New Brunswick."
The Potential Impacts of the Deployment of Solar Heating on Electrical Utilities - A workshop sponsored by the Canadian Department of Energy, Mines and Resources
Ottawa, May 1980.

"Reliability Indices: Their Meanings and Differences"
Planmetrics/Energy Management Associates, Inc. 8th Annual National Utilities Conference
Chicago, May 1980.

"Description and Bibliography of Major Economy-Security Functions
Part I - Description
Part II - Bibliography (1959-1972)
Part III - Bibliography (1973-1979)"
IEEE Power System Economics Subcommittee Working Group Papers(3).
IEEE TPAS January 1981, p.211, p.214. p.224.

"PROMOD III Evaluation of the Worth of Grid Connected WECS."
Fifth Annual Wind Energy Symposium, Ryerson Polytechnical Institute
Toronto, December 1982.

"Probabilistic Simulation in Power System Production Models"
China-U.S.A. Power System Meeting, Electrical Power Research Institute of China
Tianjin, China, June 1985.

"Computer Modeling of Wheeling Arrangements"
Electricity Consumers Resource Council Seminar
Washington, D.C. September 1985.

"Power Systems Reliability Improvement Benefits - A Framework for Analysis"
ASME Energy-Sources Technology Conference
Dallas, February 1987.

FUEL PRICE ASSUMPTIONS FOR PROMOD IV(R) ANALYSES OF OSPREY PROJECT OPERATIONS, BASE CASE

(All Values in cents/mmbtu)

	COAL		#2 OIL		#6 OIL		GAS			
	Lowest	Highest	Lowest	Highest	Lowest	Highest	Lowest Price		Highest Price	
Year	Price	Price	Price	Price	Price	Price	Winter	Summer	Winter	Summer
2000	158.3	248.2	558.2	656.1	365.2	489.2	346.4	346.2	377.6	380.1
2001	157.0	246.2	510.6	600.1	323.9	433.9	376.7	347.4	410.8	381.4
2002	162.5	254.8	496.1	583.1	315.5	422.6	377.2	347.4	411.4	381.4
2003	168.0	263.3	528.5	621.2	329.3	441.1	382.6	358.1	417.3	393.2
2004	173.4	271.9	561.0	659.4	343.1	459.6	393.4	368.9	429.1	405.0
2005	178.3	279.6	593.0	697.0	357.1	478.3	404.2	379.7	440.9	416.8
2006	182.3	285.9	614.2	721.9	368.2	493.3	415.1	390.7	452.9	428.8
2007	186.4	292.3	636.1	747.7	379.8	508.7	427.3	404.0	466.1	443.3
2008	190.6	298.9	658.8	774.4	391.6	524.6	440.7	417.6	480.8	458.3
2009	194.9	305.6	682.3	802.0	403.9	541.0	454.6	431.8	496.0	473.7
2010	199.3	312.5	706.7	830.6	416.5	558.0	468.9	446.4	511.7	489.7
2011	203.7	319.4	727.3	854.9	430.7	576.9	483.8	461.4	527.9	506.1
2012	208.3	326.5	748.6	879.9	445.3	596.5	499.1	477.0	544.7	523.1

Osprey Energy Center
Calpine
Witness: Kenneth J. Slater
Exhibit _____ (KJS-2)
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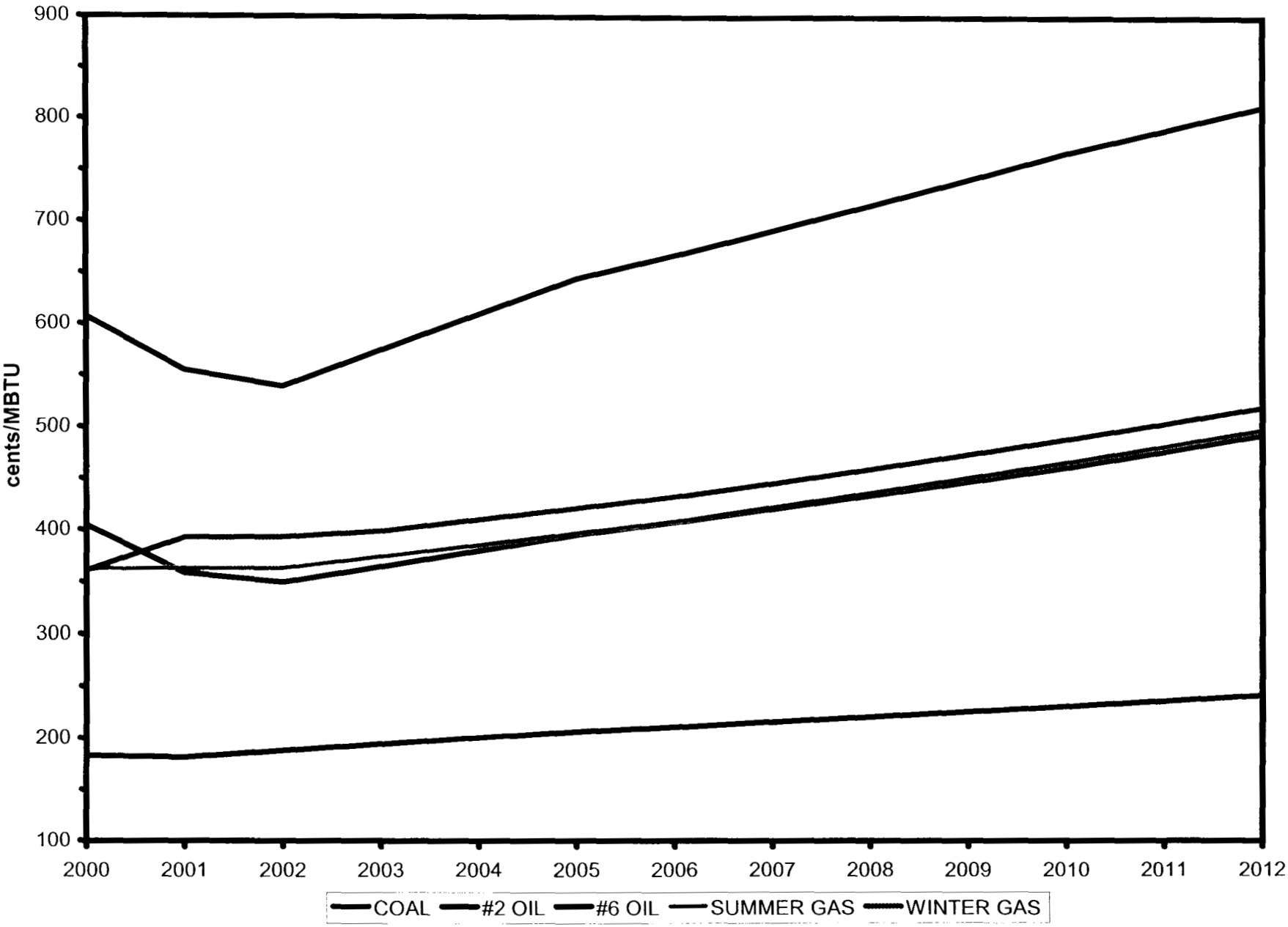
FUEL PRICE ASSUMPTIONS FOR PROMOD IV(R) ANALYSES OF OSPREY PROJECT OPERATIONS, HIGHER GAS PRICE CASE

(All Values in cents/mmbtu)

Year	COAL		#2 OIL		#6 OIL		GAS			
	Lowest Price	Highest Price	Lowest Price	Highest Price	Lowest Price	Highest Price	Lowest Price		Highest Price	
							Winter	Summer	Winter	Summer
2000	158.3	248.2	558.2	656.1	365.2	489.2	346.4	346.2	377.6	380.1
2001	157.0	246.2	510.6	600.1	323.9	433.9	376.7	347.4	410.8	381.4
2002	162.5	254.8	496.1	583.1	315.5	422.6	382.6	358.1	417.3	393.2
2003	168.0	263.3	528.5	621.2	329.3	441.1	393.4	368.9	429.1	405.0
2004	173.4	271.9	561.0	659.4	343.1	459.6	404.2	379.7	440.9	416.8
2005	178.3	279.6	593.0	697.0	357.1	478.3	415.1	390.7	452.9	428.8
2006	182.3	285.9	614.2	721.9	368.2	493.3	430.9	411.3	470.1	451.3
2007	186.4	292.3	636.1	747.7	379.8	508.7	451.9	432.8	493.2	474.9
2008	190.6	298.9	658.8	774.4	391.6	524.6	474.0	455.4	517.3	499.7
2009	194.9	305.6	682.3	802.0	403.9	541.0	497.2	479.2	542.7	525.7
2010	199.3	312.5	706.7	830.6	416.5	558.0	521.6	504.2	569.4	553.0
2011	203.7	319.4	727.3	854.9	430.7	576.9	544.1	524.3	594.0	574.9
2012	208.3	326.5	748.6	879.9	445.3	596.5	564.5	545.1	616.4	597.7

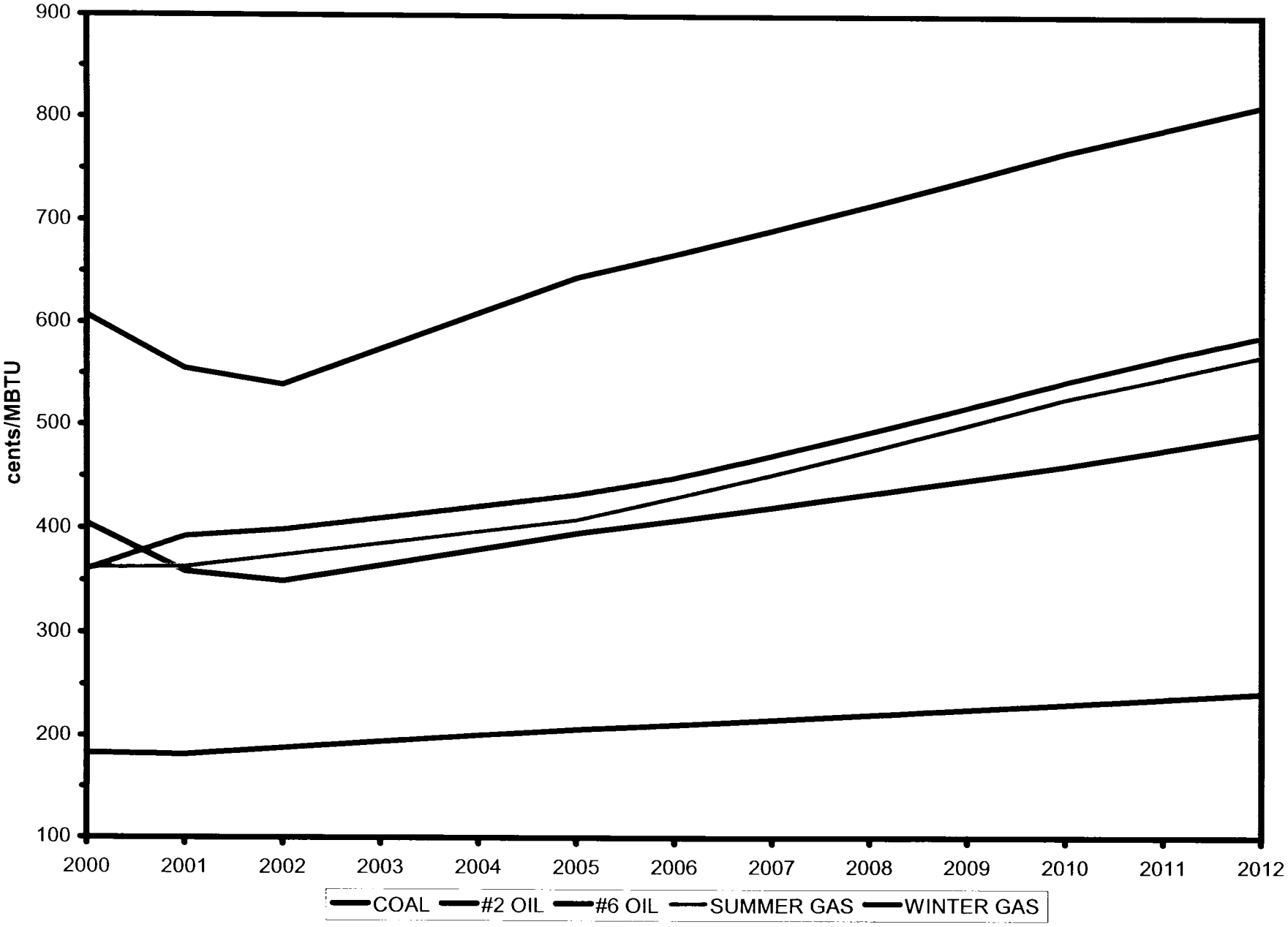
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BASE CASE FUEL PRICE ASSUMPTIONS
AVERAGE PRICES



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HIGHER NATURAL GAS FUEL PRICE ASSUMPTIONS
AVERAGE PRICES



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Page 2 of 2

EFFICIENCY AND COST-EFFECTIVENESS OF PENINSULAR FLORIDA GENERATING UNITS, 2003

Plant	Unit	Summer Capacity (MW)	Average Annual Heat Rate (Btu/kwh)	Average Annual Dispatch Cost ($/MWh)
Nuclear				
CRYSTAL	3	805	Must Run at Maximum Available Capacity	
STLUCIE	1	839	Must Run at Maximum Available Capacity	
STLUCIE	2	839	Must Run at Maximum Available Capacity	
TURKEYPT	3	697	Must Run at Maximum Available Capacity	
TURKEYPT	4	697	Must Run at Maximum Available Capacity	
Coal and Petroleum Coke				
BIG BEND	1	421	9,965	30.29
BIG BEND	2	421	9,972	30.57
BIG BEND	3	428	9,956	28.72
BIG BEND	4	442	9,943	26.93
CRYSTAL	1	386	9,679	25.40
CRYSTAL	2	488	9,596	25.26
CRYSTAL	4	714	9,094	23.67
CRYSTAL	5	697	9,092	23.41
DEERHAVN	2	228	10,608	25.20
GANNON	1	0	9,688	31.24
GANNON	2	0	9,671	31.19
GANNON	6	362	10,246	35.01
MCINTOSH	3	338	9,093	23.65
NORTHSID	1	265	9,753	23.34
NORTHSID	2	265	13,156	29.42
SCHERER	4	846	9,949	24.53
SEMINOLE	1	638	10,041	26.38
SEMINOLE	2	638	10,041	26.28
ST JOHNS	1	624	9,179	22.26
ST JOHNS	2	638	9,258	22.88
STANTON	1	442	9,777	24.99
STANTON	2	446	9,079	22.85

New Gas Combined Cycle				
BAYSIDE	1	707	7,236	29.38
BRANDY B	4	482	7,176	29.68
CANE IS	3	260	6,999	28.11
FT MYERS	3	1446	7,145	29.08
HINES EC	1	470	7,049	28.30
HINES EC	2	0	7,002	29.59
KELLEY	4	113	8,362	36.91
N SMYRNA	1	520	6,971	28.04
OKEECHOB	1	260	6,965	27.76
OKEECHOB	2	260	6,966	27.76
OSPREY	1	520	6,967	28.09
PAYNECRK	3	520	7,001	28.14
PURDOM	8	260	6,995	28.10
SANFORD	14	964	7,206	29.29
SANFORD	15	964	7,208	29.29
Other Units				
ANCLOTE	1	503	10,952	69.84
ANCLOTE	2	503	10,485	66.36
AVONPKGT	1	29	No Significant Output	
AVONPKGT	2	29	No Significant Output	
BARTOW	1	115	9,982	39.38
BARTOW	2	117	9,983	39.81
BARTOW	3	208	9,975	38.84
BARTOWGT	1	46	No Significant Output	
BARTOWGT	2	46	No Significant Output	
BARTOWGT	3	46	No Significant Output	
BARTOWGT	4	49	No Significant Output	
BAYBROGT	1	47	No Significant Output	
BAYBROGT	2	47	No Significant Output	
BAYBROGT	3	47	No Significant Output	
BAYBROGT	4	47	No Significant Output	
BGBENDGT	1	12	No Significant Output	
BGBENDGT	2	61	11,635	75.05
BGBENDGT	3	61	11,635	75.10
BRANDY B	1	0	11,224	56.71
BRANDY B	2	0	11,266	56.96
BRANDY B	3	153	11,383	56.01
CANE GT	1	30	11,166	50.91
CANE ISL	2	108	9,583	42.41
CAPECNVR	1	405	9,437	40.46
CAPECNVR	2	408	9,441	40.66
CUDJOE D	1	5	No Significant Output	
CUTLER	5	71	11,720	45.14
CUTLER	6	144	11,741	45.33

DEBARYGT	1	54	No Significant Output	
DEBARYGT	2	54	11,730	76.32
DEBARYGT	3	54	No Significant Output	
DEBARYGT	4	54	No Significant Output	
DEBARYGT	5	54	No Significant Output	
DEBARYGT	6	54	No Significant Output	
DEBARYGT	7	88	11,890	76.92
DEBARYGT	8	88	11,890	76.97
DEBARYGT	9	88	11,880	76.91
DEBARYGT	10	88	11,880	77.09
DEERHAVN	1	85	10,604	45.57
DRHVN GT	1	18	14,471	68.60
DRHVN GT	2	18	14,471	68.80
DRHVN GT	3	75	14,471	68.15
EVERGL T	1	35	17,121	74.24
EVERGL T	2	35	17,121	74.10
EVERGL T	3	35	17,121	73.81
EVERGL T	4	35	17,121	73.86
EVERGL T	5	35	17,121	73.60
EVERGL T	6	35	17,121	73.92
EVERGL T	7	35	17,121	73.65
EVERGL T	8	35	17,121	73.39
EVERGL T	9	35	17,121	73.35
EVERGL T	10	35	17,121	73.46
EVERGL T	11	35	17,121	73.04
EVERGL T	12	35	No Significant Output	
EVERGLDS	1	221	9,550	38.49
EVERGLDS	2	221	9,557	38.63
EVERGLDS	3	375	9,944	39.71
EVERGLDS	4	410	9,925	39.66
FTMYER T	1	54	No Significant Output	
FTMYER T	2	54	No Significant Output	
FTMYER T	3	54	No Significant Output	
FTMYER T	4	54	No Significant Output	
FTMYER T	5	54	No Significant Output	
FTMYER T	6	54	No Significant Output	
FTMYER T	7	54	No Significant Output	
FTMYER T	8	54	No Significant Output	
FTMYER T	9	54	No Significant Output	
FTMYER T	10	54	No Significant Output	
FTMYER T	11	54	No Significant Output	
FTMYER T	12	54	No Significant Output	
FTMYERCT	13	153	11,302	52.34
FTMYERCT	14	153	11,311	52.38
GANNONGT	1	12	No Significant Output	
HANSELCC	2	48	9,817	46.24
HANSELIC	8	3	9,300	43.19

HANSELIC	14	2	9,300	43.23
HANSELIC	15	2	9,300	43.25
HANSELIC	16	2	9,300	43.25
HANSELIC	17	2	9,300	43.23
HANSELIC	18	2	No Significant Output	
HANSELIC	19	3	No Significant Output	
HANSELIC	20	3	9,300	43.25
HARDEE	1	224	7,300	34.54
HARDEECT	1	74	9,732	45.33
HIGGNSGT	1	29	No Significant Output	
HIGGNSGT	2	29	No Significant Output	
HIGGNSGT	3	35	No Significant Output	
HIGGNSGT	4	35	No Significant Output	
HOOKERS	1	0	No Significant Output	
HOOKERS	2	0	No Significant Output	
HOOKERS	3	0	No Significant Output	
HOOKERS	4	0	No Significant Output	
HOOKERS	5	0	No Significant Output	
HOPKINGT	1	12	14,029	60.59
HOPKINGT	2	24	13,597	63.57
HOPKINS	1	75	11,357	47.25
HOPKINS	2	238	10,652	41.92
IND RIVR	1	88	10,033	42.34
IND RIVR	2	201	9,982	39.50
IND RIVR	3	319	10,469	41.65
INDRVRGT	1	37	11,540	52.40
INDRVRGT	2	37	11,540	52.51
INDRVRGT	3	108	11,100	50.84
INDRVRGT	4	108	11,100	50.84
INTER GT	1	47	No Significant Output	
INTER GT	2	47	No Significant Output	
INTER GT	3	47	No Significant Output	
INTER GT	4	47	No Significant Output	
INTER GT	5	47	No Significant Output	
INTER GT	6	47	No Significant Output	
INTER GT	7	83	12,210	79.38
INTER GT	8	83	No Significant Output	
INTER GT	9	83	No Significant Output	
INTER GT	10	83	12,030	77.69
INTER GT	11	143	12,030	78.03
INTER GT	12	76	12,572	59.75
INTER GT	13	76	12,558	59.59
INTER GT	14	76	12,523	59.47
IVEY IC	1	4	9,300	42.70
IVEY IC	2	5	9,300	42.71
IVEY IC	3	9	12,280	54.15
IVEY IC	4	6	12,280	54.23

IVEY IC	5	4	9,300	42.70
IVEY IC	6	18	9,300	42.70
KELLY	7	23	16,441	68.60
KELLY GT	1	14	No Significant Output	
KELLY GT	2	14	No Significant Output	
KELLY GT	3	14	No Significant Output	
KENEDYGT	3	54	No Significant Output	
KENEDYGT	4	54	No Significant Output	
KENEDYGT	5	54	No Significant Output	
KENEDYGT	7	153	11,380	56.05
KING	5	8	10,483	42.59
KING	6	17	12,842	51.73
KING	7	32	12,858	54.99
KING	8	50	12,710	52.43
KING DSL	1	5	No Significant Output	
KING GT	9	23	10,500	51.01
LARSEN	8	102	10,610	42.77
LARSENGT	2	10	No Significant Output	
LARSENGT	3	10	No Significant Output	
LAUDER T	1	36	15,908	66.47
LAUDER T	2	35	15,908	66.46
LAUDER T	3	35	15,908	66.53
LAUDER T	4	35	15,908	66.47
LAUDER T	5	35	15,908	66.54
LAUDER T	6	35	15,908	66.44
LAUDER T	7	35	15,908	66.55
LAUDER T	8	35	15,908	66.59
LAUDER T	9	35	15,908	66.62
LAUDER T	10	35	15,908	66.61
LAUDER T	11	35	15,908	66.70
LAUDER T	12	35	15,908	66.71
LAUDER T	13	35	16,227	67.94
LAUDER T	14	35	16,227	67.94
LAUDER T	15	35	16,227	67.92
LAUDER T	16	35	16,227	68.11
LAUDER T	17	35	16,227	68.09
LAUDER T	18	35	16,227	68.04
LAUDER T	19	35	16,227	68.02
LAUDER T	20	35	16,227	68.19
LAUDER T	21	35	16,227	68.28
LAUDER T	22	32	16,227	68.21
LAUDER T	23	32	16,227	68.15
LAUDER T	24	35	16,227	68.35
LAUDERCC	4	440	7,640	32.83
LAUDERCC	5	440	7,654	33.48
MANATEE	1	819	9,928	39.50
MANATEE	2	819	9,909	39.50

MARATHON	1	8	No Significant Output	
MARATHON	2	5	9,300	42.70
MARATHON	3	8	12,280	54.18
MARTIN	1	814	8,904	36.37
MARTIN	2	816	8,939	36.16
MARTINCC	3	445	7,232	31.20
MARTINCC	4	445	7,235	31.08
MARTINCT	1	153	11,266	52.39
MARTINCT	2	153	11,266	52.38
MCINT GT	1	17	15,000	65.71
MCINT IC	1	5	No Significant Output	
MCINTOSH	1	87	10,815	43.98
MCINTOSH	2	103	10,274	40.96
MCINTOSH	5	310	7,262	30.03
NORTH GT	3	52	No Significant Output	
NORTH GT	4	52	No Significant Output	
NORTH GT	5	52	No Significant Output	
NORTH GT	6	52	No Significant Output	
NORTHSID	3	505	9,688	40.75
OLEAN GT	1	153	11,291	52.41
OLEAN GT	2	153	11,303	52.48
OLEAN GT	3	153	11,301	52.43
OLEAN GT	4	153	11,316	52.50
OLEAN GT	5	153	11,325	52.51
PHILLIPS	1	17	13,500	55.45
PHILLIPS	2	17	13,500	55.48
POLK CT	2	153	11,366	54.72
POLK CT	3	153	11,348	54.74
POLKIGCC	1	250	10,079	29.97
PURDOM	7	48	16,947	69.23
PURDOMGT	1	12	No Significant Output	
PURDOMGT	2	12	No Significant Output	
PUTNAMCC	1	249	9,115	39.31
PUTNAMCC	2	249	9,114	39.36
REEDYCRK	1	35	10,400	45.89
RIOPINGT	1	15	No Significant Output	
RIVIERA	3	290	9,729	37.23
RIVIERA	4	290	9,729	37.52
SANFORD	3	153	8,877	40.06
SEM CT	1	153	11,357	54.83
SMITH	1	7	18,840	75.52
SMITH	2	7	18,822	75.58
SMITH	3	22	16,777	70.99
SMITH	4	32	16,798	71.08
SMITH D	1	9	No Significant Output	
SMITH CC	1	32	10,400	48.43
SMITH GT	1	26	No Significant Output	

SMITH ST	1	3	No Significant Output	
SMITH ST	2	2	No Significant Output	
SMITH ST	3	6	No Significant Output	
ST CLOUD	1	4	No Significant Output	
ST CLOUD	2	6	No Significant Output	
ST CLOUD	3	6	No Significant Output	
ST CLOUD	4	12	10,696	73.23
STOCK DS	1	9	9,300	64.95
STOCK DS	2	9	9,300	65.06
STOCK GT	1	21	No Significant Output	
STOCK GT	2	16	No Significant Output	
STOCK GT	3	16	No Significant Output	
STOCK IC	1	6	No Significant Output	
SUWAN GT	1	54	No Significant Output	
SUWAN GT	2	54	No Significant Output	
SUWAN GT	3	54	No Significant Output	
SUWANNEE	1	33	11,729	51.07
SUWANNEE	2	32	11,733	51.09
SUWANNEE	3	80	11,750	51.17
SWOOPEIC	1	5	No Significant Output	
TIGERBAY	1	194	7,553	32.32
TURKEYIC	1	14	No Significant Output	
TURKEYPT	1	410	9,433	39.54
TURKEYPT	2	400	9,395	39.80
TURNERGT	1	15	No Significant Output	
TURNERGT	2	15	No Significant Output	
TURNERGT	3	65	No Significant Output	
TURNERGT	4	65	No Significant Output	
UNIV FLA	1	36	11,166	50.41
VERO BCH	1	13	13,041	52.60
VERO BCH	2	13	8,928	36.66
VERO BCH	3	33	13,141	54.47
VERO BCH	4	56	11,739	48.61
VERO BCH	5	35	11,171	45.71

NUGs

AGRICHEM	1	6
AS-AVAIL	1	63
BAY CTY	1	11
BIOENRGY	1	10
BROWARDS	1	54
BROWARDS	2	56
CARGILL	2	15
CEDARBAY	1	250
CFRBIOGN	1	74
DADE CTY	1	43

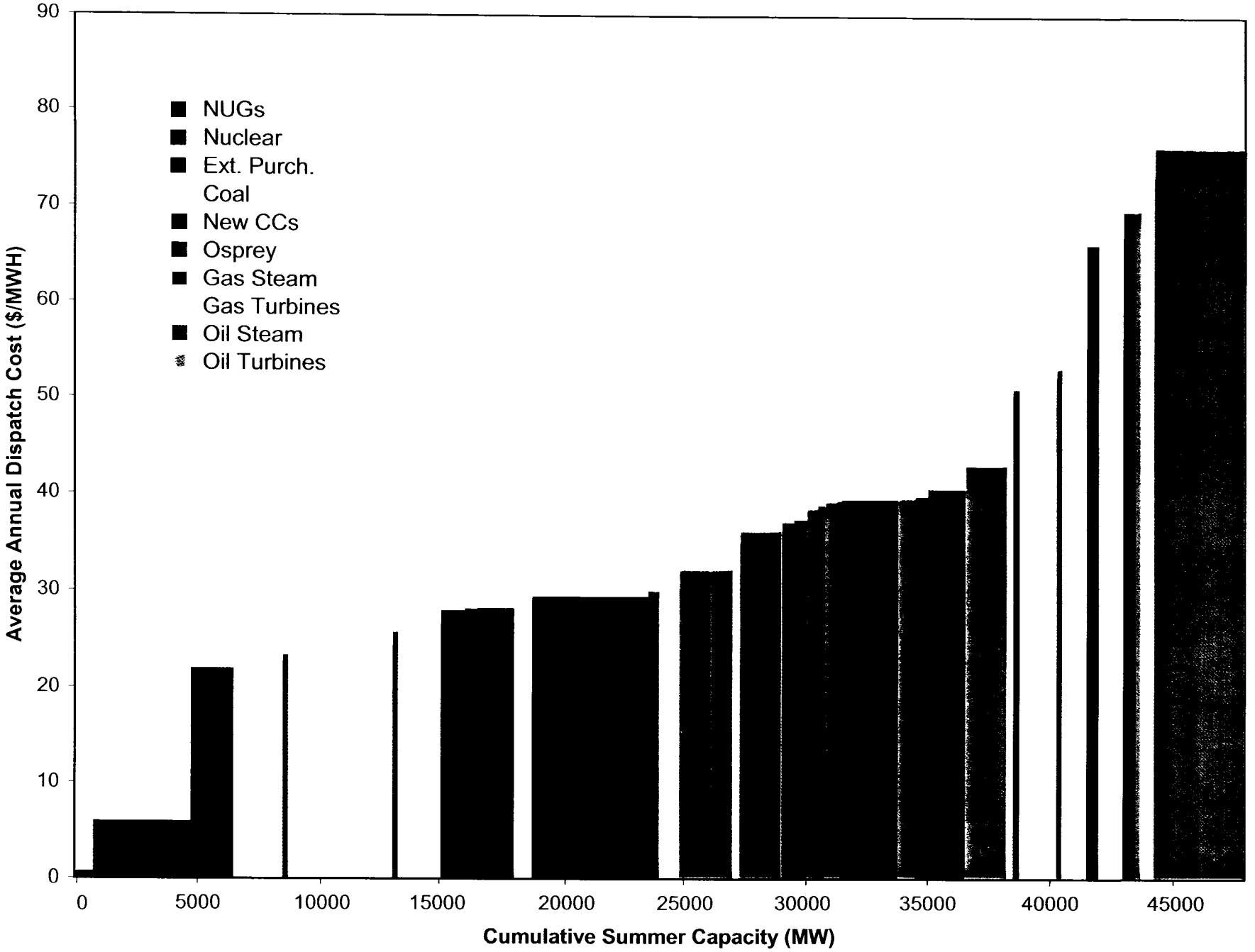
ELDORADO	1	114
FLASTONE	1	133
HILLSBOR	1	26
INDIANTN	1	330
LAKE CTY	1	13
LAKECOGN	1	110
LFC JEFF	1	9
LFC MADS	1	9
MULB-FPC	1	79
ORANGE	1	22
ORLANDO	1	79
PALMBCH	1	44
PASCO	1	109
PASCOCTY	1	23
PINELLAS	1	40
PINELLAS	2	15
RIDGE	1	40
ROYSTER	1	31
TAMPACTY	1	19
JEA-QFs		17

External Purchases

ENTERGY	1	23
SOUTHERN CO.		1615

Source: PROMOD IV(R) analyses prepared by Slater Consulting

Dispatch Cost vs. Summer Capacity 2003



Osprey Energy Center
Calpine
Witness: Kenneth J. Slater
Exhibit _____ (KJS-3A)

EFFICIENCY AND COST-EFFECTIVENESS OF PENINSULAR FLORIDA GENERATING UNITS, 2008

Plant	Unit	Summer Capacity (MW)	Average Annual Heat Rate (Btu/kwh)	Average Annual Dispatch Cost ($/MWh)
Nuclear				
CRYSTAL	3	805	Must Run at Maximum Available Capacity	
STLUCIE	1	839	Must Run at Maximum Available Capacity	
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TURKEYPT	3	697	Must Run at Maximum Available Capacity	
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CRYSTAL	2	488	9,600	28.04
CRYSTAL	4	714	9,124	26.57
CRYSTAL	5	697	9,121	26.10
DEERHAVN	2	228	10,609	28.60
MCINTOSH	3	338	9,099	26.95
MCINTOSH	4	288	8,492	24.19
NORTHSID	1	265	9,786	26.49
NORTHSID	2	265	13,421	34.04
SCHERER	4	846	9,969	27.53
SEMINOLE	1	638	10,089	29.97
SEMINOLE	2	638	10,077	29.62
ST JOHNS	1	624	9,204	25.31
ST JOHNS	2	638	9,288	25.77
STANTON	1	442	9,782	27.70
STANTON	2	446	9,086	26.03
New Gas Combined Cycle				
BAYSIDE	1	707	7,221	34.15
BAYSIDE	2	715	7,186	34.01

BRANDY B	4	482	7,254	34.71
CANE IS	3	260	7,026	32.74
FT MYERS	3	1446	7,203	33.90
GREEN CC	1	260	6,979	32.57
HINES EC	1	470	7,082	32.95
HINES EC	2	520	7,005	32.69
HINES EC	3	520	7,016	32.67
HINES EC	4	520	7,020	32.74
KELLEY	4	113	8,536	43.43
MARTINCC	5	380	6,804	31.96
MARTINCC	6	380	6,804	31.96
N SMYRNA	1	520	6,992	32.62
OKEECHOB	1	260	6,978	32.44
OKEECHOB	2	260	6,977	32.56
OSPREY	1	520	6,984	32.57
PAYNECRK	3	520	7,037	32.76
PURDOM	8	260	7,009	32.69
SANFORD	14	964	7,276	34.17
SANFORD	15	964	7,282	34.17
SEMIN CC	4	260	7,010	32.67
SEMIN CC	5	260	7,011	32.67
UNKNOWCC	1	364	6,981	32.53
UNKNOWCC	2	364	6,990	32.63

Other Units

ANCLOTE	1	503	11,581	90.11
ANCLOTE	2	503	11,378	89.16
BARTOW	1	115	9,971	46.89
BARTOW	2	117	10,003	46.60
BARTOW	3	208	9,978	46.05
BARTOWGT	1	46	No Significant Output	
BARTOWGT	2	46	No Significant Output	
BARTOWGT	3	46	No Significant Output	
BARTOWGT	4	49	No Significant Output	
BGBENDGT	1	12	No Significant Output	
BGBENDGT	2	61	No Significant Output	
BGBENDGT	3	61	No Significant Output	
BRANDY B	3	153	11,464	65.79
CANE GT	1	30	11,166	59.41
CANE ISL	2	108	9,581	49.24
CAPECNVR	1	405	9,444	48.37
CAPECNVR	2	408	9,444	48.47
CUDJOE D	1	5	No Significant Output	
CUTLER	5	71	11,721	52.49
CUTLER	6	144	11,734	52.59
DEBARYGT	1	54	No Significant Output	

DEBARYGT	2	54	No Significant Output	
DEBARYGT	3	54	No Significant Output	
DEBARYGT	4	54	No Significant Output	
DEBARYGT	5	54	No Significant Output	
DEBARYGT	6	54	No Significant Output	
DEBARYGT	7	88	No Significant Output	
DEBARYGT	8	88	No Significant Output	
DEBARYGT	9	88	No Significant Output	
DEBARYGT	10	88	No Significant Output	
DEERHAVN	1	85	10,609	52.93
DRHVN GT	1	18	No Significant Output	
DRHVN GT	2	18	No Significant Output	
DRHVN GT	3	75	No Significant Output	
EVERGL T	1	35	No Significant Output	
EVERGL T	2	35	No Significant Output	
EVERGL T	3	35	No Significant Output	
EVERGL T	4	35	No Significant Output	
EVERGL T	5	35	No Significant Output	
EVERGL T	6	35	No Significant Output	
EVERGL T	7	35	No Significant Output	
EVERGL T	8	35	No Significant Output	
EVERGL T	9	35	No Significant Output	
EVERGL T	10	35	No Significant Output	
EVERGL T	11	35	No Significant Output	
EVERGL T	12	35	No Significant Output	
EVERGLDS	1	221	9,546	44.78
EVERGLDS	2	221	9,551	44.71
EVERGLDS	3	375	9,897	45.90
EVERGLDS	4	410	9,892	45.91
FTMYER T	1	54	No Significant Output	
FTMYER T	2	54	No Significant Output	
FTMYER T	3	54	No Significant Output	
FTMYER T	4	54	No Significant Output	
FTMYER T	5	54	No Significant Output	
FTMYER T	6	54	No Significant Output	
FTMYER T	7	54	No Significant Output	
FTMYER T	8	54	No Significant Output	
FTMYER T	9	54	No Significant Output	
FTMYER T	10	54	No Significant Output	
FTMYER T	11	54	No Significant Output	
FTMYER T	12	54	No Significant Output	
FTMYERCT	13	153	11,343	61.30
FTMYERCT	14	153	11,355	61.33
GANNONGT	1	12	No Significant Output	
HANSELCC	2	48	9,777	53.15
HANSELIC	8	3	9,300	50.48
HANSELIC	14	2	9,300	50.50

HANSELIC	15	2	9,300	50.41
HANSELIC	16	2	9,300	50.51
HANSELIC	17	2	9,300	50.42
HANSELIC	18	2	No Significant Output	
HANSELIC	19	3	No Significant Output	
HANSELIC	20	3	9,300	50.40
HARDEE	1	224	7,300	39.97
HARDEECT	1	74	9,732	52.50
HOPKINGT	1	12	No Significant Output	
HOPKINGT	2	24	No Significant Output	
HOPKINS	1	75	11,386	54.86
HOPKINS	2	238	10,636	48.54
IND RIVR	1	88	10,026	49.15
IND RIVR	2	201	9,971	45.80
IND RIVR	3	319	10,463	48.23
INDRVRGT	1	37	11,540	60.96
INDRVRGT	2	37	11,540	61.06
INDRVRGT	3	108	11,100	59.03
INDRVRGT	4	108	11,100	59.15
INTER GT	1	47	No Significant Output	
INTER GT	2	47	No Significant Output	
INTER GT	3	47	No Significant Output	
INTER GT	4	47	No Significant Output	
INTER GT	5	47	No Significant Output	
INTER GT	6	47	No Significant Output	
INTER GT	7	83	No Significant Output	
INTER GT	8	83	No Significant Output	
INTER GT	9	83	No Significant Output	
INTER GT	10	83	No Significant Output	
INTER GT	11	143	No Significant Output	
INTER GT	12	76	12,568	69.17
INTER GT	13	76	12,583	69.28
INTER GT	14	76	12,567	69.23
IVEY IC	1	4	9,300	50.59
IVEY IC	2	5	9,300	50.60
IVEY IC	3	9	12,280	64.70
IVEY IC	4	6	No Significant Output	
IVEY IC	5	4	9,300	50.58
IVEY IC	6	18	9,300	50.58
KELLY	7	23	16,878	81.75
KELLY GT	1	14	No Significant Output	
KELLY GT	2	14	No Significant Output	
KELLY GT	3	14	No Significant Output	
KENEDYGT	3	54	No Significant Output	
KENEDYGT	4	54	No Significant Output	
KENEDYGT	5	54	No Significant Output	
KENEDYGT	7	153	11,306	65.11

KING	5	8	10,479	49.55
KING	6	17	12,844	60.53
KING	7	32	12,942	64.15
KING	8	50	12,728	61.06
KING DSL	1	5	No Significant Output	
KING GT	9	23	10,500	59.26
LARSEN	8	102	10,610	49.95
LARSENGT	2	10	No Significant Output	
LARSENGT	3	10	No Significant Output	
LAUDER T	1	36	No Significant Output	
LAUDER T	2	35	No Significant Output	
LAUDER T	3	35	No Significant Output	
LAUDER T	4	35	No Significant Output	
LAUDER T	5	35	No Significant Output	
LAUDER T	6	35	No Significant Output	
LAUDER T	7	35	No Significant Output	
LAUDER T	8	35	No Significant Output	
LAUDER T	9	35	No Significant Output	
LAUDER T	10	35	No Significant Output	
LAUDER T	11	35	No Significant Output	
LAUDER T	12	35	No Significant Output	
LAUDER T	13	35	No Significant Output	
LAUDER T	14	35	No Significant Output	
LAUDER T	15	35	No Significant Output	
LAUDER T	16	35	No Significant Output	
LAUDER T	17	35	No Significant Output	
LAUDER T	18	35	No Significant Output	
LAUDER T	19	35	No Significant Output	
LAUDER T	20	35	No Significant Output	
LAUDER T	21	35	No Significant Output	
LAUDER T	22	32	No Significant Output	
LAUDER T	23	32	No Significant Output	
LAUDER T	24	35	No Significant Output	
LAUDERCC	4	440	7,667	38.21
LAUDERCC	5	440	7,680	38.95
MANATEE	1	819	9,857	46.72
MANATEE	2	819	9,695	45.92
MARATHON	1	8	No Significant Output	
MARATHON	2	5	9,300	50.59
MARATHON	3	8	12,280	64.24
MARTIN	1	814	8,941	42.10
MARTIN	2	816	8,970	42.34
MARTINCC	3	445	7,263	36.26
MARTINCC	4	445	7,265	36.26
MARTINCT	1	153	11,327	61.28
MARTINCT	2	153	11,335	61.29
MCINT GT	1	17	No Significant Output	

MCINT IC	1	5	No Significant Output	
MCINTOSH	1	87	10,814	50.91
MCINTOSH	2	103	10,282	47.50
MCINTOSH	5	310	7,460	35.57
NORTH GT	3	52	No Significant Output	
NORTH GT	4	52	No Significant Output	
NORTH GT	5	52	No Significant Output	
NORTH GT	6	52	No Significant Output	
NORTHSID	3	505	9,653	50.48
OLEAN GT	1	153	11,364	61.32
OLEAN GT	2	153	11,345	61.24
OLEAN GT	3	153	11,352	61.25
OLEAN GT	4	153	11,367	61.24
OLEAN GT	5	153	11,366	61.31
PHILLIPS	1	17	13,500	65.92
PHILLIPS	2	17	13,500	65.92
POLK CT	2	153	11,353	63.94
POLK CT	3	153	11,368	63.99
POLK CT	4	153	11,393	64.00
POLK CT	5	153	11,345	63.89
POLK CT	6	153	11,336	63.85
POLKIGCC	1	250	10,267	35.35
PURDOM	7	48	18,726	87.68
PURDOMGT	1	0	No Significant Output	
PURDOMGT	2	12	No Significant Output	
PUTNAMCC	1	249	9,114	45.67
PUTNAMCC	2	249	9,110	45.70
REEDYCRK	1	35	10,400	53.12
RIVIERA	3	290	9,728	43.93
RIVIERA	4	290	9,738	44.25
SANFORD	3	153	8,877	47.44
SEM CT	1	153	11,383	64.07
SEM CT	2	153	11,422	64.21
SEM CT	3	153	11,375	64.01
SMITH	1	7	No Significant Output	
SMITH	2	7	No Significant Output	
SMITH	3	22	16,685	82.15
SMITH	4	32	16,495	81.24
SMITH D	1	9	No Significant Output	
SMITH CC	1	32	10,400	56.17
SMITH GT	1	26	No Significant Output	
SMITH ST	1	3	No Significant Output	
SMITH ST	2	2	No Significant Output	
SMITH ST	3	6	No Significant Output	
ST CLOUD	1	4	No Significant Output	
ST CLOUD	2	6	No Significant Output	
ST CLOUD	3	6	No Significant Output	

ST CLOUD	4	12	No Significant Output	
STOCK DS	1	9	No Significant Output	
STOCK DS	2	9	No Significant Output	
STOCK GT	1	21	No Significant Output	
STOCK GT	2	16	No Significant Output	
STOCK GT	3	16	No Significant Output	
STOCK IC	1	6	No Significant Output	
SUWAN GT	1	54	No Significant Output	
SUWAN GT	2	54	No Significant Output	
SUWAN GT	3	54	No Significant Output	
SWOOPEIC	1	5	No Significant Output	
TIGERBAY	1	194	7,577	37.45
TURKEYIC	1	14	No Significant Output	
TURKEYPT	1	410	9,406	46.87
TURKEYPT	2	400	9,420	46.90
TURNERGT	3	65	No Significant Output	
TURNERGT	4	65	No Significant Output	
UNIV FLA	1	36	11,166	58.41
VERO BCH	1	13	13,115	61.76
VERO BCH	2	13	8,931	42.62
VERO BCH	3	33	13,164	63.46
VERO BCH	4	56	11,785	56.74
VERO BCH	5	35	11,183	53.25

NUGs

AS-AVAIL	1	63
BAY CTY	1	11
BROWARDS	1	54
BROWARDS	2	56
CARGILL	2	15
CEDARBAY	1	250
CFRBIOGN	1	74
DADE CTY	1	43
ELDORADO	1	114
HILLSBOR	1	26
INDIANTN	1	330
LAKE CTY	1	13
LAKECOGN	1	110
LFC JEFF	1	9
LFC MADS	1	9
MULB-FPC	1	79
ORANGE	1	22
ORLANDO	1	79
PALMBCH	1	44
PASCO	1	109
PASCOCTY	1	23

PINELLAS	1	40
PINELLAS	2	15
RIDGE	1	40
ROYSTER	1	31
TAMPACTY	1	19
JEA-QFs		17

External Purchases

ENTERGY	1	23
SOUTHERN CO.		1615

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

PENINSULAR FLORIDA
SUMMARY OF EXISTING CAPACITY
AS OF JANUARY 1, 2000

UTILITY	NET CAPABILITY SUMMER	NET CAPABILITY WINTER
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOC., INC	22	22
FLORIDA MUNICIPAL POWER AGENCY	498	527
FLORIDA POWER CORPORATION	7,525	8,277
FLORIDA POWER & LIGHT COMPANY	16,444	17,234
FORT PIERCE UTILITIES AUTHORITY	119	119
GAINESVILLE REGIONAL UTILITIES	550	563
CITY OF HOMESTEAD	60	60
JACKSONVILLE ELECTRIC AUTHORITY	2,626	2,749
UTILITY BOARD OF THE CITY OF KEY WEST	52	52
KISSIMMEE UTILITY AUTHORITY	172	190
CITY OF LAKELAND	615	650
CITY OF LAKE WORTH UTILITIES	127	138
UTILITIES COMMISSION OF NEW SMYRNA BEACH	24	24
OCALA ELECTRIC UTILITY	11	11
ORLANDO UTILITIES COMMISSION	1,028	1,072
REEDY CREEK IMPROVEMENT DISTRICT	48	49
SEMINOLE ELECTRIC COOPERATIVE INC.	1,331	1,345
CITY OF ST. CLOUD	22	21
CITY OF TALLAHASSEE	429	449
TAMPA ELECTRIC COMPANY	3,455	3,594
CITY OF VERO BEACH	150	155
TOTALS		
FRCC UTILITIES EXISTING CAPACITY	35,308	37,301
NON-UTILITY GENERATING FACILITIES (FIRM)	2,060	2,124
NON-UTILITY GENERATING FACILITIES (NON-FIRM)	89	111
MERCHANT PLANT FACILITIES (FIRM)	593	593
MERCHANT PLANT FACILITIES (NON-FIRM)	15	26
TOTAL PENINSULAR FLORIDA EXISTING CAPACITY	**38,065**	**40,155**

Data Source:
Florida Reliability Coordinating Council
2000 Regional Load & Resource Plan, Peninsular Florida, July 2000

PENINSULAR FLORIDA, HISTORICAL AND PROJECTED SUMMER AND WINTER FIRM PEAK DEMANDS

1991-2012

ACTUAL PEAK DEMAND (MW)

	1991	1992	1993	1994	1995	1996	1997	1998
SUMMER	27,662	28,930	29,748	29,321	31,801	32,315	32,924	37,153
WINTER	28,179	27,215	28,149	32,618	34,552	34,762	30,932	35,907

PROJECTED FIRM PEAK DEMAND (MW)

	1999 (Actual)	2000	2001	2002	2003	2004	2005	2006
SUMMER	37,493	34,832	35,560	36,432	37,313	38,164	39,065	40,347
WINTER	40,178	36,814	37,753	38,679	39,592	40,551	41,585	42,541

PROJECTED FIRM PEAK DEMAND (MW)

	2007	2008	2009	2010	2011	2012
SUMMER	41,255	42,094	42,980	43,895	44,830	45,785
WINTER	43,445	44,386	45,316	46,281	47,266	48,272

Data Source:
Florida Reliability Coordinating Council,
1991-2009 values, 2000 Regional Load & Resource Plan, Peninsular Florida, July 2000.
2010-2012 values extrapolated at the FRCC projected average annual compond growth rates for 2006-2009.
1991-1999 actual peak demand values exclude interruptible load and load management reductions.
2000-2012 forecasted firm peak demand values include projected interruptible load and load management reduction values, and are non-coincident.

PENINSULAR FLORIDA, HISTORICAL AND PROJECTED NET ENERGY FOR LOAD AND NUMBER OF CUSTOMERS

1991 - 2012

ACTUAL NET ENERGY FOR LOAD (GWH)

	1991	1992	1993	1994	1995	1996	1997	1998
ENERGY	146,786	147,728	153,269	159,353	168,982	173,327	175,534	187,868
LOAD FACTOR	60.58%	58.29%	58.82%	62.04%	59.14%	57.26%	57.64%	57.72%
CUSTOMERS	6,155,380	6,269,358	6,410,797	6,550,760	6,687,155	6,812,603	6,948,888	7,091,803

PROJECTED NET ENERGY FOR LOAD (GWH)

	1999 (Actual)	2000	2001	2002	2003	2004	2005	2006
ENERGY	188,598	196,042	200,188	204,779	209,853	214,507	218,950	223,453
LOAD FACTOR	57.42%	55.70%	62.08%	61.92%	61.93%	61.85%	61.64%	61.34%
CUSTOMERS	7,555,341	7,517,881	7,688,054	7,832,016	7,974,676	8,113,738	8,249,138	8,380,749

PROJECTED NET ENERGY FOR LOAD (GWH)

	2007	2008	2009	2010	2011	2012
ENERGY	227,798	232,032	236,224	240,641	245,141	249,725
LOAD FACTOR	61.13%	60.97%	60.75%	59.36%	59.21%	58.89%
CUSTOMERS	8,510,779	8,640,757	8,771,153	8,905,264	9,041,425	9,179,669

Data Source:
Florida Reliability Coordinating Council,
1991-2009 Energy values, 2000 Regional Load & Resource Plan, Peninsular Florida, July 2000.
2010-2012 Energy values extrapolated at the FRCC projected average annual compound growth rates for 2006-2009.
Load factor values were calculated from these energy values and the peak demand values in Table 4.
1991-2009 Customer values, 2000 Regional Load & Resource Plan, Peninsular Florida, July 2000.
2010-2012 Customer values extrapolated at the FRCC projected average annual compound growth rates for 2006-2009.

OSPREY ENERGY CENTER
SUMMARY OF PROJECTED OPERATIONS
2003-2012

Year	PROJECTED GENERATION (GWH)	ANNUAL CAPACITY FACTOR %
2003	2,624	95.5%
2004	4,379	92.7%
2005	4,293	91.1%
2006	4,279	90.8%
2007	4,333	92.0%
2008	4,254	90.0%
2009	4,172	88.6%
2010	4,301	91.3%
2011	4,070	86.4%
2012	4,389	92.9%

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. The Project is scheduled to come into service on June 1, 2003. The annual capacity factor reported for 2003 is calculated on the basis of the Project's operations for the period June 1 - December 31, 2003.

2. The indicated capacity factors are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

OSPREY ENERGY CENTER
SUMMARY OF PROJECTED OPERATIONS, 2003-2012
HIGHER NATURAL GAS PRICE SENSITIVITY ANALYSIS

Year	PROJECTED GENERATION (GWH)	ANNUAL CAPACITY FACTOR %
2003	2,616	95.1%
2004	4,351	92.1%
2005	4,264	90.5%
2006	4,229	89.8%
2007	4,266	90.6%
2008	4,149	87.8%
2009	4,066	86.3%
2010	4,161	88.3%
2011	3,935	83.5%
2012	4,265	90.3%

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. The Project is scheduled to come into service on June 1, 2003. The annual capacity factor reported for 2003 is calculated on the basis of the Project's operations for the period June 1 - December 31, 2003.

2. The Base Case fuel price projections were developed by Slater Consulting based on actual data and the U. S. Energy Information Administration's 2000 Annual Energy Outlook Reference Case Forecast, but with the natural gas price escalations moderated to be more in keeping with the Standard & Poor's DRI forecast, which was included in the EIA's publication as a comparison forecast. The fuel prices for this sensitivity case were the same as for the Base Case except that the prices of natural gas were projected to escalate at the growth rates projected in the EIA Reference Case Forecast.

3. The indicated capacity factors are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

OSPREY ENERGY CENTER
SUMMARY OF PROJECTED OPERATIONS
LOAD GROWTH SENSITIVITY ANALYSES, 2003-2012

	LOW LOAD GROWTH		BASE LOAD		HIGH LOAD GROWTH	
	PROJECTED GENERATION	ANNUAL CAPACITY	PROJECTED GENERATION	ANNUAL CAPACITY	PROJECTED GENERATION	ANNUAL CAPACITY
Year	(GWH)	FACTOR %	(GWH)	FACTOR %	(GWH)	FACTOR %
2003	2,622	95.4%	2,624	95.5%	2,633	95.8%
2004	4,364	92.4%	4,379	92.7%	4,400	93.1%
2005	4,279	90.8%	4,293	91.1%	4,307	91.4%
2006	4,270	90.6%	4,279	90.8%	4,214	89.4%
2007	4,139	87.9%	4,333	92.0%	4,441	94.3%
2008	4,402	93.2%	4,254	90.0%	4,032	85.4%
2009	4,065	86.3%	4,172	88.6%	4,365	92.7%
2010	4,357	92.5%	4,301	91.3%	4,267	90.6%
2011	4,216	89.5%	4,070	86.4%	4,284	90.9%
2012	4,190	88.7%	4,389	92.9%	4,455	94.3%

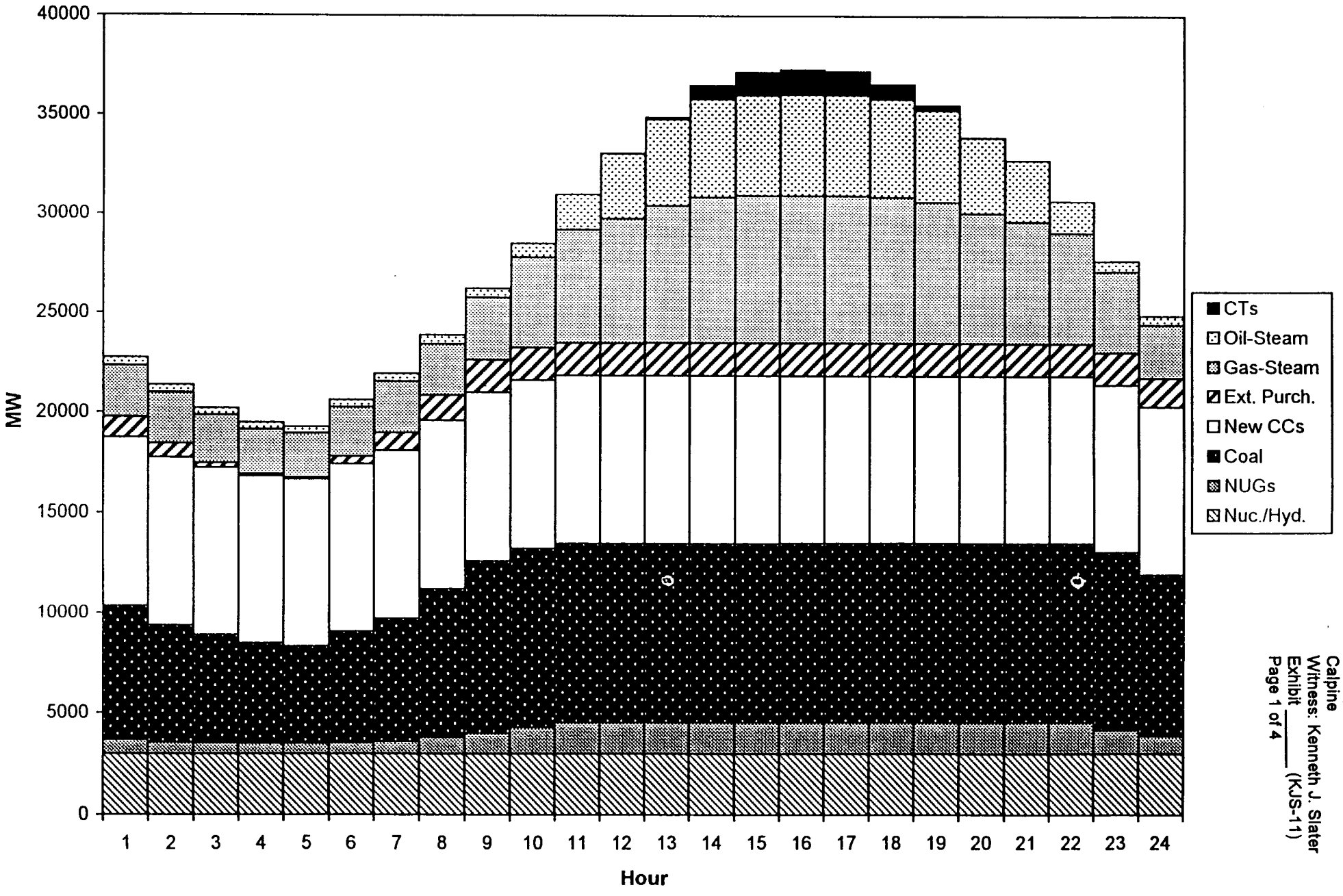
Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Note: The indicated output and capacity factor values are projected subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

Assumptions: The Base Case scenario was developed by Slater Consulting based on actual data and consideration of published sources, including the 1999 FRCC Regional Load & Resource Plan and Florida utilities' 2000 ten-year site plans. The Low Load Growth scenario reflects growth rates 0.5 percent per year less than in the Base Case. The High Load Growth scenario reflects growth rates 1.0 percent per year greater than in the Base Case.

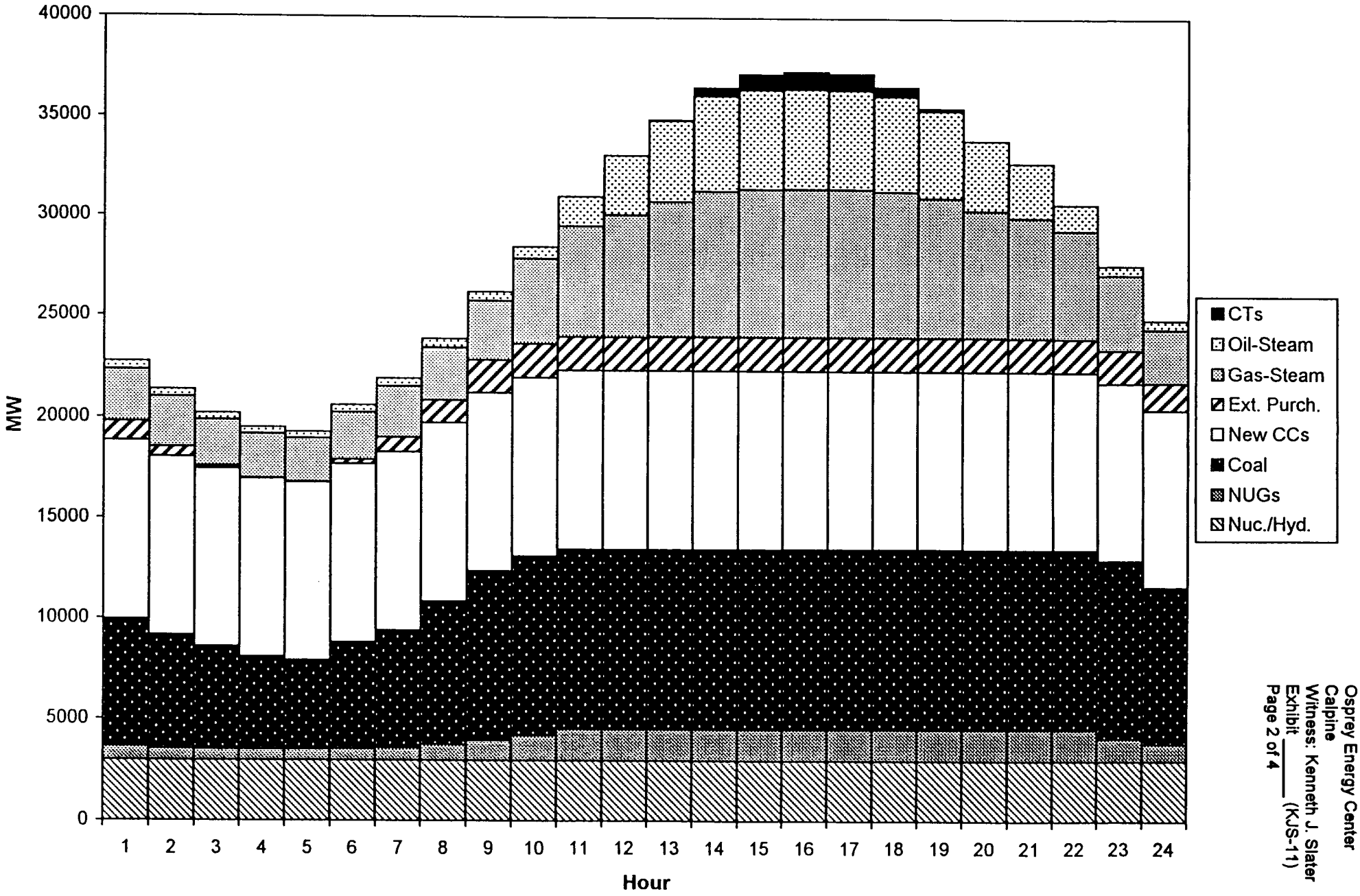
Osprey Energy Center
Calpine
Witness: Kenneth J. Slater
Exhibit _____ (KJS-10)
Page 1 of 1

PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday June 2005



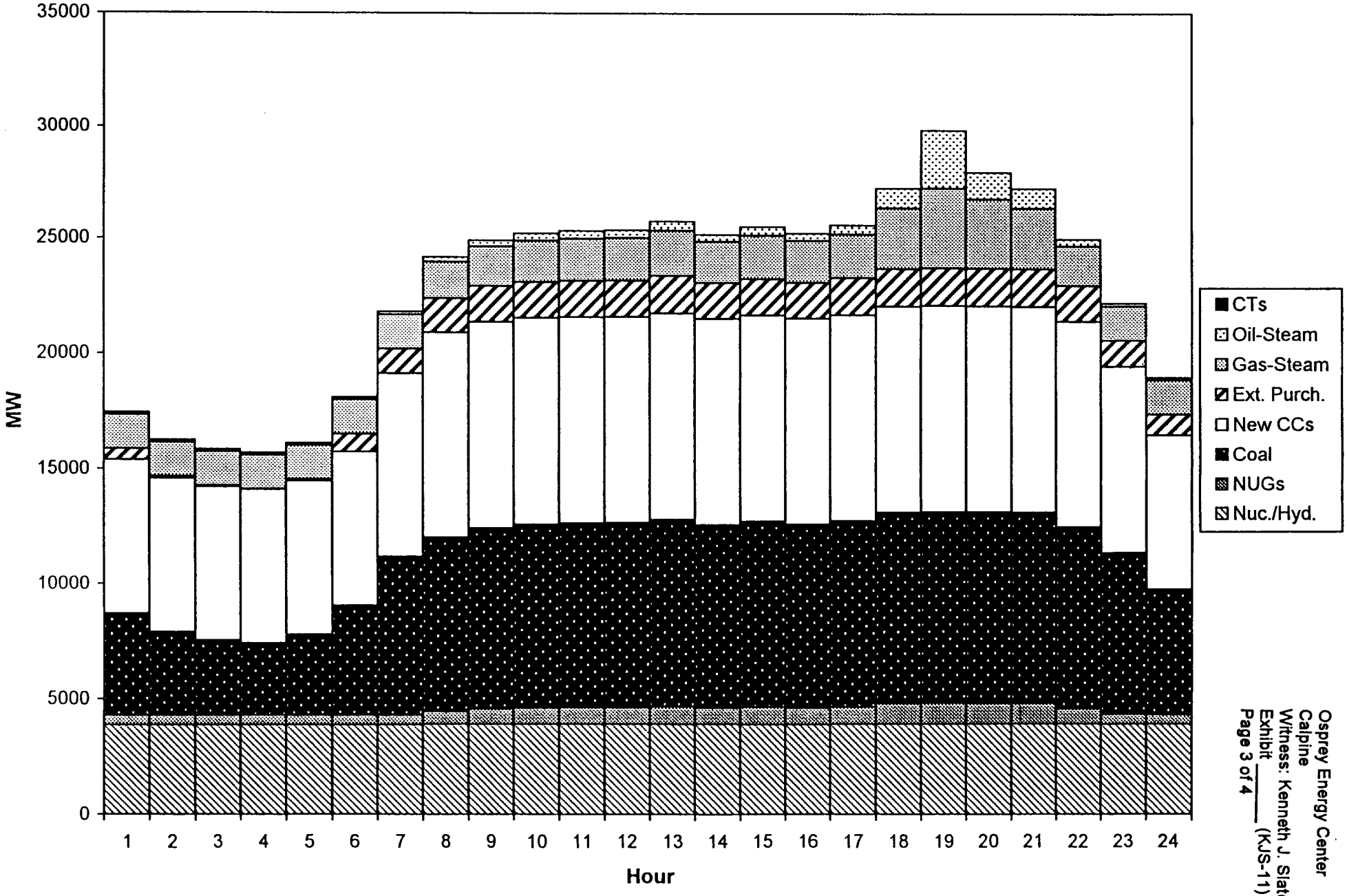
Osprey Energy Center
Calpine
Witness: Kenneth J. Slater
Exhibit _____ (KJS-11)
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PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday June 2005



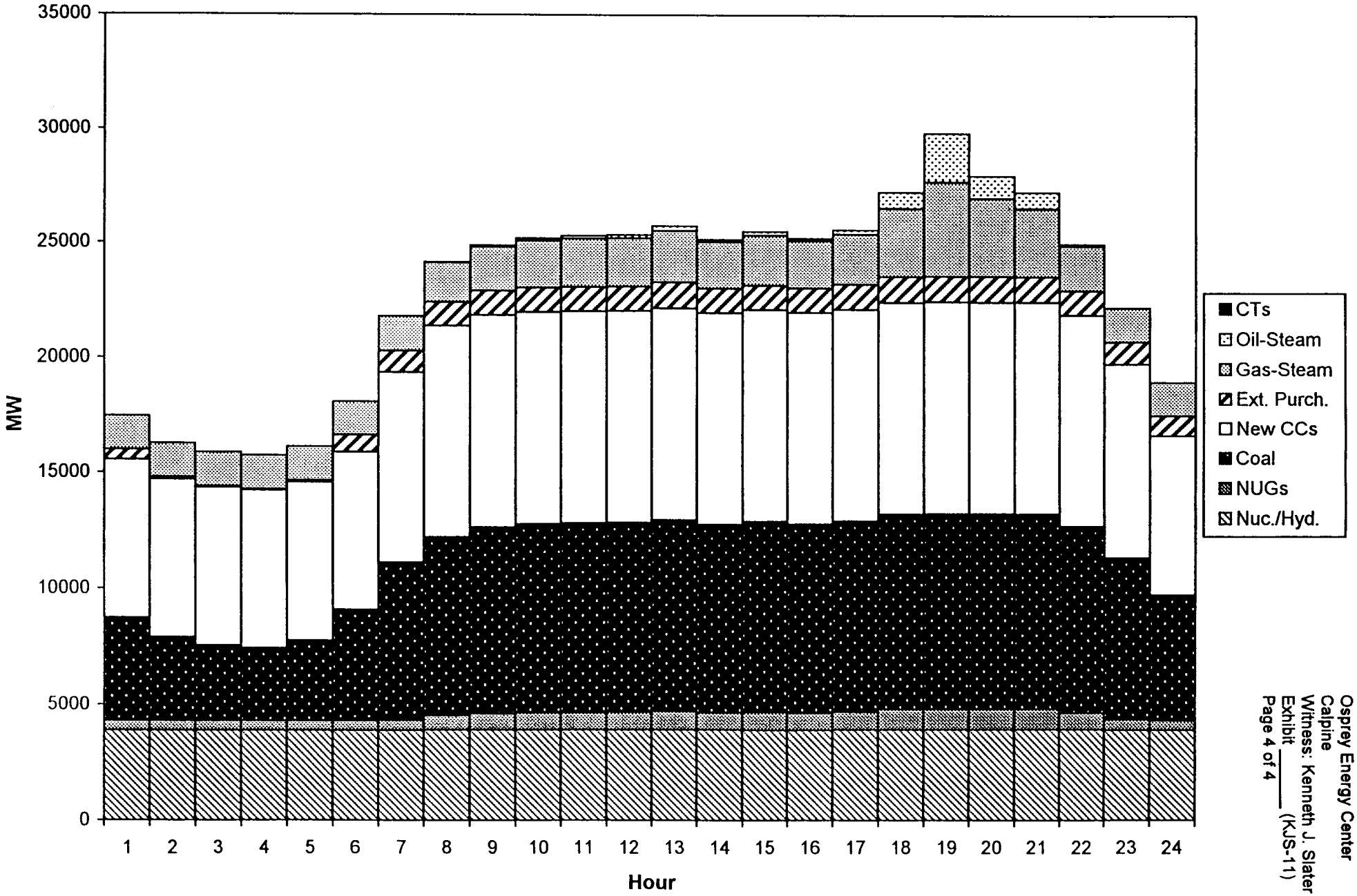
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Calpine
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PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday December 2005



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PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday December 2005



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Exhibit _____ (KJS-11)
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Market Indicators

NERC Region		MONTHLY TRENDS Oct. 1999	Nov. 1999	Dec. 1999	Dec. 1998	Year Ago Percent Change	JANUARY through DECEMBER 1997	1998	1999	1998-1999 Percent Change
NPCC	Electric Generation (gWh)	16,900	17,277	18,876	14,917	26.54%	182,537	182,468	231,281	26.75%
	Production Costs (¢/kWh)	2.41	2.35	2.28	2.36	-3.22%	2.48	2.30	2.39	3.65%
	Retail Rates (¢/kWh)	10.19	9.83	9.65	10.09	-2.58%	10.81	10.45	10.11	-3.25%
MAAC	Electric Generation (gWh)	18,924	18,925	18,789	19,777	-5.00%	210,399	228,685	252,746	10.52%
	Production Costs (¢/kWh)	2.28	2.19	2.21	1.83	20.45%	2.11	1.91	2.23	16.60%
	Retail Rates (¢/kWh)	7.53	7.35	7.41	8.18	-10.15%	8.86	8.69	8.09	-6.90%
SERC	Electric Generation (gWh)	62,249	58,045	65,901	61,472	7.20%	734,118	763,603	793,411	3.90%
	Production Costs (¢/kWh)	1.76	1.77	1.72	1.72	0.06%	1.79	1.78	1.76	-0.96%
	Retail Rates (¢/kWh)	5.71	5.50	5.53	5.49	0.18%	5.81	5.77	5.71	-1.04%
FRCC	Electric Generation (gWh)	14,169	12,328	12,908	11,963	7.90%	141,111	160,611	173,061	7.75%
	Production Costs (¢/kWh)	2.89	2.76	2.43	2.33	4.37%	2.67	2.39	2.59	8.40%
	Retail Rates (¢/kWh)	6.88	6.90	6.85	7.06	-2.27%	7.30	7.13	6.96	-2.38%
ECAR	Electric Generation (gWh)	44,321	43,829	48,515	44,598	8.78%	529,312	526,524	560,974	6.54%
	Production Costs (¢/kWh)	2.17	2.14	2.13	1.87	13.63%	1.86	1.87	2.12	13.83%
	Retail Rates (¢/kWh)	5.97	5.91	5.86	5.89	0.34%	6.03	5.98	6.01	0.50%
MAIN	Electric Generation (gWh)	19,231	18,992	20,268	19,895	1.88%	216,491	222,092	252,018	13.47%
	Production Costs (¢/kWh)	1.87	1.88	1.79	1.99	-10.12%	2.09	2.05	1.84	-10.42%
	Retail Rates (¢/kWh)	6.22	5.98	5.93	6.40	-6.56%	6.78	6.75	6.43	-4.74%
MAPP	Electric Generation (gWh)	13,282	12,703	14,241	13,496	5.52%	151,337	153,972	161,491	4.88%
	Production Costs (¢/kWh)	1.35	1.37	1.39	1.44	-3.41%	1.50	1.51	1.42	-5.77%
	Retail Rates (¢/kWh)	5.50	5.57	5.62	5.49	1.46%	5.68	5.75	5.79	0.70%
ERCOT	Electric Generation (gWh)	22,973	20,370	22,048	17,796	23.89%	226,751	240,026	287,310	19.70%
	Production Costs (¢/kWh)	2.54	2.40	2.33	1.98	18.18%	2.13	2.12	2.41	13.62%
	Retail Rates (¢/kWh)	6.50	5.88	5.75	5.75	2.26%	6.18	6.12	6.09	-0.49%
SPP	Electric Generation (gWh)	15,144	14,715	16,133	13,562	18.95%	164,934	174,334	200,862	15.22%
	Production Costs (¢/kWh)	2.12	2.08	2.06	1.80	14.33%	1.98	1.89	2.11	11.14%
	Retail Rates (¢/kWh)	5.45	5.08	5.07	5.11	-0.59%	5.60	5.58	5.52	-1.08%
WSCC	Electric Generation (gWh)	51,552	49,931	53,929	48,391	11.44%	561,608	551,533	628,226	13.91%
	Production Costs (¢/kWh)	1.86	1.67	1.58	1.47	7.28%	1.56	1.50	1.60	6.87%
	Retail Rates (¢/kWh)	7.30	6.64	6.75	6.56	7.11%	7.18	6.95	6.89	-0.86%

Source: POWERdat Database. POWERdat is a registered trademark of Resource Data International Inc. (RDI) • Boulder, Colo. • 303-444-7788. ©2000 All rights reserved. Note: Monthly production costs are estimated using current fuel prices and most recently reported nonfuel O&M costs for all regulated companies (IOUs, munis, co-ops & federal).

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PENINSULAR FLORIDA, IMPACTS OF OSPREY ENERGY CENTER ON AVERAGE ELECTRICITY GENERATION HEAT RATES AND TOTAL FUEL CONSUMPTION, 2003-2012

	Average Heat Rate (btu/kwh)			Total Primary Energy (1000*mmbtu)		Osprey Net Energy
Year	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Savings (1000*mmbtu)
2003	8,864.4	8,837.4	27.0	1,850,893	1,845,257	5,636
2004	8,781.6	8,737.8	43.7	1,874,198	1,864,864	9,334
2005	8,747.8	8,707.6	40.2	1,905,197	1,896,431	8,766
2006	8,662.8	8,626.6	36.2	1,925,724	1,917,686	8,038
2007	8,606.0	8,567.4	38.7	1,949,829	1,941,069	8,760
2008	8,576.2	8,540.5	35.7	1,976,351	1,968,125	8,226
2009	8,536.7	8,512.4	24.3	2,003,095	1,997,395	5,700
2010	8,546.1	8,518.9	27.3	2,041,883	2,035,372	6,511
2011	8,553.6	8,517.0	36.6	2,081,005	2,072,094	8,911
2012	8,575.3	8,540.2	35.1	2,124,464	2,115,761	8,703

Source: PROMOD IV(R) analyses prepared by Slater Consulting.
Note: The estimated energy savings are projections subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

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PENINSULAR FLORIDA FUEL CONSUMPTION
IMPACTS OF OSPREY ENERGY CENTER, 2003-2012

(All Values in 1,000 x MMBtu)

	Nuclear			Coal and Other Solid Fuels			Natural Gas			No. 6 Oil			No. 2 Oil		
Year	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference
2003	295,404	295,404	0	769,940	766,231	3,709	663,815	669,766	(5,951)	118,105	110,713	7,392	3,629	3,143	486
2004	321,616	321,616	0	754,909	740,695	14,214	704,970	723,490	(18,520)	89,530	76,408	13,122	3,173	2,655	518
2005	316,996	316,996	0	751,478	743,067	8,411	745,061	755,649	(10,588)	88,372	77,868	10,504	3,290	2,851	439
2006	303,928	303,928	0	743,161	733,395	9,766	791,044	801,777	(10,733)	84,927	76,126	8,801	2,664	2,460	204
2007	312,117	312,117	0	716,668	705,680	10,988	829,301	846,518	(17,217)	89,310	74,427	14,883	2,433	2,327	106
2008	326,697	326,697	0	711,361	703,313	8,048	863,388	874,371	(10,983)	72,295	61,396	10,899	2,610	2,348	262
2009	294,962	294,962	0	716,748	712,157	4,591	897,024	905,427	(8,403)	91,584	82,485	9,099	2,777	2,364	413
2010	321,069	321,069	0	716,779	708,527	8,252	917,233	927,076	(9,843)	84,616	76,538	8,078	2,186	2,162	24
2011	316,945	316,945	0	723,043	709,318	13,725	937,705	952,935	(15,230)	100,807	90,683	10,124	2,505	2,213	292
2012	331,247	331,247	0	734,896	723,896	11,000	946,332	957,427	(11,095)	108,899	100,566	8,333	3,090	2,625	465

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Note: The project's estimated primary fuel consumption impacts shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

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PENINSULAR FLORIDA, FUEL CONSUMPTION
IMPACTS OF OSPREY ENERGY CENTER, 2003-2012

(All Values in GWh)

	Nuclear			Coal and Other Solid Fuels			Natural Gas			No. 6 Oil			No. 2 Oil		
Year	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference
2003	28,539	28,539	0	79,879	79,444	435	87,441	88,664	(1,223)	12,061	11,331	730	357	311	46
2004	31,071	31,071	0	78,413	76,929	1,484	94,014	96,914	(2,900)	9,169	7,831	1,338	310	263	47
2005	30,625	30,625	0	78,211	77,290	921	99,111	101,185	(2,074)	9,076	7,995	1,081	318	278	40
2006	29,362	29,362	0	77,429	76,407	1,022	106,125	108,042	(1,917)	8,702	7,840	862	262	243	19
2007	30,153	30,153	0	74,651	73,490	1,161	111,992	114,720	(2,728)	9,139	7,641	1,498	242	231	11
2008	31,562	31,562	0	74,029	73,254	775	116,868	118,757	(1,889)	7,394	6,328	1,066	256	232	24
2009	28,496	28,496	0	74,744	74,131	613	121,351	122,947	(1,596)	9,385	8,471	914	271	234	37
2010	31,018	31,018	0	74,622	73,742	880	124,057	125,815	(1,758)	8,652	7,832	820	209	204	5
2011	30,620	30,620	0	75,216	73,803	1,413	126,515	129,017	(2,502)	10,292	9,271	1,021	235	207	28
2012	32,001	32,001	0	76,502	75,472	1,030	127,443	129,382	(1,939)	11,093	10,254	839	291	247	44

Source: PROMOD IV(R) analyses perpared by Slater Consulting.

Note: The Project's estimated primary fuel consumption impacts shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

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PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, BASE CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	208,800	32.83	33.37	0.54	113	85
2004	213,424	31.81	32.55	0.74	158	193
2005	217,791	32.92	33.67	0.75	163	294
2006	222,299	33.36	33.96	0.60	133	369
2007	226,565	33.75	34.48	0.73	165	454
2008	230,447	34.34	34.96	0.62	143	521
2009	234,645	35.85	36.60	0.75	176	595
2010	238,924	36.77	37.51	0.74	177	664
2011	243,289	38.81	39.65	0.84	204	735
2012	247,742	40.27	41.02	0.75	186	794

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Note: The estimated wholesale energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

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PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, HIGHER FUEL PRICE SENSITIVITY CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	208,800	32.88	33.43	0.55	115	86
2004	213,424	31.92	32.59	0.67	143	184
2005	217,791	33.06	33.81	0.75	163	285
2006	222,299	33.71	34.35	0.64	142	366
2007	226,565	34.49	35.22	0.73	165	451
2008	230,447	35.43	36.09	0.66	152	522
2009	234,645	37.29	38.03	0.74	174	595
2010	238,924	38.76	39.53	0.77	184	666
2011	243,289	41.04	41.87	0.83	202	737
2012	247,742	42.63	43.51	0.88	218	806

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. The Base Case fuel price projections were developed by Slater Consulting based on actual data and the U. S. Energy Information Administration's 2000 Annual Energy Outlook Reference Case Forecast, but with the natural gas price escalations moderated to be more in keeping with the Standard & Poor's DRI forecast, which was included in the EIA's publication as a comparison forecast. The fuel prices for this sensitivity case were the same as for the Base Case except that the prices of natural gas were projected to escalate at the growth rates projected in the EIA's Reference Case Forecast.

2. The estimated wholesale energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

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PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, LOW LOAD GROWTH SENSITIVITY CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	205,684	32.46	32.69	0.23	47	36
2004	209,187	30.97	31.62	0.65	136	128
2005	212,400	32.10	32.84	0.74	157	226
2006	215,713	32.26	32.85	0.59	127	298
2007	218,754	32.58	33.14	0.56	123	361
2008	221,389	33.09	33.56	0.47	104	409
2009	224,295	34.12	34.75	0.63	141	469
2010	227,242	34.96	35.56	0.60	136	522
2011	230,238	36.64	37.08	0.44	101	557
2012	233,280	37.46	38.40	0.94	219	627

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. This Low Load Growth scenario reflects growth rates 0.5 percent per year less than in the Base Case.

2. The estimated wholesale energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

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PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, HIGH LOAD GROWTH SENSITIVITY CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	215,127	34.16	34.57	0.41	88	66
2004	222,089	33.44	34.29	0.85	189	195
2005	228,900	35.07	35.99	0.92	211	326
2006	235,976	35.94	36.75	0.81	191	434
2007	242,907	36.59	37.43	0.84	204	539
2008	249,539	38.02	39.04	1.02	255	657
2009	256,627	40.26	41.26	1.00	257	766
2010	263,921	42.51	43.51	1.00	264	868
2011	271,429	46.36	47.63	1.27	345	989
2012	279,162	49.17	50.64	1.47	410	1,119

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. This High Load Growth scenario reflects growth rates 1.0 percent per year greater than in the Base Case.

2. The estimated energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utlities.

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COMPARISON OF PENINSULAR FLORIDA
PLANNED AND PROPOSED GENERATING UNITS

PLANNED & PROPOSED UTILITY/UNIT	IN-SERVICE YEAR	SUMMER CAPACITY MW	WINTER CAPACITY MW	PRIMARY FUEL	ALTERNATE FUEL	HEAT RATE (Btu/kWH)	EQUIVALENT AVAILABILITY FACTOR %	TOTAL INSTALLED COST ($/KW) 1/	DIRECT CONSTRUCTION COST ($/KW) 1/	TECHNOLOGY TYPE
OLEANDER 2/	2002	777	910	GAS	NO. 2	9,700	97	N/A	$235	COMBUSTION TURBINE
OSPREY ENERGY 3/	2003	496	578	GAS	NONE	6,800	94	N/A	$357	COMBINED CYCLE
FPL/MARTIN CT	2001	298	362	GAS	NO. 2	10,450	98	$371	$323	COMBUSTION TURBINE
FPL/FT.MYERS	2002	930	1,073	GAS	NONE	6,830	96	$557	$502	COMB. CYCLE/REPOWER
FPL/SANFORD 4-5	2002	1,132	1,342	GAS	NONE	6,860	96	$703	$591	COMB. CYCLE/REPOWER
FPL/FT.MYERS CT	2003	298	362	GAS	NO. 2	10,450	98	$378	$323	COMBUSTION TURBINE
FPL/MARTIN 5-6	2006	788	858	GAS	NO. 2	6,346	96	$679	$484	COMBINED CYCLE
FPL/UNSITED	2007	394	429	GAS	NO. 2	6,830	96	$783	$552	COMBINED CYCLE
FPL/UNSITED	2008	394	429	GAS	NO. 2	6,830	96	$798	$552	COMBINED CYCLE
FPL/UNSITED	2009	394	429	GAS	NO. 2	6,830	96	$812	$552	COMBINED CYCLE
TALLAH/PURDOM 8	2000	233	262	GAS	NO. 2	6,940	NR	$483	$434	COMBINED CYCLE
FPC/INTRCSS 12-14	2000	240	282	GAS	NO. 2	13,272	91	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
FPC/HINES 2	2003	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPC/HINES 3	2005	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPC/HINES 4	2007	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPC/HINES 5	2009	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
TECO/POLK 2	2000	155	180	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
TECO/POLK 3	2002	155	180	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
TECO/BAYSIDE 1	2003	698	796	GAS	NO. 2	7,080	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
TECO/BAYSIDE 2	2004	711	802	GAS	NO. 2	7,050	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
TECO/POLK 4-6	2005	465	540	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
TECO/UNSITED	2009	155	180	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
GVLLE/J.R. KELLY	2001	110	110	GAS	NO. 2	8,000	84	$375	$368	COMBINED CYCLE
SEC/PAYNE CRK 4/	2002	488	572	GAS	NO. 2	6,170	93	$412	$378	COMBINED CYCLE
FMPA-KUA CANE 3	2001	244	267	GAS	NO. 2	6,815	92	$430	$320	COMBINED CYCLE
LKLAND McINTSH 5	2002	337	384	GAS	NO. 2	6,523	91	$749	$671	COMBINED CYCLE
LKLAND McINTSH 4	2004	288	288	PET.COKE	COAL	8,452	81	$1,617	$1,317	PRESSURE FLUID BED
LKLAND McINTSH 6	2009	32	46	GAS	NO. 2	10,624	98	$992	$742	COMBUSTION TURBINE
JEA KENNEDY CT 7	2000	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$261	COMBUSTION TURBINE
JEA BANDY CT 1-3	2001	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$264	COMBUSTION TURBINE
JEA NORTHSID 1-2	2002	265	265	ET. COK	COAL	9,946	90	NOT REPORTED	$658	CIRCULATING FLUID BED

DATA SOURCES:

1/ TOTAL INSTALLED COST AND DIRECT CONSTRUCTION COST DATA IS REPORTED DIRECTLY FROM THE INDIVIDUAL UTILITY'S 2000 TEN-YEAR SITE PLAN, SCHEDULE 9.

2/ OLEANDER POWER PROJECT DATA IS BASED ON INFORMATION FILED IN THE APRIL 2000 TEN-YEAR SITE PLAN, AND INCLUDES THE COST OF DIRECTLY ASSOCIATED TRANSMISSION LINES.

3/ OSPREY ENERGY CENTER DATA IS BASED ON INFORMATION FROM NEED DETERMINATION AND TEN-YEAR SITE PLAN FILINGS AND INCLUDE THE COSTS OF DIRECTLY ASSOCIATED TRANSMISSION LINES. HEAT RATE IS CALCULATED BASED ON HIGHER HEATING VALUE (HHV).

4/ SEMINOLE ELECTRIC COOPERATIVE'S HEAT RATE FOR THE PAYNE CREEK UNIT 3 IS REPORTED BASED ON LOWER HEATING VALUE (LHV).

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SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK WITHOUT OSPREY ENERGY CENTER

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000	36,033	1,697	2,653	40,383	37,728	2,655	7.04	2,896	34,832	5,551	15.94
2001	38,244	1,699	2,653	42,596	38,445	4,151	10.80	2,885	35,560	7,036	19.79
2002	39,380	1,675	2,906	43,961	39,282	4,679	11.91	2,850	36,432	7,529	20.67
2003	41,484	1,583	3,221	46,288	40,157	6,131	15.27	2,844	37,313	8,975	24.05
2004	42,615	1,583	2,768	46,966	41,004	5,962	14.54	2,840	38,164	8,802	23.06
2005	43,211	1,583	2,658	47,452	41,905	5,547	13.24	2,840	39,065	8,387	21.47
2006	44,651	1,583	2,525	48,759	43,190	5,569	12.89	2,843	40,347	8,412	20.85
2007	45,364	1,583	2,220	49,167	44,097	5,070	11.50	2,842	41,255	7,912	19.18
2008	46,393	1,583	2,205	50,181	44,926	5,255	11.70	2,832	42,094	8,087	19.21
2009	47,100	1,583	2,096	50,779	45,810	4,969	10.85	2,830	42,980	7,799	18.15

NOTE: 1. 777 MW - 300 MW = 477 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 300 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK WITH OSPREY ENERGY CENTER, 496 MW IN 2003

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000	36,033	1,697	2,653	40,383	37,728	2,655	7.04	2,896	34,832	5,551	15.94
2001	38,244	1,699	2,653	42,596	38,445	4,151	10.80	2,885	35,560	7,036	19.79
2002	39,380	1,675	2,906	43,961	39,282	4,679	11.91	2,850	36,432	7,529	20.67
2003	41,980	1,583	3,221	46,784	40,157	6,627	16.50	2,844	37,313	9,471	25.38
2004	43,111	1,583	2,768	47,462	41,004	6,458	15.75	2,840	38,164	9,298	24.36
2005	43,707	1,583	2,658	47,948	41,905	6,043	14.42	2,840	39,065	8,883	22.74
2006	45,147	1,583	2,525	49,255	43,190	6,065	14.04	2,843	40,347	8,908	22.08
2007	45,860	1,583	2,220	49,663	44,097	5,566	12.62	2,842	41,255	8,408	20.38
2008	46,889	1,583	2,205	50,677	44,926	5,751	12.80	2,832	42,094	8,583	20.39
2009	47,596	1,583	2,096	51,275	45,810	5,465	11.93	2,830	42,980	8,295	19.30

Notes: 1. THE INDICATED RESERVE MARGIN IMPROVEMENTS ARE SUBJECT TO THE PROJECT'S OUTPUT BEING CONTRACTUALLY COMMITTED TO SEMINOLE AND OTHER PENINSULAR FLORIDA LOAD-SERVING UTILITIES.

2. 496 MW OF OSPREY ENERGY CENTER ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2003

3. 777 MW - 300 MW = 477 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 300 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SOURCES: Florida Reliability Coordinating Council, 2000 Regional Load & Resource Plan, Peninsular Florida, July, 2000
Calpine Construction Finance Company, L.P.

Osprey Energy Center
Calpine
Witness: Kenneth J. Slater
Exhibit _____ (KJS-20)
Page 1 of 1

SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK WITHOUT OSPREY ENERGY CENTER

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7.22	4,080	36,814	7,031	19.10
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7.07	4,058	37,753	7,012	18.57
2002/03	43,513	1,583	3,365	48,461	42,739	5,722	13.39	4,060	38,679	9,782	25.29
2003/04	45,329	1,583	2,912	49,824	43,663	6,161	14.11	4,071	39,592	10,232	25.84
2004/05	45,881	1,583	2,802	50,266	44,638	5,628	12.61	4,087	40,551	9,715	23.96
2005/06	46,845	1,583	2,669	51,097	45,694	5,403	11.82	4,109	41,585	9,512	22.87
2006/07	48,177	1,583	2,324	52,084	46,668	5,416	11.61	4,127	42,541	9,543	22.43
2007/08	49,520	1,583	2,309	53,412	47,573	5,839	12.27	4,128	43,445	9,967	22.94
2008/09	50,129	1,583	2,200	53,912	48,531	5,381	11.09	4,145	44,386	9,526	21.46
2009/10	51,316	1,583	1,778	54,677	49,478	5,199	10.51	4,162	45,316	9,361	20.66

NOTE: 1. 910 MW - 340 MW = 570 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002/03, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 340 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK WITH OSPREY ENERGY CENTER, 578 MW IN 2003/04

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7.22	4,080	36,814	7,031	19.10
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7.07	4,058	37,753	7,012	18.57
2002/03	43,513	1,583	3,365	48,461	42,739	5,722	13.39	4,060	38,679	9,782	25.29
2003/04	45,907	1,583	2,912	50,402	43,663	6,739	15.43	4,071	39,592	10,810	27.30
2004/05	46,459	1,583	2,802	50,844	44,638	6,206	13.90	4,087	40,551	10,293	25.38
2005/06	47,423	1,583	2,669	51,675	45,694	5,981	13.09	4,109	41,585	10,090	24.26
2006/07	48,755	1,583	2,324	52,662	46,668	5,994	12.84	4,127	42,541	10,121	23.79
2007/08	50,098	1,583	2,309	53,990	47,573	6,417	13.49	4,128	43,445	10,545	24.27
2008/09	50,707	1,583	2,200	54,490	48,531	5,959	12.28	4,145	44,386	10,104	22.76
2009/10	51,894	1,583	1,778	55,255	49,478	5,777	11.68	4,162	45,316	9,939	21.93

NOTES: 1. THE INDICATED RESERVE MARGIN IMPROVEMENTS ARE SUBJECT TO THE PROJECT'S OUTPUT BEING CONTRACTUALLY COMMITTED TO SEMINOLE AND OTHER PENINSULAR FLORIDA LOAD-SERVING UTILITIES.
2. 578 MW OF OSPREY ENERGY CENTER ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2003/04
3. 910 MW - 340 MW = 570 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002/03, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 340 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SOURCES: Florida Reliability Coordinating Council, 2000 Regional Load & Resource Plan, Peninsular Florida, July, 2000
Calpine Construction Finance Company, L.P.

Osprey Energy Center
Calpine
Witness: Kenneth J. Slater
Exhibit _____ (KJS-21)
Page 1 of 1

PENINSULAR FLORIDA EMISSIONS IMPACTS OF OSPREY ENERGY CENTER, 2003-2012

(All Values in 1000's lbs)

	Sulfur Dioxide		Nitrogen Oxides	
Year	Without Osprey	With Osprey	Without Osprey	With Osprey
2003	759,691	767,350	458,702	452,861
2004	702,289	669,806	426,740	412,805
2005	695,946	674,697	423,137	413,850
2006	677,817	654,902	417,541	405,467
2007	658,449	632,952	405,652	392,771
2008	639,130	611,603	391,615	382,230
2009	669,806	660,623	408,957	401,142
2010	679,140	657,030	410,514	400,657
2011	702,883	677,446	418,612	407,683
2012	743,653	720,617	437,591	426,875

Source: PROMOD IV(R) analyses prepared by Slater Consulting.
Note: The estimated emission impacts shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for the Osprey Energy Center in Polk County by Seminole Electric Cooperative, Inc. and Calpine Construction Finance Company, L.P.	)	DOCKET NO. _____

EXHIBITS

OF

MICHEL P. ARMAND, P.E.

ON BEHALF OF

CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001748-EC EXHIBIT NO. 9
COMPANY/ WITNESS: Calpine / Armand
DATE: 3-12-01

MICHEL P. ARMAND

Michel Armand is a Senior Engagement Manager in the Transmission Planning sub-practice area of Navigant Consulting, Inc. He has 33 years of utility experience in transmission and distribution planning and engineering both in New York and in Florida. He has conducted numerous studies in the area of transmission reliability and network security, and is extremely knowledgeable of the Florida transmission system. He has expertise in managing corporate staff involved in load flow, short circuit and transient stability studies, including the determination of operating limits, the development of remedial action schemes, and the development of methods to assess system-wide losses. In addition, he has testified before the Nuclear Regulatory Commission (NRC) and various state courts in condemnation hearings, and in Florida PSC power plant "NEED' hearings. He was involved in restructuring and privatization studies of the State Utility Company as Energy Advisor to the Prime Minister of Haiti. He has consulted with the Transmission Agency of Northern California, the Bonneville Power Administration and the California ISO in assessing Operating Transfer Capabilities (OTC) for spring and summer across the California Oregon Interconnection (COI) . Mr. Armand has also performed numerous transmission system impact assessment for merchant power projects in Texas, California and Florida.

EDUCATION

MBA - Baruch College of the City University of New York
New York

BEE - City College of the City University of New York
New York

BA - College St. Martial
Port-Au-Prince, Haiti

PROFESSIONAL HISTORY

Navigant Consulting, Inc. formerly Resource Management International, Inc.
Manager

Government of Haiti
Energy Consultant - Prime Minister's Office

Florida Power & Light Company
Director, Protection and Control Systems

Consolidated Edison Company of New York
Senior Engineer

REPRESENTATIVE PROJECT EXPERIENCE

Duke Energy Power Services. 1998

Duke Energy Power Services retained NCI to provide transmission planning analyses in support of a 500Mw plant at New Smyrna Beach in Florida. Duke also requested that NCI prepare testimony in support of their petition to the Florida Public Service Commission for a Determination of Need for power plants. Michel Armand was project manager for this work and prepared the resulting testimony. NCI conducted Power Flow Studies to determine the best configuration to integrate a 500Mw power plant in the vicinity of New Smyrna Beach, Florida. NCI also prepared and filed testimony in support of Duke's Needs Petition Hearing before the Florida Public Service Commission.

St. Lucie Nuclear Unit No. 2 - Regulatory Licensing. Florida Power and Light Company. Miami, Florida. 1979
As Supervisor of Reliability and System Security for Florida Power and Light Company (FPL), responsible for testing and assessing the dynamic performance of the planned generation and transmission system, I was called to testify about the ability of the system to support the addition of a second nuclear unit at St. Lucie Power Station. In testimony before the NRC Atomic Safety and Licensing Appeal Board, the adequacy of the transmission grid was demonstrated and the operating license was subsequently granted.

500 kV Interconnection with Georgia. Florida Power and Light Company. Miami, Florida. 1980
As Supervisor of Reliability in the System Planning Department at Florida Power and Light Company (FPL), and member of the 500 kV project team, performed the evaluations necessary to justify the construction of two 500 kV lines from the Georgia state line in the north to a point 310 miles south. Wrote testimony in support of the economic and reliability benefits of the lines in proceedings of the Florida Transmission Line Siting Act before the Public Service Commission and the State Cabinet. Conducted technical studies to define the line parameter, the ancillary equipment and the termination of various segments of the project. Given the considerable benefits of reducing oil consumption in favor of coal, the project was given accelerated depreciation privileges for rate making purposes.

Breaker Duty Evaluation Program. Florida Power and Light Company. Miami, Florida. 1981
As Project Manager, oversaw the definition, design, development, testing, and implementation of an automated system to evaluate the adequacy of transmission circuit breakers on the Florida Light and Power (FPL) system. Coordinated the work of equipment specialists, computer programmers and systems planners to arrive at a program which consistently and accurately performs the many calculations required. The very serious potential for human errors was practically eliminated, and these long lead items could be ordered within reasonable schedules.

Audit of Energy Reduction Marketing Program. Florida Power and Light Company. Miami, Florida. 1983
As auditor, performed an independent assessment of the various marketing product offerings and determined their effectiveness in achieving the goals of the demand side programs. Recommended a market segmentation approach where the effectiveness of specific programs was shown to be related to the four distinct weather regions of Florida. Also provided valuable insight to the marketing team on the behavior of the load during

winter and summer, i.e., pool pumps, an 800 MW load then, were rescheduled to different time slots to avoid the early morning peak in the winter and the late afternoon peak in the summer.

Economic Evaluation of Power Generation Asset. Florida Power and Light Company. Miami, Florida. 1984
As Project Manager, conducted examination of options available to determine final disposition of questionable assets. The asset could be kept in use, put into long-term reserve shut down, retired, or sold. Taking into account the various interests of the operating groups, recommendation was made to choose the long-term reserve shut down as the most attractive option financially, from a capacity addition standpoint, and from considerations of system adequacy and reliability.

Analysis of Electric System Losses. Florida Power and Light Company. Miami, Florida. 1984
As lead investigator, I was charged with a determination of accounting for losses on the Florida Power and Light (FPL) system. As the system was experiencing rapid growth, economic decisions to select among alternative proposals were based on crude assumptions regarding system losses. Electric power system losses in the United States run into the billions of dollars each year. Selection among competing alternatives could sometimes be made on the basis of their contribution to reducing system losses. Over a three month period, all the departments having an impact were visited, huge amounts of data collected, tens of employees interviewed and, finally, one document produced. In it, for the first time in one document, the issue of system losses was addressed in all its major components, and its myriad of implications. The report is still used today as a reference document in any effort to reduce system losses in a systematic fashion.

Blackout Prevention by Automated Fast Action. Florida Power and Light Company. Miami, Florida. 1985
As Manager, Power Supply Technical Services, was charged with recommending programs and actions to prevent another blackout similar to the one on May 17, 1985, which put the Greater Miami, Ft. Lauderdale area in the dark for three hours. The result wa a computer program that monitors the system for specific conditions and takes remedial action within a 15-20 second time window. Severe economic penalties were incurred until this system went in place and economic dispatch was resumed. The same concept was replicatd in another part of the system providing additional economic benefit.

Transmission Outage Data Base. Florida Power and Light Company. Miami, Florida. 1989
As Project Manager, was tasked with the charge of researching, developing, and implementing a transmission outage data base system.

The purpose was to collect information in such a way that it could be stored, analyzed, categorized, and utilized by many departments involved in the designing, engineering, construction, and operation of the transmission system. The task involved the collection of valid requirements from all concerned parties, the resolution of conflicting demands and, finally, securing agreement on analysis and categorization of data covering the prior period of 1983 to 1987. The information proved invaluable to the system operators, transmission maintenance personnel and the transmission design and engineering staff. Unexpected results of this effort: the data was also used to show potential industrial customers the reliability of a particular transmission line (since data went back to 1983); used in court proceedings dealing with the issue of power quality; and used in regulatory hearings dealing with needed new transmission corridors.

Privatization Strategy for Haiti Electric Utility. Prime Minister Office - Government of Haiti. Port-Au-Prince, Haiti. 1996
As Energy Advisor in the office of the Prime Minister, responsible for developing and recommending options t restructure the state owned utility. In the framework of privatization of money-losing state enterprises, I evaluated various of options: restructuring and improving operations as an independent commercial operation owned by the state; contract with a foreign entity for the management and operation within a fixed time period; lease the assets and the franchise for a 25-30 year period with the assets plus additions reverting the state at contract expiration; and an outright sale to private investors, local and/or foreign. Each option was evaluated based on economic, financial, and political risk considerations, and presented to the cabinet. The lease option was selected as the final objective preceded by a five-year management contract to increase the value of the assets and the lease. Parliament approved the concept and laws are being passed or modified to allow the state and the operator to achieve their objective.

PROFESSIONAL MEMBERSHIPS

Society of Professional Engineers
Institute of Electrical & Electronic Engineers

Osprey Energy Center
Calpine
Witness: Michel P. Armand
Exhibit _____ (MPA-2)



PROPOSED 530 MW FLORIDA GENERATING FACILITY

OSPREY ENERGY CENTER

Prepared For

CALPINE EASTERN CORPORATION

UNPUBLISHED WORK © FEBRUARY 2000

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CONSULTING, INC.

CONFIDENTIAL

March 1, 2000

VIA FEDERAL EXPRESS

Mr. Paul A. Barnett
Director - Asset Optimization
Calpine Eastern Corporation
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

Subject: Transmission System Analysis in Support of
Calpine Eastern Corporation Osprey Energy Center

Dear Paul:

Enclosed are four copies of the subject report prepared in accordance with our agreement with Calpine Eastern Corporation.

The starting point for this study is the year 2004 summer peak case filed with the Federal Energy Regulatory Commission (FERC) by the Florida Reliability Coordinating Council (FRCC), fiscal year 1998, Revision 5. This base case was obtained from the FERC-1999 Form 715 Regional Power Flow Cases and Transmission Planning Reports, Website updated 10/12/1999.

The FRCC case submitted to FERC was carefully reviewed, and the data on generation resources was compared to the individual utility Ten Year Site Plans filed with the Florida Public Service Commission. Although several merchant plants have been announced, some requiring a Need Determination approval and some not, none were represented in the base cases. Only generation containing the Official Ten Year Site Plans were represented and dispatched if needed.

The transmission system was scrutinized, especially around the projected site for the Osprey Energy Center. Except for some minor transmission inconsistencies in the FPL system, there appears to be no wholesale tampering with the representation of the Florida transmission system.

Therefore, the powerflow studies discussed in the enclosed report evaluated:

- Pre- and post-project transmission system performance for the year 2004, when the Florida system experiences peak loading conditions and imports 3,600 MW of power from Georgia.
- Pre- and post-project transmission system performance for the year 2004 when the Florida system is at peak load and imports 2,400 MW of power from Georgia.
- Pre- and post-project transmission system performance for the year 2004 when the Florida system is loaded to 60% of summer peak load and imports 2,400 MW of power from Georgia. This load level is considered the average loading of the Florida system.

Based on the studies discussed in the enclosed report, it appear that:

1. The proposed 530 MW Osprey Energy can reliably deliver its output into the Florida Transmission System.
2. Some minor overloads, at peak and at peak import, following certain system element outages, can be resolved by either system upgrade or reduction in plant output.
3. At average load conditions, 60% of summer peak, no overloaded facility was uncovered under all dispatch scenarios modeled and outages simulated.

We look forward to discussing the enclosed report with you, at your convenience. In the interim, please call me at (407) 895-7000 should you have any questions on the enclosed.

Sincerely,

Michel P. Armand/lcb

Michel P. Armand
Manager

PROPOSED 530 MW FLORIDA GENERATING FACILITY

OSPREY ENERGY CENTER

Prepared For

CALPINE EASTERN CORPORATION

Prepared By



Navigant™
CONSULTING, INC.

UNPUBLISHED WORK © MARCH 2000

CALPINE EASTERN CORPORATION

PROPOSED 530 NW OSPREY ENERGY CENTER

RESULTS OF POWERFLOW STUDIES - 2004

SECTION 1 EXECUTIVE SUMMARY

Calpine Eastern Corporation (Calpine) is proposing to build a 530 MW merchant plant facility in Florida. The facility will be sited in Polk County at the Recker Substation of Tampa Electric Company , and is projected to begin commercial operation before the summer of 2004. Calpine retained Navigant Consulting, Inc. (Navigant Consulting) to assist them in evaluating the interconnection of the proposed Osprey Energy Center (OEC) project with the Florida transmission network.

In providing this support, Navigant Consulting performed a series of preliminary power flow studies evaluating:

- Summer 2004 transmission system performance at peak load, importing 3600 MW from the Southern Company, with and without the Osprey Energy Center project.
- Summer 2004 transmission system performance at peak load, importing 2400 MW from the Southern Company, with and without the Osprey Energy Center project.
- Summer 2004 transmission system performance at an average 60% of peak load (70% of peak for TECO), importing 2400 MW from the Southern Company, with and without the Osprey Energy Center project.

To determine the ability of the project to deliver its output over the Florida transmission system, the total capacity of the plant (530 MW) was scheduled alternatively to Florida Power and Light Company (FPL), Florida Power Corporation (FPC), Tampa Electric Company (TEC), Jacksonville Electric Authority (JEA), and Seminole Electric Cooperative (SEC). Each of these dispatch scenarios was modeled and tested with the three base cases.

In summary, these studies (which are summarized in Table 1-1 and discussed in detail in Sections 2 and 3, show that for the conditions modeled:

1. None of the lines in the vicinity of the proposed Osprey Energy Center were overloaded in the eighteen base cases that were developed for these studies, and which model system normal conditions (all facilities in service).
2. During the summer 2004 peak load period, when importing 2400 MW from Southern, loss of the Recker-Gapway 230-kV line causes the Ariana 230/69-kV transformer to load up the 103.8 percent of its emergency rating for all dispatch scenarios. Similarly, loss of the McIntosh-Lake Agnes 230-kV circuit causes the

Lake Agnes-Recker 230-kV circuit to load up the 102.6 percent of its emergency rating when the plant output is scheduled to FPL, FPC, JEA, and SEC. Also, loss of the Griffin-Lakeland West 230-kV circuit causees the Osceola-Lake Agnes 230-kV circuit to load up to its emergency rating when the plant output is scheduled to FPC, JEA, and SEC.

3. During the summer 2004 peak load period, when importing 3600 MW from Georgia, loss of the Recker-Gapway 230-kV circuit causes the Ariana 230/69-kV transformer to load up to 104.6 percent of its emergency rating.

4. At average loading conditions on the Florida transmission system (60% for the rest of the state, 70% for Tampa), no overload is noticed for all the contingencies simulated and for all dispatch scenarios.

Therefore, based on the preliminary studies discussed in this report, it appears that:

1. 530 MW can be reliably sited at the Osprey Energy Center.

2. The output of the plant can be delivered without imposing undue burden on the Florida transmission system. System upgrade considerations must be weighted against reducing plant output following the specific contingencies which could cause overloads.

TABLE 1-1
SUMMARY OF POWERFLOW BASE CASES EVALUATED

Year	Case	Georgia Imports (MW)	OEC* Generation (MW)	Output Delivered to:
2004	2004.PI	3,600	- 0 -	N/A
	2004.PIa	3,600	530	Florida Power & Light
	2004.PIb	3,600	530	Florida Power Corporation
	2004.PIc	3,600	530	Tampa Electric Company
	2004.PId	3,600	530	Jacksonville Electric Authority
	2004.PIe	3,600	530	Seminole Electric Cooperative
2004	2004.	2,400	- 0 -	N/A
	2004.a	2,400	530	Florida Power & Light
	2004.b	2,400	530	Florida Power Corporation
	2004.c	2,400	530	Tampa Electric Company
	2004.d	2,400	530	Jacksonville Electric Authority
	2004.e	2,400	530	Seminole Electric Cooperative
2004	2004-60	2,400	- 0 -	N/A
	2004-60a	2,400	530	Florida Power & Light
	2004-60b	2,400	530	Florida Power Corporation
	2004-60c	2,400	530	Tampa Electric Company
	2004-60d	2,400	500	Jacksonville Electric Authority
	2004-60e	2,400	530	Seminole Electric Cooperative

* Osprey Energy Center

As discussed in Section 2 (Results of Power Flow Studies), each of the cases summarized in Table 1-1 were used as a starting point in evaluating system performance under both normal and single facility (line or generator) – (N-1) outage conditions.

Documents reviewed and utilized by Navigant Consulting during these studies included:

- FPL's *1999 Ten Year Plant Site Plan*
- FPC's *1999 Ten Year Site Plan*
- TEC's *1999 Ten Year Site Plan*
- FRCC's *1997 Final Transmission System Constraints Maps*
- FRCC's *1997 Transfer Capability Study: FLA/SOV Interface*
- FRCC's *1999 Reliability Study*

The powerflow base cases used in these studies were based on the 2004 Summer Base Case filed with FERC by the Florida Reliability Coordinating Council (FRCC), FY1998, Revision 5. This FRCC case was reviewed and compared to the Ten Year Site Plans of FPL, FPC, TEC, JEA, and SEC.

Case 2004.PI was obtained by increasing the import from Georgia to 3600 MW and reducing FPL generation in the south end by 1,200 MW. All loads were maintained at peak summer level.

Case 2004-60 was obtained by scaling loads in Florida to represent 60% of summer peak (except for Tampa, where the average load level is 70% of summer peak). Generation in Florida was re-dispatched for each control area. Import from the Southern Company was maintained and interchange schedules were modified.

SECTION 2 POWERFLOW BASE CASE DEVELOPMENT

As noted in the Executive Summary, the powerflow base cases used in these studies were based on the 2004 summer peak case filed with FERC by the Florida Reliability Coordinating Council (FRCC), fiscal year 1998, Revision 5. This powerflow case represented the system in peninsular Florida as consisting of nineteen control areas with a combined load of approximately 39,860 MW, and on-line generation of approximately 38,520 MW (both utility and non-utility). Interchange into Florida was approximately 2400 MW and Florida system losses were around 1000 MW. The nineteen control areas and the load and generation represented in each, are summarized in Table 2-1.

TABLE 2-1
Florida Control Area Loads and Generation in FRCC 2004 Peak Case

Control Area	Load (MW)	Generation (MW)
FPL	19,544	16,471
FPC	9,834	7,782
Fort Pierce	113	63
Gainesville	438	430
Homestead	62	35
Jacksonville	2,825	3,121
Key West	128	0
Kissimmee	277	392
Lake Worth	85	56
New Smyrna Beach	80	18
Orlando	1,129	1,328
Seminole	318	2,804
Lakeland	601	1,070
City of Starke	16	0
Tallahassee	555	558
Tampa	3,522	3,986
FMPA	152	150
Cedar Bay	0	251
Reedy Creek	182	0

The FRCC case submitted to FERC was carefully reviewed and the data on generation resources was compared to the individual utility Ten Year Site plans filed with the Florida Public Service Commission. Although several merchant plants have been announced, some requiring a Need Determination approval and some not, none were represented in the base cases. Only generation contained the Official Ten Year Site Plans were represented and dispatched if needed.

The transmission system was scrutinized, especially around the projected site for the Osprey Energy Center. Except for some minor transmission inconsistencies in the FPL system, there appears to be no wholesale tampering with the representation of the Florida transmission system.

The result of these efforts was acceptance of the FERC-2004 Summer Base Case, FY1998, Revision 5, as a legitimate starting point for the evaluation, based on the load and resource characteristics summarized in Table 2-2. The Osprey Energy Center generation was added to the base case and was integrated at the Recker Substation bus. This case was labeled 2004.sav.

Case 2004.PI.sav was derived by increasing the import in case 2004.sav to 3600 MW. This was accomplished by increasing generation in Georgia by slightly over 1200 MW, and decreasing FPL generation at Turkey Point and Port Everglades by approximately 1200 MW. Cape Canaveral No. 2, the FPL swing generator, was adjusted to provide the additional capacity required.

Case 2004-60.sav was derived by modifying the base case, 2004.sav, to represent loading conditions of 60% of peak, except for Tampa, which was represented at 70%. The 60% load level is considered average loading of the Florida system, and represents a considerable portion of the load duration curve for Florida. Therefore, this load level has always been the benchmark of all transmission assessment studies by powerflow or by transient stability conducted by the PRCC. To achieve such reduction, the load in each control area was scaled down to sixty percent. The total generation required for each area was calculated by adding load, plus generation, plus interchange, and then re-dispatching each area by the removal of appropriate generating units to achieve total required generation. There were a few exceptions.

TABLE 2-2
2004 – Base Case
FY 1998 – Revision 5
Peak Load 2400 MW Import

LOAD, LOSSES, INTERCHANGE, AND GENERATIONS MODELED

Control Area	Load	Losses	Interchange	Generation
1 FPL	19,544	475	-3,548	16,471
2 FPC	9,834	258	-2,310	7,782
3 Ft. Pierce	113	1	-51	63
4 GVL	438	5	-13	430
5 HST	62	0	-27	35
6 JEA	2,825	52	244	3,121
7 KEY	128	6	-134	0
8 KIS	277	8	107	392
9 LWU	85	0	-29	56
10 NSB	80	0	-62	18
11 OUC	1,129	24	175	1,328
12 SEC	318	52	2,434	2,804
13 LAK	601	7	462	1,070
14 STK	16	0	-16	0
15 TAL	555	14	-11	558
16 TEC	3,522	93	371	3,986
17 FMP	152	2	-4	150
18 NUG	0	1	250.0	251
19 RCU	182	1	-183	0

SECTION 3 RESULTS OF POWER FLOW STUDIES

As discussed in Section 2, three base cases: 2004.PI.sav, 2004.sav, and 2004-60.sav, were developed as a starting point. These three base cases had the proposed Osprey Energy Center at 0 MW. Next, five individual dispatches were established as follows:

a) Simulated all the plant output being delivered to FPL;

b) Simulated all the plant output being delivered to FPC;

c) Simulated all the plant output being sold to TEC;

d) Simulated all the plant output being delivered to JEA; and

e) Simulated all the plant output being delivered to SEC.

In all, eighteen base cases (summarized in Table 3-1) were developed in order to evaluate the effects of the proposed 530 MW Osprey Energy Center on the performance of the Florida system. Each of these eighteen cases, summarized in Table 3-1, were used as a starting point in evaluating system performance under normal conditions by comparing pre- and post-project powerflows over key lines and equipment in the proximity of the plant and over certain facilities monitored in past FRCC transmission studies.

In addition, thirty-five (35) single line or generator outages (N-1) were simulated on all the eighteen base cases to assess performance under other than normal conditions. Navigant Consulting also monitored flows over twelve of the thirteen constrained transmission paths discussed in the FRCC 1997 Final Transmission System Constraint Maps. Table 3-2 is a list of the single outages simulated on each of the eighteen base cases. Table 3-3 is a tabulation of the FRCC constrained paths and the transmission circuits affected. Constrained paths #15 and #16 are the Stanton-Rio Pinar 230-kV line. Because the studies performed represent summer season peak load conditions, and, therefore, power transfer from Georgia to Florida, Constraint #13 (which deals with flows from Florida to Georgia) was not checked. Appendix IV is a summary of total constrained path flows in graphic and tabular form, representing the pre- and post-project performance for the 18 base cases.

The contingencies listed in Table 3-2 represent a broad array of outages throughout the Florida system designed to test any negative impact this new plant may have. Some of the outages selected are similar to those selected for past FRCC transmission assessment studies. Some are not expected to be impacted by the new plant; others could potentially be influenced by whether the plant output is scheduled to different receiving parties. In all cases, the most pessimistic conditions were modeled.

The circuits monitored, as shown in Table 3-4, represent all facilities around the plant

location that could experience loading problems, as well as some circuits that have shown a tendency in past FRCC studies to exhibit thermal loading problems.

2004.PI CASES

The result of these cases, representing summer peak loading in Florida and peak import of 3600 MW from Georgia, are summarized in Appendix I, which presents information about the lines monitored, the specific outage, the pre-project conditions, and the five dispatch scenarios; i.e., the plant output respectively delivered to FPL, FPC, TEC, JEA, and SEC.

The analysis reveals that when the Recker to Gapway 230-kV circuit is out of service, the Ariana 230/69-kV autotransformer loads up to:

- 104.6 percent of its emergency rating when the plant output is dispatched to TEC,
- 104.2 percent when the output is sent to FPL,
- 103.9 percent when the output is dispatched to FPC, and
- 103.8 percent when the output is sent to either JEA or SEC.

Also, under peak import conditions and for the specific control area dispatches simulated, loss of the Manatee-Big Bend 230-kV circuit, causes the Buckeye-Ruskin Metering section of the Big Bend-Johnson 230-kV circuit to reach 100.8 percent of its thermal rating. This loading is highly dependent on actual generation at Manatee, and is not an unusual occurrence.

The distribution of flows over the various lines emanating form the Recker Substation for the various dispatch scenarios are shown in Appendix I-A.

2004. CASES

The results of these cases representing summer peak loading in Florida, and an import of 2400 MW, are summarized in Appendix II, which presents information about the lines monitored, the specific outage, the pre-project conditions, and the five dispatch scenarios, i.e., the plant output respectively delivered to FPL, FPC, TEC, JEA, and SEC.

The analysis reveals again that when the Recker to Gapway 230-kV circuit is out of service, the Ariana 230/69-kV exceeds its rated thermal limit:

- 103.8 percent of its emergency rating when the plant output is dispatched to TEC,
- 103.4 percent when the plant output is dispatched to FPL,
- 103.1 percent when the plant output is dispatched to either FPC or JEA, and
- 103 percent when the output is dispatched to SEC.

Also, when the McIntosh-Lake Agnes 230-kV circuit is out of service under peak load conditions, the Recker-Lake Agnes 230-kV circuit experiences loading around 103 percent of its emergency rating when the plant output is dispatched to FPC, JEA, and SEC, and loading of 100 percent of its emergency rating when the output is dispatched to FPL. However, loading is within limits when the output is dispatched to TEC.

When the 230-kV circuit Griffin-Lakeland West is out of service, the Osceola-Lake Agnes 230-kV circuit reaches it emergency thermal rating when the plant output is dispatched to either FPC, JEA, or SEC. When the output is dispatched to FPL or TEC, the line loading is below its emergency thermal rating. Appendix II-A shows the distribution of flows over the various lines emanating from the Recker Substation for the various dispatch scenarios.

2004-60 CASES

The results of these cases representing 60% of summer peak loading in Florida, and an import of 2400 MW from Georgia are summarized in Appendix III, which presents information about the lines monitored, the specific outage, the pre-project conditions, and the five dispatch scenarios; i.e., the plant output respectively delivered to FPL, FPC, TEC, JEA, and SEC.

The analysis reveals that for all the scenarios and all the contingencies simulated, no monitored lines in the proximity of the plant or around the system reached their thermal limits. Since the 60% load level represents the average loading of the Florida system, it appears that the proposed plant can be dispatched most of the time. Appendix III-A shows the distribution of flows over the various lines coming out of the plant for the various dispatch scenarios.

TABLE 3-1
SUMMARY OF POWERFLOW BASE CASES EVALUATED

Year	Case	Georgia Imports (MW)	OEC * Generation (MW)	Output Delivered to:
2004	2004.PI	3,600	- 0 -	N/A
	2004.PIa	3,600	530	Florida Power & Light
	2004.PIb	3,600	530	Florida Power Corporation
	2004.PIc	3,600	530	Tampa Electric Company
	2004.PId	3,600	530	Jacksonville Electric Authority
	2004.PIe	3,600	530	Seminole Electric Cooperative
2004	2004.	2,400	- 0 -	N/A
	2004.a	2,400	530	Florida Power & Light
	2004.b	2,400	530	Florida Power Corporation
	2004.c	2,400	530	Tampa Electric Company
	2004.d	2,400	530	Jacksonville Electric Authority
	2004.e	2,400	530	Seminole Electric Cooperative
2004	2004-60	2,400	- 0 -	N/A
	2004-60a	2,400	530	Florida Power & Light
	2004-60b	2,400	530	Florida Power Corporation
	2004-60c	2,400	530	Tampa Electric Company
	2004-60d	2,400	530	Jacksonville Electric Authority
	2004-60e	2,400	530	Seminole Electric Cooperative

* OEC = Osprey Energy Center

TABLE 3-2
INDEX TO OUTAGE CONTINGENCIES

Outage #	Bus 1	kV	Bus 2	kV	CKT
1	Osceola	230	OUCCITP2	230	1
2	Osceola	230	LKAGNES	230	1
3	Osceloa	69	Studio	69	1
4	Sheld	230	LK TARPON	230	1
5	Ruskin T	230	Manatee	230	1
6	RUSKMTR8	230	Buckeye	230	1
7	B Bend	230	Manatee	230	1
8	PEBB	230	Barcola	230	1
9	PEBB	230	N Bartow	230	1
10	PEBB	230	CREWSLK	230	1
11	HARDESUB	230	CC Plant	230	1
12	Recker	230	CREWSLK	230	1
13	Recker	230	LKAGNES	230	1
14	Selose T	230	N Bartow	230	1
15	Selose T	230	Wlk Wale	230	1
16	Recker	230	Gapway	230	1
17	Eaton Pk	230	TENOROC	230	1
18	Eaton Pk	230	CREWSLK	230	1
19	TENOROC	230	I-State	230	1
20	West	230	I-State	230	1
21	TENOROC	230	McIntosh	230	1
22	LKAGNES	230	McIntosh	230	1
23	West	230	Barcola	230	1
24	West	230	Griffin	230	1
25	Sheld	230	Sheld-NW	69	1
26	Sheld	230	Sheld-SE	69	1
27	Camp LK	230	Cent Fla	230	1
28	IND RIV	230	Stanton	230	1
29	Curry FD	230	Stanton	230	1
30	BRKRIDGE	500	CRYST RV	500	1
31	Kathleen	500	Cent Fla	500	1
32	Martin 1	22	814 MW	Gen	1
33	Manatee 1	22	783 MW	Gen	1
34	Gannon 6	22	362 MW	Gen	1
35	B Bend4	22	439 MW	Gen	1

TABLE 3-3
LIST OF CONSTRAINED PATHS IN FLORIDA

Const. Number	Constrained Path Name	Transmission Lines Involved
5	Lake Tarpon - Sheldon	Three Lake Tarpon-Sheldon: 230-kV lines.
6	Central-South East	Poinsett-Martin & Poinsett-Midway: 500-kV Lines Malabar-Midway & Malabar-Emerson: 230-kV Lines Malabar-West: 138-kV Line
7	Central-South	Ruskin-Manatee: 230-kV Line Big Bend-Manatee: 230-kV Line Big Bend-Ruskin: 230-kV Line
8	Northwest-Central	2 Silver Spring North-Silver Springs: 230-kv Line
9	Brookridge-South	Brookridge-Lake Tarpon: 500-kV Line Brookridge-Brooksville West: 230-kV Line Brookridge-Hudson: 230-kV Line
10	Northeast-Central	Duval-Poinsett & Rice-Poinsett: 500-kV Lines Putnam-Volusia & Bunnell-Volusia: 230-kV Lines
11	Sylvan-North Longwood	Sylvan-North Longwood: 230-kV Line
12	Georgia-Florida	Hatch-Duval & Thalman-Duval: 500-kV Lines Pine Grove-Sunannee & Kingsland-Yulee: 230-kV Lines South Bainbridge-Tallahassee (sub 20): 230-kV Line Callaway-Port St. Joe: 230-kV Line Pine Grove-Jasper, Tarver-Jasper: 115-kV Line Scholtz-Woodruff: 115-kV Line Twin Lake-Suwannee Pl: 115-kV Line
13	Florida-Georgia	Same as 12 (flows reversed)
14	Crystal River-South	Crystal River-Brookridge: 500-kV Line CR Plant-Brookridge: 230-kV Line CR Plant-Cryst RE: 230-kV Line
15	Cape Canaveral-Indian River	Cape Canaveral-Indian River: 230-kV Line
16	Indian River-Cape Canaveral	Indian River-Cape Canaveral: 230-kV Line
17	Stanton-Central Florida	Stanton-Rio Pinar: 230-kV Line

TABLE 3-4
MONITORED BRANCHES

Bus 1	kV 1	Bus 2	kV 2	CKT	Area
SN Plant	230	Sylvan	230	1	1
Sylvan	230	N Longwd	230	1	1
Ind Riv	230	Stanton	230	1	11
Buckeye	230	Ruskmtr8	230	1	1
Silvr SP	230	Silv Spn	230	1	2
Silvr SP	230	Ocala 1	230	1	2
Rio Pinr	230	Curry FD	230	1	2
Stanton	230	Curry FD	230	1	11
Osceola	230	LkAgnes	230	1	16
Sheld	230	Lk Tarpon	230	1	2
Pebb	230	Crewslk	230	1	16
Pebb	230	N Bartow	230	1	16
Recker	230	LkAgnes	230	1	16
Recker	230	Ariana	230	1	16
Recker	230	Crewslk	230	1	16
B Bend	230	Manatee	230	1	1
Ruskin	230	Manatee	230	1	1
Ind Riv	230	Ind Riv	115	1	11
Sheld	230	Sheld-NW	69	1	16
Largo	230	Largo A	69	1	2
CLMT EST	230	CLMT EST	69	1	16
Eleven W	230	Eleven-E	69	1	16
Winderme	230	Winderme	69	1	2
Pasadena	230	Pasadena	115	1	2
Ariana	230	Ariana N	69	1	16
Selose	230	Selose N	69	1	16
Gapway	230	Gapway	69	1	16
Crewslk	230	Crewslk	69	1	13
Tenoroc	230	Tenoroc	69	1	13
Barcola	230	West	230	1	13
Eaton Pk	230	Crewslk	230	1	13
Eaton Pk	230	Eaton Pk	69	1	13
Eaton Pk	230	Tenorock	230	1	13
Recker	230	Gapway	230	1	16
SN Plant	115	Turner	115	1	1

APPENDIX I

Table II

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-1	SN PLANT	230	SYLVAN	230	1	1						
2004PI-1	SYLVAN	230	N LONGWD	230	1	1						
2004PI-1	IND RIV	230	STANTON	230	1	11						
2004PI-1	SN PLANT	115	TURNER	115	1	1						
2004PI-1	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-1	SILVR SP	230	SILV SPN	230	1	2						
2004PI-1	SILVR SP	230	OCALA 1	230	1	2						
2004PI-1	RIO PINR	230	CURRY FD	230	1	2						
2004PI-1	STANTON	230	CURRY FD	230	1	2						
2004PI-1	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-1	SHELD	230	LK TARPN	230	1	2						
2004PI-1	PEBB	230	CREWSLK	230	1	13						
2004PI-1	PEBB	230	N BARTOW	230	1	2						
2004PI-1	RECKER	230	LKAGNES	230	1	16						
2004PI-1	RECKER	230	ARIANA	230	1	16						
2004PI-1	RECKER	230	CREWSLK	230	1	13						
2004PI-1	B BEND	230	MANATEE	230	1	1						
2004PI-1	RUSKIN T	230	MANATEE	230	1	1						
2004PI-1	IND RIV	230	IND RIV	115	1	11						
2004PI-1	SHELD	230	SHELD-NW	69	1	16						
2004PI-1	LARGO	230	LARGO A	69	1	2						
2004PI-1	CLMT EST	230	CLMT EST	69	1	2						
2004PI-1	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-1	WINDERME	230	WINDERME	69	1	2						
2004PI-1	PASADENA	230	PASADENA	115	1	2						
2004PI-1	ARIANA	230	ARIANA-N	69	1	16						
2004PI-1	SELOSE	230	SELOSE-N	69	1	16						
2004PI-1	GAPWAY	230	GAPWAY	69	1	16						
2004PI-1	CREWSLK	230	CREWSLK	69	1	13						
2004PI-1	TENOROC	230	TENOROC	69	1	13						
2004PI-1	BARCOLA	230	WEST	230	1	2						
2004PI-1	EATON PK	230	CREWSLK	230	1	13						
2004PI-1	EATON PK	230	EATON PK	69	1	13						
2004PI-1	EATON PK	230	TENOROC	230	1	13						
2004PI-1	RECKER	230	GAPWAY	230	1	16						
2004PI-1	SN PLANT	115	TURNER	115	1	1						
2004PI-2	SN PLANT	230	SYLVAN	230	1	1						
2004PI-2	SYLVAN	230	N LONGWD	230	1	1						
2004PI-2	IND RIV	230	STANTON	230	1	11						
2004PI-2	SN PLANT	115	TURNER	115	1	1						
2004PI-2	BUCKEYE	230	RUSKMTR8	230	1	1		100.8				
2004PI-2	SILVR SP	230	SILV SPN	230	1	2						
2004PI-2	SILVR SP	230	OCALA 1	230	1	2						
2004PI-2	RIO PINR	230	CURRY FD	230	1	2						
2004PI-2	STANTON	230	CURRY FD	230	1	2						
2004PI-2	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-2	SHELD	230	LK TARPN	230	1	2						
2004PI-2	PEBB	230	CREWSLK	230	1	13						
2004PI-2	PEBB	230	N BARTOW	230	1	2						
2004PI-2	RECKER	230	LKAGNES	230	1	16						
2004PI-2	RECKER	230	ARIANA	230	1	16						
2004PI-2	RECKER	230	CREWSLK	230	1	13						
2004PI-2	B BEND	230	MANATEE	230	1	1						
2004PI-2	RUSKIN T	230	MANATEE	230	1	1						
2004PI-2	IND RIV	230	IND RIV	115	1	11						
2004PI-2	SHELD	230	SHELD-NW	69	1	16						
2004PI-2	LARGO	230	LARGO A	69	1	2						
2004PI-2	CLMT EST	230	CLMT EST	69	1	2						
2004PI-2	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-2	WINDERME	230	WINDERME	69	1	2						
2004PI-2	PASADENA	230	PASADENA	115	1	2						
2004PI-2	ARIANA	230	ARIANA-N	69	1	16						
2004PI-2	SELOSE	230	SELOSE-N	69	1	16						
2004PI-2	GAPWAY	230	GAPWAY	69	1	16						
2004PI-2	CREWSLK	230	CREWSLK	69	1	13						
2004PI-2	TENOROC	230	TENOROC	69	1	13						
2004PI-2	BARCOLA	230	WEST	230	1	2						
2004PI-2	EATON PK	230	CREWSLK	230	1	13						
2004PI-2	EATON PK	230	EATON PK	69	1	13						
2004PI-2	EATON PK	230	TENOROC	230	1	13						
2004PI-2	RECKER	230	GAPWAY	230	1	16						
2004PI-2	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-3	SN PLANT	230	SYLVAN	230	1	1						
2004PI-3	SYLVAN	230	N LONGWD	230	1	1						
2004PI-3	IND RIV	230	STANTON	230	1	11						
2004PI-3	SN PLANT	115	TURNER	115	1	1						
2004PI-3	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-3	SILVR SP	230	SILV SPN	230	1	2						
2004PI-3	SILVR SP	230	OCALA 1	230	1	2						
2004PI-3	RIO PINR	230	CURRY FD	230	1	2						
2004PI-3	STANTON	230	CURRY FD	230	1	2						
2004PI-3	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-3	SHELD	230	LK TARPN	230	1	2						
2004PI-3	PEBB	230	CREWSLK	230	1	13						
2004PI-3	PEBB	230	N BARTOW	230	1	2						
2004PI-3	RECKER	230	LKAGNES	230	1	16						
2004PI-3	RECKER	230	ARIANA	230	1	16						
2004PI-3	RECKER	230	CREWSLK	230	1	13						
2004PI-3	B BEND	230	MANATEE	230	1	1						
2004PI-3	RUSKIN T	230	MANATEE	230	1	1						
2004PI-3	IND RIV	230	IND RIV	115	1	11						
2004PI-3	SHELD	230	SHELD-NW	69	1	16						
2004PI-3	LARGO	230	LARGO A	69	1	2						
2004PI-3	CLMT EST	230	CLMT EST	69	1	2						
2004PI-3	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-3	WINDERME	230	WINDERME	69	1	2						
2004PI-3	PASADENA	230	PASADENA	115	1	2						
2004PI-3	ARIANA	230	ARIANA-N	69	1	16						
2004PI-3	SELOSE	230	SELOSE-N	69	1	16						
2004PI-3	GAPWAY	230	GAPWAY	69	1	16						
2004PI-3	CREWSLK	230	CREWSLK	69	1	13						
2004PI-3	TENOROC	230	TENOROC	69	1	13						
2004PI-3	BARCOLA	230	WEST	230	1	2						
2004PI-3	EATON PK	230	CREWSLK	230	1	13						
2004PI-3	EATON PK	230	EATON PK	69	1	13						
2004PI-3	EATON PK	230	TENOROC	230	1	13						
2004PI-3	RECKER	230	GAPWAY	230	1	16						
2004PI-3	SN PLANT	115	TURNER	115	1	1						
2004PI-4	SN PLANT	230	SYLVAN	230	1	1						
2004PI-4	SYLVAN	230	N LONGWD	230	1	1						
2004PI-4	IND RIV	230	STANTON	230	1	11						
2004PI-4	SN PLANT	115	TURNER	115	1	1						
2004PI-4	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-4	SILVR SP	230	SILV SPN	230	1	2						
2004PI-4	SILVR SP	230	OCALA 1	230	1	2						
2004PI-4	RIO PINR	230	CURRY FD	230	1	2						
2004PI-4	STANTON	230	CURRY FD	230	1	2						
2004PI-4	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-4	SHELD	230	LK TARPN	230	1	2						
2004PI-4	PEBB	230	CREWSLK	230	1	13						
2004PI-4	PEBB	230	N BARTOW	230	1	2						
2004PI-4	RECKER	230	LKAGNES	230	1	16						
2004PI-4	RECKER	230	ARIANA	230	1	16						
2004PI-4	RECKER	230	CREWSLK	230	1	13						
2004PI-4	B BEND	230	MANATEE	230	1	1						
2004PI-4	RUSKIN T	230	MANATEE	230	1	1						
2004PI-4	IND RIV	230	IND RIV	115	1	11						
2004PI-4	SHELD	230	SHELD-NW	69	1	16						
2004PI-4	LARGO	230	LARGO A	69	1	2						
2004PI-4	CLMT EST	230	CLMT EST	69	1	2						
2004PI-4	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-4	WINDERME	230	WINDERME	69	1	2						
2004PI-4	PASADENA	230	PASADENA	115	1	2						
2004PI-4	ARIANA	230	ARIANA-N	69	1	16						
2004PI-4	SELOSE	230	SELOSE-N	69	1	16						
2004PI-4	GAPWAY	230	GAPWAY	69	1	16						
2004PI-4	CREWSLK	230	CREWSLK	69	1	13						
2004PI-4	TENOROC	230	TENOROC	69	1	13						
2004PI-4	BARCOLA	230	WEST	230	1	2						
2004PI-4	EATON PK	230	CREWSLK	230	1	13						
2004PI-4	EATON PK	230	EATON PK	69	1	13						
2004PI-4	EATON PK	230	TENOROC	230	1	13						
2004PI-4	RECKER	230	GAPWAY	230	1	16						
2004PI-4	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-5	SN PLANT	230	SYLVAN	230	1	1						
2004PI-5	SYLVAN	230	N LONGWD	230	1	1						
2004PI-5	IND RIV	230	STANTON	230	1	11						
2004PI-5	SN PLANT	115	TURNER	115	1	1						
2004PI-5	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-5	SILVR SP	230	SILV SPN	230	1	2						
2004PI-5	SILVR SP	230	OCALA 1	230	1	2						
2004PI-5	RIO PINR	230	CURRY FD	230	1	2						
2004PI-5	STANTON	230	CURRY FD	230	1	2						
2004PI-5	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-5	SHELD	230	LK TARPN	230	1	2						
2004PI-5	PEBB	230	CREWSLK	230	1	13						
2004PI-5	PEBB	230	N BARTOW	230	1	2						
2004PI-5	RECKER	230	LKAGNES	230	1	16						
2004PI-5	RECKER	230	ARIANA	230	1	16						
2004PI-5	RECKER	230	CREWSLK	230	1	13						
2004PI-5	B BEND	230	MANATEE	230	1	1						
2004PI-5	RUSKIN T	230	MANATEE	230	1	1						
2004PI-5	IND RIV	230	IND RIV	115	1	11						
2004PI-5	SHELD	230	SHELD-NW	69	1	16						
2004PI-5	LARGO	230	LARGO A	69	1	2						
2004PI-5	CLMT EST	230	CLMT EST	69	1	2						
2004PI-5	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-5	WINDERME	230	WINDERME	69	1	2						
2004PI-5	PASADENA	230	PASADENA	115	1	2						
2004PI-5	ARIANA	230	ARIANA-N	69	1	16						
2004PI-5	SELOSE	230	SELOSE-N	69	1	16						
2004PI-5	GAPWAY	230	GAPWAY	69	1	16						
2004PI-5	CREWSLK	230	CREWSLK	69	1	13						
2004PI-5	TENOROC	230	TENOROC	69	1	13						
2004PI-5	BARCOLA	230	WEST	230	1	2						
2004PI-5	EATON PK	230	CREWSLK	230	1	13						
2004PI-5	EATON PK	230	EATON PK	69	1	13						
2004PI-5	EATON PK	230	TENOROC	230	1	13						
2004PI-5	RECKER	230	GAPWAY	230	1	16						
2004PI-5	SN PLANT	115	TURNER	115	1	1						
2004PI-6	SN PLANT	230	SYLVAN	230	1	1						
2004PI-6	SYLVAN	230	N LONGWD	230	1	1						
2004PI-6	IND RIV	230	STANTON	230	1	11						
2004PI-6	SN PLANT	115	TURNER	115	1	1						
2004PI-6	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-6	SILVR SP	230	SILV SPN	230	1	2						
2004PI-6	SILVR SP	230	OCALA 1	230	1	2						
2004PI-6	RIO PINR	230	CURRY FD	230	1	2						
2004PI-6	STANTON	230	CURRY FD	230	1	2						
2004PI-6	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-6	SHELD	230	LK TARPN	230	1	2						
2004PI-6	PEBB	230	CREWSLK	230	1	13						
2004PI-6	PEBB	230	N BARTOW	230	1	2						
2004PI-6	RECKER	230	LKAGNES	230	1	16						
2004PI-6	RECKER	230	ARIANA	230	1	16						
2004PI-6	RECKER	230	CREWSLK	230	1	13						
2004PI-6	B BEND	230	MANATEE	230	1	1						
2004PI-6	RUSKIN T	230	MANATEE	230	1	1						
2004PI-6	IND RIV	230	IND RIV	115	1	11						
2004PI-6	SHELD	230	SHELD-NW	69	1	16						
2004PI-6	LARGO	230	LARGO A	69	1	2						
2004PI-6	CLMT EST	230	CLMT EST	69	1	2						
2004PI-6	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-6	WINDERME	230	WINDERME	69	1	2						
2004PI-6	PASADENA	230	PASADENA	115	1	2						
2004PI-6	ARIANA	230	ARIANA-N	69	1	16						
2004PI-6	SELOSE	230	SELOSE-N	69	1	16						
2004PI-6	GAPWAY	230	GAPWAY	69	1	16						
2004PI-6	CREWSLK	230	CREWSLK	69	1	13						
2004PI-6	TENOROC	230	TENOROC	69	1	13						
2004PI-6	BARCOLA	230	WEST	230	1	2						
2004PI-6	EATON PK	230	CREWSLK	230	1	13						
2004PI-6	EATON PK	230	EATON PK	69	1	13						
2004PI-6	EATON PK	230	TENOROC	230	1	13						
2004PI-6	RECKER	230	GAPWAY	230	1	16						
2004PI-6	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-7	SN PLANT	230	SYLVAN	230	1	1						
2004PI-7	SYLVAN	230	N LONGWD	230	1	1						
2004PI-7	IND RIV	230	STANTON	230	1	11						
2004PI-7	SN PLANT	115	TURNER	115	1	1						
2004PI-7	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-7	SILVR SP	230	SILV SPN	230	1	2						
2004PI-7	SILVR SP	230	OCALA 1	230	1	2						
2004PI-7	RIO PINR	230	CURRY FD	230	1	2						
2004PI-7	STANTON	230	CURRY FD	230	1	2						
2004PI-7	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-7	SHELD	230	LK TARPN	230	1	2						
2004PI-7	PEBB	230	CREWSLK	230	1	13						
2004PI-7	PEBB	230	N BARTOW	230	1	2						
2004PI-7	RECKER	230	LKAGNES	230	1	16						
2004PI-7	RECKER	230	ARIANA	230	1	16						
2004PI-7	RECKER	230	CREWSLK	230	1	13						
2004PI-7	B BEND	230	MANATEE	230	1	1						
2004PI-7	RUSKIN T	230	MANATEE	230	1	1						
2004PI-7	IND RIV	230	IND RIV	115	1	11						
2004PI-7	SHELD	230	SHELD-NW	69	1	16						
2004PI-7	LARGO	230	LARGO A	69	1	2						
2004PI-7	CLMT EST	230	CLMT EST	69	1	2						
2004PI-7	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-7	WINDERME	230	WINDERME	69	1	2						
2004PI-7	PASADENA	230	PASADENA	115	1	2						
2004PI-7	ARIANA	230	ARIANA-N	69	1	16						
2004PI-7	SELOSE	230	SELOSE-N	69	1	16						
2004PI-7	GAPWAY	230	GAPWAY	69	1	16						
2004PI-7	CREWSLK	230	CREWSLK	69	1	13						
2004PI-7	TENOROC	230	TENOROC	69	1	13						
2004PI-7	BARCOLA	230	WEST	230	1	2						
2004PI-7	EATON PK	230	CREWSLK	230	1	13						
2004PI-7	EATON PK	230	EATON PK	69	1	13						
2004PI-7	EATON PK	230	TENOROC	230	1	13						
2004PI-7	RECKER	230	GAPWAY	230	1	16						
2004PI-7	SN PLANT	115	TURNER	115	1	1						
2004PI-8	SN PLANT	230	SYLVAN	230	1	1						
2004PI-8	SYLVAN	230	N LONGWD	230	1	1						
2004PI-8	IND RIV	230	STANTON	230	1	11						
2004PI-8	SN PLANT	115	TURNER	115	1	1						
2004PI-8	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-8	SILVR SP	230	SILV SPN	230	1	2						
2004PI-8	SILVR SP	230	OCALA 1	230	1	2						
2004PI-8	RIO PINR	230	CURRY FD	230	1	2						
2004PI-8	STANTON	230	CURRY FD	230	1	2						
2004PI-8	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-8	SHELD	230	LK TARPN	230	1	2						
2004PI-8	PEBB	230	CREWSLK	230	1	13						
2004PI-8	PEBB	230	N BARTOW	230	1	2						
2004PI-8	RECKER	230	LKAGNES	230	1	16						
2004PI-8	RECKER	230	ARIANA	230	1	16						
2004PI-8	RECKER	230	CREWSLK	230	1	13						
2004PI-8	B BEND	230	MANATEE	230	1	1						
2004PI-8	RUSKIN T	230	MANATEE	230	1	1						
2004PI-8	IND RIV	230	IND RIV	115	1	11						
2004PI-8	SHELD	230	SHELD-NW	69	1	16						
2004PI-8	LARGO	230	LARGO A	69	1	2						
2004PI-8	CLMT EST	230	CLMT EST	69	1	2						
2004PI-8	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-8	WINDERME	230	WINDERME	69	1	2						
2004PI-8	PASADENA	230	PASADENA	115	1	2						
2004PI-8	ARIANA	230	ARIANA-N	69	1	16						
2004PI-8	SELOSE	230	SELOSE-N	69	1	16						
2004PI-8	GAPWAY	230	GAPWAY	69	1	16						
2004PI-8	CREWSLK	230	CREWSLK	69	1	13						
2004PI-8	TENOROC	230	TENOROC	69	1	13						
2004PI-8	BARCOLA	230	WEST	230	1	2						
2004PI-8	EATON PK	230	CREWSLK	230	1	13						
2004PI-8	EATON PK	230	EATON PK	69	1	13						
2004PI-8	EATON PK	230	TENOROC	230	1	13						
2004PI-8	RECKER	230	GAPWAY	230	1	16						
2004PI-8	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-9	SN PLANT	230	SYLVAN	230	1	1						
2004PI-9	SYLVAN	230	N LONGWD	230	1	1						
2004PI-9	IND RIV	230	STANTON	230	1	11						
2004PI-9	SN PLANT	115	TURNER	115	1	1						
2004PI-9	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-9	SILVR SP	230	SILV SPN	230	1	2						
2004PI-9	SILVR SP	230	OCALA 1	230	1	2						
2004PI-9	RIO PINR	230	CURRY FD	230	1	2						
2004PI-9	STANTON	230	CURRY FD	230	1	2						
2004PI-9	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-9	SHELD	230	LK TARPN	230	1	2						
2004PI-9	PEBB	230	CREWSLK	230	1	13						
2004PI-9	PEBB	230	N BARTOW	230	1	2						
2004PI-9	RECKER	230	LKAGNES	230	1	16						
2004PI-9	RECKER	230	ARIANA	230	1	16						
2004PI-9	RECKER	230	CREWSLK	230	1	13						
2004PI-9	B BEND	230	MANATEE	230	1	1						
2004PI-9	RUSKIN T	230	MANATEE	230	1	1						
2004PI-9	IND RIV	230	IND RIV	115	1	11						
2004PI-9	SHELD	230	SHELD-NW	69	1	16						
2004PI-9	LARGO	230	LARGO A	69	1	2						
2004PI-9	CLMT EST	230	CLMT EST	69	1	2						
2004PI-9	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-9	WINDERME	230	WINDERME	69	1	2						
2004PI-9	PASADENA	230	PASADENA	115	1	2						
2004PI-9	ARIANA	230	ARIANA-N	69	1	16						
2004PI-9	SELOSE	230	SELOSE-N	69	1	16						
2004PI-9	GAPWAY	230	GAPWAY	69	1	16						
2004PI-9	CREWSLK	230	CREWSLK	69	1	13						
2004PI-9	TENOROC	230	TENOROC	69	1	13						
2004PI-9	BARCOLA	230	WEST	230	1	2						
2004PI-9	EATON PK	230	CREWSLK	230	1	13						
2004PI-9	EATON PK	230	EATON PK	69	1	13						
2004PI-9	EATON PK	230	TENOROC	230	1	13						
2004PI-9	RECKER	230	GAPWAY	230	1	16						
2004PI-9	SN PLANT	115	TURNER	115	1	1						
2004PI-10	SN PLANT	230	SYLVAN	230	1	1						
2004PI-10	SYLVAN	230	N LONGWD	230	1	1						
2004PI-10	IND RIV	230	STANTON	230	1	11						
2004PI-10	SN PLANT	115	TURNER	115	1	1						
2004PI-10	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-10	SILVR SP	230	SILV SPN	230	1	2						
2004PI-10	SILVR SP	230	OCALA 1	230	1	2						
2004PI-10	RIO PINR	230	CURRY FD	230	1	2						
2004PI-10	STANTON	230	CURRY FD	230	1	2						
2004PI-10	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-10	SHELD	230	LK TARPN	230	1	2						
2004PI-10	PEBB	230	CREWSLK	230	1	13						
2004PI-10	PEBB	230	N BARTOW	230	1	2						
2004PI-10	RECKER	230	LKAGNES	230	1	16						
2004PI-10	RECKER	230	ARIANA	230	1	16						
2004PI-10	RECKER	230	CREWSLK	230	1	13						
2004PI-10	B BEND	230	MANATEE	230	1	1						
2004PI-10	RUSKIN T	230	MANATEE	230	1	1						
2004PI-10	IND RIV	230	IND RIV	115	1	11						
2004PI-10	SHELD	230	SHELD-NW	69	1	16						
2004PI-10	LARGO	230	LARGO A	69	1	2						
2004PI-10	CLMT EST	230	CLMT EST	69	1	2						
2004PI-10	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-10	WINDERME	230	WINDERME	69	1	2						
2004PI-10	PASADENA	230	PASADENA	115	1	2						
2004PI-10	ARIANA	230	ARIANA-N	69	1	16						
2004PI-10	SELOSE	230	SELOSE-N	69	1	16						
2004PI-10	GAPWAY	230	GAPWAY	69	1	16						
2004PI-10	CREWSLK	230	CREWSLK	69	1	13						
2004PI-10	TENOROC	230	TENOROC	69	1	13						
2004PI-10	BARCOLA	230	WEST	230	1	2						
2004PI-10	EATON PK	230	CREWSLK	230	1	13						
2004PI-10	EATON PK	230	EATON PK	69	1	13						
2004PI-10	EATON PK	230	TENOROC	230	1	13						
2004PI-10	RECKER	230	GAPWAY	230	1	16						
2004PI-10	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-11	SN PLANT	230	SYLVAN	230	1	1						
2004PI-11	SYLVAN	230	N LONGWD	230	1	1						
2004PI-11	IND RIV	230	STANTON	230	1	11						
2004PI-11	SN PLANT	115	TURNER	115	1	1						
2004PI-11	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-11	SILVR SP	230	SILV SPN	230	1	2						
2004PI-11	SILVR SP	230	OCALA 1	230	1	2						
2004PI-11	RIO PINR	230	CURRY FD	230	1	2						
2004PI-11	STANTON	230	CURRY FD	230	1	2						
2004PI-11	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-11	SHELD	230	LK TARPN	230	1	2						
2004PI-11	PEBB	230	CREWSLK	230	1	13						
2004PI-11	PEBB	230	N BARTOW	230	1	2						
2004PI-11	RECKER	230	LKAGNES	230	1	16						
2004PI-11	RECKER	230	ARIANA	230	1	16						
2004PI-11	RECKER	230	CREWSLK	230	1	13						
2004PI-11	B BEND	230	MANATEE	230	1	1						
2004PI-11	RUSKIN T	230	MANATEE	230	1	1						
2004PI-11	IND RIV	230	IND RIV	115	1	11						
2004PI-11	SHELD	230	SHELD-NW	69	1	16						
2004PI-11	LARGO	230	LARGO A	69	1	2						
2004PI-11	CLMT EST	230	CLMT EST	69	1	2						
2004PI-11	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-11	WINDERME	230	WINDERME	69	1	2						
2004PI-11	PASADENA	230	PASADENA	115	1	2						
2004PI-11	ARIANA	230	ARIANA-N	69	1	16						
2004PI-11	SELOSE	230	SELOSE-N	69	1	16						
2004PI-11	GAPWAY	230	GAPWAY	69	1	16						
2004PI-11	CREWSLK	230	CREWSLK	69	1	13						
2004PI-11	TENOROC	230	TENOROC	69	1	13						
2004PI-11	BARCOLA	230	WEST	230	1	2						
2004PI-11	EATON PK	230	CREWSLK	230	1	13						
2004PI-11	EATON PK	230	EATON PK	69	1	13						
2004PI-11	EATON PK	230	TENOROC	230	1	13						
2004PI-11	RECKER	230	GAPWAY	230	1	16						
2004PI-11	SN PLANT	115	TURNER	115	1	1						
2004PI-12	SN PLANT	230	SYLVAN	230	1	1						
2004PI-12	SYLVAN	230	N LONGWD	230	1	1						
2004PI-12	IND RIV	230	STANTON	230	1	11						
2004PI-12	SN PLANT	115	TURNER	115	1	1						
2004PI-12	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-12	SILVR SP	230	SILV SPN	230	1	2						
2004PI-12	SILVR SP	230	OCALA 1	230	1	2						
2004PI-12	RIO PINR	230	CURRY FD	230	1	2						
2004PI-12	STANTON	230	CURRY FD	230	1	2						
2004PI-12	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-12	SHELD	230	LK TARPN	230	1	2						
2004PI-12	PEBB	230	CREWSLK	230	1	13						
2004PI-12	PEBB	230	N BARTOW	230	1	2						
2004PI-12	RECKER	230	LKAGNES	230	1	16						
2004PI-12	RECKER	230	ARIANA	230	1	16						
2004PI-12	RECKER	230	CREWSLK	230	1	13						
2004PI-12	B BEND	230	MANATEE	230	1	1						
2004PI-12	RUSKIN T	230	MANATEE	230	1	1						
2004PI-12	IND RIV	230	IND RIV	115	1	11						
2004PI-12	SHELD	230	SHELD-NW	69	1	16						
2004PI-12	LARGO	230	LARGO A	69	1	2						
2004PI-12	CLMT EST	230	CLMT EST	69	1	2						
2004PI-12	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-12	WINDERME	230	WINDERME	69	1	2						
2004PI-12	PASADENA	230	PASADENA	115	1	2						
2004PI-12	ARIANA	230	ARIANA-N	69	1	16						
2004PI-12	SELOSE	230	SELOSE-N	69	1	16						
2004PI-12	GAPWAY	230	GAPWAY	69	1	16						
2004PI-12	CREWSLK	230	CREWSLK	69	1	13						
2004PI-12	TENOROC	230	TENOROC	69	1	13						
2004PI-12	BARCOLA	230	WEST	230	1	2						
2004PI-12	EATON PK	230	CREWSLK	230	1	13						
2004PI-12	EATON PK	230	EATON PK	69	1	13						
2004PI-12	EATON PK	230	TENOROC	230	1	13						
2004PI-12	RECKER	230	GAPWAY	230	1	16						
2004PI-12	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-13	SN PLANT	230	SYLVAN	230	1	1						
2004PI-13	SYLVAN	230	N LONGWD	230	1	1						
2004PI-13	IND RIV	230	STANTON	230	1	11						
2004PI-13	SN PLANT	115	TURNER	115	1	1						
2004PI-13	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-13	SILVR SP	230	SILV SPN	230	1	2						
2004PI-13	SILVR SP	230	OCALA 1	230	1	2						
2004PI-13	RIO PINR	230	CURRY FD	230	1	2						
2004PI-13	STANTON	230	CURRY FD	230	1	2						
2004PI-13	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-13	SHELD	230	LK TARPN	230	1	2						
2004PI-13	PEBB	230	CREWSLK	230	1	13						
2004PI-13	PEBB	230	N BARTOW	230	1	2						
2004PI-13	RECKER	230	LKAGNES	230	1	16						
2004PI-13	RECKER	230	ARIANA	230	1	16						
2004PI-13	RECKER	230	CREWSLK	230	1	13						
2004PI-13	B BEND	230	MANATEE	230	1	1						
2004PI-13	RUSKIN T	230	MANATEE	230	1	1						
2004PI-13	IND RIV	230	IND RIV	115	1	11						
2004PI-13	SHELD	230	SHELD-NW	69	1	16						
2004PI-13	LARGO	230	LARGO A	69	1	2						
2004PI-13	CLMT EST	230	CLMT EST	69	1	2						
2004PI-13	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-13	WINDERME	230	WINDERME	69	1	2						
2004PI-13	PASADENA	230	PASADENA	115	1	2						
2004PI-13	ARIANA	230	ARIANA-N	69	1	16						
2004PI-13	SELOSE	230	SELOSE-N	69	1	16						
2004PI-13	GAPWAY	230	GAPWAY	69	1	16						
2004PI-13	CREWSLK	230	CREWSLK	69	1	13						
2004PI-13	TENOROC	230	TENOROC	69	1	13						
2004PI-13	BARCOLA	230	WEST	230	1	2						
2004PI-13	EATON PK	230	CREWSLK	230	1	13						
2004PI-13	EATON PK	230	EATON PK	69	1	13						
2004PI-13	EATON PK	230	TENOROC	230	1	13						
2004PI-13	RECKER	230	GAPWAY	230	1	16						
2004PI-13	SN PLANT	115	TURNER	115	1	1						
2004PI-15	SN PLANT	230	SYLVAN	230	1	1						
2004PI-15	SYLVAN	230	N LONGWD	230	1	1						
2004PI-15	IND RIV	230	STANTON	230	1	11						
2004PI-15	SN PLANT	115	TURNER	115	1	1						
2004PI-15	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-15	SILVR SP	230	SILV SPN	230	1	2						
2004PI-15	SILVR SP	230	OCALA 1	230	1	2						
2004PI-15	RIO PINR	230	CURRY FD	230	1	2						
2004PI-15	STANTON	230	CURRY FD	230	1	2						
2004PI-15	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-15	SHELD	230	LK TARPN	230	1	2						
2004PI-15	PEBB	230	CREWSLK	230	1	13						
2004PI-15	PEBB	230	N BARTOW	230	1	2						
2004PI-15	RECKER	230	LKAGNES	230	1	16						
2004PI-15	RECKER	230	ARIANA	230	1	16						
2004PI-15	RECKER	230	CREWSLK	230	1	13						
2004PI-15	B BEND	230	MANATEE	230	1	1						
2004PI-15	RUSKIN T	230	MANATEE	230	1	1						
2004PI-15	IND RIV	230	IND RIV	115	1	11						
2004PI-15	SHELD	230	SHELD-NW	69	1	16						
2004PI-15	LARGO	230	LARGO A	69	1	2						
2004PI-15	CLMT EST	230	CLMT EST	69	1	2						
2004PI-15	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-15	WINDERME	230	WINDERME	69	1	2						
2004PI-15	PASADENA	230	PASADENA	115	1	2						
2004PI-15	ARIANA	230	ARIANA-N	69	1	16						
2004PI-15	SELOSE	230	SELOSE-N	69	1	16						
2004PI-15	GAPWAY	230	GAPWAY	69	1	16						
2004PI-15	CREWSLK	230	CREWSLK	69	1	13						
2004PI-15	TENOROC	230	TENOROC	69	1	13						
2004PI-15	BARCOLA	230	WEST	230	1	2						
2004PI-15	EATON PK	230	CREWSLK	230	1	13						
2004PI-15	EATON PK	230	EATON PK	69	1	13						
2004PI-15	EATON PK	230	TENOROC	230	1	13						
2004PI-15	RECKER	230	GAPWAY	230	1	16						
2004PI-15	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-16	SN PLANT	230	SYLVAN	230	1	1						
2004PI-16	SYLVAN	230	N LONGWD	230	1	1						
2004PI-16	IND RIV	230	STANTON	230	1	11						
2004PI-16	SN PLANT	115	TURNER	115	1	1						
2004PI-16	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-16	SILVR SP	230	SILV SPN	230	1	2						
2004PI-16	SILVR SP	230	OCALA 1	230	1	2						
2004PI-16	RIO PINR	230	CURRY FD	230	1	2						
2004PI-16	STANTON	230	CURRY FD	230	1	2						
2004PI-16	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-16	SHELD	230	LK TARPN	230	1	2						
2004PI-16	PEBB	230	CREWSLK	230	1	13						
2004PI-16	PEBB	230	N BARTOW	230	1	2						
2004PI-16	RECKER	230	LKAGNES	230	1	16						
2004PI-16	RECKER	230	ARIANA	230	1	16						
2004PI-16	RECKER	230	CREWSLK	230	1	13						
2004PI-16	B BEND	230	MANATEE	230	1	1						
2004PI-16	RUSKIN T	230	MANATEE	230	1	1						
2004PI-16	IND RIV	230	IND RIV	115	1	11						
2004PI-16	SHELD	230	SHELD-NW	69	1	16						
2004PI-16	LARGO	230	LARGO A	69	1	2						
2004PI-16	CLMT EST	230	CLMT EST	69	1	2						
2004PI-16	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-16	WINDERME	230	WINDERME	69	1	2						
2004PI-16	PASADENA	230	PASADENA	115	1	2						
2004PI-16	ARIANA	230	ARIANA-N	69	1	16						
2004PI-16	SELOSE	230	SELOSE-N	69	1	16						
2004PI-16	GAPWAY	230	GAPWAY	69	1	16						
2004PI-16	CREWSLK	230	CREWSLK	69	1	13						
2004PI-16	TENOROC	230	TENOROC	69	1	13						
2004PI-16	BARCOLA	230	WEST	230	1	2						
2004PI-16	EATON PK	230	CREWSLK	230	1	13						
2004PI-16	EATON PK	230	EATON PK	69	1	13						
2004PI-16	EATON PK	230	TENOROC	230	1	13						
2004PI-16	RECKER	230	GAPWAY	230	1	16						
2004PI-16	SN PLANT	115	TURNER	115	1	1						
2004PI-17	SN PLANT	230	SYLVAN	230	1	1						
2004PI-17	SYLVAN	230	N LONGWD	230	1	1						
2004PI-17	IND RIV	230	STANTON	230	1	11						
2004PI-17	SN PLANT	115	TURNER	115	1	1						
2004PI-17	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-17	SILVR SP	230	SILV SPN	230	1	2						
2004PI-17	SILVR SP	230	OCALA 1	230	1	2						
2004PI-17	RIO PINR	230	CURRY FD	230	1	2						
2004PI-17	STANTON	230	CURRY FD	230	1	2						
2004PI-17	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-17	SHELD	230	LK TARPN	230	1	2						
2004PI-17	PEBB	230	CREWSLK	230	1	13						
2004PI-17	PEBB	230	N BARTOW	230	1	2						
2004PI-17	RECKER	230	LKAGNES	230	1	16						
2004PI-17	RECKER	230	ARIANA	230	1	16						
2004PI-17	RECKER	230	CREWSLK	230	1	13						
2004PI-17	B BEND	230	MANATEE	230	1	1						
2004PI-17	RUSKIN T	230	MANATEE	230	1	1						
2004PI-17	IND RIV	230	IND RIV	115	1	11						
2004PI-17	SHELD	230	SHELD-NW	69	1	16						
2004PI-17	LARGO	230	LARGO A	69	1	2						
2004PI-17	CLMT EST	230	CLMT EST	69	1	2						
2004PI-17	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-17	WINDERME	230	WINDERME	69	1	2						
2004PI-17	PASADENA	230	PASADENA	115	1	2						
2004PI-17	ARIANA	230	ARIANA-N	69	1	16						
2004PI-17	SELOSE	230	SELOSE-N	69	1	16						
2004PI-17	GAPWAY	230	GAPWAY	69	1	16						
2004PI-17	CREWSLK	230	CREWSLK	69	1	13						
2004PI-17	TENOROC	230	TENOROC	69	1	13						
2004PI-17	BARCOLA	230	WEST	230	1	2						
2004PI-17	EATON PK	230	CREWSLK	230	1	13						
2004PI-17	EATON PK	230	EATON PK	69	1	13						
2004PI-17	EATON PK	230	TENOROC	230	1	13						
2004PI-17	RECKER	230	GAPWAY	230	1	16						
2004PI-17	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-18	SN PLANT	230	SYLVAN	230	1	1						
2004PI-18	SYLVAN	230	N LONGWD	230	1	1						
2004PI-18	IND RIV	230	STANTON	230	1	11						
2004PI-18	SN PLANT	115	TURNER	115	1	1						
2004PI-18	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-18	SILVR SP	230	SILV SPN	230	1	2						
2004PI-18	SILVR SP	230	OCALA 1	230	1	2						
2004PI-18	RIO PINR	230	CURRY FD	230	1	2						
2004PI-18	STANTON	230	CURRY FD	230	1	2						
2004PI-18	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-18	SHELD	230	LK TARPN	230	1	2						
2004PI-18	PEBB	230	CREWSLK	230	1	13						
2004PI-18	PEBB	230	N BARTOW	230	1	2						
2004PI-18	RECKER	230	LKAGNES	230	1	16						
2004PI-18	RECKER	230	ARIANA	230	1	16						
2004PI-18	RECKER	230	CREWSLK	230	1	13						
2004PI-18	B BEND	230	MANATEE	230	1	1						
2004PI-18	RUSKIN T	230	MANATEE	230	1	1						
2004PI-18	IND RIV	230	IND RIV	115	1	11						
2004PI-18	SHELD	230	SHELD-NW	69	1	16						
2004PI-18	LARGO	230	LARGO A	69	1	2						
2004PI-18	CLMT EST	230	CLMT EST	69	1	2						
2004PI-18	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-18	WINDERME	230	WINDERME	69	1	2						
2004PI-18	PASADENA	230	PASADENA	115	1	2						
2004PI-18	ARIANA	230	ARIANA-N	69	1	16						
2004PI-18	SELOSE	230	SELOSE-N	69	1	16						
2004PI-18	GAPWAY	230	GAPWAY	69	1	16						
2004PI-18	CREWSLK	230	CREWSLK	69	1	13						
2004PI-18	TENOROC	230	TENOROC	69	1	13						
2004PI-18	BARCOLA	230	WEST	230	1	2						
2004PI-18	EATON PK	230	CREWSLK	230	1	13						
2004PI-18	EATON PK	230	EATON PK	69	1	13						
2004PI-18	EATON PK	230	TENOROC	230	1	13						
2004PI-18	RECKER	230	GAPWAY	230	1	16						
2004PI-18	SN PLANT	115	TURNER	115	1	1						
2004PI-19	SN PLANT	230	SYLVAN	230	1	1						
2004PI-19	SYLVAN	230	N LONGWD	230	1	1						
2004PI-19	IND RIV	230	STANTON	230	1	11						
2004PI-19	SN PLANT	115	TURNER	115	1	1						
2004PI-19	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-19	SILVR SP	230	SILV SPN	230	1	2						
2004PI-19	SILVR SP	230	OCALA 1	230	1	2						
2004PI-19	RIO PINR	230	CURRY FD	230	1	2						
2004PI-19	STANTON	230	CURRY FD	230	1	2						
2004PI-19	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-19	SHELD	230	LK TARPN	230	1	2						
2004PI-19	PEBB	230	CREWSLK	230	1	13						
2004PI-19	PEBB	230	N BARTOW	230	1	2						
2004PI-19	RECKER	230	LKAGNES	230	1	16						
2004PI-19	RECKER	230	ARIANA	230	1	16						
2004PI-19	RECKER	230	CREWSLK	230	1	13						
2004PI-19	B BEND	230	MANATEE	230	1	1						
2004PI-19	RUSKIN T	230	MANATEE	230	1	1						
2004PI-19	IND RIV	230	IND RIV	115	1	11						
2004PI-19	SHELD	230	SHELD-NW	69	1	16						
2004PI-19	LARGO	230	LARGO A	69	1	2						
2004PI-19	CLMT EST	230	CLMT EST	69	1	2						
2004PI-19	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-19	WINDERME	230	WINDERME	69	1	2						
2004PI-19	PASADENA	230	PASADENA	115	1	2						
2004PI-19	ARIANA	230	ARIANA-N	69	1	16						
2004PI-19	SELOSE	230	SELOSE-N	69	1	16						
2004PI-19	GAPWAY	230	GAPWAY	69	1	16						
2004PI-19	CREWSLK	230	CREWSLK	69	1	13						
2004PI-19	TENOROC	230	TENOROC	69	1	13						
2004PI-19	BARCOLA	230	WEST	230	1	2						
2004PI-19	EATON PK	230	CREWSLK	230	1	13						
2004PI-19	EATON PK	230	EATON PK	69	1	13						
2004PI-19	EATON PK	230	TENOROC	230	1	13						
2004PI-19	RECKER	230	GAPWAY	230	1	16						
2004PI-19	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-20	SN PLANT	230	SYLVAN	230	1	1						
2004PI-20	SYLVAN	230	N LONGWD	230	1	1						
2004PI-20	IND RIV	230	STANTON	230	1	11						
2004PI-20	SN PLANT	115	TURNER	115	1	1						
2004PI-20	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-20	SILVR SP	230	SILV SPN	230	1	2						
2004PI-20	SILVR SP	230	OCALA 1	230	1	2						
2004PI-20	RIO PINR	230	CURRY FD	230	1	2						
2004PI-20	STANTON	230	CURRY FD	230	1	2						
2004PI-20	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-20	SHELD	230	LK TARPN	230	1	2						
2004PI-20	PEBB	230	CREWSLK	230	1	13						
2004PI-20	PEBB	230	N BARTOW	230	1	2						
2004PI-20	RECKER	230	LKAGNES	230	1	16						
2004PI-20	RECKER	230	ARIANA	230	1	16						
2004PI-20	RECKER	230	CREWSLK	230	1	13						
2004PI-20	B BEND	230	MANATEE	230	1	1						
2004PI-20	RUSKIN T	230	MANATEE	230	1	1						
2004PI-20	IND RIV	230	IND RIV	115	1	11						
2004PI-20	SHELD	230	SHELD-NW	69	1	16						
2004PI-20	LARGO	230	LARGO A	69	1	2						
2004PI-20	CLMT EST	230	CLMT EST	69	1	2						
2004PI-20	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-20	WINDERME	230	WINDERME	69	1	2						
2004PI-20	PASADENA	230	PASADENA	115	1	2						
2004PI-20	ARIANA	230	ARIANA-N	69	1	16						
2004PI-20	SELOSE	230	SELOSE-N	69	1	16						
2004PI-20	GAPWAY	230	GAPWAY	69	1	16						
2004PI-20	CREWSLK	230	CREWSLK	69	1	13						
2004PI-20	TENOROC	230	TENOROC	69	1	13						
2004PI-20	BARCOLA	230	WEST	230	1	2						
2004PI-20	EATON PK	230	CREWSLK	230	1	13						
2004PI-20	EATON PK	230	EATON PK	69	1	13						
2004PI-20	EATON PK	230	TENOROC	230	1	13						
2004PI-20	RECKER	230	GAPWAY	230	1	16						
2004PI-20	SN PLANT	115	TURNER	115	1	1						
2004PI-21	SN PLANT	230	SYLVAN	230	1	1						
2004PI-21	SYLVAN	230	N LONGWD	230	1	1						
2004PI-21	IND RIV	230	STANTON	230	1	11						
2004PI-21	SN PLANT	115	TURNER	115	1	1						
2004PI-21	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-21	SILVR SP	230	SILV SPN	230	1	2						
2004PI-21	SILVR SP	230	OCALA 1	230	1	2						
2004PI-21	RIO PINR	230	CURRY FD	230	1	2						
2004PI-21	STANTON	230	CURRY FD	230	1	2						
2004PI-21	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-21	SHELD	230	LK TARPN	230	1	2						
2004PI-21	PEBB	230	CREWSLK	230	1	13						
2004PI-21	PEBB	230	N BARTOW	230	1	2						
2004PI-21	RECKER	230	LKAGNES	230	1	16						
2004PI-21	RECKER	230	ARIANA	230	1	16						
2004PI-21	RECKER	230	CREWSLK	230	1	13						
2004PI-21	B BEND	230	MANATEE	230	1	1						
2004PI-21	RUSKIN T	230	MANATEE	230	1	1						
2004PI-21	IND RIV	230	IND RIV	115	1	11						
2004PI-21	SHELD	230	SHELD-NW	69	1	16						
2004PI-21	LARGO	230	LARGO A	69	1	2						
2004PI-21	CLMT EST	230	CLMT EST	69	1	2						
2004PI-21	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-21	WINDERME	230	WINDERME	69	1	2						
2004PI-21	PASADENA	230	PASADENA	115	1	2						
2004PI-21	ARIANA	230	ARIANA-N	69	1	16						
2004PI-21	SELOSE	230	SELOSE-N	69	1	16						
2004PI-21	GAPWAY	230	GAPWAY	69	1	16						
2004PI-21	CREWSLK	230	CREWSLK	69	1	13						
2004PI-21	TENOROC	230	TENOROC	69	1	13						
2004PI-21	BARCOLA	230	WEST	230	1	2						
2004PI-21	EATON PK	230	CREWSLK	230	1	13						
2004PI-21	EATON PK	230	EATON PK	69	1	13						
2004PI-21	EATON PK	230	TENOROC	230	1	13						
2004PI-21	RECKER	230	GAPWAY	230	1	16						
2004PI-21	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-22	SN PLANT	230	SYLVAN	230	1	1						
2004PI-22	SYLVAN	230	N LONGWD	230	1	1						
2004PI-22	IND RIV	230	STANTON	230	1	11						
2004PI-22	SN PLANT	115	TURNER	115	1	1						
2004PI-22	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-22	SILVR SP	230	SILV SPN	230	1	2						
2004PI-22	SILVR SP	230	OCALA 1	230	1	2						
2004PI-22	RIO PINR	230	CURRY FD	230	1	2						
2004PI-22	STANTON	230	CURRY FD	230	1	2						
2004PI-22	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-22	SHELD	230	LK TARPN	230	1	2						
2004PI-22	PEBB	230	CREWSLK	230	1	13						
2004PI-22	PEBB	230	N BARTOW	230	1	2						
2004PI-22	RECKER	230	LKAGNES	230	1	16						
2004PI-22	RECKER	230	ARIANA	230	1	16						
2004PI-22	RECKER	230	CREWSLK	230	1	13						
2004PI-22	B BEND	230	MANATEE	230	1	1						
2004PI-22	RUSKIN T	230	MANATEE	230	1	1						
2004PI-22	IND RIV	230	IND RIV	115	1	11						
2004PI-22	SHELD	230	SHELD-NW	69	1	16						
2004PI-22	LARGO	230	LARGO A	69	1	2						
2004PI-22	CLMT EST	230	CLMT EST	69	1	2						
2004PI-22	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-22	WINDERME	230	WINDERME	69	1	2						
2004PI-22	PASADENA	230	PASADENA	115	1	2						
2004PI-22	ARIANA	230	ARIANA-N	69	1	16						
2004PI-22	SELOSE	230	SELOSE-N	69	1	16						
2004PI-22	GAPWAY	230	GAPWAY	69	1	16						
2004PI-22	CREWSLK	230	CREWSLK	69	1	13						
2004PI-22	TENOROC	230	TENOROC	69	1	13						
2004PI-22	BARCOLA	230	WEST	230	1	2						
2004PI-22	EATON PK	230	CREWSLK	230	1	13						
2004PI-22	EATON PK	230	EATON PK	69	1	13						
2004PI-22	EATON PK	230	TENOROC	230	1	13						
2004PI-22	RECKER	230	GAPWAY	230	1	16						
2004PI-22	SN PLANT	115	TURNER	115	1	1						
2004PI-23	SN PLANT	230	SYLVAN	230	1	1						
2004PI-23	SYLVAN	230	N LONGWD	230	1	1						
2004PI-23	IND RIV	230	STANTON	230	1	11						
2004PI-23	SN PLANT	115	TURNER	115	1	1						
2004PI-23	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-23	SILVR SP	230	SILV SPN	230	1	2						
2004PI-23	SILVR SP	230	OCALA 1	230	1	2						
2004PI-23	RIO PINR	230	CURRY FD	230	1	2						
2004PI-23	STANTON	230	CURRY FD	230	1	2						
2004PI-23	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-23	SHELD	230	LK TARPN	230	1	2						
2004PI-23	PEBB	230	CREWSLK	230	1	13						
2004PI-23	PEBB	230	N BARTOW	230	1	2						
2004PI-23	RECKER	230	LKAGNES	230	1	16						
2004PI-23	RECKER	230	ARIANA	230	1	16						
2004PI-23	RECKER	230	CREWSLK	230	1	13						
2004PI-23	B BEND	230	MANATEE	230	1	1						
2004PI-23	RUSKIN T	230	MANATEE	230	1	1						
2004PI-23	IND RIV	230	IND RIV	115	1	11						
2004PI-23	SHELD	230	SHELD-NW	69	1	16						
2004PI-23	LARGO	230	LARGO A	69	1	2						
2004PI-23	CLMT EST	230	CLMT EST	69	1	2						
2004PI-23	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-23	WINDERME	230	WINDERME	69	1	2						
2004PI-23	PASADENA	230	PASADENA	115	1	2						
2004PI-23	ARIANA	230	ARIANA-N	69	1	16						
2004PI-23	SELOSE	230	SELOSE-N	69	1	16						
2004PI-23	GAPWAY	230	GAPWAY	69	1	16						
2004PI-23	CREWSLK	230	CREWSLK	69	1	13						
2004PI-23	TENOROC	230	TENOROC	69	1	13						
2004PI-23	BARCOLA	230	WEST	230	1	2						
2004PI-23	EATON PK	230	CREWSLK	230	1	13						
2004PI-23	EATON PK	230	EATON PK	69	1	13						
2004PI-23	EATON PK	230	TENOROC	230	1	13						
2004PI-23	RECKER	230	GAPWAY	230	1	16						
2004PI-23	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-24	SN PLANT	230	SYLVAN	230	1	1						
2004PI-24	SYLVAN	230	N LONGWD	230	1	1						
2004PI-24	IND RIV	230	STANTON	230	1	11						
2004PI-24	SN PLANT	115	TURNER	115	1	1						
2004PI-24	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-24	SILVR SP	230	SILV SPN	230	1	2						
2004PI-24	SILVR SP	230	OCALA 1	230	1	2						
2004PI-24	RIO PINR	230	CURRY FD	230	1	2						
2004PI-24	STANTON	230	CURRY FD	230	1	2						
2004PI-24	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-24	SHELD	230	LK TARPN	230	1	2						
2004PI-24	PEBB	230	CREWSLK	230	1	13						
2004PI-24	PEBB	230	N BARTOW	230	1	2						
2004PI-24	RECKER	230	LKAGNES	230	1	16						
2004PI-24	RECKER	230	ARIANA	230	1	16						
2004PI-24	RECKER	230	CREWSLK	230	1	13						
2004PI-24	B BEND	230	MANATEE	230	1	1						
2004PI-24	RUSKIN T	230	MANATEE	230	1	1						
2004PI-24	IND RIV	230	IND RIV	115	1	11						
2004PI-24	SHELD	230	SHELD-NW	69	1	16						
2004PI-24	LARGO	230	LARGO A	69	1	2						
2004PI-24	CLMT EST	230	CLMT EST	69	1	2						
2004PI-24	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-24	WINDERME	230	WINDERME	69	1	2						
2004PI-24	PASADENA	230	PASADENA	115	1	2						
2004PI-24	ARIANA	230	ARIANA-N	69	1	16						
2004PI-24	SELOSE	230	SELOSE-N	69	1	16						
2004PI-24	GAPWAY	230	GAPWAY	69	1	16						
2004PI-24	CREWSLK	230	CREWSLK	69	1	13						
2004PI-24	TENOROC	230	TENOROC	69	1	13						
2004PI-24	BARCOLA	230	WEST	230	1	2						
2004PI-24	EATON PK	230	CREWSLK	230	1	13						
2004PI-24	EATON PK	230	EATON PK	69	1	13						
2004PI-24	EATON PK	230	TENOROC	230	1	13						
2004PI-24	RECKER	230	GAPWAY	230	1	16						
2004PI-24	SN PLANT	115	TURNER	115	1	1						
2004PI-25	SN PLANT	230	SYLVAN	230	1	1						
2004PI-25	SYLVAN	230	N LONGWD	230	1	1						
2004PI-25	IND RIV	230	STANTON	230	1	11						
2004PI-25	SN PLANT	115	TURNER	115	1	1						
2004PI-25	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-25	SILVR SP	230	SILV SPN	230	1	2						
2004PI-25	SILVR SP	230	OCALA 1	230	1	2						
2004PI-25	RIO PINR	230	CURRY FD	230	1	2						
2004PI-25	STANTON	230	CURRY FD	230	1	2						
2004PI-25	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-25	SHELD	230	LK TARPN	230	1	2						
2004PI-25	PEBB	230	CREWSLK	230	1	13						
2004PI-25	PEBB	230	N BARTOW	230	1	2						
2004PI-25	RECKER	230	LKAGNES	230	1	16						
2004PI-25	RECKER	230	ARIANA	230	1	16						
2004PI-25	RECKER	230	CREWSLK	230	1	13						
2004PI-25	B BEND	230	MANATEE	230	1	1						
2004PI-25	RUSKIN T	230	MANATEE	230	1	1						
2004PI-25	IND RIV	230	IND RIV	115	1	11						
2004PI-25	SHELD	230	SHELD-NW	69	1	16						
2004PI-25	LARGO	230	LARGO A	69	1	2						
2004PI-25	CLMT EST	230	CLMT EST	69	1	2						
2004PI-25	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-25	WINDERME	230	WINDERME	69	1	2						
2004PI-25	PASADENA	230	PASADENA	115	1	2						
2004PI-25	ARIANA	230	ARIANA-N	69	1	16						
2004PI-25	SELOSE	230	SELOSE-N	69	1	16						
2004PI-25	GAPWAY	230	GAPWAY	69	1	16						
2004PI-25	CREWSLK	230	CREWSLK	69	1	13						
2004PI-25	TENOROC	230	TENOROC	69	1	13						
2004PI-25	BARCOLA	230	WEST	230	1	2						
2004PI-25	EATON PK	230	CREWSLK	230	1	13						
2004PI-25	EATON PK	230	EATON PK	69	1	13						
2004PI-25	EATON PK	230	TENOROC	230	1	13						
2004PI-25	RECKER	230	GAPWAY	230	1	16						
2004PI-25	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-26	SN PLANT	230	SYLVAN	230	1	1						
2004PI-26	SYLVAN	230	N LONGWD	230	1	1						
2004PI-26	IND RIV	230	STANTON	230	1	11						
2004PI-26	SN PLANT	115	TURNER	115	1	1						
2004PI-26	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-26	SILVR SP	230	SILV SPN	230	1	2						
2004PI-26	SILVR SP	230	OCALA 1	230	1	2						
2004PI-26	RIO PINR	230	CURRY FD	230	1	2						
2004PI-26	STANTON	230	CURRY FD	230	1	2						
2004PI-26	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-26	SHELD	230	LK TARPN	230	1	2						
2004PI-26	PEBB	230	CREWSLK	230	1	13						
2004PI-26	PEBB	230	N BARTOW	230	1	2						
2004PI-26	RECKER	230	LKAGNES	230	1	16						
2004PI-26	RECKER	230	ARIANA	230	1	16						
2004PI-26	RECKER	230	CREWSLK	230	1	13						
2004PI-26	B BEND	230	MANATEE	230	1	1						
2004PI-26	RUSKIN T	230	MANATEE	230	1	1						
2004PI-26	IND RIV	230	IND RIV	115	1	11						
2004PI-26	SHELD	230	SHELD-NW	69	1	16						
2004PI-26	LARGO	230	LARGO A	69	1	2						
2004PI-26	CLMT EST	230	CLMT EST	69	1	2						
2004PI-26	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-26	WINDERME	230	WINDERME	69	1	2						
2004PI-26	PASADENA	230	PASADENA	115	1	2						
2004PI-26	ARIANA	230	ARIANA-N	69	1	16						
2004PI-26	SELOSE	230	SELOSE-N	69	1	16						
2004PI-26	GAPWAY	230	GAPWAY	69	1	16						
2004PI-26	CREWSLK	230	CREWSLK	69	1	13						
2004PI-26	TENOROC	230	TENOROC	69	1	13						
2004PI-26	BARCOLA	230	WEST	230	1	2						
2004PI-26	EATON PK	230	CREWSLK	230	1	13						
2004PI-26	EATON PK	230	EATON PK	69	1	13						
2004PI-26	EATON PK	230	TENOROC	230	1	13						
2004PI-26	RECKER	230	GAPWAY	230	1	16						
2004PI-26	SN PLANT	115	TURNER	115	1	1						
2004PI-27	SN PLANT	230	SYLVAN	230	1	1						
2004PI-27	SYLVAN	230	N LONGWD	230	1	1						
2004PI-27	IND RIV	230	STANTON	230	1	11						
2004PI-27	SN PLANT	115	TURNER	115	1	1						
2004PI-27	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-27	SILVR SP	230	SILV SPN	230	1	2						
2004PI-27	SILVR SP	230	OCALA 1	230	1	2						
2004PI-27	RIO PINR	230	CURRY FD	230	1	2						
2004PI-27	STANTON	230	CURRY FD	230	1	2						
2004PI-27	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-27	SHELD	230	LK TARPN	230	1	2						
2004PI-27	PEBB	230	CREWSLK	230	1	13						
2004PI-27	PEBB	230	N BARTOW	230	1	2						
2004PI-27	RECKER	230	LKAGNES	230	1	16						
2004PI-27	RECKER	230	ARIANA	230	1	16						
2004PI-27	RECKER	230	CREWSLK	230	1	13						
2004PI-27	B BEND	230	MANATEE	230	1	1						
2004PI-27	RUSKIN T	230	MANATEE	230	1	1						
2004PI-27	IND RIV	230	IND RIV	115	1	11						
2004PI-27	SHELD	230	SHELD-NW	69	1	16						
2004PI-27	LARGO	230	LARGO A	69	1	2						
2004PI-27	CLMT EST	230	CLMT EST	69	1	2						
2004PI-27	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-27	WINDERME	230	WINDERME	69	1	2						
2004PI-27	PASADENA	230	PASADENA	115	1	2						
2004PI-27	ARIANA	230	ARIANA-N	69	1	16						
2004PI-27	SELOSE	230	SELOSE-N	69	1	16						
2004PI-27	GAPWAY	230	GAPWAY	69	1	16						
2004PI-27	CREWSLK	230	CREWSLK	69	1	13						
2004PI-27	TENOROC	230	TENOROC	69	1	13						
2004PI-27	BARCOLA	230	WEST	230	1	2						
2004PI-27	EATON PK	230	CREWSLK	230	1	13						
2004PI-27	EATON PK	230	EATON PK	69	1	13						
2004PI-27	EATON PK	230	TENOROC	230	1	13						
2004PI-27	RECKER	230	GAPWAY	230	1	16						
2004PI-27	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-28	SN PLANT	230	SYLVAN	230	1	1						
2004PI-28	SYLVAN	230	N LONGWD	230	1	1						
2004PI-28	IND RIV	230	STANTON	230	1	11						
2004PI-28	SN PLANT	115	TURNER	115	1	1						
2004PI-28	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-28	SILVR SP	230	SILV SPN	230	1	2						
2004PI-28	SILVR SP	230	OCALA 1	230	1	2						
2004PI-28	RIO PINR	230	CURRY FD	230	1	2						
2004PI-28	STANTON	230	CURRY FD	230	1	2						
2004PI-28	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-28	SHELD	230	LK TARPN	230	1	2						
2004PI-28	PEBB	230	CREWSLK	230	1	13						
2004PI-28	PEBB	230	N BARTOW	230	1	2						
2004PI-28	RECKER	230	LKAGNES	230	1	16						
2004PI-28	RECKER	230	ARIANA	230	1	16						
2004PI-28	RECKER	230	CREWSLK	230	1	13						
2004PI-28	B BEND	230	MANATEE	230	1	1						
2004PI-28	RUSKIN T	230	MANATEE	230	1	1						
2004PI-28	IND RIV	230	IND RIV	115	1	11						
2004PI-28	SHELD	230	SHELD-NW	69	1	16						
2004PI-28	LARGO	230	LARGO A	69	1	2						
2004PI-28	CLMT EST	230	CLMT EST	69	1	2						
2004PI-28	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-28	WINDERME	230	WINDERME	69	1	2						
2004PI-28	PASADENA	230	PASADENA	115	1	2						
2004PI-28	ARIANA	230	ARIANA-N	69	1	16						
2004PI-28	SELOSE	230	SELOSE-N	69	1	16						
2004PI-28	GAPWAY	230	GAPWAY	69	1	16						
2004PI-28	CREWSLK	230	CREWSLK	69	1	13						
2004PI-28	TENOROC	230	TENOROC	69	1	13						
2004PI-28	BARCOLA	230	WEST	230	1	2						
2004PI-28	EATON PK	230	CREWSLK	230	1	13						
2004PI-28	EATON PK	230	EATON PK	69	1	13						
2004PI-28	EATON PK	230	TENOROC	230	1	13						
2004PI-28	RECKER	230	GAPWAY	230	1	16						
2004PI-28	SN PLANT	115	TURNER	115	1	1						
2004PI-29	SN PLANT	230	SYLVAN	230	1	1						
2004PI-29	SYLVAN	230	N LONGWD	230	1	1						
2004PI-29	IND RIV	230	STANTON	230	1	11						
2004PI-29	SN PLANT	115	TURNER	115	1	1						
2004PI-29	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-29	SILVR SP	230	SILV SPN	230	1	2						
2004PI-29	SILVR SP	230	OCALA 1	230	1	2						
2004PI-29	RIO PINR	230	CURRY FD	230	1	2						
2004PI-29	STANTON	230	CURRY FD	230	1	2						
2004PI-29	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-29	SHELD	230	LK TARPN	230	1	2						
2004PI-29	PEBB	230	CREWSLK	230	1	13						
2004PI-29	PEBB	230	N BARTOW	230	1	2						
2004PI-29	RECKER	230	LKAGNES	230	1	16						
2004PI-29	RECKER	230	ARIANA	230	1	16						
2004PI-29	RECKER	230	CREWSLK	230	1	13						
2004PI-29	B BEND	230	MANATEE	230	1	1						
2004PI-29	RUSKIN T	230	MANATEE	230	1	1						
2004PI-29	IND RIV	230	IND RIV	115	1	11						
2004PI-29	SHELD	230	SHELD-NW	69	1	16						
2004PI-29	LARGO	230	LARGO A	69	1	2						
2004PI-29	CLMT EST	230	CLMT EST	69	1	2						
2004PI-29	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-29	WINDERME	230	WINDERME	69	1	2						
2004PI-29	PASADENA	230	PASADENA	115	1	2						
2004PI-29	ARIANA	230	ARIANA-N	69	1	16		104.2	103.9	104.6	103.8	103.8
2004PI-29	SELOSE	230	SELOSE-N	69	1	16						
2004PI-29	GAPWAY	230	GAPWAY	69	1	16						
2004PI-29	CREWSLK	230	CREWSLK	69	1	13						
2004PI-29	TENOROC	230	TENOROC	69	1	13						
2004PI-29	BARCOLA	230	WEST	230	1	2						
2004PI-29	EATON PK	230	CREWSLK	230	1	13						
2004PI-29	EATON PK	230	EATON PK	69	1	13						
2004PI-29	EATON PK	230	TENOROC	230	1	13						
2004PI-29	RECKER	230	GAPWAY	230	1	16						
2004PI-29	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-30	SN PLANT	230	SYLVAN	230	1	1						
2004PI-30	SYLVAN	230	N LONGWD	230	1	1						
2004PI-30	IND RIV	230	STANTON	230	1	11						
2004PI-30	SN PLANT	115	TURNER	115	1	1						
2004PI-30	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-30	SILVR SP	230	SILV SPN	230	1	2						
2004PI-30	SILVR SP	230	OCALA 1	230	1	2						
2004PI-30	RIO PINR	230	CURRY FD	230	1	2						
2004PI-30	STANTON	230	CURRY FD	230	1	2						
2004PI-30	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-30	SHELD	230	LK TARPN	230	1	2						
2004PI-30	PEBB	230	CREWSLK	230	1	13						
2004PI-30	PEBB	230	N BARTOW	230	1	2						
2004PI-30	RECKER	230	LKAGNES	230	1	16						
2004PI-30	RECKER	230	ARIANA	230	1	16						
2004PI-30	RECKER	230	CREWSLK	230	1	13						
2004PI-30	B BEND	230	MANATEE	230	1	1						
2004PI-30	RUSKIN T	230	MANATEE	230	1	1						
2004PI-30	IND RIV	230	IND RIV	115	1	11						
2004PI-30	SHELD	230	SHELD-NW	69	1	16						
2004PI-30	LARGO	230	LARGO A	69	1	2						
2004PI-30	CLMT EST	230	CLMT EST	69	1	2						
2004PI-30	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-30	WINDERME	230	WINDERME	69	1	2						
2004PI-30	PASADENA	230	PASADENA	115	1	2						
2004PI-30	ARIANA	230	ARIANA-N	69	1	16						
2004PI-30	SELOSE	230	SELOSE-N	69	1	16						
2004PI-30	GAPWAY	230	GAPWAY	69	1	16						
2004PI-30	CREWSLK	230	CREWSLK	69	1	13						
2004PI-30	TENOROC	230	TENOROC	69	1	13						
2004PI-30	BARCOLA	230	WEST	230	1	2						
2004PI-30	EATON PK	230	CREWSLK	230	1	13						
2004PI-30	EATON PK	230	EATON PK	69	1	13						
2004PI-30	EATON PK	230	TENOROC	230	1	13						
2004PI-30	RECKER	230	GAPWAY	230	1	16						
2004PI-30	SN PLANT	115	TURNER	115	1	1						
2004PI-31	SN PLANT	230	SYLVAN	230	1	1						
2004PI-31	SYLVAN	230	N LONGWD	230	1	1						
2004PI-31	IND RIV	230	STANTON	230	1	11						
2004PI-31	SN PLANT	115	TURNER	115	1	1						
2004PI-31	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-31	SILVR SP	230	SILV SPN	230	1	2						
2004PI-31	SILVR SP	230	OCALA 1	230	1	2						
2004PI-31	RIO PINR	230	CURRY FD	230	1	2						
2004PI-31	STANTON	230	CURRY FD	230	1	2						
2004PI-31	OSCEOLA	230	LKAGNES	230	1	16						
2004PI-31	SHELD	230	LK TARPN	230	1	2						
2004PI-31	PEBB	230	CREWSLK	230	1	13						
2004PI-31	PEBB	230	N BARTOW	230	1	2						
2004PI-31	RECKER	230	LKAGNES	230	1	16						
2004PI-31	RECKER	230	ARIANA	230	1	16						
2004PI-31	RECKER	230	CREWSLK	230	1	13						
2004PI-31	B BEND	230	MANATEE	230	1	1						
2004PI-31	RUSKIN T	230	MANATEE	230	1	1						
2004PI-31	IND RIV	230	IND RIV	115	1	11						
2004PI-31	SHELD	230	SHELD-NW	69	1	16						
2004PI-31	LARGO	230	LARGO A	69	1	2						
2004PI-31	CLMT EST	230	CLMT EST	69	1	2						
2004PI-31	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-31	WINDERME	230	WINDERME	69	1	2						
2004PI-31	PASADENA	230	PASADENA	115	1	2						
2004PI-31	ARIANA	230	ARIANA-N	69	1	16						
2004PI-31	SELOSE	230	SELOSE-N	69	1	16						
2004PI-31	GAPWAY	230	GAPWAY	69	1	16						
2004PI-31	CREWSLK	230	CREWSLK	69	1	13						
2004PI-31	TENOROC	230	TENOROC	69	1	13						
2004PI-31	BARCOLA	230	WEST	230	1	2						
2004PI-31	EATON PK	230	CREWSLK	230	1	13						
2004PI-31	EATON PK	230	EATON PK	69	1	13						
2004PI-31	EATON PK	230	TENOROC	230	1	13						
2004PI-31	RECKER	230	GAPWAY	230	1	16						
2004PI-31	SN PLANT	115	TURNER	115	1	1						

Table II

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004PI-32	SN PLANT	230	SYLVAN	230	1	1						
2004PI-32	SYLVAN	230	N LONGWD	230	1	1						
2004PI-32	IND RIV	230	STANTON	230	1	11						
2004PI-32	SN PLANT	115	TURNER	115	1	1						
2004PI-32	BUCKEYE	230	RUSKMTR8	230	1	1						
2004PI-32	SILVR SP	230	SILV SPN	230	1	2						
2004PI-32	SILVR SP	230	OCALA 1	230	1	2						
2004PI-32	RIO PINR	230	CURRY FD	230	1	2						
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2004PI-32	RUSKIN T	230	MANATEE	230	1	1						
2004PI-32	IND RIV	230	IND RIV	115	1	11						
2004PI-32	SHELD	230	SHELD-NW	69	1	16						
2004PI-32	LARGO	230	LARGO A	69	1	2						
2004PI-32	CLMT EST	230	CLMT EST	69	1	2						
2004PI-32	11TH AVE	230	ELEVEN-E	69	1	16						
2004PI-32	WINDERME	230	WINDERME	69	1	2						
2004PI-32	PASADENA	230	PASADENA	115	1	2						
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2004PI-32	SELOSE	230	SELOSE-N	69	1	16						
2004PI-32	GAPWAY	230	GAPWAY	69	1	16						
2004PI-32	CREWSLK	230	CREWSLK	69	1	13						
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2004PI-32	BARCOLA	230	WEST	230	1	2						
2004PI-32	EATON PK	230	CREWSLK	230	1	13						
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Table II

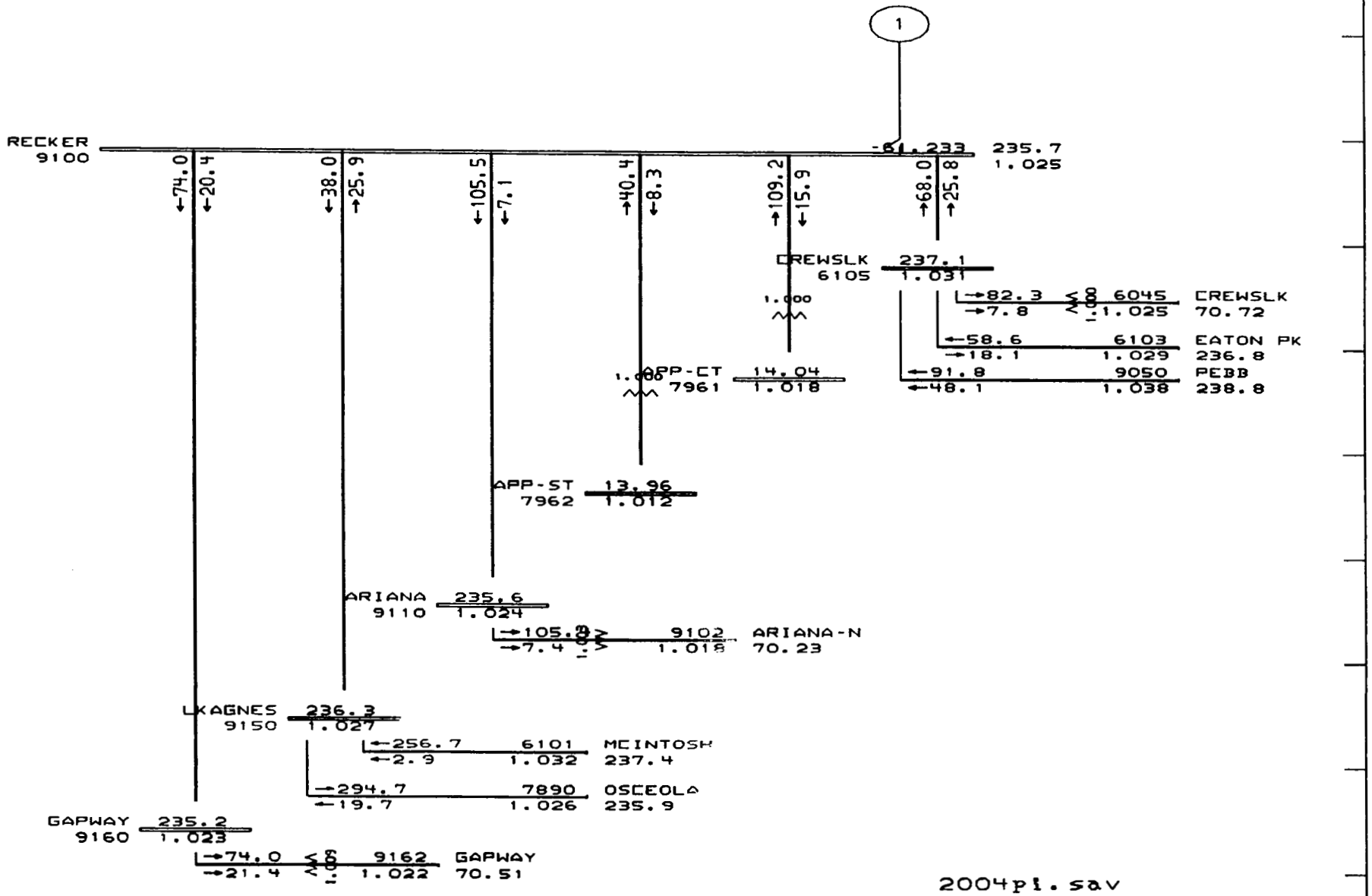
Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

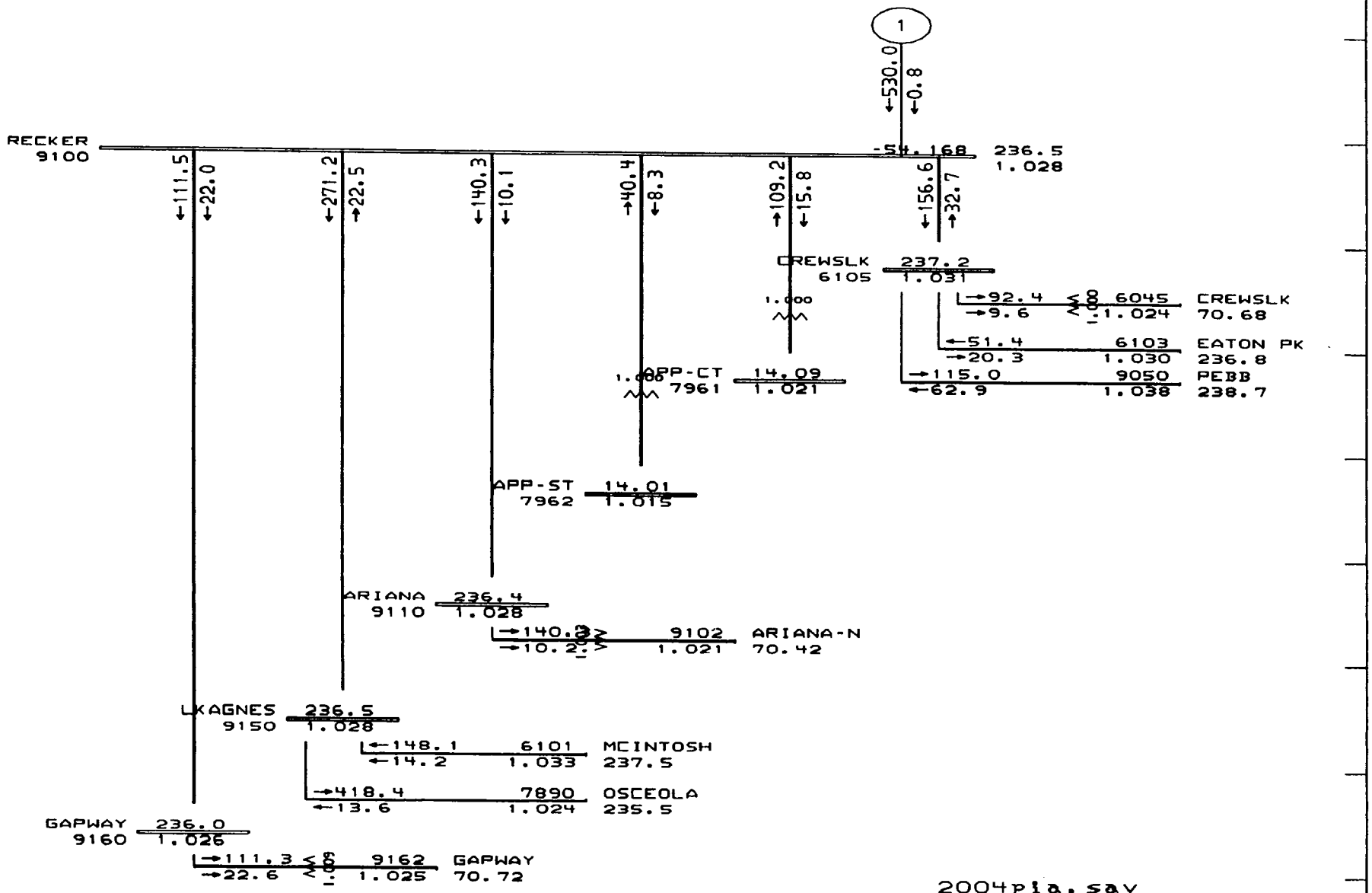
100% Load Base Case

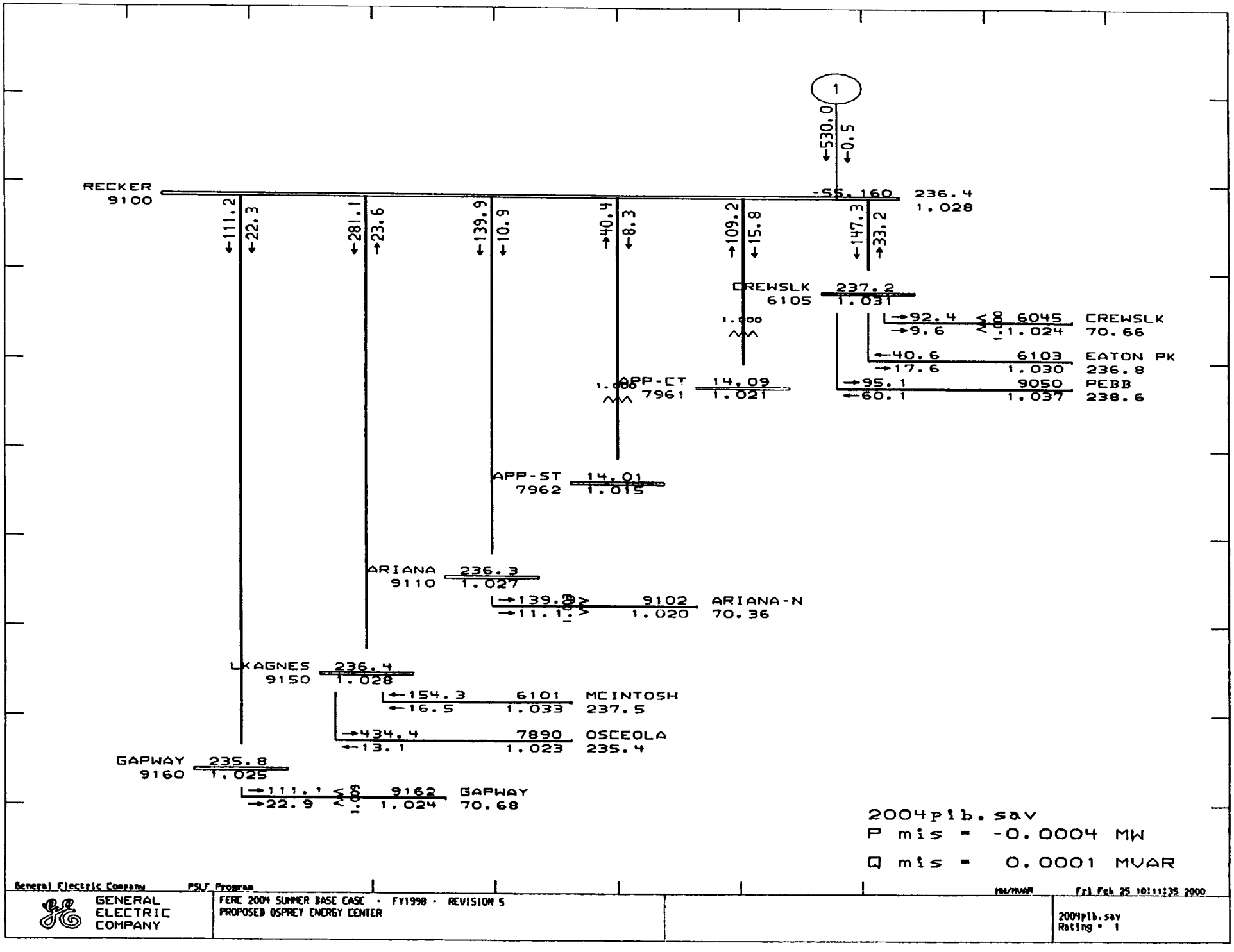
All Flows above 100% of Emergency rating are Shown

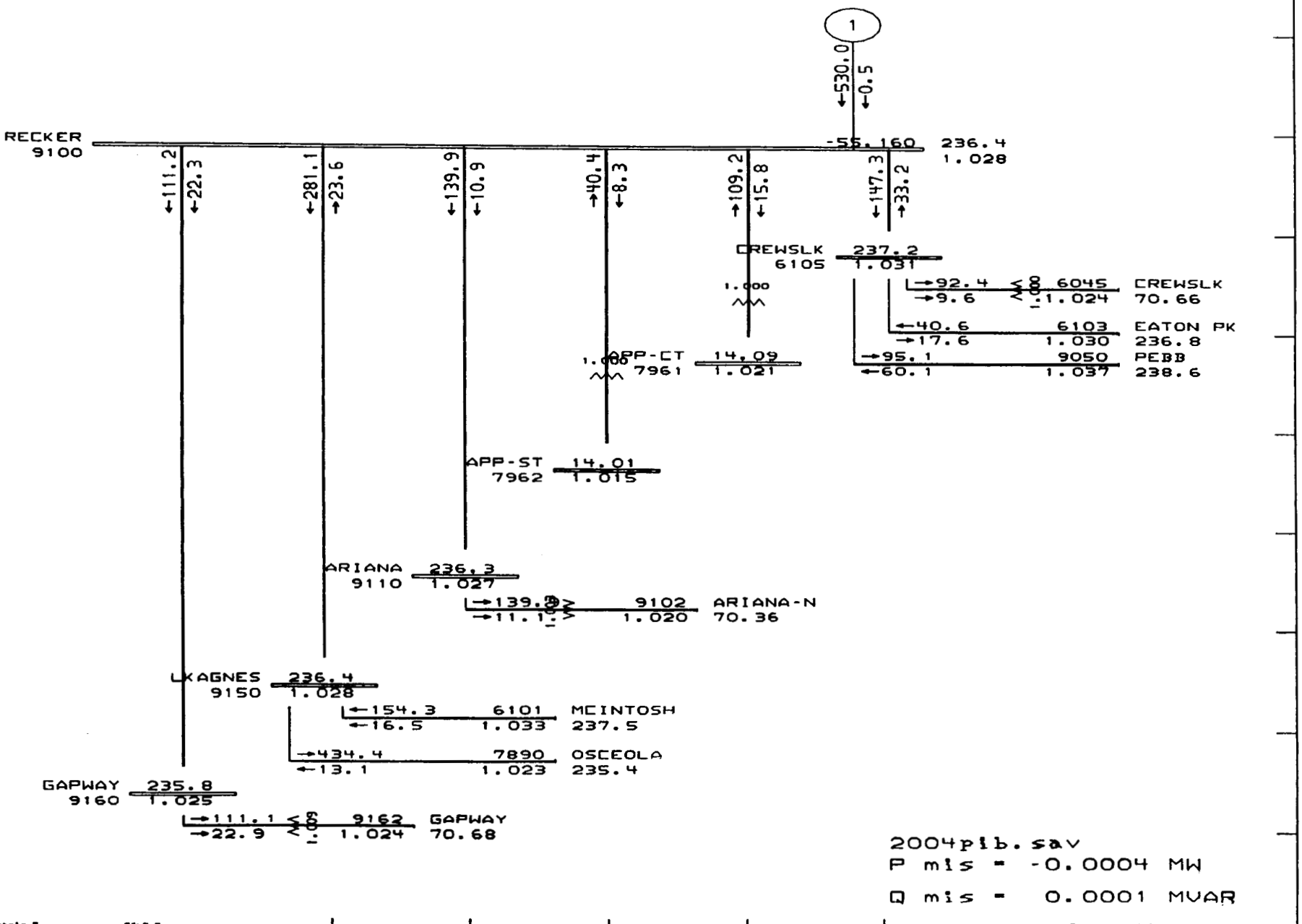
Monitored Branches							Case 2004PI Base No OEC Gen	Case 2004PIA Sell to FPL	Case 2004PIB Sell to FPC	Case 2004PIC Sell to TEC	Case 2004PID Sell to JEA	Case 2004PIE Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
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2004PI-34	SYLVAN	230	N LONGWD	230	1	1						
2004PI-34	IND RIV	230	STANTON	230	1	11						
2004PI-34	SN PLANT	115	TURNER	115	1	1						
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2004PI-34	SHELD	230	LK TARPN	230	1	2						
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2004PI-34	B BEND	230	MANATEE	230	1	1						
2004PI-34	RUSKIN T	230	MANATEE	230	1	1						
2004PI-34	IND RIV	230	IND RIV	115	1	11						
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2004PI-34	CLMT EST	230	CLMT EST	69	1	2						
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2004PI-34	PASADENA	230	PASADENA	115	1	2						
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2004PI-34	SELOSE	230	SELOSE-N	69	1	16						
2004PI-34	GAPWAY	230	GAPWAY	69	1	16						
2004PI-34	CREWSLK	230	CREWSLK	69	1	13						
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2004PI-35	SELOSE	230	SELOSE-N	69	1	16						
2004PI-35	GAPWAY	230	GAPWAY	69	1	16						
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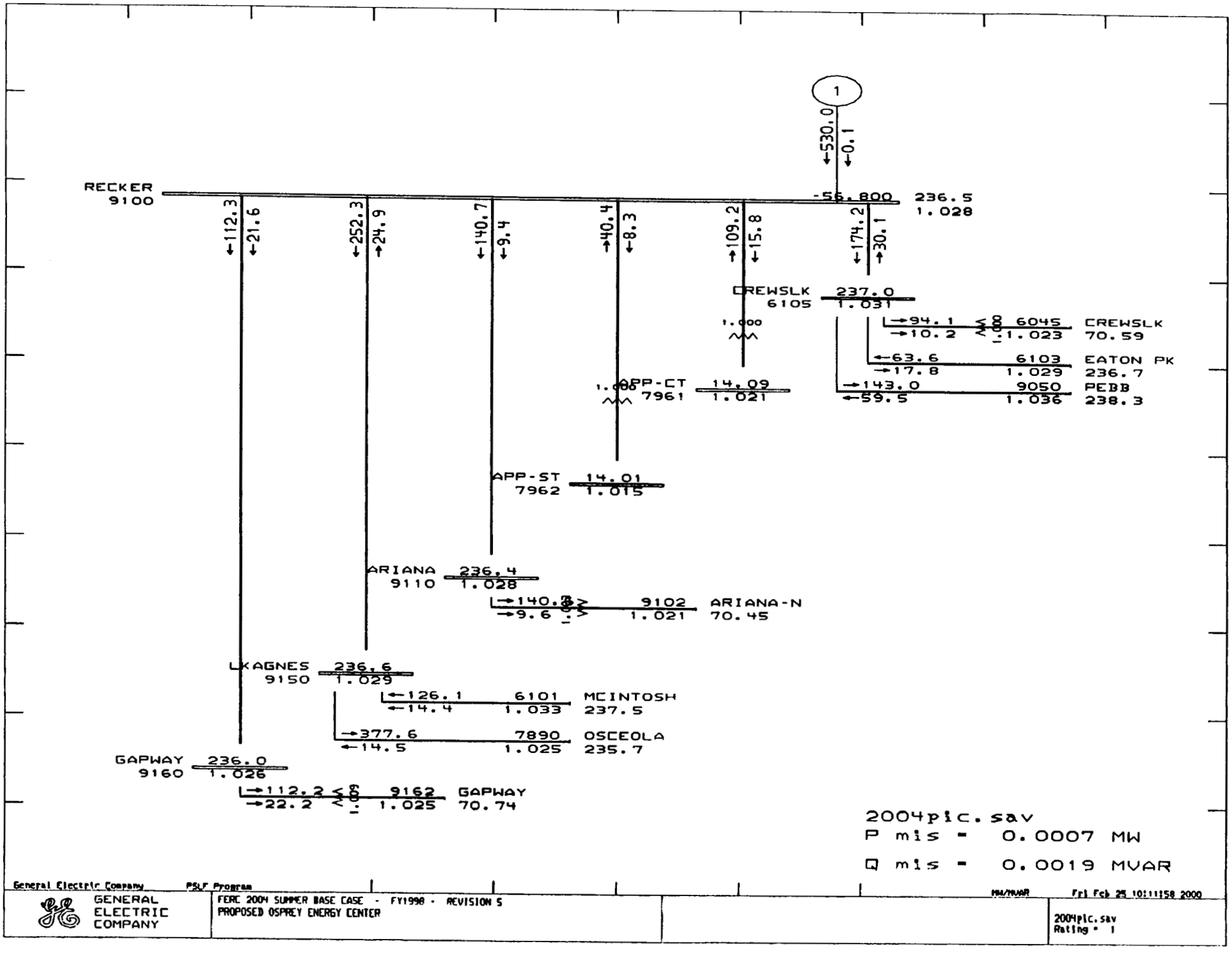
APPENDIX I-A

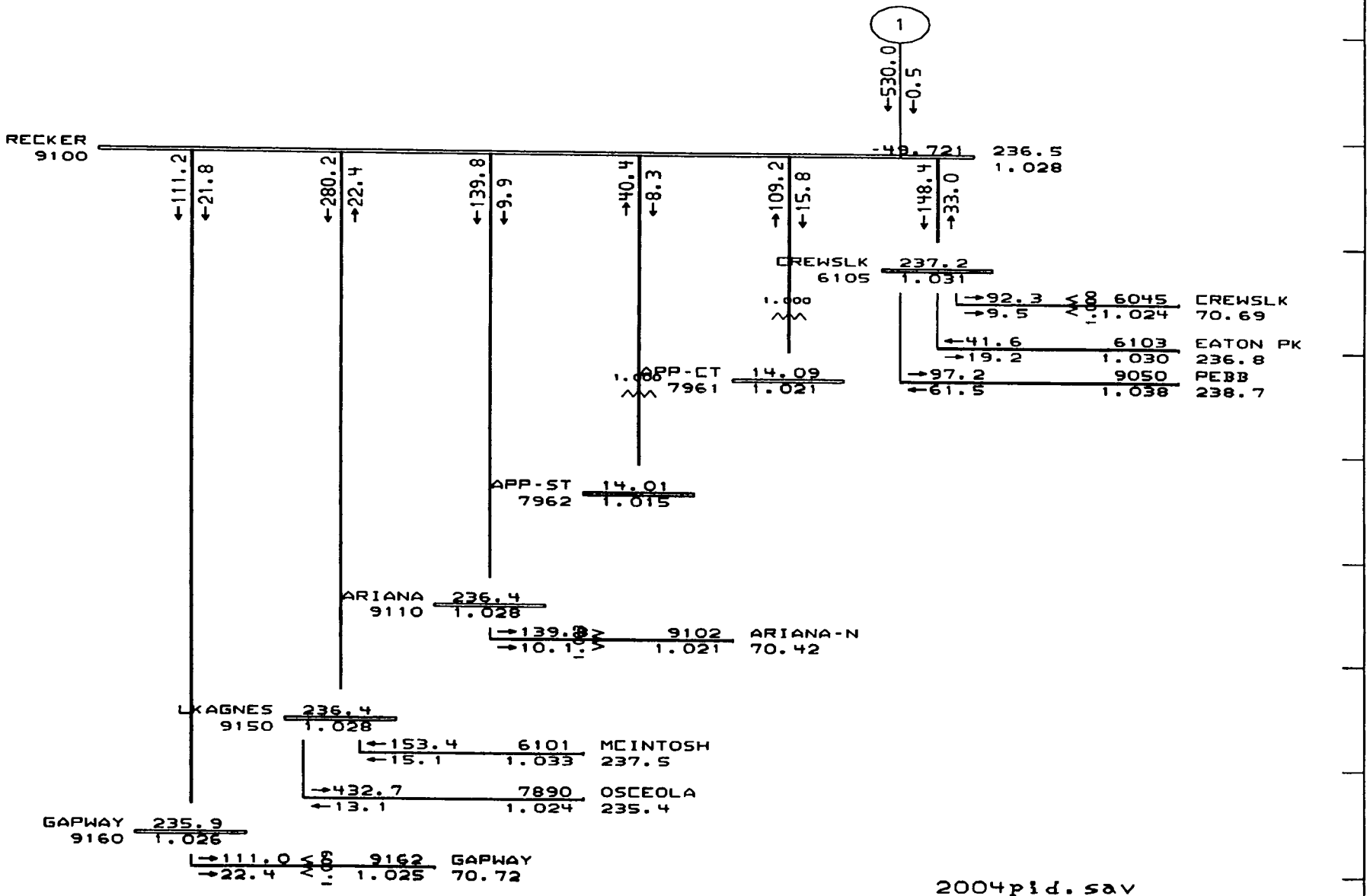

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EATON PK
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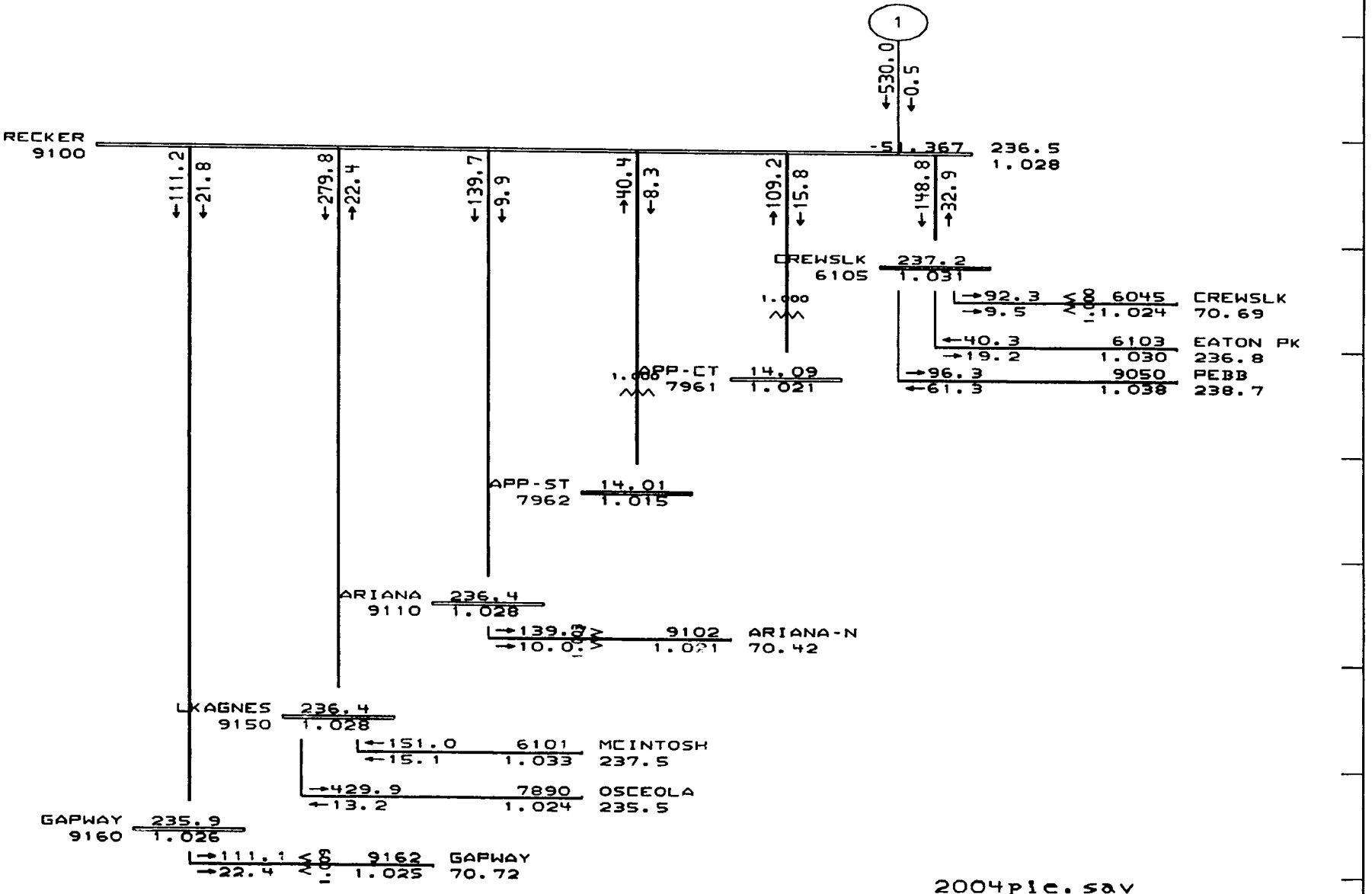


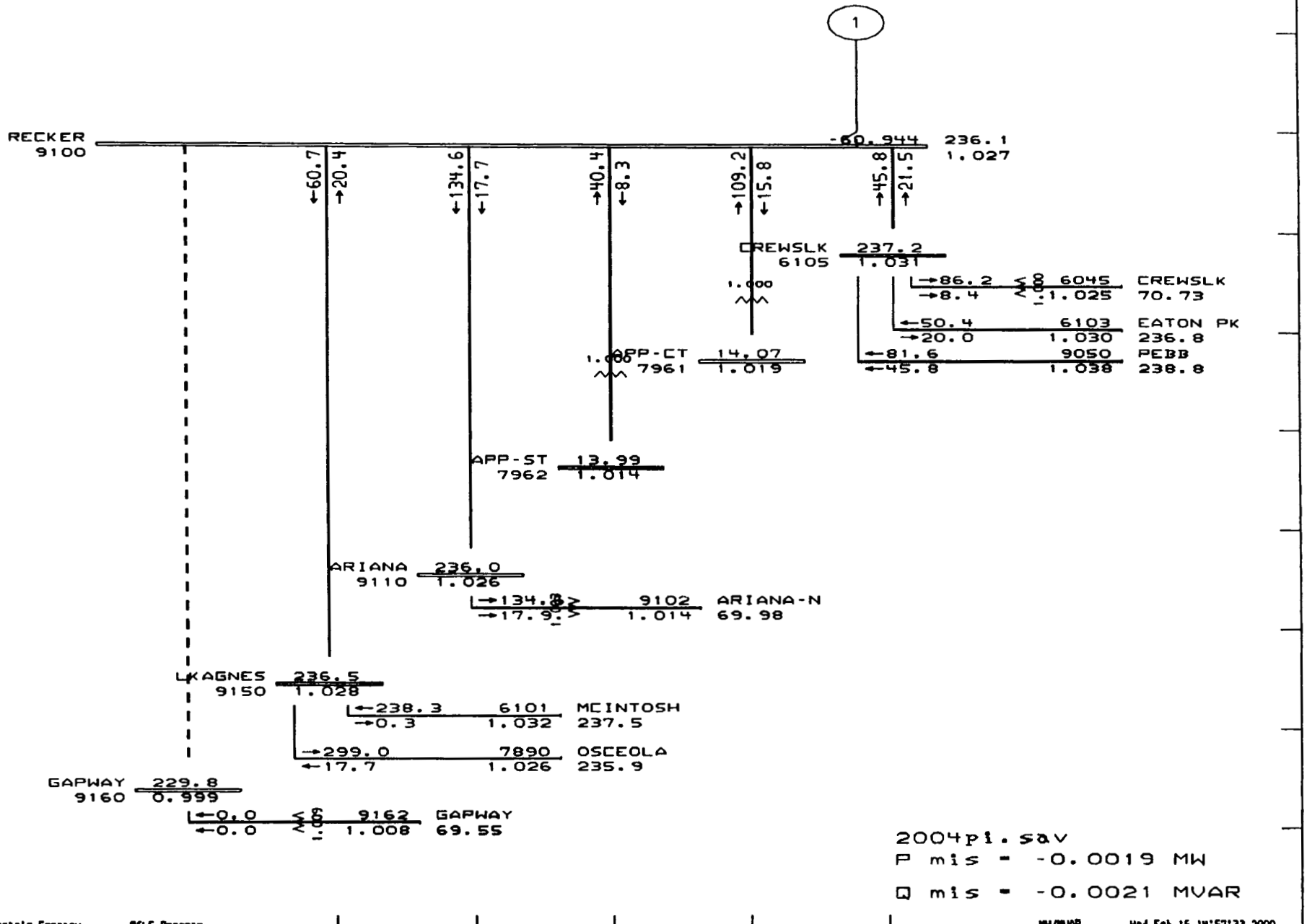
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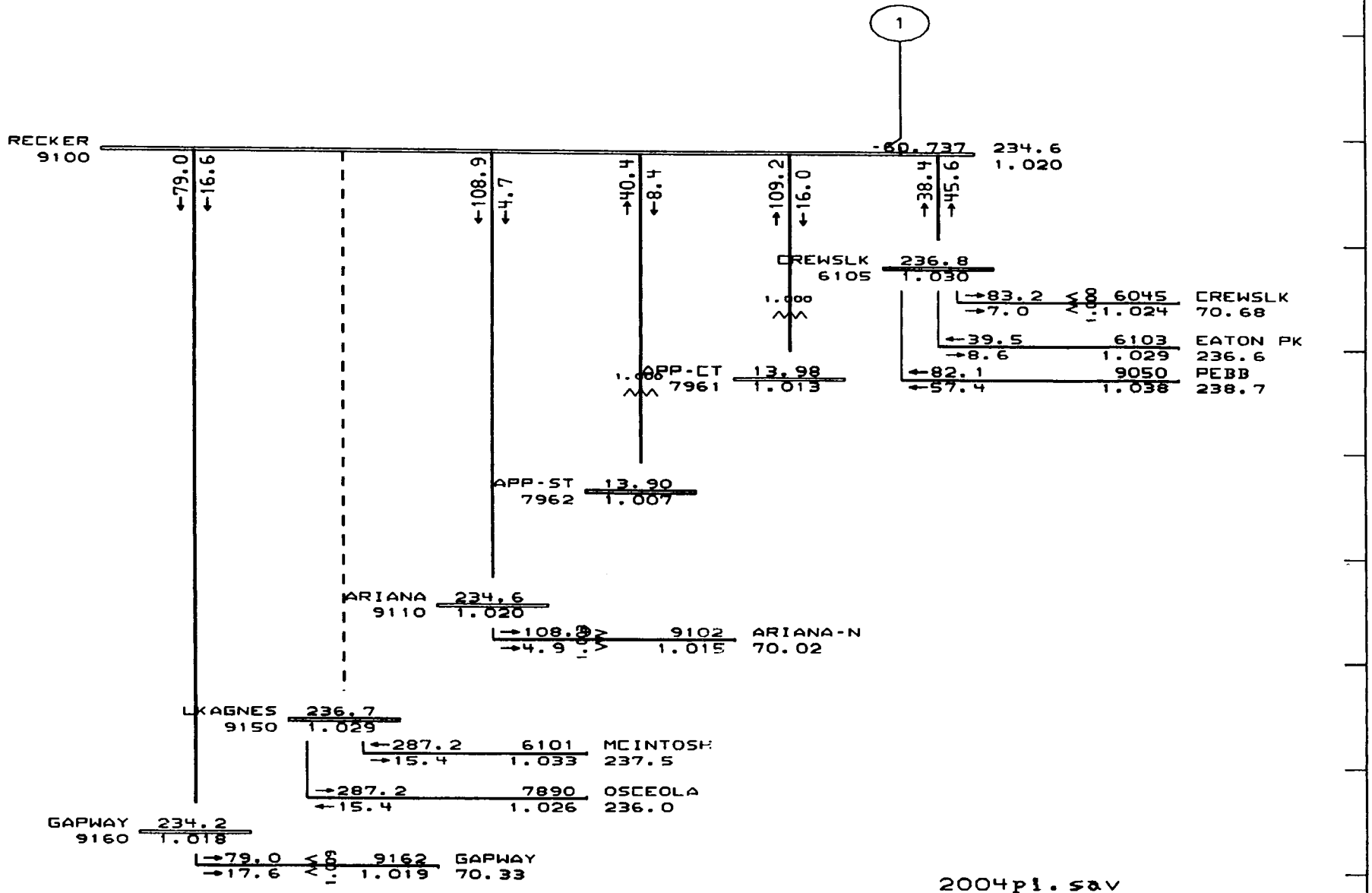
GENERAL ELECTRIC COMPANY

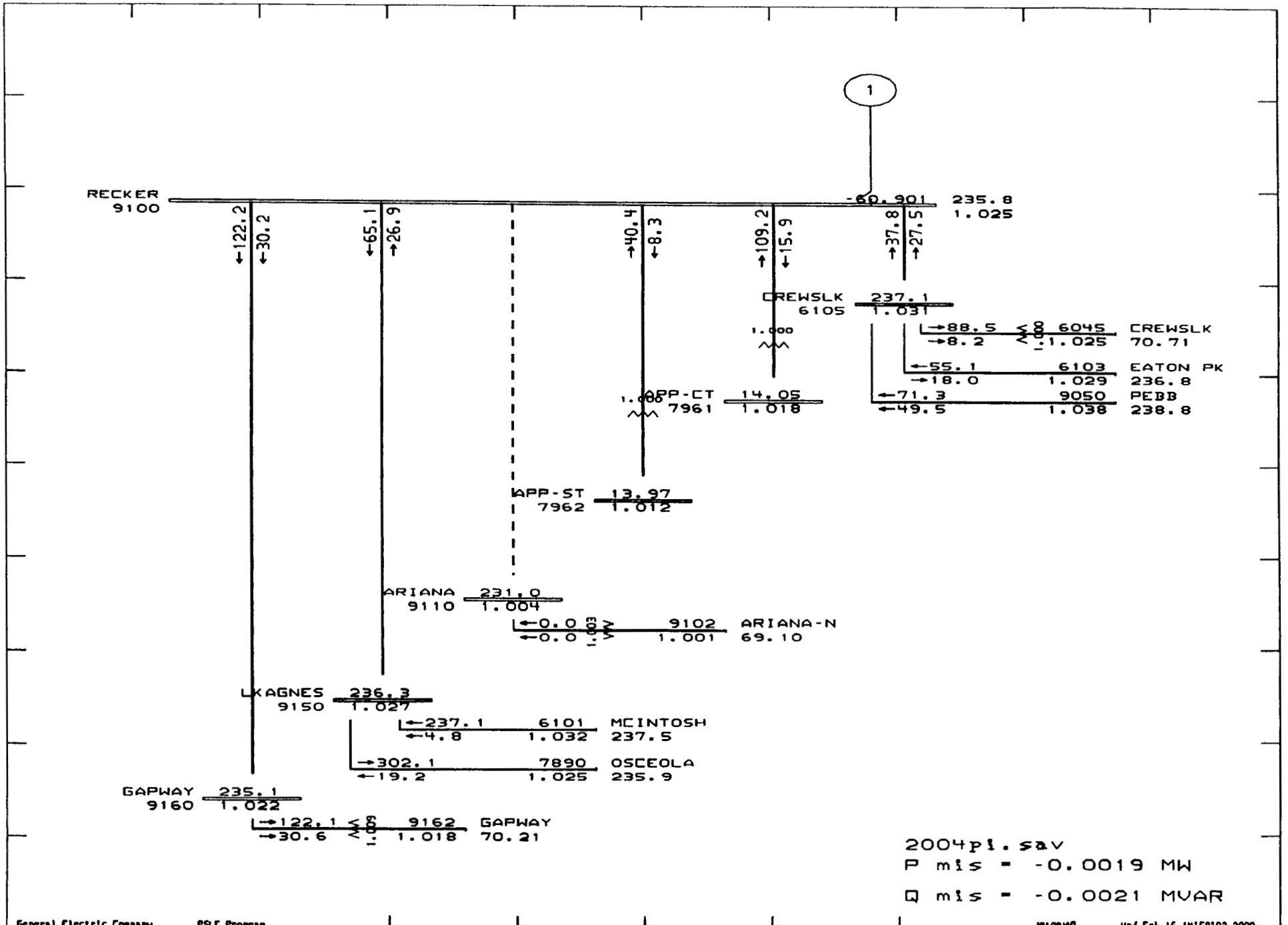
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PROPOSED OSPREY ENERGY CENTER

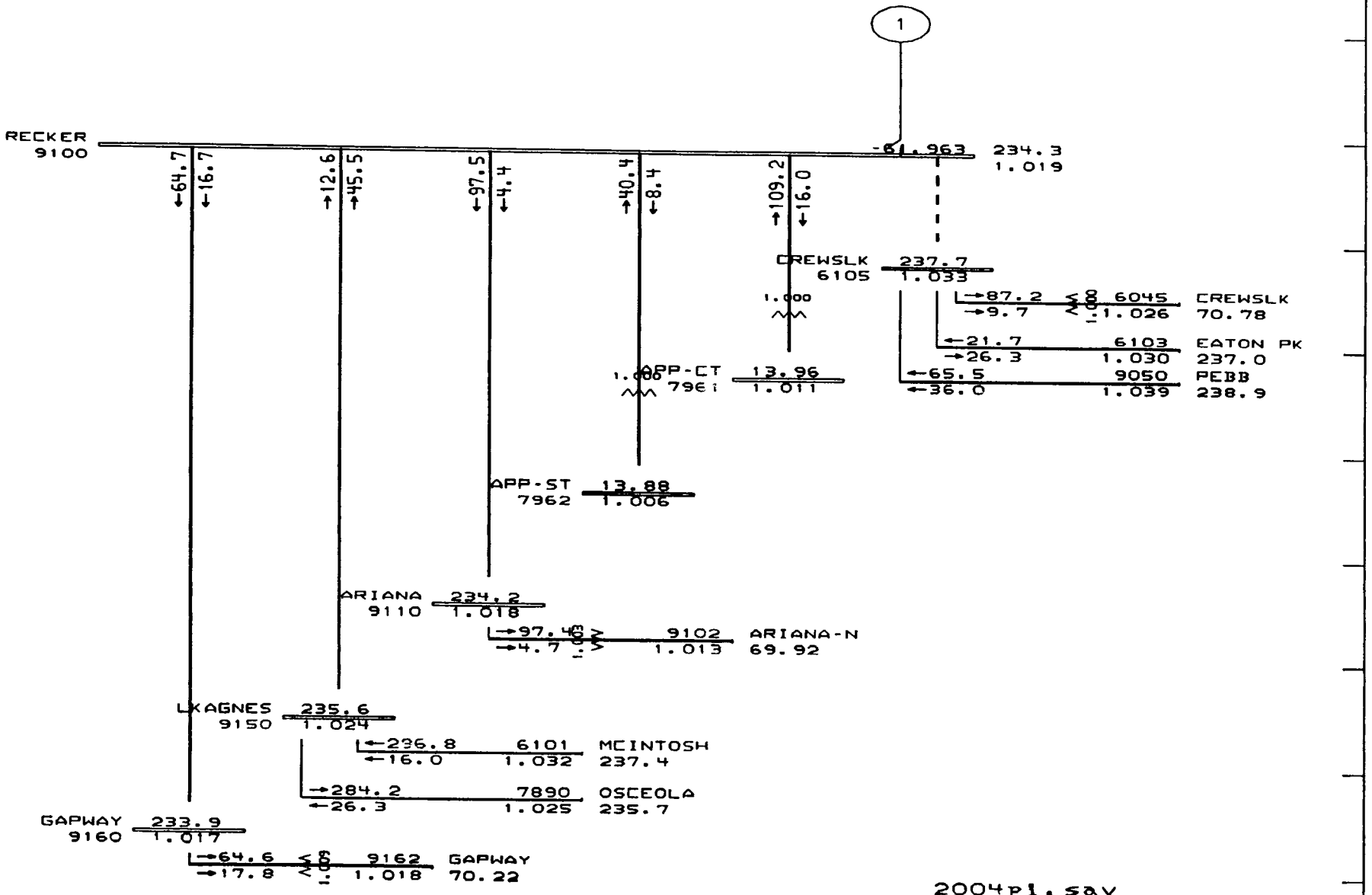
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→111.1 ≤ 9162 GAPWAY
→22.4 ≥ 1.025 70.72
2004pic.sav
P mis = 0.0005 MW
Q mis = -0.0027 MVAR
General Electric Company PSLF Program
MW/MVAR Fri Feb 25 10:12:26 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004pic.sav
Rating = 1


1
RECKER
9100
-60.944
236.1
1.027
←60.7
→20.4
←134.6
←17.7
→40.4
←8.3
→109.2
←15.8
→45.8
←21.5
CREWSLK 237.2
6105 1.031
1.000
→86.2
→8.4
6045
1.025
CREWSLK
70.73
←50.4
→20.0
6103
1.030
EATON PK
236.8
←81.6
←45.8
9050
1.038
PEBB
238.8
APP-CT 14.07
1.000 7961 1.019
APP-ST 13.99
7962 1.014
ARIANA 236.0
9110 1.026
→134.8
→17.9
9102
1.014
ARIANA-N
69.98
LKAGNES 236.5
9150 1.028
←238.3
→0.3
6101
1.032
MCINTOSH
237.5
→299.0
←17.7
7890
1.026
OSCEOLA
235.9
GAPWAY 229.8
9160 0.999
←0.0
←0.0
9162
1.008
GAPWAY
69.55
2004pi.sav
P mis = -0.0019 MW
Q mis = -0.0021 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:57:33 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004pi.sav
Rating = 1


1
RECKER
9100
-60.737 234.6
1.020
→79.0
←16.6
→108.9
←4.7
→40.4
←8.4
→109.2
←16.0
→38.4
←45.6
CREWSLK 236.8
6105 1.030
1.000
→83.2 ≤ 6045 CREWSLK
→7.0 ≥ 1.024 70.68
←39.5 6103 EATON PK
→8.6 1.029 236.6
APP-CT 13.98
1.000 7961 1.013
←82.1 9050 PEBB
←57.4 1.038 238.7
APP-ST 13.90
7962 1.007
ARIANA 234.6
9110 1.020
→108.9 ≤ 9102 ARIANA-N
→4.9 ≥ 1.015 70.02
LKAGNES 236.7
9150 1.029
←287.2 6101 MCINTOSH
→15.4 1.033 237.5
→287.2 7890 OSCEOLA
←15.4 1.026 236.0
GAPWAY 234.2
9160 1.018
→79.0 ≤ 9162 GAPWAY
→17.6 ≥ 1.019 70.33
2004pl.sav
P mis = -0.0019 MW
Q mis = -0.0021 MVAR


1
RECKER
9100
-60.901
235.8
1.025
←122.2
←30.2
←65.1
←26.9
→40.4
←8.3
→109.2
←15.9
→37.8
←27.5
CREWSLK 237.1
6105 1.031
1.000
→88.5
→8.2
6045
1.025
CREWSLK
70.71
←55.1
→18.0
6103
1.029
EATON PK
236.8
APP-CT 14.05
1.000 7961 1.018
←71.3
←49.5
9050
1.038
PEBB
238.8
APP-ST 13.97
7962 1.012
ARIANA 231.0
9110 1.004
←0.0
←0.0
1.000
9102
1.001
ARIANA-N
69.10
LKAGNES 236.3
9150 1.027
←237.1
←4.8
6101
1.032
MCINTOSH
237.5
→302.1
←19.2
7890
1.025
OSCEOLA
235.9
GAPWAY 235.1
9160 1.022
→122.1
→30.6
1.000
9162
1.018
GAPWAY
70.21
2004pl.sav
P mis = -0.0019 MW
Q mis = -0.0021 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 14:58:02 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004pl.sav
Rating = 1



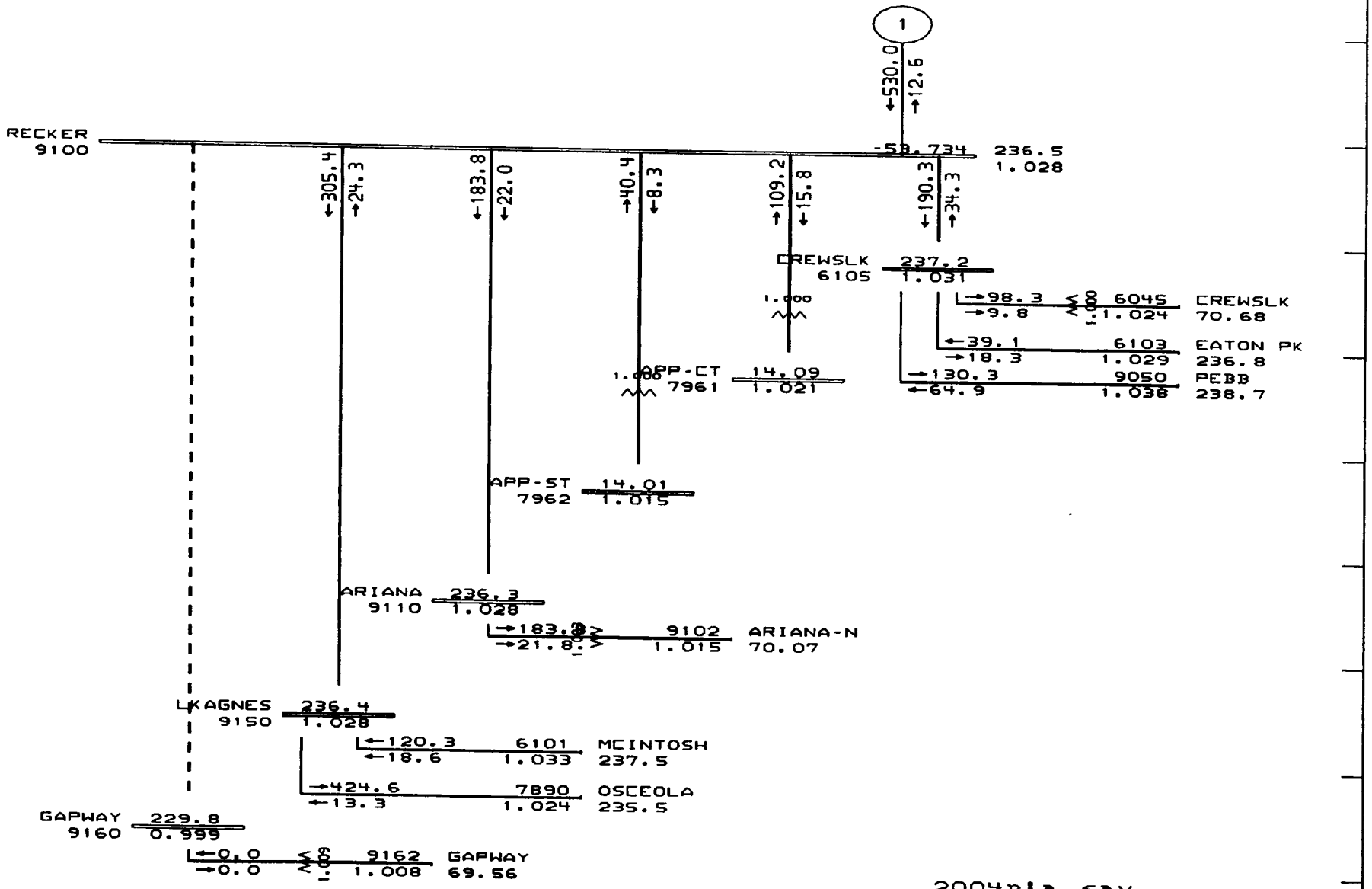
General Electric Company PSLF Program

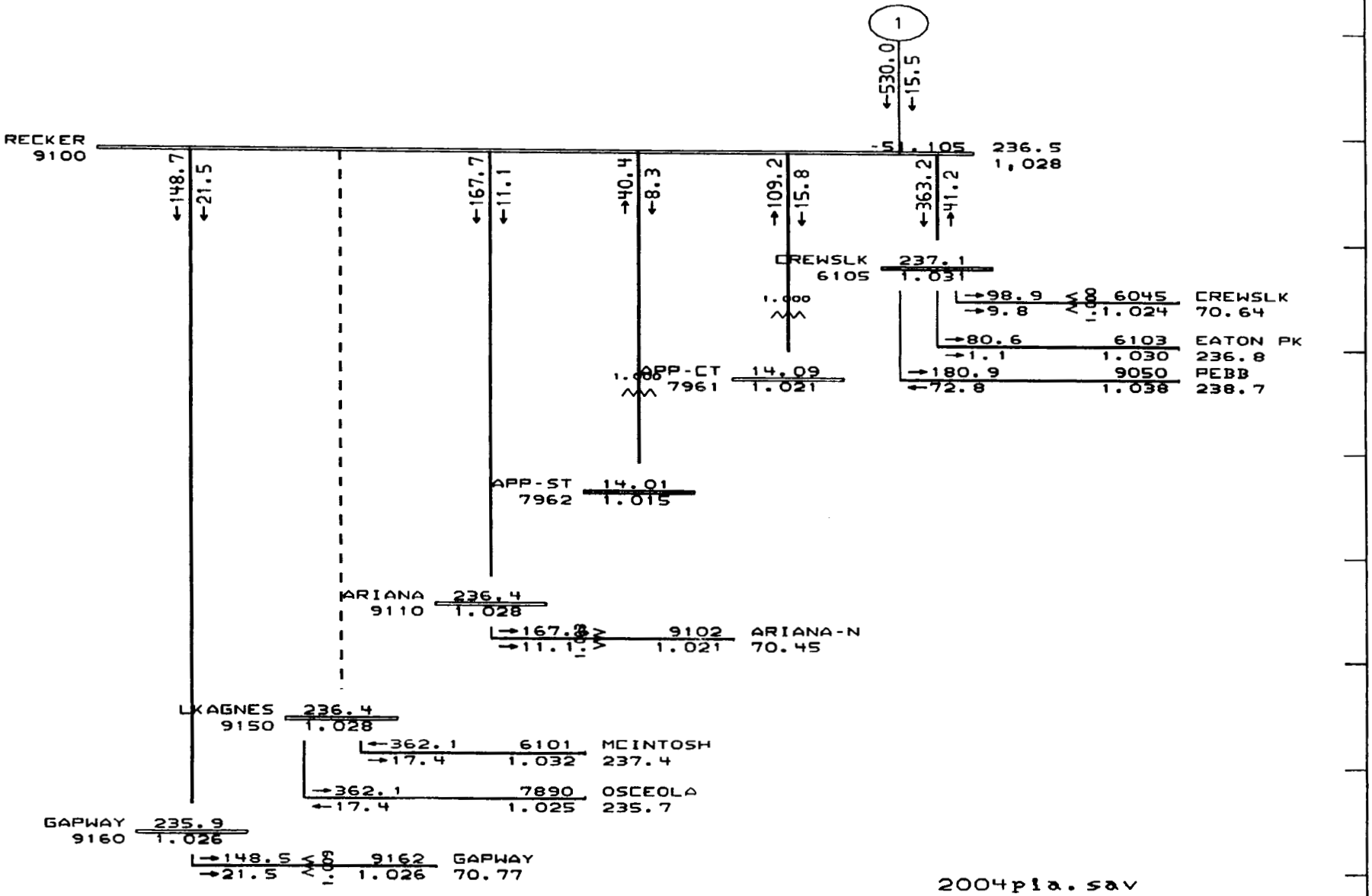
GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

MW/MVAR Wed Feb 16 15:00:55 2000

2004pl.sav
Rating = 1


1
530.0
12.6
RECKER
9100
-58.734
236.5
1.028
305.4
24.3
183.8
22.0
40.4
8.3
109.2
15.8
190.3
34.3
CREWSLK
6105
237.2
1.031
1.000
98.3
9.8
6045
1.024
CREWSLK
70.68
39.1
18.3
6103
1.029
EATON PK
236.8
APP-CT
7961
1.000
14.09
1.021
130.3
64.9
9050
1.038
PEBB
238.7
APP-ST
7962
14.01
1.015
ARIANA
9110
236.3
1.028
183.8
21.8
9102
1.015
ARIANA-N
70.07
LKAGNES
9150
236.4
1.028
120.3
18.6
6101
1.033
MCINTOSH
237.5
424.6
13.3
7890
1.024
OSCEOLA
235.5
GAPWAY
9160
229.8
0.999
0.0
0.0
9162
1.008
GAPWAY
69.56
2004pla.sav
P mis = -0.0019 MW
Q mis = 0.0009 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 15:01:14 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004pla.sav
Rating = 1

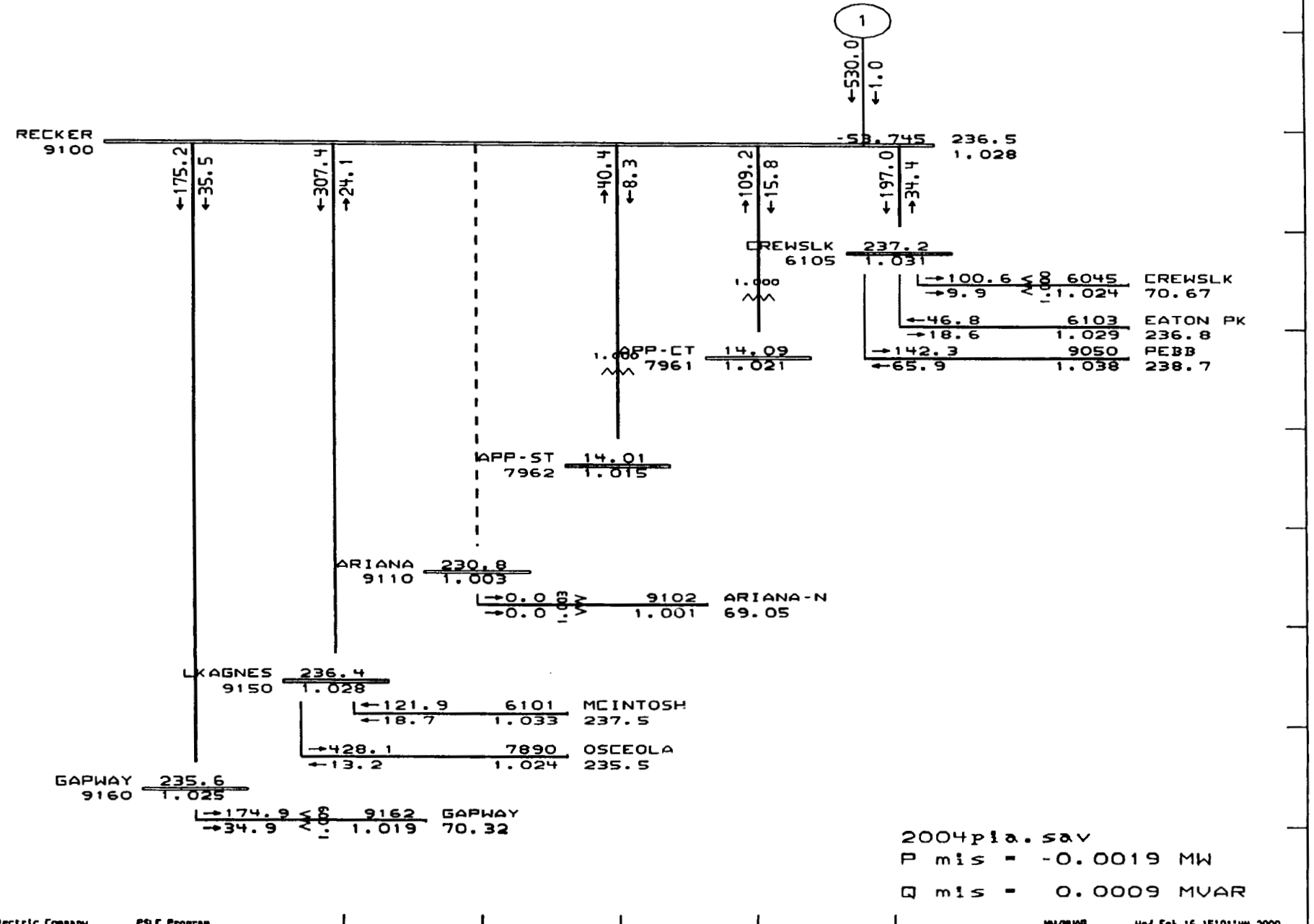


General Electric Company PSLF Program MW/MVAR Wed Feb 16 15:01:29 2000

GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

2004pia.sav
Rating = 1

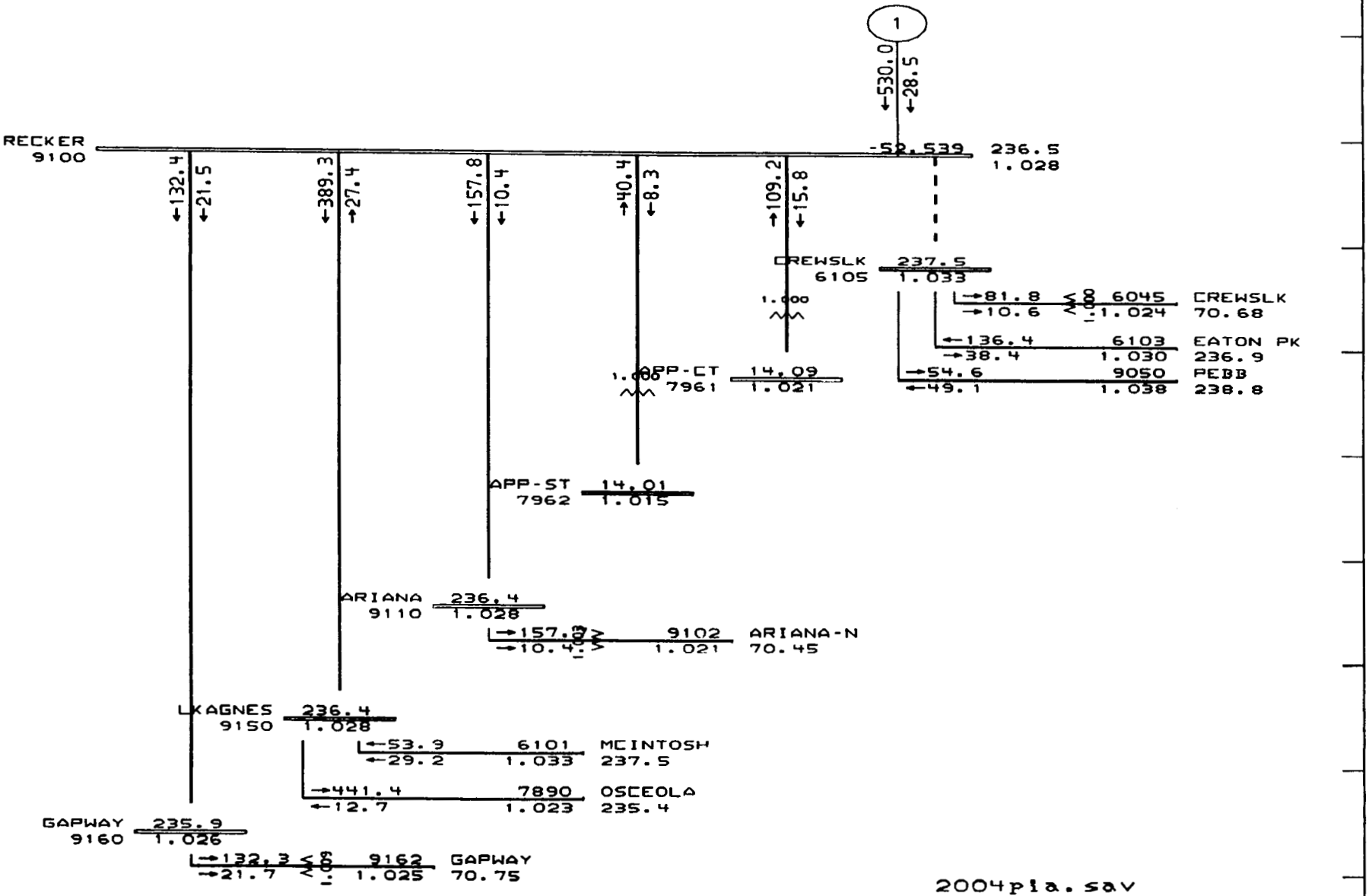


General Electric Company PSLF Program MW/MVAR Wed Feb 16 15:01:44 2000

GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

2004pia.sav
Rating = 1

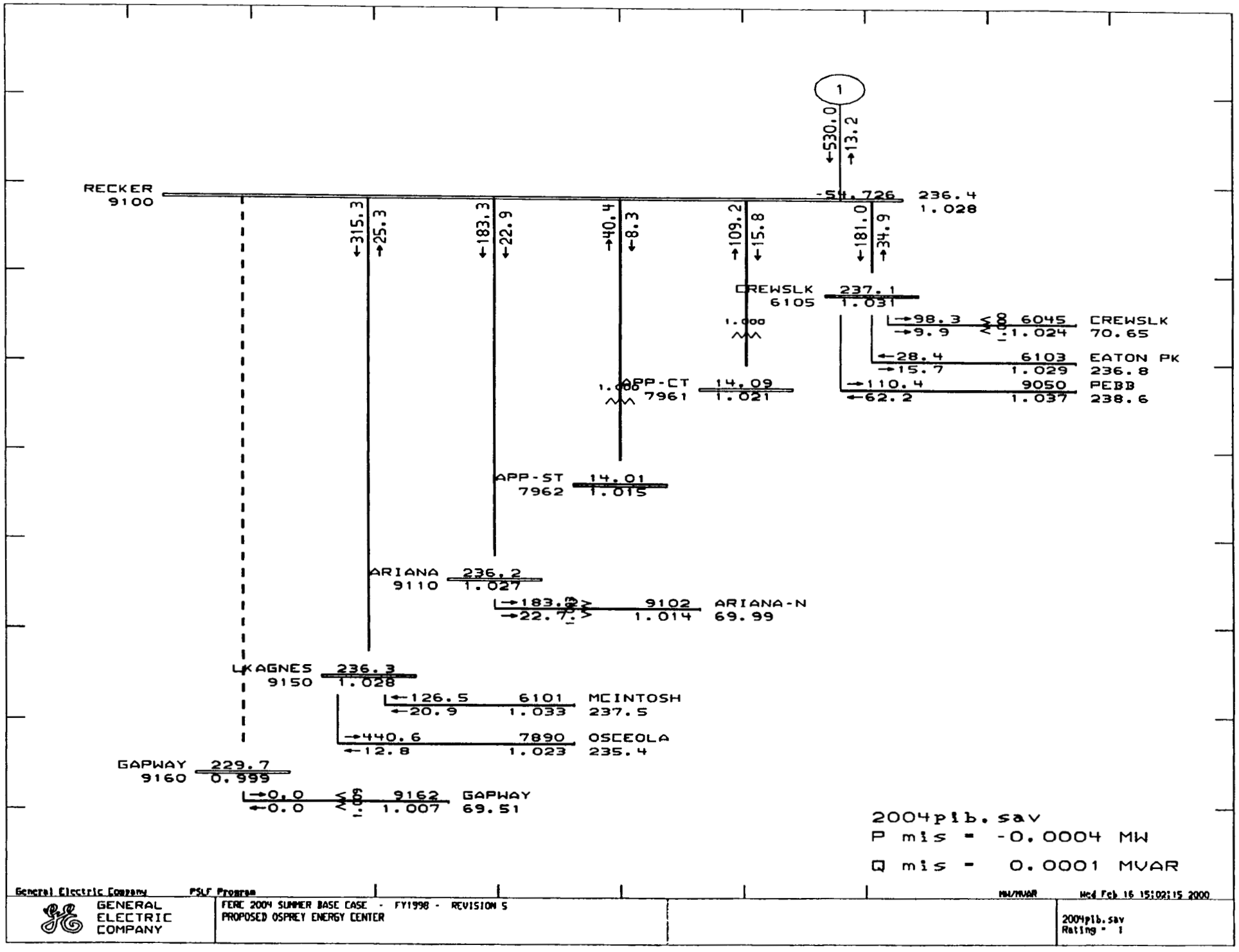


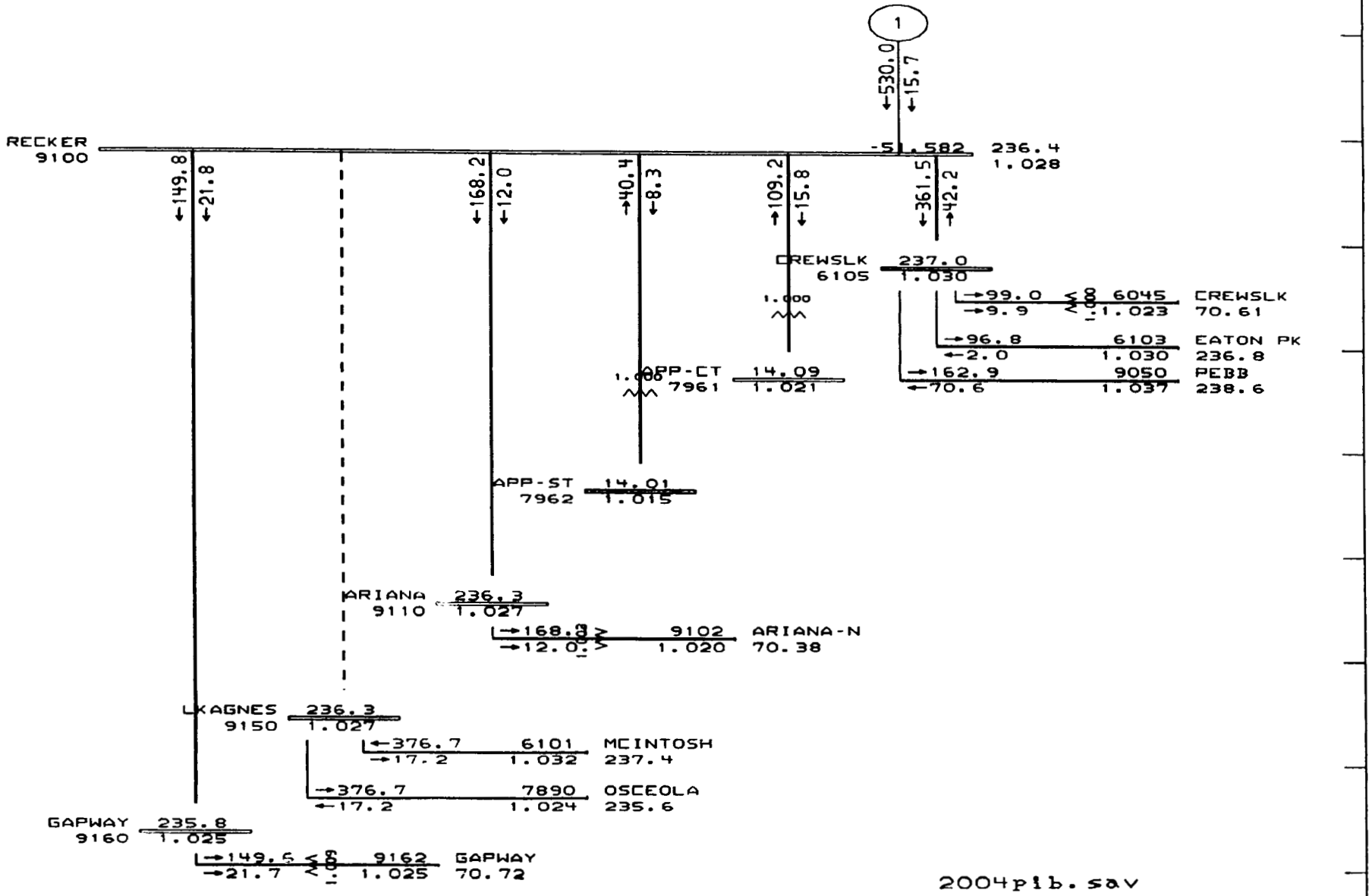
General Electric Company PSLF Program MW/MVAR Wed Feb 16 15:01:59 2000

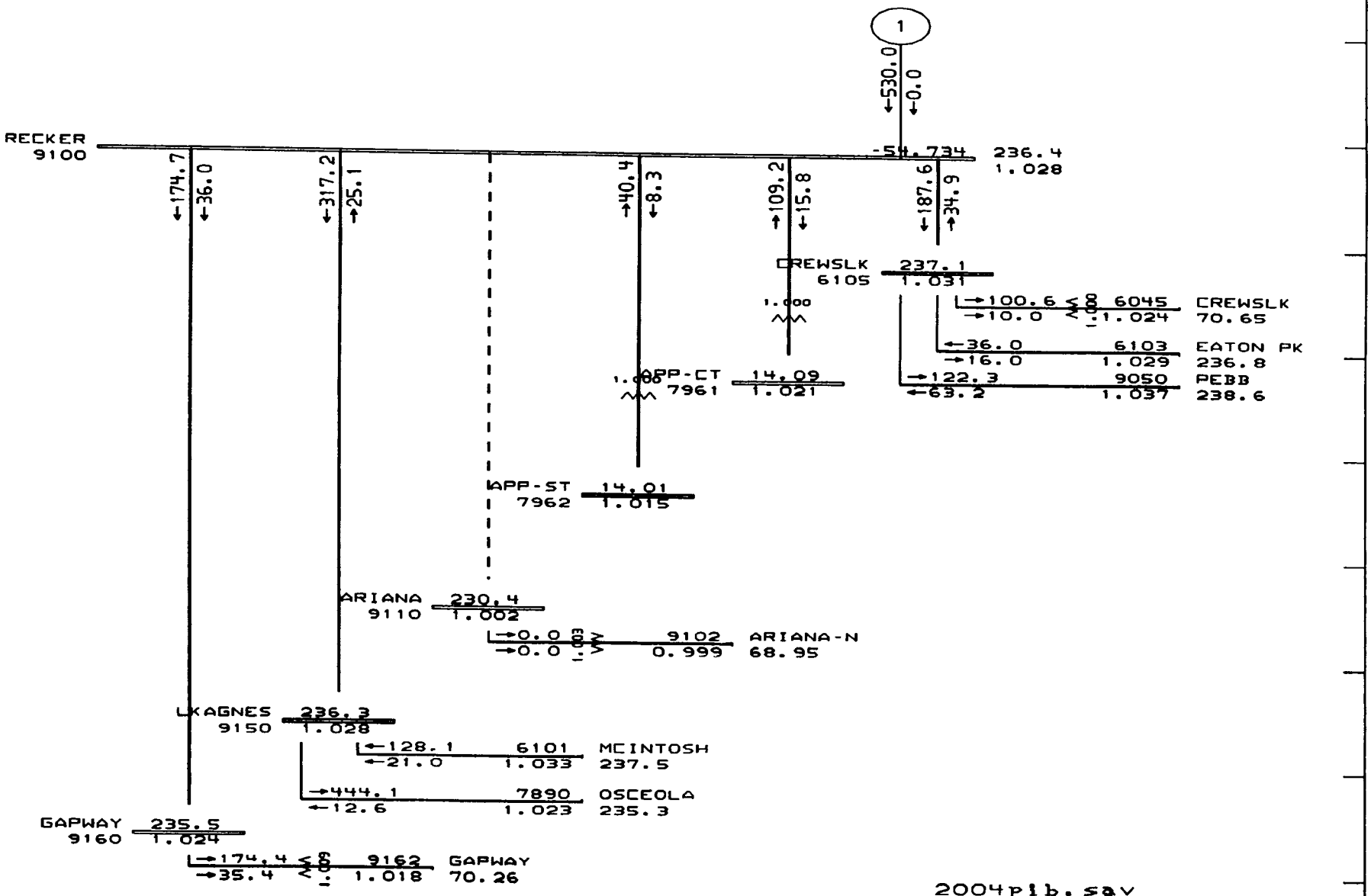
GENERAL ELECTRIC COMPANY

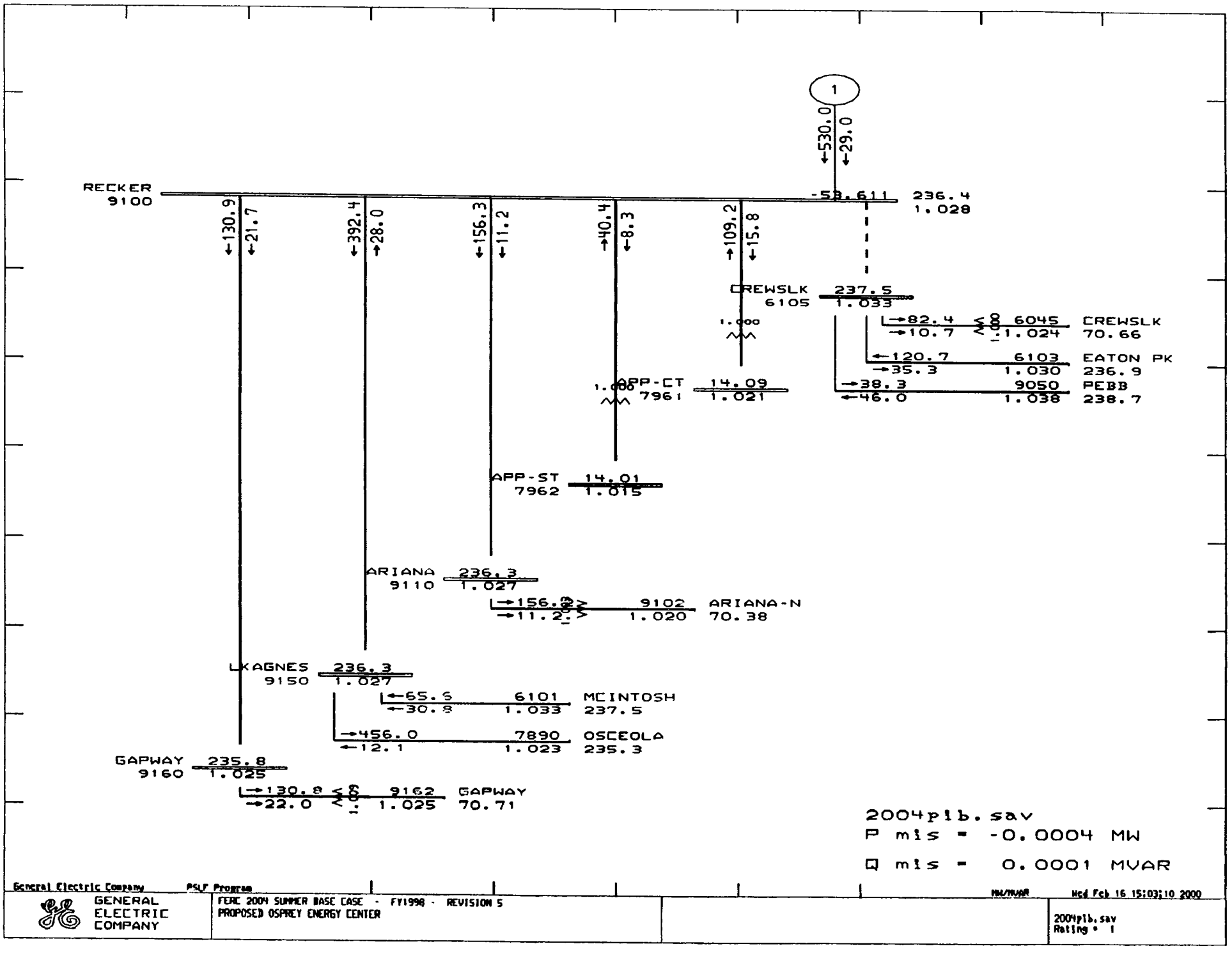
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

2004pia.sav
Rating = 1


RECKER
9100
-54.726
236.4
1.028
←530.0
→13.2
1
←315.3
→25.3
←183.3
→22.9
→40.4
←8.3
→109.2
←15.8
←181.0
→34.9
CREWSLK 237.1
6105 1.031
1.000
→98.3
→9.9
6045
1.024
CREWSLK
70.65
←28.4
→15.7
6103
1.029
EATON PK
236.8
1.000
APP-CT 14.09
7961 1.021
→110.4
←62.2
9050
1.037
PEBB
238.6
APP-ST 14.01
7962 1.015
ARIANA 236.2
9110 1.027
→183.2
→22.7
9102
1.014
ARIANA-N
69.99
LKAGNES 236.3
9150 1.028
←126.5
←20.9
6101
1.033
MCINTOSH
237.5
→440.6
←12.8
7890
1.023
OSCEOLA
235.4
GAPWAY 229.7
9160 0.999
→0.0
←0.0
9162
1.007
GAPWAY
69.51
2004plb.sav
P mis = -0.0004 MW
Q mis = 0.0001 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 15:02:15 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004plb.sav
Rating = 1


1
←530.0
←15.7
RECKER
9100
-51.582
236.4
1.028
←149.8
←21.8
←168.2
←12.0
→40.4
←8.3
→109.2
←15.8
←361.5
→42.2
CREWSLK 237.0
6105 1.030
→99.0 6045 CREWSLK
→9.9 1.023 70.61
→96.8 6103 EATON PK
←2.0 1.030 236.8
1.000
APP-CT 14.09
7961 1.021
→162.9 9050 PEBB
←70.6 1.037 238.6
1.000
APP-ST 14.01
7962 1.015
ARIANA 236.3
9110 1.027
→168.8 9102 ARIANA-N
→12.0 1.020 70.38
LKAGNES 236.3
9150 1.027
←376.7 6101 MCINTOSH
→17.2 1.032 237.4
→376.7 7890 OSCEOLA
←17.2 1.024 235.6
GAPWAY 235.8
9160 1.025
→149.6 9162 GAPWAY
→21.7 1.025 70.72
2004pib.sav
P mis = -0.0004 MW
Q mis = 0.0001 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 15:02:31 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004pib.sav
Rating = 1


1
←530.0
←0.0
RECKER
9100
-54.734
236.4
1.028
←174.7
←36.0
←317.2
→25.1
→40.4
←8.3
→109.2
←15.8
←187.6
→34.9
CREWSLK
6105
237.1
1.031
1.000
→100.6 ≤ 8
→10.0
6045
1.024
CREWSLK
70.65
←36.0
→16.0
6103
1.029
EATON PK
236.8
APP-CT
7961
14.09
1.021
→122.3
←63.2
9050
1.037
PEBB
238.6
APP-ST
7962
14.01
1.015
ARIANA
9110
230.4
1.002
→0.0 ≤ 8
→0.0
9102
0.999
ARIANA-N
68.95
LAGNES
9150
236.3
1.028
←128.1
←21.0
6101
1.033
MCINTOSH
237.5
→444.1
←12.6
7890
1.023
OSCEOLA
235.3
GAPWAY
9160
235.5
1.024
→174.4 ≤ 8
→35.4
9162
1.018
GAPWAY
70.26
2004plb.sav
P mis = -0.0004 MW
Q mis = 0.0001 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 15:02:49 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004plb.sav
Rating = 1

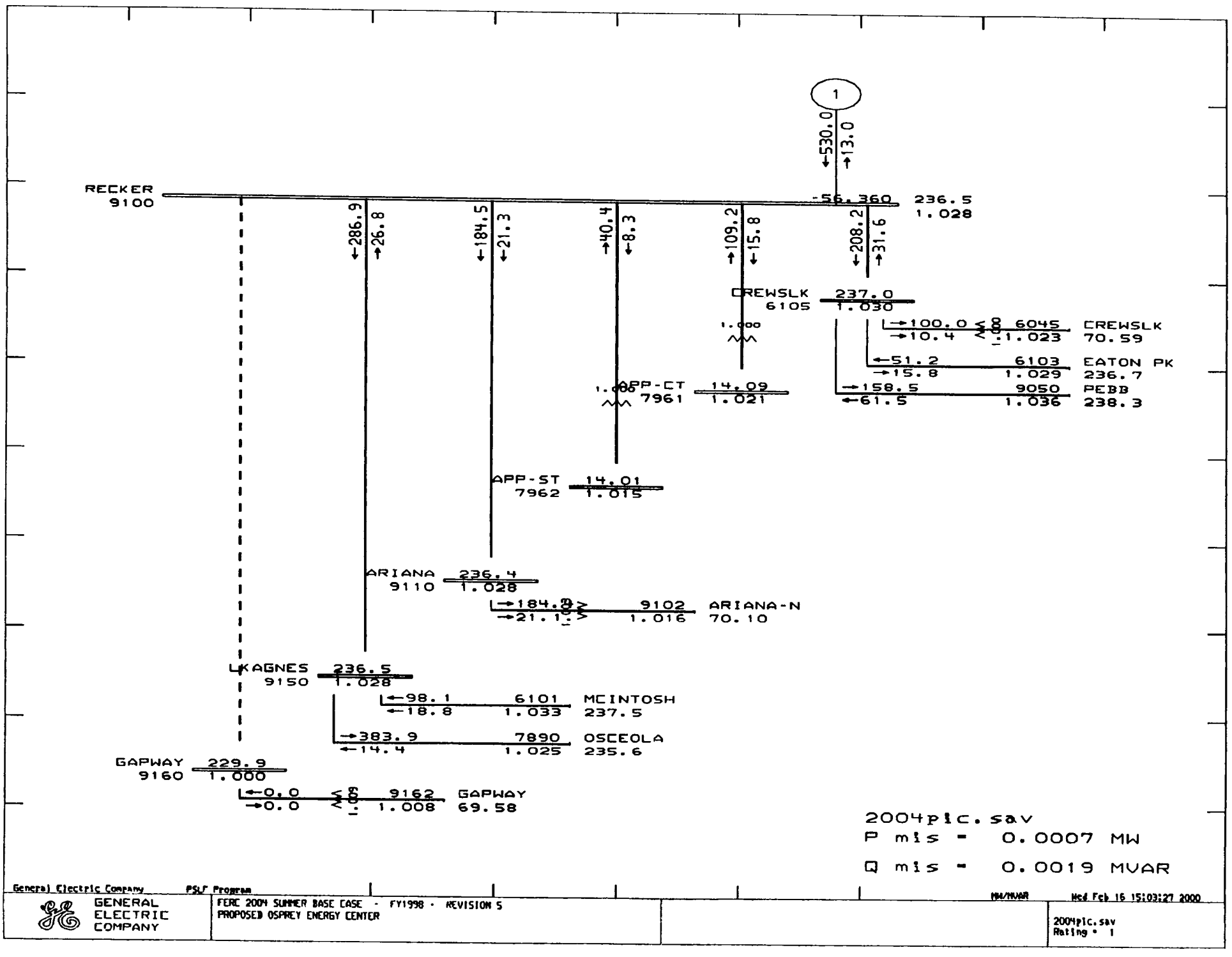


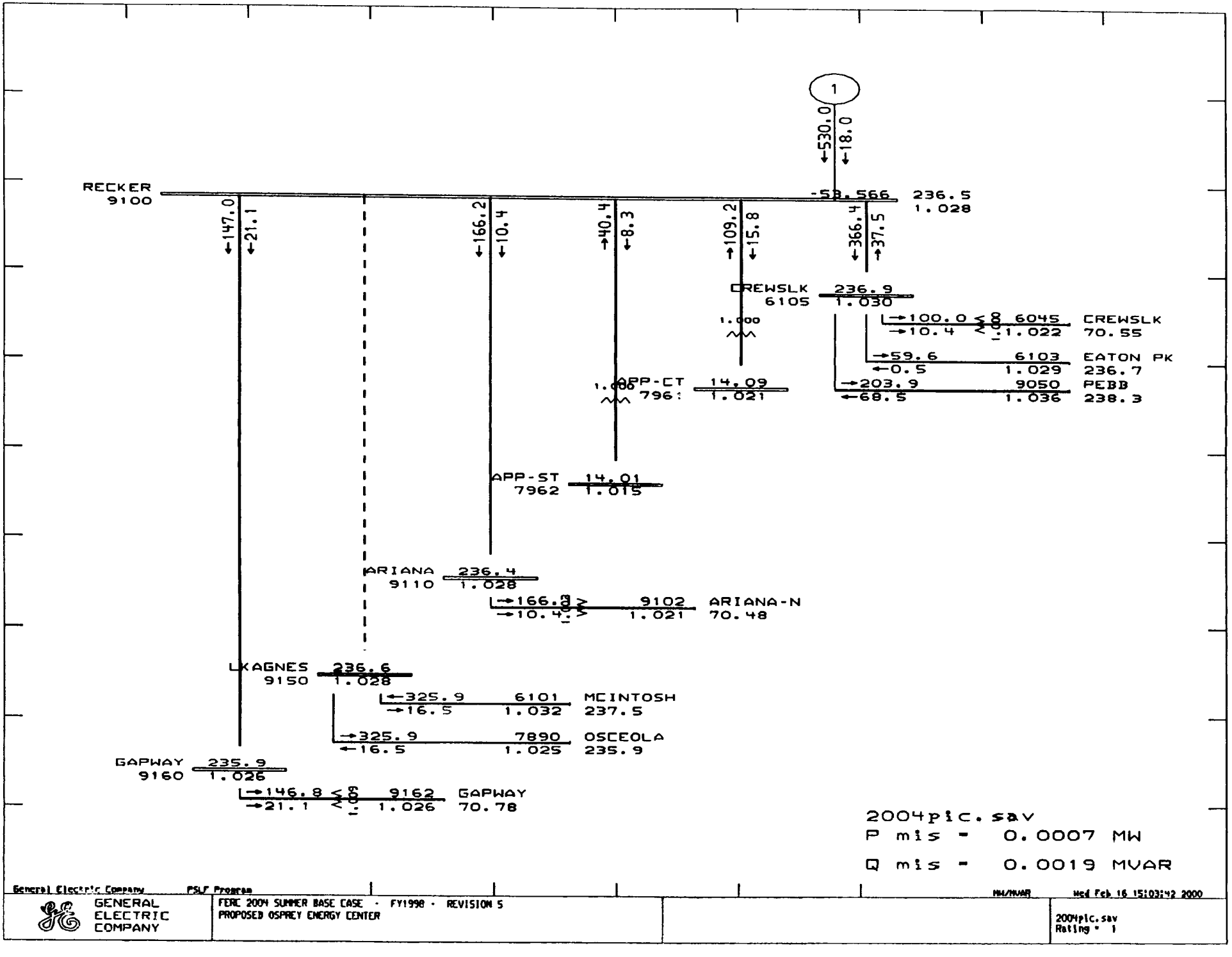
General Electric Company PSLF Program MW/MVAR Wed Feb 16 15:03:10 2000

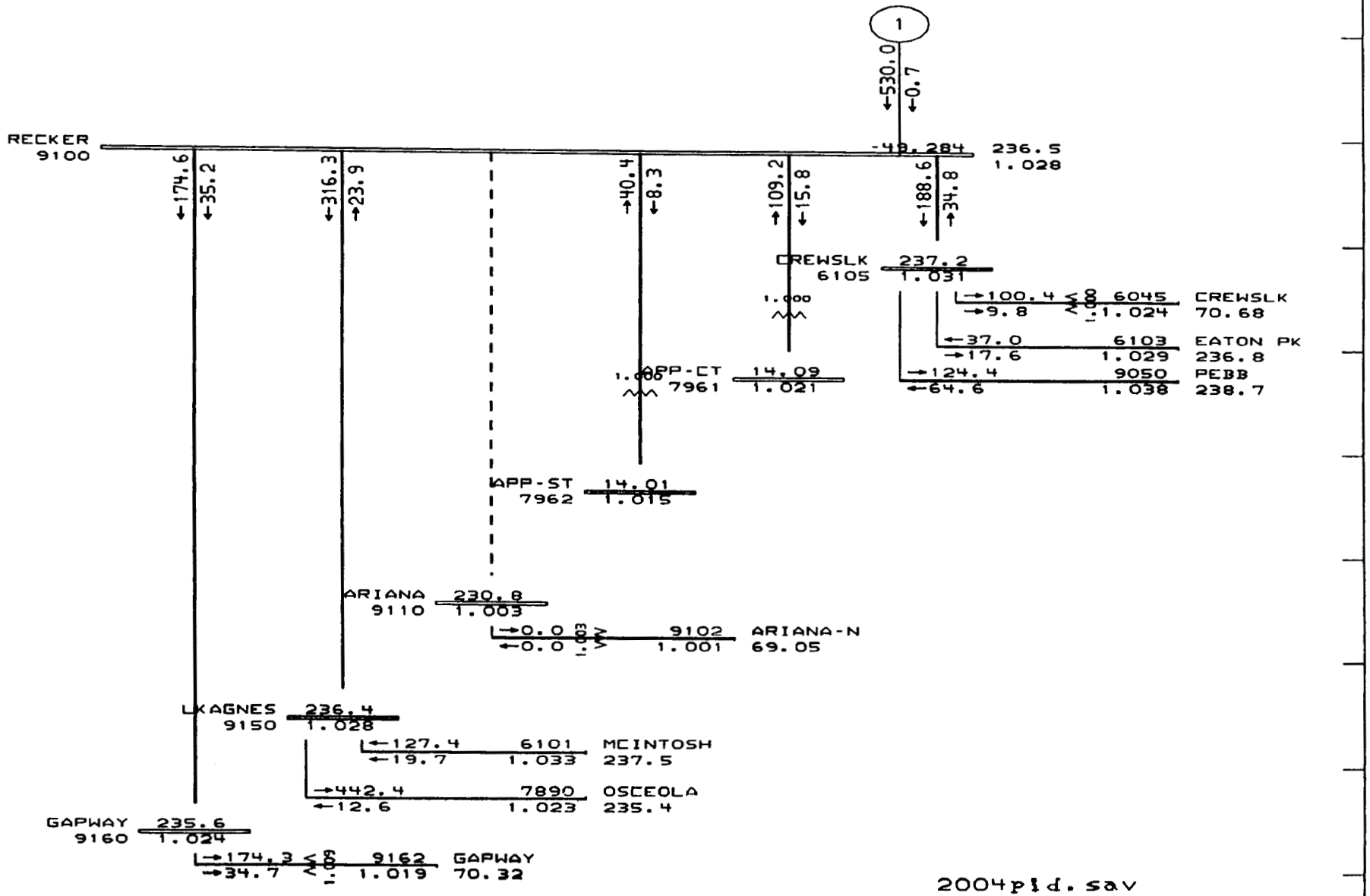
GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

2004plb.sav
Rating = 1


RECKER
9100
1
←530.0
→13.0
56.360
236.5
1.028
←286.9
→26.8
←184.5
→21.3
→40.4
←8.3
→109.2
←15.8
←208.2
→31.6
CREWSLK
6105
237.0
1.030
1.000
→100.0
→10.4
6045
1.023
CREWSLK
70.59
←51.2
→15.8
6103
1.029
EATON PK
236.7
APP-CT
7961
14.09
1.021
1.000
→158.5
←61.5
9050
1.036
PEBB
238.3
APP-ST
7962
14.01
1.015
ARIANA
9110
236.4
1.028
→184.8
→21.1
9102
1.016
ARIANA-N
70.10
LKAGNES
9150
236.5
1.028
←98.1
←18.8
6101
1.033
MCINTOSH
237.5
→383.9
←14.4
7890
1.025
OSCEOLA
235.6
GAPWAY
9160
229.9
1.000
←0.0
→0.0
9162
1.008
GAPWAY
69.58
2004pic.sav
P mis = 0.0007 MW
Q mis = 0.0019 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 15:03:27 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004pic.sav
Rating = 1


1
←530.0
←18.0
RECKER
9100
-53.566
236.5
1.028
←147.0
←21.1
←166.2
←10.4
→40.4
←8.3
→109.2
←15.8
→366.4
←37.5
CREWSLK 236.9
6105 1.030
1.000
→100.0 ≤ 8 6045 CREWSLK
→10.4 ≤ 1.1.022 70.55
→59.6 6103 EATON PK
←0.5 1.029 236.7
1.000 APP-CT 14.09
796: 1.021
→203.9 9050 PEBB
←68.5 1.036 238.3
APP-ST 14.01
7962 1.015
ARIANA 236.4
9110 1.028
→166.8 ≤ 9102 ARIANA-N
→10.4 ≤ 1.021 70.48
LKAGNES 236.6
9150 1.028
←325.9 6101 MCINTOSH
→16.5 1.032 237.5
→325.9 7890 OSCEOLA
←16.5 1.025 235.9
GAPWAY 235.9
9160 1.026
→146.8 ≤ 9162 GAPWAY
→21.1 ≤ 1.026 70.78
2004pic.sav
P mis = 0.0007 MW
Q mis = 0.0019 MVAR
General Electric Company PSLF Program
MW/MVAR Wed Feb 16 15:03:42 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004pic.sav
Rating = 1

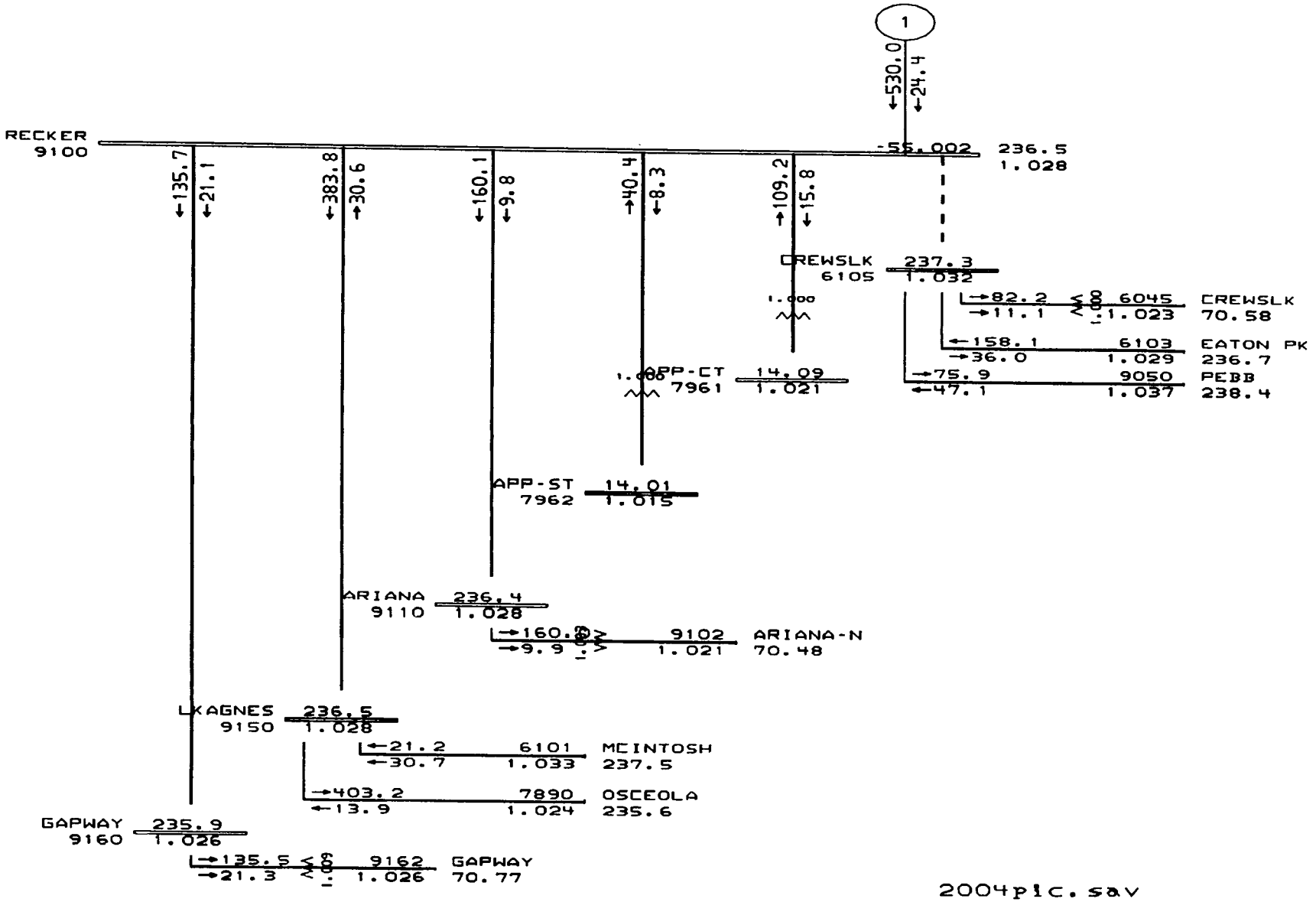


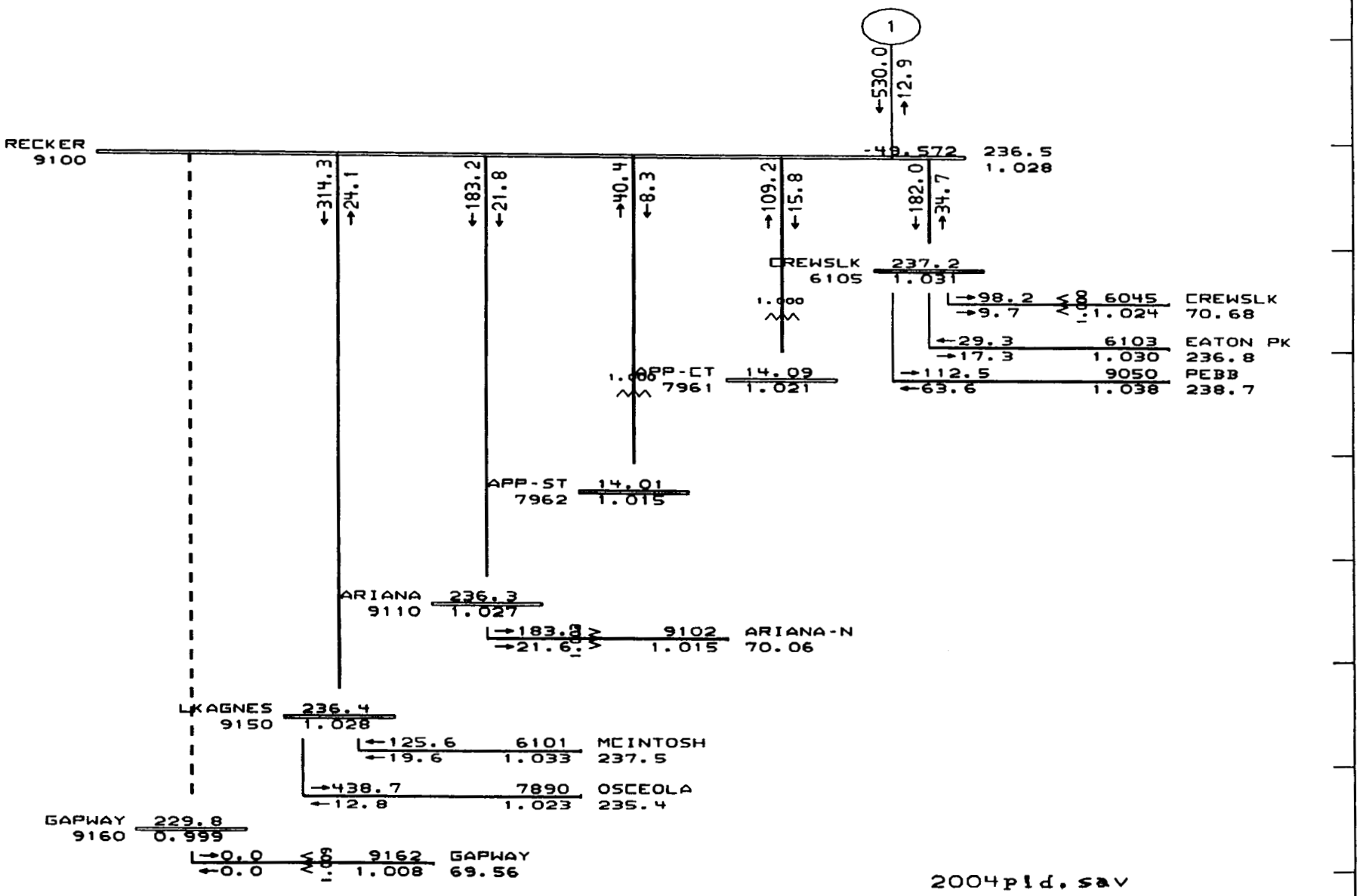
General Electric Company PSLF Program MW/MVAR Wed Feb 16 15:03:59 2000

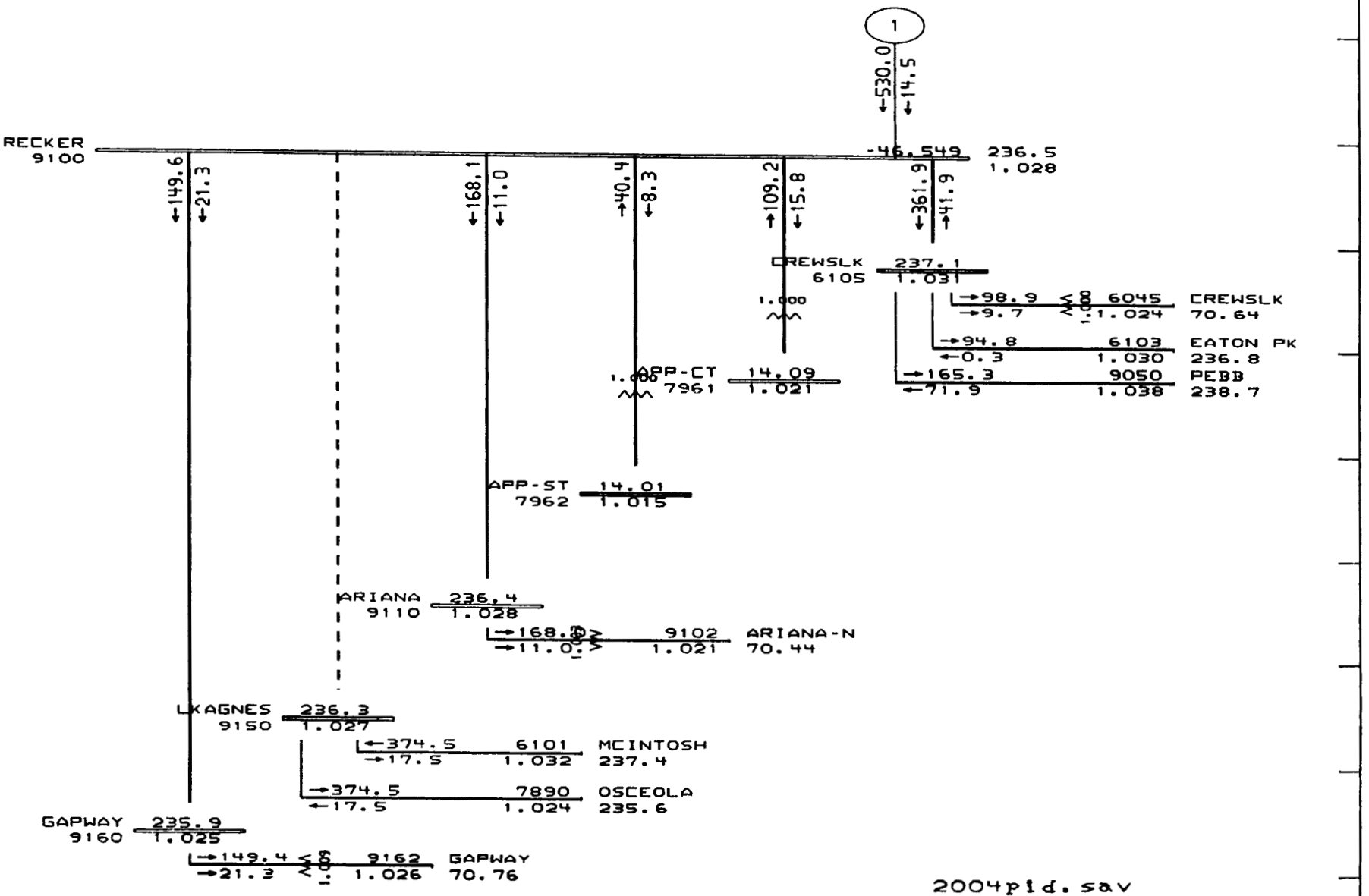
GENERAL ELECTRIC COMPANY

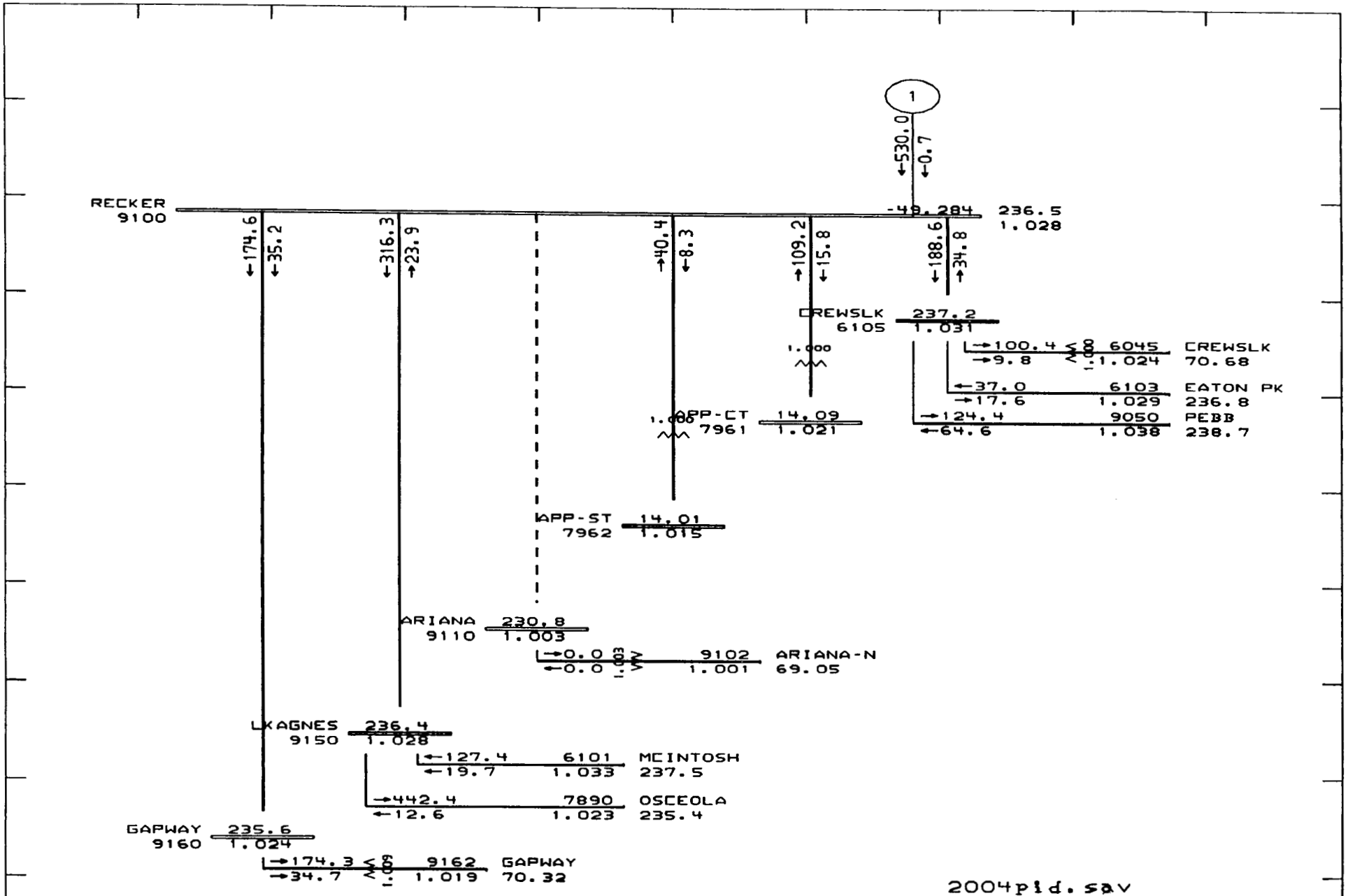
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

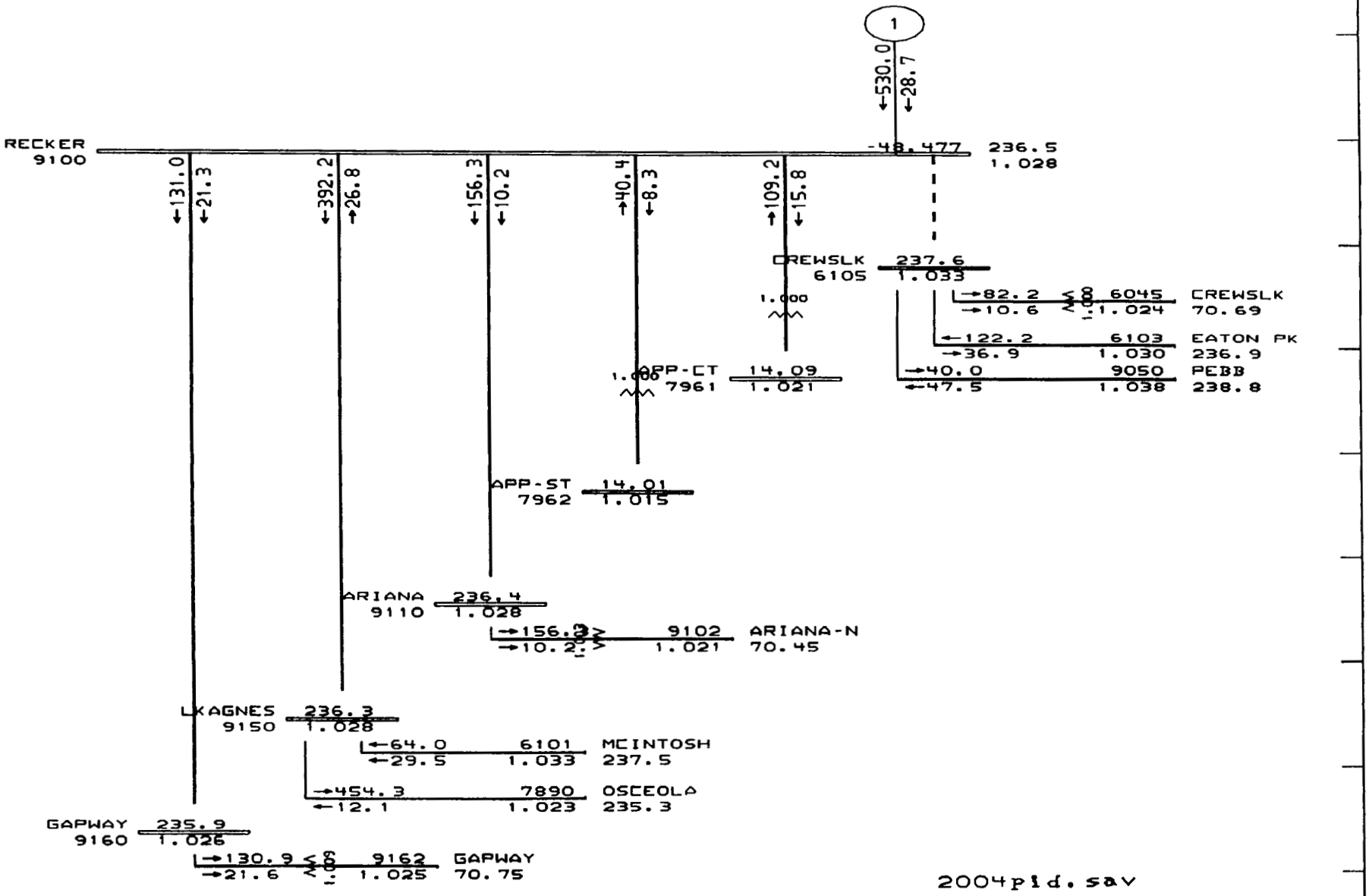
2004pld.sav
Rating = 1

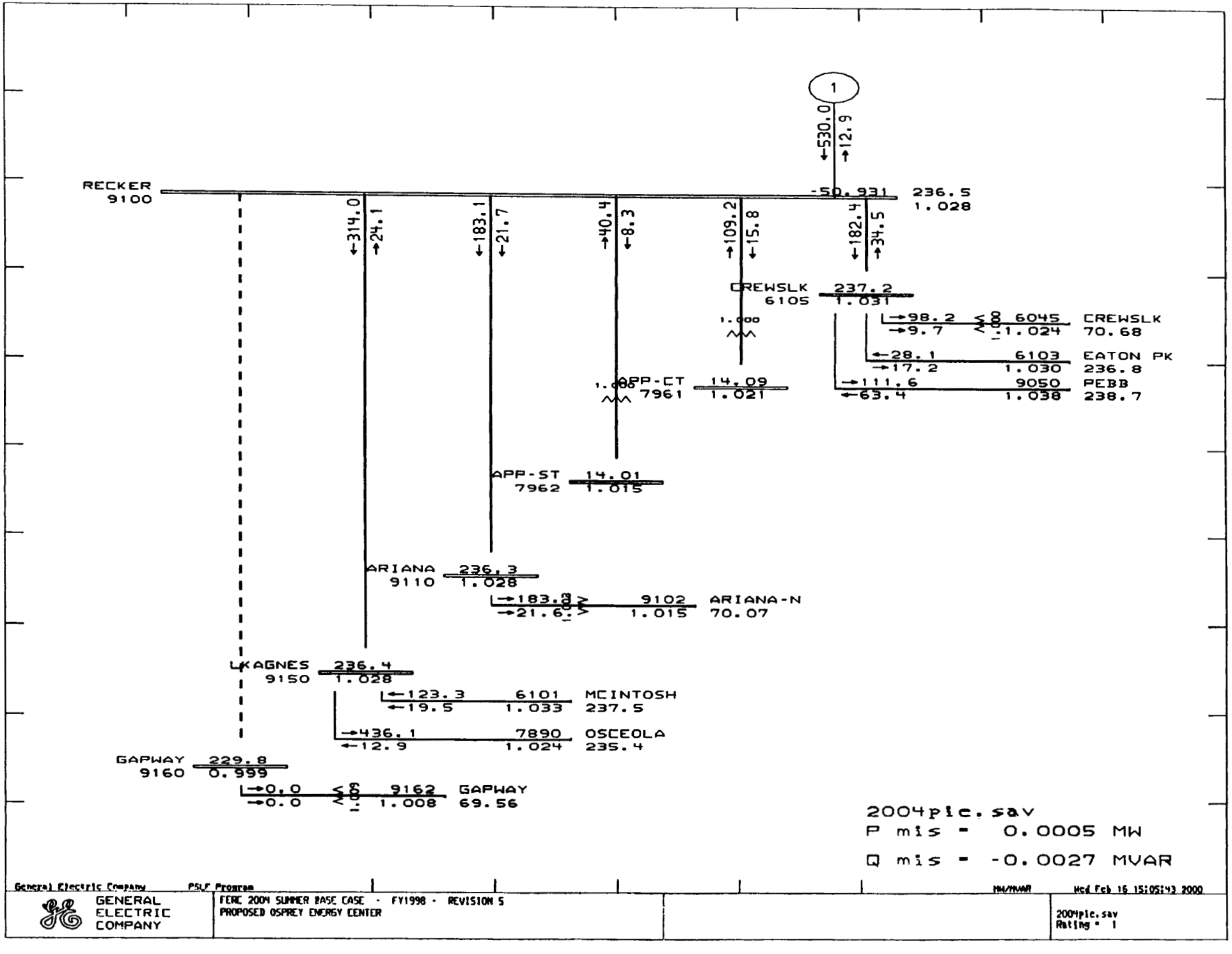

1
530.0
24.4
RECKER
9100
55.002
236.5
1.028
135.7
21.1
383.8
30.6
160.1
9.8
40.4
8.3
109.2
15.8
CREWSLK
6105
237.3
1.032
1.000
82.2
11.1
6045
1.023
CREWSLK
70.58
158.1
36.0
6103
1.029
EATON PK
236.7
APP-CT
7961
14.09
1.021
75.9
47.1
9050
1.037
PEBB
238.4
APP-ST
7962
14.01
1.015
ARIANA
9110
236.4
1.028
160.8
9.9
9102
1.021
ARIANA-N
70.48
LKAGNES
9150
236.5
1.028
21.2
30.7
6101
1.033
MCINTOSH
237.5
403.2
13.9
7890
1.024
OSCEOLA
235.6
GAPWAY
9160
235.9
1.026
135.5
21.3
9162
1.026
GAPWAY
70.77
2004pic.sav
P mis = 0.0007 MW
Q mis = 0.0019 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 15:04:15 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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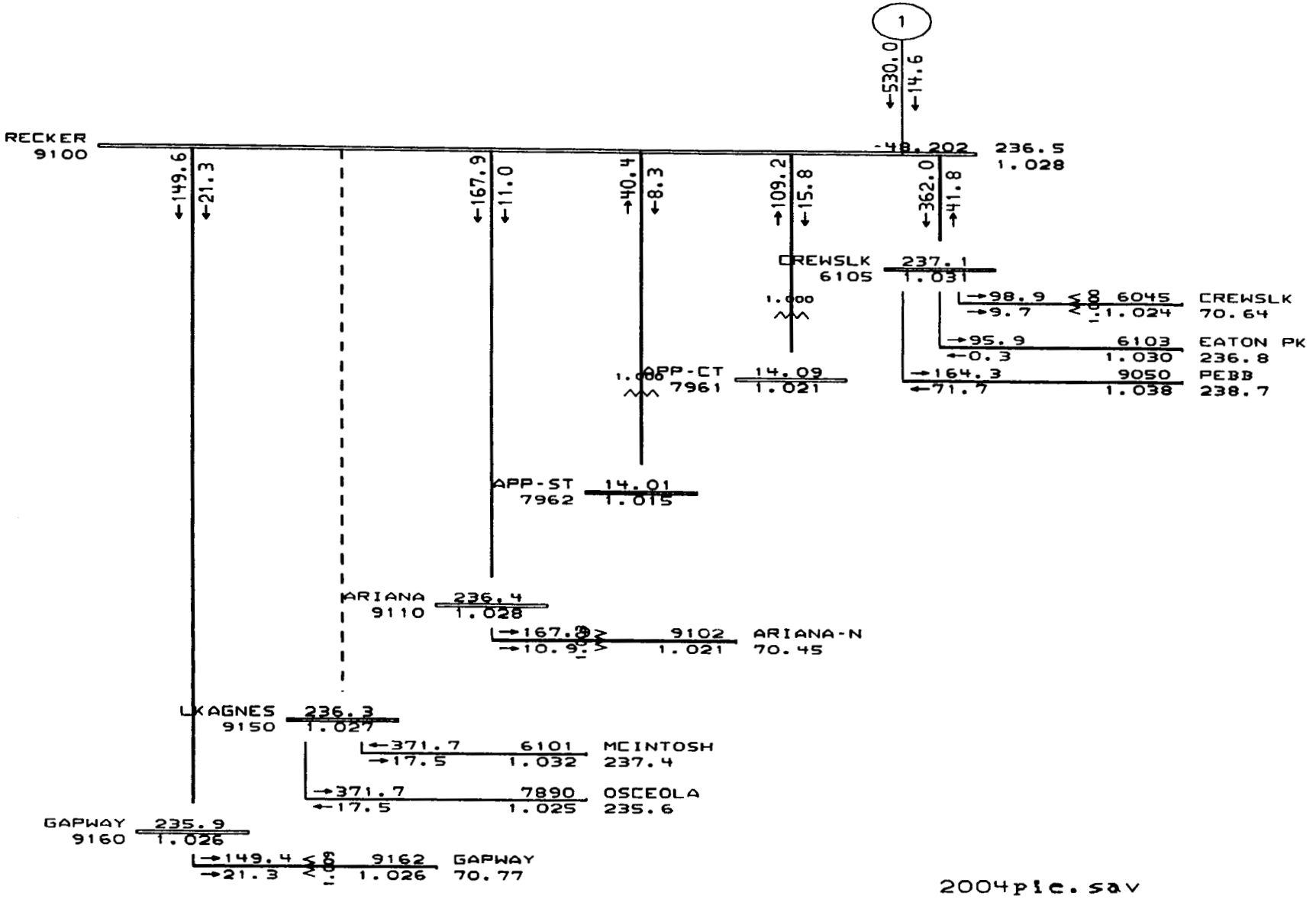

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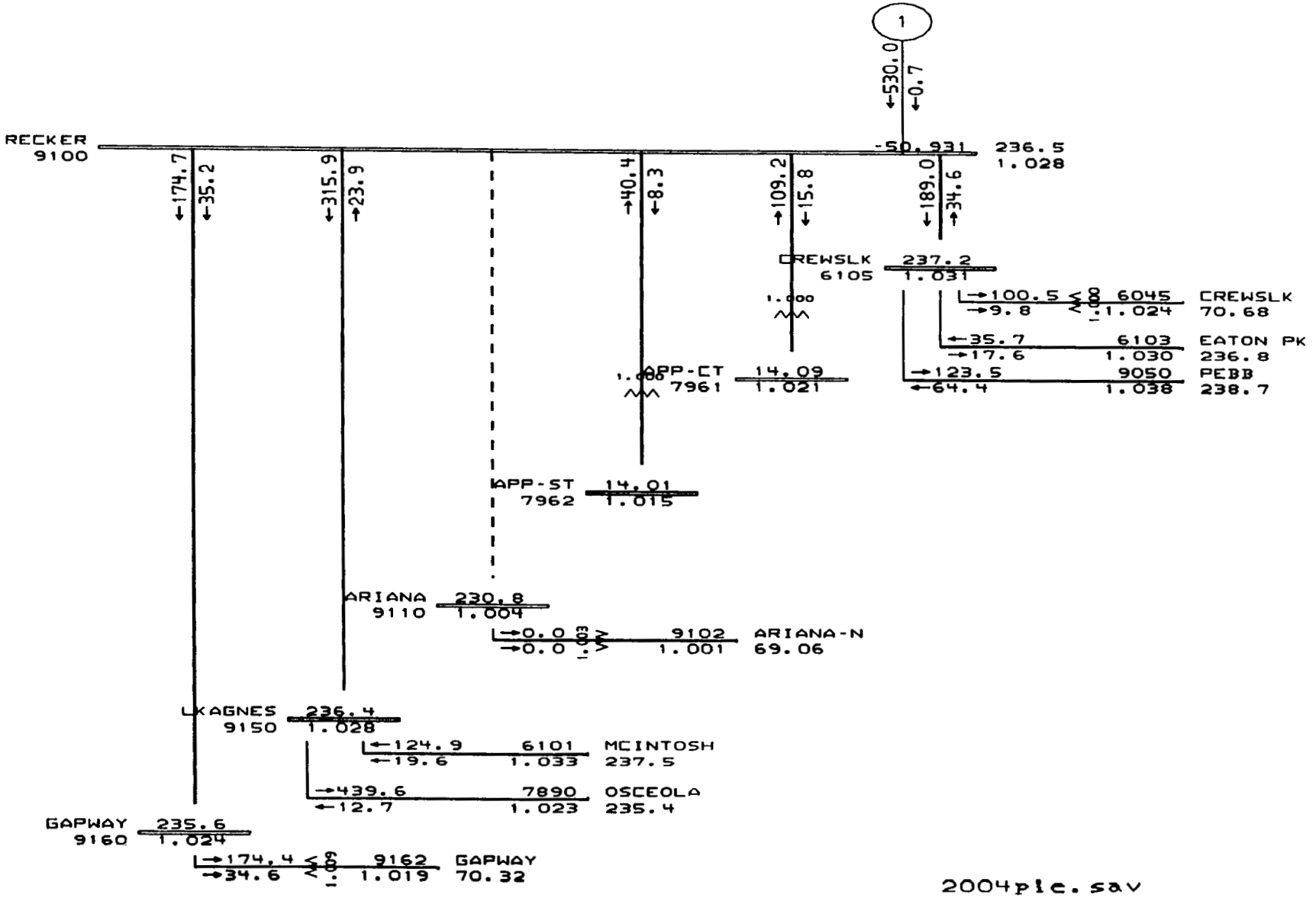

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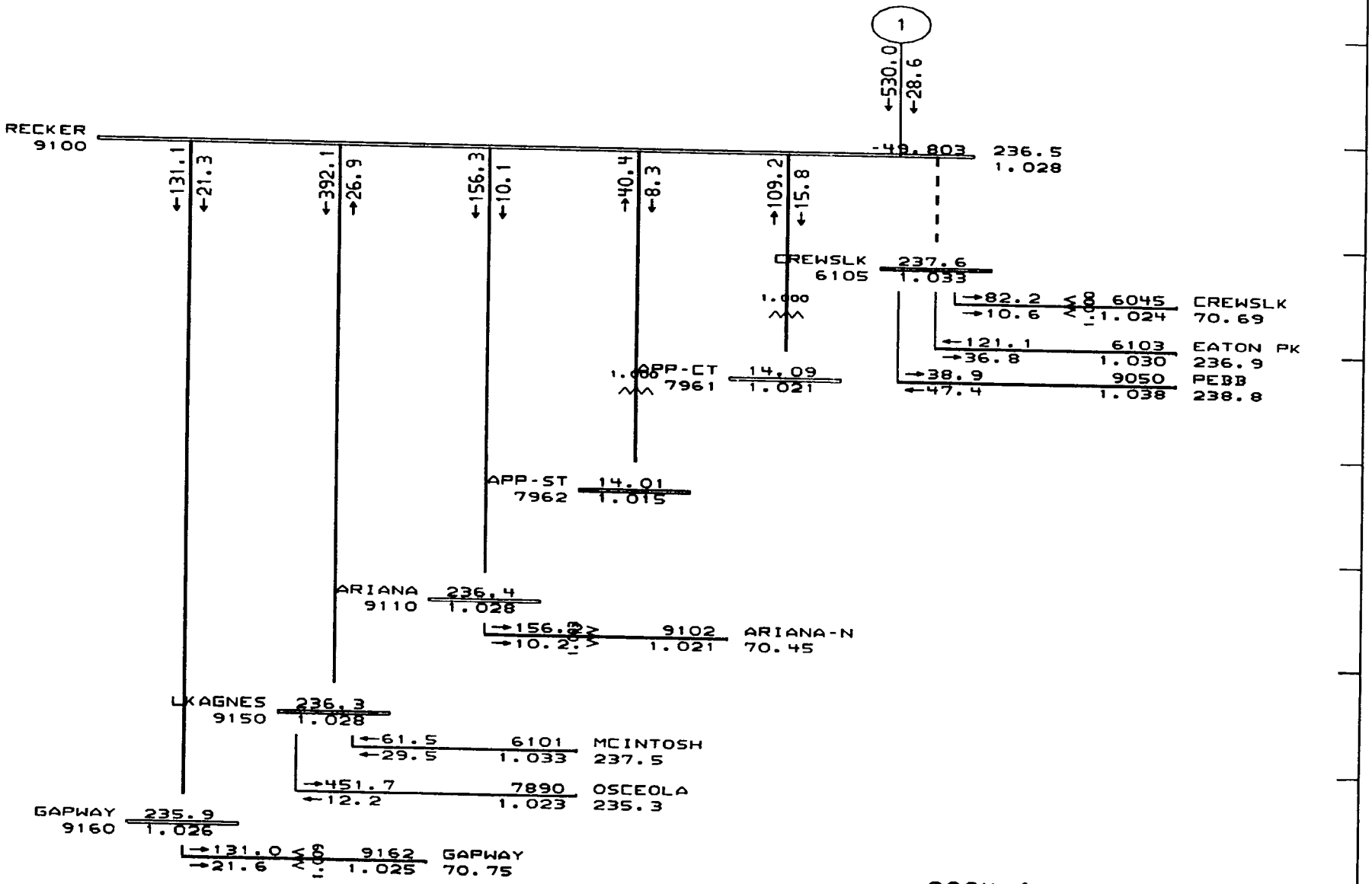


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GENERAL ELECTRIC COMPANY

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PROPOSED OSPREY ENERGY CENTER

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PROPOSED OSPREY ENERGY CENTER
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APPENDIX II

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-1	SN PLANT	230	SYLVAN	230	1	1						
2004-1	SYLVAN	230	N LONGWD	230	1	1						
2004-1	IND RIV	230	STANTON	230	1	11						
2004-1	SN PLANT	115	TURNER	115	1	1						
2004-1	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-1	SILVR SP	230	SILV SPN	230	1	2						
2004-1	SILVR SP	230	OCALA 1	230	1	2						
2004-1	RIO PINR	230	CURRY FD	230	1	2						
2004-1	STANTON	230	CURRY FD	230	1	2						
2004-1	OSCEOLA	230	LKAGNES	230	1	16						
2004-1	SHELD	230	LK TARPN	230	1	2						
2004-1	PEBB	230	CREWSLK	230	1	13						
2004-1	PEBB	230	N BARTOW	230	1	2						
2004-1	RECKER	230	LKAGNES	230	1	16						
2004-1	RECKER	230	ARIANA	230	1	16						
2004-1	RECKER	230	CREWSLK	230	1	13						
2004-1	B BEND	230	MANATEE	230	1	1						
2004-1	RUSKIN T	230	MANATEE	230	1	1						
2004-1	IND RIV	230	IND RIV	115	1	11						
2004-1	SHELD	230	SHELD-NW	69	1	16						
2004-1	LARGO	230	LARGO A	69	1	2						
2004-1	CLMT EST	230	CLMT EST	69	1	2						
2004-1	11TH AVE	230	ELEVEN-E	69	1	16						
2004-1	WINDERME	230	WINDERME	69	1	2						
2004-1	PASADENA	230	PASADENA	115	1	2						
2004-1	ARIANA	230	ARIANA-N	69	1	16						
2004-1	SELOSE	230	SELOSE-N	69	1	16						
2004-1	GAPWAY	230	GAPWAY	69	1	16						
2004-1	CREWSLK	230	CREWSLK	69	1	13						
2004-1	TENOROC	230	TENOROC	69	1	13						
2004-1	BARCOLA	230	WEST	230	1	2						
2004-1	EATON PK	230	CREWSLK	230	1	13						
2004-1	EATON PK	230	EATON PK	69	1	13						
2004-1	EATON PK	230	TENOROC	230	1	13						
2004-1	RECKER	230	GAPWAY	230	1	16						
2004-1	SN PLANT	115	TURNER	115	1	1						
2004-2	SN PLANT	230	SYLVAN	230	1	1						
2004-2	SYLVAN	230	N LONGWD	230	1	1						
2004-2	IND RIV	230	STANTON	230	1	11						
2004-2	SN PLANT	115	TURNER	115	1	1						
2004-2	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-2	SILVR SP	230	SILV SPN	230	1	2						
2004-2	SILVR SP	230	OCALA 1	230	1	2						
2004-2	RIO PINR	230	CURRY FD	230	1	2						
2004-2	STANTON	230	CURRY FD	230	1	2						
2004-2	OSCEOLA	230	LKAGNES	230	1	16						
2004-2	SHELD	230	LK TARPN	230	1	2						
2004-2	PEBB	230	CREWSLK	230	1	13						
2004-2	PEBB	230	N BARTOW	230	1	2						
2004-2	RECKER	230	LKAGNES	230	1	16						
2004-2	RECKER	230	ARIANA	230	1	16						
2004-2	RECKER	230	CREWSLK	230	1	13						
2004-2	B BEND	230	MANATEE	230	1	1						
2004-2	RUSKIN T	230	MANATEE	230	1	1						
2004-2	IND RIV	230	IND RIV	115	1	11						
2004-2	SHELD	230	SHELD-NW	69	1	16						
2004-2	LARGO	230	LARGO A	69	1	2						
2004-2	CLMT EST	230	CLMT EST	69	1	2						
2004-2	11TH AVE	230	ELEVEN-E	69	1	16						
2004-2	WINDERME	230	WINDERME	69	1	2						
2004-2	PASADENA	230	PASADENA	115	1	2						
2004-2	ARIANA	230	ARIANA-N	69	1	16						
2004-2	SELOSE	230	SELOSE-N	69	1	16						
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2004-2	TENOROC	230	TENOROC	69	1	13						
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2004-2	EATON PK	230	CREWSLK	230	1	13						
2004-2	EATON PK	230	EATON PK	69	1	13						
2004-2	EATON PK	230	TENOROC	230	1	13						
2004-2	RECKER	230	GAPWAY	230	1	16						
2004-2	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-3	SN PLANT	230	SYLVAN	230	1	1						
2004-3	SYLVAN	230	N LONGWD	230	1	1						
2004-3	IND RIV	230	STANTON	230	1	11						
2004-3	SN PLANT	115	TURNER	115	1	1						
2004-3	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-3	SILVR SP	230	SILV SPN	230	1	2						
2004-3	SILVR SP	230	OCALA 1	230	1	2						
2004-3	RIO PINR	230	CURRY FD	230	1	2						
2004-3	STANTON	230	CURRY FD	230	1	2						
2004-3	OSCEOLA	230	LKAGNES	230	1	16						
2004-3	SHELD	230	LK TARPN	230	1	2						
2004-3	PEBB	230	CREWSLK	230	1	13						
2004-3	PEBB	230	N BARTOW	230	1	2						
2004-3	RECKER	230	LKAGNES	230	1	16						
2004-3	RECKER	230	ARIANA	230	1	16						
2004-3	RECKER	230	CREWSLK	230	1	13						
2004-3	B BEND	230	MANATEE	230	1	1						
2004-3	RUSKIN T	230	MANATEE	230	1	1						
2004-3	IND RIV	230	IND RIV	115	1	11						
2004-3	SHELD	230	SHELD-NW	69	1	16						
2004-3	LARGO	230	LARGO A	69	1	2						
2004-3	CLMT EST	230	CLMT EST	69	1	2						
2004-3	11TH AVE	230	ELEVEN-E	69	1	16						
2004-3	WINDERME	230	WINDERME	69	1	2						
2004-3	PASADENA	230	PASADENA	115	1	2						
2004-3	ARIANA	230	ARIANA-N	69	1	16						
2004-3	SELOSE	230	SELOSE-N	69	1	16						
2004-3	GAPWAY	230	GAPWAY	69	1	16						
2004-3	CREWSLK	230	CREWSLK	69	1	13						
2004-3	TENOROC	230	TENOROC	69	1	13						
2004-3	BARCOLA	230	WEST	230	1	2						
2004-3	EATON PK	230	CREWSLK	230	1	13						
2004-3	EATON PK	230	EATON PK	69	1	13						
2004-3	EATON PK	230	TENOROC	230	1	13						
2004-3	RECKER	230	GAPWAY	230	1	16						
2004-3	SN PLANT	115	TURNER	115	1	1						
2004-4	SN PLANT	230	SYLVAN	230	1	1						
2004-4	SYLVAN	230	N LONGWD	230	1	1						
2004-4	IND RIV	230	STANTON	230	1	11						
2004-4	SN PLANT	115	TURNER	115	1	1						
2004-4	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-4	SILVR SP	230	SILV SPN	230	1	2						
2004-4	SILVR SP	230	OCALA 1	230	1	2						
2004-4	RIO PINR	230	CURRY FD	230	1	2						
2004-4	STANTON	230	CURRY FD	230	1	2						
2004-4	OSCEOLA	230	LKAGNES	230	1	16						
2004-4	SHELD	230	LK TARPN	230	1	2						
2004-4	PEBB	230	CREWSLK	230	1	13						
2004-4	PEBB	230	N BARTOW	230	1	2						
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2004-4	RECKER	230	ARIANA	230	1	16						
2004-4	RECKER	230	CREWSLK	230	1	13						
2004-4	B BEND	230	MANATEE	230	1	1						
2004-4	RUSKIN T	230	MANATEE	230	1	1						
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2004-4	BARCOLA	230	WEST	230	1	2						
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2004-4	EATON PK	230	TENOROC	230	1	13						
2004-4	RECKER	230	GAPWAY	230	1	16						
2004-4	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-5	SN PLANT	230	SYLVAN	230	1	1						
2004-5	SYLVAN	230	N LONGWD	230	1	1						
2004-5	IND RIV	230	STANTON	230	1	11						
2004-5	SN PLANT	115	TURNER	115	1	1						
2004-5	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-5	SILVR SP	230	SILV SPN	230	1	2						
2004-5	SILVR SP	230	OCALA 1	230	1	2						
2004-5	RIO PINR	230	CURRY FD	230	1	2						
2004-5	STANTON	230	CURRY FD	230	1	2						
2004-5	OSCEOLA	230	LKAGNES	230	1	16						
2004-5	SHELD	230	LK TARPN	230	1	2						
2004-5	PEBB	230	CREWSLK	230	1	13						
2004-5	PEBB	230	N BARTOW	230	1	2						
2004-5	RECKER	230	LKAGNES	230	1	16						
2004-5	RECKER	230	ARIANA	230	1	16						
2004-5	RECKER	230	CREWSLK	230	1	13						
2004-5	B BEND	230	MANATEE	230	1	1						
2004-5	RUSKIN T	230	MANATEE	230	1	1						
2004-5	IND RIV	230	IND RIV	115	1	11						
2004-5	SHELD	230	SHELD-NW	69	1	16						
2004-5	LARGO	230	LARGO A	69	1	2						
2004-5	CLMT EST	230	CLMT EST	69	1	2						
2004-5	11TH AVE	230	ELEVEN-E	69	1	16						
2004-5	WINDERME	230	WINDERME	69	1	2						
2004-5	PASADENA	230	PASADENA	115	1	2						
2004-5	ARIANA	230	ARIANA-N	69	1	16						
2004-5	SELOSE	230	SELOSE-N	69	1	16						
2004-5	GAPWAY	230	GAPWAY	69	1	16						
2004-5	CREWSLK	230	CREWSLK	69	1	13						
2004-5	TENOROC	230	TENOROC	69	1	13						
2004-5	BARCOLA	230	WEST	230	1	2						
2004-5	EATON PK	230	CREWSLK	230	1	13						
2004-5	EATON PK	230	EATON PK	69	1	13						
2004-5	EATON PK	230	TENOROC	230	1	13						
2004-5	RECKER	230	GAPWAY	230	1	16						
2004-5	SN PLANT	115	TURNER	115	1	1						
2004-6	SN PLANT	230	SYLVAN	230	1	1						
2004-6	SYLVAN	230	N LONGWD	230	1	1						
2004-6	IND RIV	230	STANTON	230	1	11						
2004-6	SN PLANT	115	TURNER	115	1	1						
2004-6	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-6	SILVR SP	230	SILV SPN	230	1	2						
2004-6	SILVR SP	230	OCALA 1	230	1	2						
2004-6	RIO PINR	230	CURRY FD	230	1	2						
2004-6	STANTON	230	CURRY FD	230	1	2						
2004-6	OSCEOLA	230	LKAGNES	230	1	16			100.8		100.2	100.1
2004-6	SHELD	230	LK TARPN	230	1	2						
2004-6	PEBB	230	CREWSLK	230	1	13						
2004-6	PEBB	230	N BARTOW	230	1	2						
2004-6	RECKER	230	LKAGNES	230	1	16						
2004-6	RECKER	230	ARIANA	230	1	16						
2004-6	RECKER	230	CREWSLK	230	1	13						
2004-6	B BEND	230	MANATEE	230	1	1						
2004-6	RUSKIN T	230	MANATEE	230	1	1						
2004-6	IND RIV	230	IND RIV	115	1	11						
2004-6	SHELD	230	SHELD-NW	69	1	16						
2004-6	LARGO	230	LARGO A	69	1	2						
2004-6	CLMT EST	230	CLMT EST	69	1	2						
2004-6	11TH AVE	230	ELEVEN-E	69	1	16						
2004-6	WINDERME	230	WINDERME	69	1	2						
2004-6	PASADENA	230	PASADENA	115	1	2						
2004-6	ARIANA	230	ARIANA-N	69	1	16						
2004-6	SELOSE	230	SELOSE-N	69	1	16						
2004-6	GAPWAY	230	GAPWAY	69	1	16						
2004-6	CREWSLK	230	CREWSLK	69	1	13						
2004-6	TENOROC	230	TENOROC	69	1	13						
2004-6	BARCOLA	230	WEST	230	1	2						
2004-6	EATON PK	230	CREWSLK	230	1	13						
2004-6	EATON PK	230	EATON PK	69	1	13						
2004-6	EATON PK	230	TENOROC	230	1	13						
2004-6	RECKER	230	GAPWAY	230	1	16						
2004-6	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-7	SN PLANT	230	SYLVAN	230	1	1						
2004-7	SYLVAN	230	N LONGWD	230	1	1						
2004-7	IND RIV	230	STANTON	230	1	11						
2004-7	SN PLANT	115	TURNER	115	1	1						
2004-7	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-7	SILVR SP	230	SILV SPN	230	1	2						
2004-7	SILVR SP	230	OCALA 1	230	1	2						
2004-7	RIO PINR	230	CURRY FD	230	1	2						
2004-7	STANTON	230	CURRY FD	230	1	2						
2004-7	OSCEOLA	230	LKAGNES	230	1	16						
2004-7	SHELD	230	LK TARPN	230	1	2						
2004-7	PEBB	230	CREWSLK	230	1	13						
2004-7	PEBB	230	N BARTOW	230	1	2						
2004-7	RECKER	230	LKAGNES	230	1	16						
2004-7	RECKER	230	ARIANA	230	1	16						
2004-7	RECKER	230	CREWSLK	230	1	13						
2004-7	B BEND	230	MANATEE	230	1	1						
2004-7	RUSKIN T	230	MANATEE	230	1	1						
2004-7	IND RIV	230	IND RIV	115	1	11						
2004-7	SHELD	230	SHELD-NW	69	1	16						
2004-7	LARGO	230	LARGO A	69	1	2						
2004-7	CLMT EST	230	CLMT EST	69	1	2						
2004-7	11TH AVE	230	ELEVEN-E	69	1	16						
2004-7	WINDERME	230	WINDERME	69	1	2						
2004-7	PASADENA	230	PASADENA	115	1	2						
2004-7	ARIANA	230	ARIANA-N	69	1	16						
2004-7	SELOSE	230	SELOSE-N	69	1	16						
2004-7	GAPWAY	230	GAPWAY	69	1	16						
2004-7	CREWSLK	230	CREWSLK	69	1	13						
2004-7	TENOROC	230	TENOROC	69	1	13						
2004-7	BARCOLA	230	WEST	230	1	2						
2004-7	EATON PK	230	CREWSLK	230	1	13						
2004-7	EATON PK	230	EATON PK	69	1	13						
2004-7	EATON PK	230	TENOROC	230	1	13						
2004-7	RECKER	230	GAPWAY	230	1	16						
2004-7	SN PLANT	115	TURNER	115	1	1						
2004-8	SN PLANT	230	SYLVAN	230	1	1						
2004-8	SYLVAN	230	N LONGWD	230	1	1						
2004-8	IND RIV	230	STANTON	230	1	11						
2004-8	SN PLANT	115	TURNER	115	1	1						
2004-8	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-8	SILVR SP	230	SILV SPN	230	1	2						
2004-8	SILVR SP	230	OCALA 1	230	1	2						
2004-8	RIO PINR	230	CURRY FD	230	1	2						
2004-8	STANTON	230	CURRY FD	230	1	2						
2004-8	OSCEOLA	230	LKAGNES	230	1	16						
2004-8	SHELD	230	LK TARPN	230	1	2						
2004-8	PEBB	230	CREWSLK	230	1	13						
2004-8	PEBB	230	N BARTOW	230	1	2						
2004-8	RECKER	230	LKAGNES	230	1	16						
2004-8	RECKER	230	ARIANA	230	1	16						
2004-8	RECKER	230	CREWSLK	230	1	13						
2004-8	B BEND	230	MANATEE	230	1	1						
2004-8	RUSKIN T	230	MANATEE	230	1	1						
2004-8	IND RIV	230	IND RIV	115	1	11						
2004-8	SHELD	230	SHELD-NW	69	1	16						
2004-8	LARGO	230	LARGO A	69	1	2						
2004-8	CLMT EST	230	CLMT EST	69	1	2						
2004-8	11TH AVE	230	ELEVEN-E	69	1	16						
2004-8	WINDERME	230	WINDERME	69	1	2						
2004-8	PASADENA	230	PASADENA	115	1	2						
2004-8	ARIANA	230	ARIANA-N	69	1	16						
2004-8	SELOSE	230	SELOSE-N	69	1	16						
2004-8	GAPWAY	230	GAPWAY	69	1	16						
2004-8	CREWSLK	230	CREWSLK	69	1	13						
2004-8	TENOROC	230	TENOROC	69	1	13						
2004-8	BARCOLA	230	WEST	230	1	2						
2004-8	EATON PK	230	CREWSLK	230	1	13						
2004-8	EATON PK	230	EATON PK	69	1	13						
2004-8	EATON PK	230	TENOROC	230	1	13						
2004-8	RECKER	230	GAPWAY	230	1	16						
2004-8	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-9	SN PLANT	230	SYLVAN	230	1	1						
2004-9	SYLVAN	230	N LONGWD	230	1	1						
2004-9	IND RIV	230	STANTON	230	1	11						
2004-9	SN PLANT	115	TURNER	115	1	1						
2004-9	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-9	SILVR SP	230	SILV SPN	230	1	2						
2004-9	SILVR SP	230	OCALA 1	230	1	2						
2004-9	RIO PINR	230	CURRY FD	230	1	2						
2004-9	STANTON	230	CURRY FD	230	1	2						
2004-9	OSCEOLA	230	LKAGNES	230	1	16						
2004-9	SHELD	230	LK TARPN	230	1	2						
2004-9	PEBB	230	CREWSLK	230	1	13						
2004-9	PEBB	230	N BARTOW	230	1	2						
2004-9	RECKER	230	LKAGNES	230	1	16						
2004-9	RECKER	230	ARIANA	230	1	16						
2004-9	RECKER	230	CREWSLK	230	1	13						
2004-9	B BEND	230	MANATEE	230	1	1						
2004-9	RUSKIN T	230	MANATEE	230	1	1						
2004-9	IND RIV	230	IND RIV	115	1	11						
2004-9	SHELD	230	SHELD-NW	69	1	16						
2004-9	LARGO	230	LARGO A	69	1	2						
2004-9	CLMT EST	230	CLMT EST	69	1	2						
2004-9	11TH AVE	230	ELEVEN-E	69	1	16						
2004-9	WINDERME	230	WINDERME	69	1	2						
2004-9	PASADENA	230	PASADENA	115	1	2						
2004-9	ARIANA	230	ARIANA-N	69	1	16						
2004-9	SELOSE	230	SELOSE-N	69	1	16						
2004-9	GAPWAY	230	GAPWAY	69	1	16						
2004-9	CREWSLK	230	CREWSLK	69	1	13						
2004-9	TENOROC	230	TENOROC	69	1	13						
2004-9	BARCOLA	230	WEST	230	1	2						
2004-9	EATON PK	230	CREWSLK	230	1	13						
2004-9	EATON PK	230	EATON PK	69	1	13						
2004-9	EATON PK	230	TENOROC	230	1	13						
2004-9	RECKER	230	GAPWAY	230	1	16						
2004-9	SN PLANT	115	TURNER	115	1	1						
2004-10	SN PLANT	230	SYLVAN	230	1	1						
2004-10	SYLVAN	230	N LONGWD	230	1	1						
2004-10	IND RIV	230	STANTON	230	1	11						
2004-10	SN PLANT	115	TURNER	115	1	1						
2004-10	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-10	SILVR SP	230	SILV SPN	230	1	2						
2004-10	SILVR SP	230	OCALA 1	230	1	2						
2004-10	RIO PINR	230	CURRY FD	230	1	2						
2004-10	STANTON	230	CURRY FD	230	1	2						
2004-10	OSCEOLA	230	LKAGNES	230	1	16						
2004-10	SHELD	230	LK TARPN	230	1	2						
2004-10	PEBB	230	CREWSLK	230	1	13						
2004-10	PEBB	230	N BARTOW	230	1	2						
2004-10	RECKER	230	LKAGNES	230	1	16						
2004-10	RECKER	230	ARIANA	230	1	16						
2004-10	RECKER	230	CREWSLK	230	1	13						
2004-10	B BEND	230	MANATEE	230	1	1						
2004-10	RUSKIN T	230	MANATEE	230	1	1						
2004-10	IND RIV	230	IND RIV	115	1	11						
2004-10	SHELD	230	SHELD-NW	69	1	16						
2004-10	LARGO	230	LARGO A	69	1	2						
2004-10	CLMT EST	230	CLMT EST	69	1	2						
2004-10	11TH AVE	230	ELEVEN-E	69	1	16						
2004-10	WINDERME	230	WINDERME	69	1	2						
2004-10	PASADENA	230	PASADENA	115	1	2						
2004-10	ARIANA	230	ARIANA-N	69	1	16						
2004-10	SELOSE	230	SELOSE-N	69	1	16						
2004-10	GAPWAY	230	GAPWAY	69	1	16						
2004-10	CREWSLK	230	CREWSLK	69	1	13						
2004-10	TENOROC	230	TENOROC	69	1	13						
2004-10	BARCOLA	230	WEST	230	1	2						
2004-10	EATON PK	230	CREWSLK	230	1	13						
2004-10	EATON PK	230	EATON PK	69	1	13						
2004-10	EATON PK	230	TENOROC	230	1	13						
2004-10	RECKER	230	GAPWAY	230	1	16						
2004-10	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-11	SN PLANT	230	SYLVAN	230	1	1						
2004-11	SYLVAN	230	N LONGWD	230	1	1						
2004-11	IND RIV	230	STANTON	230	1	11						
2004-11	SN PLANT	115	TURNER	115	1	1						
2004-11	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-11	SILVR SP	230	SILV SPN	230	1	2						
2004-11	SILVR SP	230	OCALA 1	230	1	2						
2004-11	RIO PINR	230	CURRY FD	230	1	2						
2004-11	STANTON	230	CURRY FD	230	1	2						
2004-11	OSCEOLA	230	LKAGNES	230	1	16						
2004-11	SHELD	230	LK TARPN	230	1	2						
2004-11	PEBB	230	CREWSLK	230	1	13						
2004-11	PEBB	230	N BARTOW	230	1	2						
2004-11	RECKER	230	LKAGNES	230	1	16						
2004-11	RECKER	230	ARIANA	230	1	16						
2004-11	RECKER	230	CREWSLK	230	1	13						
2004-11	B BEND	230	MANATEE	230	1	1						
2004-11	RUSKIN T	230	MANATEE	230	1	1						
2004-11	IND RIV	230	IND RIV	115	1	11						
2004-11	SHELD	230	SHELD-NW	69	1	16						
2004-11	LARGO	230	LARGO A	69	1	2						
2004-11	CLMT EST	230	CLMT EST	69	1	2						
2004-11	11TH AVE	230	ELEVEN-E	69	1	16						
2004-11	WINDERME	230	WINDERME	69	1	2						
2004-11	PASADENA	230	PASADENA	115	1	2						
2004-11	ARIANA	230	ARIANA-N	69	1	16						
2004-11	SELOSE	230	SELOSE-N	69	1	16						
2004-11	GAPWAY	230	GAPWAY	69	1	16						
2004-11	CREWSLK	230	CREWSLK	69	1	13						
2004-11	TENOROC	230	TENOROC	69	1	13						
2004-11	BARCOLA	230	WEST	230	1	2						
2004-11	EATON PK	230	CREWSLK	230	1	13						
2004-11	EATON PK	230	EATON PK	69	1	13						
2004-11	EATON PK	230	TENOROC	230	1	13						
2004-11	RECKER	230	GAPWAY	230	1	16						
2004-11	SN PLANT	115	TURNER	115	1	1						
2004-12	SN PLANT	230	SYLVAN	230	1	1						
2004-12	SYLVAN	230	N LONGWD	230	1	1						
2004-12	IND RIV	230	STANTON	230	1	11						
2004-12	SN PLANT	115	TURNER	115	1	1						
2004-12	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-12	SILVR SP	230	SILV SPN	230	1	2						
2004-12	SILVR SP	230	OCALA 1	230	1	2						
2004-12	RIO PINR	230	CURRY FD	230	1	2						
2004-12	STANTON	230	CURRY FD	230	1	2						
2004-12	OSCEOLA	230	LKAGNES	230	1	16						
2004-12	SHELD	230	LK TARPN	230	1	2						
2004-12	PEBB	230	CREWSLK	230	1	13						
2004-12	PEBB	230	N BARTOW	230	1	2						
2004-12	RECKER	230	LKAGNES	230	1	16						
2004-12	RECKER	230	ARIANA	230	1	16						
2004-12	RECKER	230	CREWSLK	230	1	13						
2004-12	B BEND	230	MANATEE	230	1	1						
2004-12	RUSKIN T	230	MANATEE	230	1	1						
2004-12	IND RIV	230	IND RIV	115	1	11						
2004-12	SHELD	230	SHELD-NW	69	1	16						
2004-12	LARGO	230	LARGO A	69	1	2						
2004-12	CLMT EST	230	CLMT EST	69	1	2						
2004-12	11TH AVE	230	ELEVEN-E	69	1	16						
2004-12	WINDERME	230	WINDERME	69	1	2						
2004-12	PASADENA	230	PASADENA	115	1	2						
2004-12	ARIANA	230	ARIANA-N	69	1	16						
2004-12	SELOSE	230	SELOSE-N	69	1	16						
2004-12	GAPWAY	230	GAPWAY	69	1	16						
2004-12	CREWSLK	230	CREWSLK	69	1	13						
2004-12	TENOROC	230	TENOROC	69	1	13						
2004-12	BARCOLA	230	WEST	230	1	2						
2004-12	EATON PK	230	CREWSLK	230	1	13						
2004-12	EATON PK	230	EATON PK	69	1	13						
2004-12	EATON PK	230	TENOROC	230	1	13						
2004-12	RECKER	230	GAPWAY	230	1	16						
2004-12	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-13	SN PLANT	230	SYLVAN	230	1	1						
2004-13	SYLVAN	230	N LONGWD	230	1	1						
2004-13	IND RIV	230	STANTON	230	1	11						
2004-13	SN PLANT	115	TURNER	115	1	1						
2004-13	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-13	SILVR SP	230	SILV SPN	230	1	2						
2004-13	SILVR SP	230	OCALA 1	230	1	2						
2004-13	RIO PINR	230	CURRY FD	230	1	2						
2004-13	STANTON	230	CURRY FD	230	1	2						
2004-13	OSCEOLA	230	LKAGNES	230	1	16						
2004-13	SHELD	230	LK TARPN	230	1	2						
2004-13	PEBB	230	CREWSLK	230	1	13						
2004-13	PEBB	230	N BARTOW	230	1	2						
2004-13	RECKER	230	LKAGNES	230	1	16						
2004-13	RECKER	230	ARIANA	230	1	16						
2004-13	RECKER	230	CREWSLK	230	1	13						
2004-13	B BEND	230	MANATEE	230	1	1						
2004-13	RUSKIN T	230	MANATEE	230	1	1						
2004-13	IND RIV	230	IND RIV	115	1	11						
2004-13	SHELD	230	SHELD-NW	69	1	16						
2004-13	LARGO	230	LARGO A	69	1	2						
2004-13	CLMT EST	230	CLMT EST	69	1	2						
2004-13	11TH AVE	230	ELEVEN-E	69	1	16						
2004-13	WINDERME	230	WINDERME	69	1	2						
2004-13	PASADENA	230	PASADENA	115	1	2						
2004-13	ARIANA	230	ARIANA-N	69	1	16						
2004-13	SELOSE	230	SELOSE-N	69	1	16						
2004-13	GAPWAY	230	GAPWAY	69	1	16						
2004-13	CREWSLK	230	CREWSLK	69	1	13						
2004-13	TENOROC	230	TENOROC	69	1	13						
2004-13	BARCOLA	230	WEST	230	1	2						
2004-13	EATON PK	230	CREWSLK	230	1	13						
2004-13	EATON PK	230	EATON PK	69	1	13						
2004-13	EATON PK	230	TENOROC	230	1	13						
2004-13	RECKER	230	GAPWAY	230	1	16						
2004-13	SN PLANT	115	TURNER	115	1	1						
2004-15	SN PLANT	230	SYLVAN	230	1	1						
2004-15	SYLVAN	230	N LONGWD	230	1	1						
2004-15	IND RIV	230	STANTON	230	1	11						
2004-15	SN PLANT	115	TURNER	115	1	1						
2004-15	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-15	SILVR SP	230	SILV SPN	230	1	2						
2004-15	SILVR SP	230	OCALA 1	230	1	2						
2004-15	RIO PINR	230	CURRY FD	230	1	2						
2004-15	STANTON	230	CURRY FD	230	1	2						
2004-15	OSCEOLA	230	LKAGNES	230	1	16						
2004-15	SHELD	230	LK TARPN	230	1	2						
2004-15	PEBB	230	CREWSLK	230	1	13						
2004-15	PEBB	230	N BARTOW	230	1	2						
2004-15	RECKER	230	LKAGNES	230	1	16						
2004-15	RECKER	230	ARIANA	230	1	16						
2004-15	RECKER	230	CREWSLK	230	1	13						
2004-15	B BEND	230	MANATEE	230	1	1						
2004-15	RUSKIN T	230	MANATEE	230	1	1						
2004-15	IND RIV	230	IND RIV	115	1	11						
2004-15	SHELD	230	SHELD-NW	69	1	16						
2004-15	LARGO	230	LARGO A	69	1	2						
2004-15	CLMT EST	230	CLMT EST	69	1	2						
2004-15	11TH AVE	230	ELEVEN-E	69	1	16						
2004-15	WINDERME	230	WINDERME	69	1	2						
2004-15	PASADENA	230	PASADENA	115	1	2						
2004-15	ARIANA	230	ARIANA-N	69	1	16						
2004-15	SELOSE	230	SELOSE-N	69	1	16						
2004-15	GAPWAY	230	GAPWAY	69	1	16						
2004-15	CREWSLK	230	CREWSLK	69	1	13						
2004-15	TENOROC	230	TENOROC	69	1	13						
2004-15	BARCOLA	230	WEST	230	1	2						
2004-15	EATON PK	230	CREWSLK	230	1	13						
2004-15	EATON PK	230	EATON PK	69	1	13						
2004-15	EATON PK	230	TENOROC	230	1	13						
2004-15	RECKER	230	GAPWAY	230	1	16						
2004-15	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-16	SN PLANT	230	SYLVAN	230	1	1						
2004-16	SYLVAN	230	N LONGWD	230	1	1						
2004-16	IND RIV	230	STANTON	230	1	11						
2004-16	SN PLANT	115	TURNER	115	1	1						
2004-16	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-16	SILVR SP	230	SILV SPN	230	1	2						
2004-16	SILVR SP	230	OCALA 1	230	1	2						
2004-16	RIO PINR	230	CURRY FD	230	1	2						
2004-16	STANTON	230	CURRY FD	230	1	2						
2004-16	OSCEOLA	230	LKAGNES	230	1	16						
2004-16	SHELD	230	LK TARPN	230	1	2						
2004-16	PEBB	230	CREWSLK	230	1	13						
2004-16	PEBB	230	N BARTOW	230	1	2						
2004-16	RECKER	230	LKAGNES	230	1	16						
2004-16	RECKER	230	ARIANA	230	1	16						
2004-16	RECKER	230	CREWSLK	230	1	13						
2004-16	B BEND	230	MANATEE	230	1	1						
2004-16	RUSKIN T	230	MANATEE	230	1	1						
2004-16	IND RIV	230	IND RIV	115	1	11						
2004-16	SHELD	230	SHELD-NW	69	1	16						
2004-16	LARGO	230	LARGO A	69	1	2						
2004-16	CLMT EST	230	CLMT EST	69	1	2						
2004-16	11TH AVE	230	ELEVEN-E	69	1	16						
2004-16	WINDERME	230	WINDERME	69	1	2						
2004-16	PASADENA	230	PASADENA	115	1	2						
2004-16	ARIANA	230	ARIANA-N	69	1	16						
2004-16	SELOSE	230	SELOSE-N	69	1	16						
2004-16	GAPWAY	230	GAPWAY	69	1	16						
2004-16	CREWSLK	230	CREWSLK	69	1	13						
2004-16	TENOROC	230	TENOROC	69	1	13						
2004-16	BARCOLA	230	WEST	230	1	2						
2004-16	EATON PK	230	CREWSLK	230	1	13						
2004-16	EATON PK	230	EATON PK	69	1	13						
2004-16	EATON PK	230	TENOROC	230	1	13						
2004-16	RECKER	230	GAPWAY	230	1	16						
2004-16	SN PLANT	115	TURNER	115	1	1						
2004-17	SN PLANT	230	SYLVAN	230	1	1						
2004-17	SYLVAN	230	N LONGWD	230	1	1						
2004-17	IND RIV	230	STANTON	230	1	11						
2004-17	SN PLANT	115	TURNER	115	1	1						
2004-17	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-17	SILVR SP	230	SILV SPN	230	1	2						
2004-17	SILVR SP	230	OCALA 1	230	1	2						
2004-17	RIO PINR	230	CURRY FD	230	1	2						
2004-17	STANTON	230	CURRY FD	230	1	2						
2004-17	OSCEOLA	230	LKAGNES	230	1	16						
2004-17	SHELD	230	LK TARPN	230	1	2						
2004-17	PEBB	230	CREWSLK	230	1	13						
2004-17	PEBB	230	N BARTOW	230	1	2						
2004-17	RECKER	230	LKAGNES	230	1	16						
2004-17	RECKER	230	ARIANA	230	1	16						
2004-17	RECKER	230	CREWSLK	230	1	13						
2004-17	B BEND	230	MANATEE	230	1	1						
2004-17	RUSKIN T	230	MANATEE	230	1	1						
2004-17	IND RIV	230	IND RIV	115	1	11						
2004-17	SHELD	230	SHELD-NW	69	1	16						
2004-17	LARGO	230	LARGO A	69	1	2						
2004-17	CLMT EST	230	CLMT EST	69	1	2						
2004-17	11TH AVE	230	ELEVEN-E	69	1	16						
2004-17	WINDERME	230	WINDERME	69	1	2						
2004-17	PASADENA	230	PASADENA	115	1	2						
2004-17	ARIANA	230	ARIANA-N	69	1	16						
2004-17	SELOSE	230	SELOSE-N	69	1	16						
2004-17	GAPWAY	230	GAPWAY	69	1	16						
2004-17	CREWSLK	230	CREWSLK	69	1	13						
2004-17	TENOROC	230	TENOROC	69	1	13						
2004-17	BARCOLA	230	WEST	230	1	2						
2004-17	EATON PK	230	CREWSLK	230	1	13						
2004-17	EATON PK	230	EATON PK	69	1	13						
2004-17	EATON PK	230	TENOROC	230	1	13						
2004-17	RECKER	230	GAPWAY	230	1	16						
2004-17	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-18	SN PLANT	230	SYLVAN	230	1	1						
2004-18	SYLVAN	230	N LONGWD	230	1	1						
2004-18	IND RIV	230	STANTON	230	1	11						
2004-18	SN PLANT	115	TURNER	115	1	1						
2004-18	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-18	SILVR SP	230	SILV SPN	230	1	2						
2004-18	SILVR SP	230	OCALA 1	230	1	2						
2004-18	RIO PINR	230	CURRY FD	230	1	2						
2004-18	STANTON	230	CURRY FD	230	1	2						
2004-18	OSCEOLA	230	LKAGNES	230	1	16						
2004-18	SHELD	230	LK TARPN	230	1	2						
2004-18	PEBB	230	CREWSLK	230	1	13						
2004-18	PEBB	230	N BARTOW	230	1	2						
2004-18	RECKER	230	LKAGNES	230	1	16		100.0	103.2		102.6	102.1
2004-18	RECKER	230	ARIANA	230	1	16						
2004-18	RECKER	230	CREWSLK	230	1	13						
2004-18	B BEND	230	MANATEE	230	1	1						
2004-18	RUSKIN T	230	MANATEE	230	1	1						
2004-18	IND RIV	230	IND RIV	115	1	11						
2004-18	SHELD	230	SHELD-NW	69	1	16						
2004-18	LARGO	230	LARGO A	69	1	2						
2004-18	CLMT EST	230	CLMT EST	69	1	2						
2004-18	11TH AVE	230	ELEVEN-E	69	1	16						
2004-18	WINDERME	230	WINDERME	69	1	2						
2004-18	PASADENA	230	PASADENA	115	1	2						
2004-18	ARIANA	230	ARIANA-N	69	1	16						
2004-18	SELOSE	230	SELOSE-N	69	1	16						
2004-18	GAPWAY	230	GAPWAY	69	1	16						
2004-18	CREWSLK	230	CREWSLK	69	1	13						
2004-18	TENOROC	230	TENOROC	69	1	13						
2004-18	BARCOLA	230	WEST	230	1	2						
2004-18	EATON PK	230	CREWSLK	230	1	13						
2004-18	EATON PK	230	EATON PK	69	1	13						
2004-18	EATON PK	230	TENOROC	230	1	13						
2004-18	RECKER	230	GAPWAY	230	1	16						
2004-18	SN PLANT	115	TURNER	115	1	1						
2004-19	SN PLANT	230	SYLVAN	230	1	1						
2004-19	SYLVAN	230	N LONGWD	230	1	1						
2004-19	IND RIV	230	STANTON	230	1	11						
2004-19	SN PLANT	115	TURNER	115	1	1						
2004-19	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-19	SILVR SP	230	SILV SPN	230	1	2						
2004-19	SILVR SP	230	OCALA 1	230	1	2						
2004-19	RIO PINR	230	CURRY FD	230	1	2						
2004-19	STANTON	230	CURRY FD	230	1	2						
2004-19	OSCEOLA	230	LKAGNES	230	1	16						
2004-19	SHELD	230	LK TARPN	230	1	2						
2004-19	PEBB	230	CREWSLK	230	1	13						
2004-19	PEBB	230	N BARTOW	230	1	2						
2004-19	RECKER	230	LKAGNES	230	1	16						
2004-19	RECKER	230	ARIANA	230	1	16						
2004-19	RECKER	230	CREWSLK	230	1	13						
2004-19	B BEND	230	MANATEE	230	1	1						
2004-19	RUSKIN T	230	MANATEE	230	1	1						
2004-19	IND RIV	230	IND RIV	115	1	11						
2004-19	SHELD	230	SHELD-NW	69	1	16						
2004-19	LARGO	230	LARGO A	69	1	2						
2004-19	CLMT EST	230	CLMT EST	69	1	2						
2004-19	11TH AVE	230	ELEVEN-E	69	1	16						
2004-19	WINDERME	230	WINDERME	69	1	2						
2004-19	PASADENA	230	PASADENA	115	1	2						
2004-19	ARIANA	230	ARIANA-N	69	1	16						
2004-19	SELOSE	230	SELOSE-N	69	1	16						
2004-19	GAPWAY	230	GAPWAY	69	1	16						
2004-19	CREWSLK	230	CREWSLK	69	1	13						
2004-19	TENOROC	230	TENOROC	69	1	13						
2004-19	BARCOLA	230	WEST	230	1	2						
2004-19	EATON PK	230	CREWSLK	230	1	13						
2004-19	EATON PK	230	EATON PK	69	1	13						
2004-19	EATON PK	230	TENOROC	230	1	13						
2004-19	RECKER	230	GAPWAY	230	1	16						
2004-19	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-20	SN PLANT	230	SYLVAN	230	1	1						
2004-20	SYLVAN	230	N LONGWD	230	1	1						
2004-20	IND RIV	230	STANTON	230	1	11						
2004-20	SN PLANT	115	TURNER	115	1	1						
2004-20	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-20	SILVR SP	230	SILV SPN	230	1	2						
2004-20	SILVR SP	230	OCALA 1	230	1	2						
2004-20	RIO PINR	230	CURRY FD	230	1	2						
2004-20	STANTON	230	CURRY FD	230	1	2						
2004-20	OSCEOLA	230	LKAGNES	230	1	16						
2004-20	SHELD	230	LK TARPN	230	1	2						
2004-20	PEBB	230	CREWSLK	230	1	13						
2004-20	PEBB	230	N BARTOW	230	1	2						
2004-20	RECKER	230	LKAGNES	230	1	16						
2004-20	RECKER	230	ARIANA	230	1	16						
2004-20	RECKER	230	CREWSLK	230	1	13						
2004-20	B BEND	230	MANATEE	230	1	1						
2004-20	RUSKIN T	230	MANATEE	230	1	1						
2004-20	IND RIV	230	IND RIV	115	1	11						
2004-20	SHELD	230	SHELD-NW	69	1	16						
2004-20	LARGO	230	LARGO A	69	1	2						
2004-20	CLMT EST	230	CLMT EST	69	1	2						
2004-20	11TH AVE	230	ELEVEN-E	69	1	16						
2004-20	WINDERME	230	WINDERME	69	1	2						
2004-20	PASADENA	230	PASADENA	115	1	2						
2004-20	ARIANA	230	ARIANA-N	69	1	16						
2004-20	SELOSE	230	SELOSE-N	69	1	16						
2004-20	GAPWAY	230	GAPWAY	69	1	16						
2004-20	CREWSLK	230	CREWSLK	69	1	13						
2004-20	TENOROC	230	TENOROC	69	1	13						
2004-20	BARCOLA	230	WEST	230	1	2						
2004-20	EATON PK	230	CREWSLK	230	1	13						
2004-20	EATON PK	230	EATON PK	69	1	13						
2004-20	EATON PK	230	TENOROC	230	1	13						
2004-20	RECKER	230	GAPWAY	230	1	16						
2004-20	SN PLANT	115	TURNER	115	1	1						
2004-21	SN PLANT	230	SYLVAN	230	1	1						
2004-21	SYLVAN	230	N LONGWD	230	1	1						
2004-21	IND RIV	230	STANTON	230	1	11						
2004-21	SN PLANT	115	TURNER	115	1	1						
2004-21	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-21	SILVR SP	230	SILV SPN	230	1	2						
2004-21	SILVR SP	230	OCALA 1	230	1	2						
2004-21	RIO PINR	230	CURRY FD	230	1	2						
2004-21	STANTON	230	CURRY FD	230	1	2						
2004-21	OSCEOLA	230	LKAGNES	230	1	16						
2004-21	SHELD	230	LK TARPN	230	1	2						
2004-21	PEBB	230	CREWSLK	230	1	13						
2004-21	PEBB	230	N BARTOW	230	1	2						
2004-21	RECKER	230	LKAGNES	230	1	16						
2004-21	RECKER	230	ARIANA	230	1	16						
2004-21	RECKER	230	CREWSLK	230	1	13						
2004-21	B BEND	230	MANATEE	230	1	1						
2004-21	RUSKIN T	230	MANATEE	230	1	1						
2004-21	IND RIV	230	IND RIV	115	1	11						
2004-21	SHELD	230	SHELD-NW	69	1	16						
2004-21	LARGO	230	LARGO A	69	1	2						
2004-21	CLMT EST	230	CLMT EST	69	1	2						
2004-21	11TH AVE	230	ELEVEN-E	69	1	16						
2004-21	WINDERME	230	WINDERME	69	1	2						
2004-21	PASADENA	230	PASADENA	115	1	2						
2004-21	ARIANA	230	ARIANA-N	69	1	16						
2004-21	SELOSE	230	SELOSE-N	69	1	16						
2004-21	GAPWAY	230	GAPWAY	69	1	16						
2004-21	CREWSLK	230	CREWSLK	69	1	13						
2004-21	TENOROC	230	TENOROC	69	1	13						
2004-21	BARCOLA	230	WEST	230	1	2						
2004-21	EATON PK	230	CREWSLK	230	1	13						
2004-21	EATON PK	230	EATON PK	69	1	13						
2004-21	EATON PK	230	TENOROC	230	1	13						
2004-21	RECKER	230	GAPWAY	230	1	16						
2004-21	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-22	SN PLANT	230	SYLVAN	230	1	1						
2004-22	SYLVAN	230	N LONGWD	230	1	1						
2004-22	IND RIV	230	STANTON	230	1	11						
2004-22	SN PLANT	115	TURNER	115	1	1						
2004-22	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-22	SILVR SP	230	SILV SPN	230	1	2						
2004-22	SILVR SP	230	OCALA 1	230	1	2						
2004-22	RIO PINR	230	CURRY FD	230	1	2						
2004-22	STANTON	230	CURRY FD	230	1	2						
2004-22	OSCEOLA	230	LKAGNES	230	1	16						
2004-22	SHELD	230	LK TARPN	230	1	2						
2004-22	PEBB	230	CREWSLK	230	1	13						
2004-22	PEBB	230	N BARTOW	230	1	2						
2004-22	RECKER	230	LKAGNES	230	1	16						
2004-22	RECKER	230	ARIANA	230	1	16						
2004-22	RECKER	230	CREWSLK	230	1	13						
2004-22	B BEND	230	MANATEE	230	1	1						
2004-22	RUSKIN T	230	MANATEE	230	1	1						
2004-22	IND RIV	230	IND RIV	115	1	11						
2004-22	SHELD	230	SHELD-NW	69	1	16						
2004-22	LARGO	230	LARGO A	69	1	2						
2004-22	CLMT EST	230	CLMT EST	69	1	2						
2004-22	11TH AVE	230	ELEVEN-E	69	1	16						
2004-22	WINDERME	230	WINDERME	69	1	2						
2004-22	PASADENA	230	PASADENA	115	1	2						
2004-22	ARIANA	230	ARIANA-N	69	1	16						
2004-22	SELOSE	230	SELOSE-N	69	1	16						
2004-22	GAPWAY	230	GAPWAY	69	1	16						
2004-22	CREWSLK	230	CREWSLK	69	1	13						
2004-22	TENOROC	230	TENOROC	69	1	13						
2004-22	BARCOLA	230	WEST	230	1	2						
2004-22	EATON PK	230	CREWSLK	230	1	13						
2004-22	EATON PK	230	EATON PK	69	1	13						
2004-22	EATON PK	230	TENOROC	230	1	13						
2004-22	RECKER	230	GAPWAY	230	1	16						
2004-22	SN PLANT	115	TURNER	115	1	1						
2004-23	SN PLANT	230	SYLVAN	230	1	1						
2004-23	SYLVAN	230	N LONGWD	230	1	1						
2004-23	IND RIV	230	STANTON	230	1	11						
2004-23	SN PLANT	115	TURNER	115	1	1						
2004-23	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-23	SILVR SP	230	SILV SPN	230	1	2						
2004-23	SILVR SP	230	OCALA 1	230	1	2						
2004-23	RIO PINR	230	CURRY FD	230	1	2						
2004-23	STANTON	230	CURRY FD	230	1	2						
2004-23	OSCEOLA	230	LKAGNES	230	1	16						
2004-23	SHELD	230	LK TARPN	230	1	2						
2004-23	PEBB	230	CREWSLK	230	1	13						
2004-23	PEBB	230	N BARTOW	230	1	2						
2004-23	RECKER	230	LKAGNES	230	1	16						
2004-23	RECKER	230	ARIANA	230	1	16						
2004-23	RECKER	230	CREWSLK	230	1	13						
2004-23	B BEND	230	MANATEE	230	1	1						
2004-23	RUSKIN T	230	MANATEE	230	1	1						
2004-23	IND RIV	230	IND RIV	115	1	11						
2004-23	SHELD	230	SHELD-NW	69	1	16						
2004-23	LARGO	230	LARGO A	69	1	2						
2004-23	CLMT EST	230	CLMT EST	69	1	2						
2004-23	11TH AVE	230	ELEVEN-E	69	1	16						
2004-23	WINDERME	230	WINDERME	69	1	2						
2004-23	PASADENA	230	PASADENA	115	1	2						
2004-23	ARIANA	230	ARIANA-N	69	1	16						
2004-23	SELOSE	230	SELOSE-N	69	1	16						
2004-23	GAPWAY	230	GAPWAY	69	1	16						
2004-23	CREWSLK	230	CREWSLK	69	1	13						
2004-23	TENOROC	230	TENOROC	69	1	13						
2004-23	BARCOLA	230	WEST	230	1	2						
2004-23	EATON PK	230	CREWSLK	230	1	13						
2004-23	EATON PK	230	EATON PK	69	1	13						
2004-23	EATON PK	230	TENOROC	230	1	13						
2004-23	RECKER	230	GAPWAY	230	1	16						
2004-23	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
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100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-24	SN PLANT	230	SYLVAN	230	1	1						
2004-24	SYLVAN	230	N LONGWD	230	1	1						
2004-24	IND RIV	230	STANTON	230	1	11						
2004-24	SN PLANT	115	TURNER	115	1	1						
2004-24	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-24	SILVR SP	230	SILV SPN	230	1	2						
2004-24	SILVR SP	230	OCALA 1	230	1	2						
2004-24	RIO PINR	230	CURRY FD	230	1	2						
2004-24	STANTON	230	CURRY FD	230	1	2						
2004-24	OSCEOLA	230	LKAGNES	230	1	16						
2004-24	SHELD	230	LK TARPN	230	1	2						
2004-24	PEBB	230	CREWSLK	230	1	13						
2004-24	PEBB	230	N BARTOW	230	1	2						
2004-24	RECKER	230	LKAGNES	230	1	16						
2004-24	RECKER	230	ARIANA	230	1	16						
2004-24	RECKER	230	CREWSLK	230	1	13						
2004-24	B BEND	230	MANATEE	230	1	1						
2004-24	RUSKIN T	230	MANATEE	230	1	1						
2004-24	IND RIV	230	IND RIV	115	1	11						
2004-24	SHELD	230	SHELD-NW	69	1	16						
2004-24	LARGO	230	LARGO A	69	1	2						
2004-24	CLMT EST	230	CLMT EST	69	1	2						
2004-24	11TH AVE	230	ELEVEN-E	69	1	16						
2004-24	WINDERME	230	WINDERME	69	1	2						
2004-24	PASADENA	230	PASADENA	115	1	2						
2004-24	ARIANA	230	ARIANA-N	69	1	16						
2004-24	SELOSE	230	SELOSE-N	69	1	16						
2004-24	GAPWAY	230	GAPWAY	69	1	16						
2004-24	CREWSLK	230	CREWSLK	69	1	13						
2004-24	TENOROC	230	TENOROC	69	1	13						
2004-24	BARCOLA	230	WEST	230	1	2						
2004-24	EATON PK	230	CREWSLK	230	1	13						
2004-24	EATON PK	230	EATON PK	69	1	13						
2004-24	EATON PK	230	TENOROC	230	1	13						
2004-24	RECKER	230	GAPWAY	230	1	16						
2004-24	SN PLANT	115	TURNER	115	1	1						
2004-25	SN PLANT	230	SYLVAN	230	1	1						
2004-25	SYLVAN	230	N LONGWD	230	1	1						
2004-25	IND RIV	230	STANTON	230	1	11						
2004-25	SN PLANT	115	TURNER	115	1	1						
2004-25	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-25	SILVR SP	230	SILV SPN	230	1	2						
2004-25	SILVR SP	230	OCALA 1	230	1	2						
2004-25	RIO PINR	230	CURRY FD	230	1	2						
2004-25	STANTON	230	CURRY FD	230	1	2						
2004-25	OSCEOLA	230	LKAGNES	230	1	16						
2004-25	SHELD	230	LK TARPN	230	1	2						
2004-25	PEBB	230	CREWSLK	230	1	13						
2004-25	PEBB	230	N BARTOW	230	1	2						
2004-25	RECKER	230	LKAGNES	230	1	16						
2004-25	RECKER	230	ARIANA	230	1	16						
2004-25	RECKER	230	CREWSLK	230	1	13						
2004-25	B BEND	230	MANATEE	230	1	1						
2004-25	RUSKIN T	230	MANATEE	230	1	1						
2004-25	IND RIV	230	IND RIV	115	1	11						
2004-25	SHELD	230	SHELD-NW	69	1	16						
2004-25	LARGO	230	LARGO A	69	1	2						
2004-25	CLMT EST	230	CLMT EST	69	1	2						
2004-25	11TH AVE	230	ELEVEN-E	69	1	16						
2004-25	WINDERME	230	WINDERME	69	1	2						
2004-25	PASADENA	230	PASADENA	115	1	2						
2004-25	ARIANA	230	ARIANA-N	69	1	16						
2004-25	SELOSE	230	SELOSE-N	69	1	16						
2004-25	GAPWAY	230	GAPWAY	69	1	16						
2004-25	CREWSLK	230	CREWSLK	69	1	13						
2004-25	TENOROC	230	TENOROC	69	1	13						
2004-25	BARCOLA	230	WEST	230	1	2						
2004-25	EATON PK	230	CREWSLK	230	1	13						
2004-25	EATON PK	230	EATON PK	69	1	13						
2004-25	EATON PK	230	TENOROC	230	1	13						
2004-25	RECKER	230	GAPWAY	230	1	16						
2004-25	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-26	SN PLANT	230	SYLVAN	230	1	1						
2004-26	SYLVAN	230	N LONGWD	230	1	1						
2004-26	IND RIV	230	STANTON	230	1	11						
2004-26	SN PLANT	115	TURNER	115	1	1						
2004-26	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-26	SILVR SP	230	SILV SPN	230	1	2						
2004-26	SILVR SP	230	OCALA 1	230	1	2						
2004-26	RIO PINR	230	CURRY FD	230	1	2						
2004-26	STANTON	230	CURRY FD	230	1	2						
2004-26	OSCEOLA	230	LKAGNES	230	1	16						
2004-26	SHELD	230	LK TARPN	230	1	2						
2004-26	PEBB	230	CREWSLK	230	1	13						
2004-26	PEBB	230	N BARTOW	230	1	2						
2004-26	RECKER	230	LKAGNES	230	1	16						
2004-26	RECKER	230	ARIANA	230	1	16						
2004-26	RECKER	230	CREWSLK	230	1	13						
2004-26	B BEND	230	MANATEE	230	1	1						
2004-26	RUSKIN T	230	MANATEE	230	1	1						
2004-26	IND RIV	230	IND RIV	115	1	11						
2004-26	SHELD	230	SHELD-NW	69	1	16						
2004-26	LARGO	230	LARGO A	69	1	2						
2004-26	CLMT EST	230	CLMT EST	69	1	2						
2004-26	11TH AVE	230	ELEVEN-E	69	1	16						
2004-26	WINDERME	230	WINDERME	69	1	2						
2004-26	PASADENA	230	PASADENA	115	1	2						
2004-26	ARIANA	230	ARIANA-N	69	1	16						
2004-26	SELOSE	230	SELOSE-N	69	1	16						
2004-26	GAPWAY	230	GAPWAY	69	1	16						
2004-26	CREWSLK	230	CREWSLK	69	1	13						
2004-26	TENOROC	230	TENOROC	69	1	13						
2004-26	BARCOLA	230	WEST	230	1	2						
2004-26	EATON PK	230	CREWSLK	230	1	13						
2004-26	EATON PK	230	EATON PK	69	1	13						
2004-26	EATON PK	230	TENOROC	230	1	13						
2004-26	RECKER	230	GAPWAY	230	1	16						
2004-26	SN PLANT	115	TURNER	115	1	1						
2004-27	SN PLANT	230	SYLVAN	230	1	1						
2004-27	SYLVAN	230	N LONGWD	230	1	1						
2004-27	IND RIV	230	STANTON	230	1	11						
2004-27	SN PLANT	115	TURNER	115	1	1						
2004-27	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-27	SILVR SP	230	SILV SPN	230	1	2						
2004-27	SILVR SP	230	OCALA 1	230	1	2						
2004-27	RIO PINR	230	CURRY FD	230	1	2						
2004-27	STANTON	230	CURRY FD	230	1	2						
2004-27	OSCEOLA	230	LKAGNES	230	1	16						
2004-27	SHELD	230	LK TARPN	230	1	2						
2004-27	PEBB	230	CREWSLK	230	1	13						
2004-27	PEBB	230	N BARTOW	230	1	2						
2004-27	RECKER	230	LKAGNES	230	1	16						
2004-27	RECKER	230	ARIANA	230	1	16						
2004-27	RECKER	230	CREWSLK	230	1	13						
2004-27	B BEND	230	MANATEE	230	1	1						
2004-27	RUSKIN T	230	MANATEE	230	1	1						
2004-27	IND RIV	230	IND RIV	115	1	11						
2004-27	SHELD	230	SHELD-NW	69	1	16						
2004-27	LARGO	230	LARGO A	69	1	2						
2004-27	CLMT EST	230	CLMT EST	69	1	2						
2004-27	11TH AVE	230	ELEVEN-E	69	1	16						
2004-27	WINDERME	230	WINDERME	69	1	2						
2004-27	PASADENA	230	PASADENA	115	1	2						
2004-27	ARIANA	230	ARIANA-N	69	1	16						
2004-27	SELOSE	230	SELOSE-N	69	1	16						
2004-27	GAPWAY	230	GAPWAY	69	1	16						
2004-27	CREWSLK	230	CREWSLK	69	1	13						
2004-27	TENOROC	230	TENOROC	69	1	13						
2004-27	BARCOLA	230	WEST	230	1	2						
2004-27	EATON PK	230	CREWSLK	230	1	13						
2004-27	EATON PK	230	EATON PK	69	1	13						
2004-27	EATON PK	230	TENOROC	230	1	13						
2004-27	RECKER	230	GAPWAY	230	1	16						
2004-27	SN PLANT	115	TURNER	115	1	1						

Table I

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-28	SN PLANT	230	SYLVAN	230	1	1						
2004-28	SYLVAN	230	N LONGWD	230	1	1						
2004-28	IND RIV	230	STANTON	230	1	11						
2004-28	SN PLANT	115	TURNER	115	1	1						
2004-28	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-28	SILVR SP	230	SILV SPN	230	1	2						
2004-28	SILVR SP	230	OCALA 1	230	1	2						
2004-28	RIO PINR	230	CURRY FD	230	1	2						
2004-28	STANTON	230	CURRY FD	230	1	2						
2004-28	OSCEOLA	230	LKAGNES	230	1	16						
2004-28	SHELD	230	LK TARPN	230	1	2						
2004-28	PEBB	230	CREWSLK	230	1	13						
2004-28	PEBB	230	N BARTOW	230	1	2						
2004-28	RECKER	230	LKAGNES	230	1	16						
2004-28	RECKER	230	ARIANA	230	1	16						
2004-28	RECKER	230	CREWSLK	230	1	13						
2004-28	B BEND	230	MANATEE	230	1	1						
2004-28	RUSKIN T	230	MANATEE	230	1	1						
2004-28	IND RIV	230	IND RIV	115	1	11						
2004-28	SHELD	230	SHELD-NW	69	1	16						
2004-28	LARGO	230	LARGO A	69	1	2						
2004-28	CLMT EST	230	CLMT EST	69	1	2						
2004-28	11TH AVE	230	ELEVEN-E	69	1	16						
2004-28	WINDERME	230	WINDERME	69	1	2						
2004-28	PASADENA	230	PASADENA	115	1	2						
2004-28	ARIANA	230	ARIANA-N	69	1	16						
2004-28	SELOSE	230	SELOSE-N	69	1	16						
2004-28	GAPWAY	230	GAPWAY	69	1	16						
2004-28	CREWSLK	230	CREWSLK	69	1	13						
2004-28	TENOROC	230	TENOROC	69	1	13						
2004-28	BARCOLA	230	WEST	230	1	2						
2004-28	EATON PK	230	CREWSLK	230	1	13						
2004-28	EATON PK	230	EATON PK	69	1	13						
2004-28	EATON PK	230	TENOROC	230	1	13						
2004-28	RECKER	230	GAPWAY	230	1	16						
2004-28	SN PLANT	115	TURNER	115	1	1						
2004-29	SN PLANT	230	SYLVAN	230	1	1						
2004-29	SYLVAN	230	N LONGWD	230	1	1						
2004-29	IND RIV	230	STANTON	230	1	11						
2004-29	SN PLANT	115	TURNER	115	1	1						
2004-29	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-29	SILVR SP	230	SILV SPN	230	1	2						
2004-29	SILVR SP	230	OCALA 1	230	1	2						
2004-29	RIO PINR	230	CURRY FD	230	1	2						
2004-29	STANTON	230	CURRY FD	230	1	2						
2004-29	OSCEOLA	230	LKAGNES	230	1	16						
2004-29	SHELD	230	LK TARPN	230	1	2						
2004-29	PEBB	230	CREWSLK	230	1	13						
2004-29	PEBB	230	N BARTOW	230	1	2						
2004-29	RECKER	230	LKAGNES	230	1	16						
2004-29	RECKER	230	ARIANA	230	1	16						
2004-29	RECKER	230	CREWSLK	230	1	13						
2004-29	B BEND	230	MANATEE	230	1	1						
2004-29	RUSKIN T	230	MANATEE	230	1	1						
2004-29	IND RIV	230	IND RIV	115	1	11						
2004-29	SHELD	230	SHELD-NW	69	1	16						
2004-29	LARGO	230	LARGO A	69	1	2						
2004-29	CLMT EST	230	CLMT EST	69	1	2						
2004-29	11TH AVE	230	ELEVEN-E	69	1	16						
2004-29	WINDERME	230	WINDERME	69	1	2						
2004-29	PASADENA	230	PASADENA	115	1	2						
2004-29	ARIANA	230	ARIANA-N	69	1	16		103.4	103.1	103.8	103.1	103.0
2004-29	SELOSE	230	SELOSE-N	69	1	16						
2004-29	GAPWAY	230	GAPWAY	69	1	16						
2004-29	CREWSLK	230	CREWSLK	69	1	13						
2004-29	TENOROC	230	TENOROC	69	1	13						
2004-29	BARCOLA	230	WEST	230	1	2						
2004-29	EATON PK	230	CREWSLK	230	1	13						
2004-29	EATON PK	230	EATON PK	69	1	13						
2004-29	EATON PK	230	TENOROC	230	1	13						
2004-29	RECKER	230	GAPWAY	230	1	16						
2004-29	SN PLANT	115	TURNER	115	1	1						

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Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

100% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-30	SN PLANT	230	SYLVAN	230	1	1						
2004-30	SYLVAN	230	N LONGWD	230	1	1						
2004-30	IND RIV	230	STANTON	230	1	11						
2004-30	SN PLANT	115	TURNER	115	1	1						
2004-30	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-30	SILVR SP	230	SILV SPN	230	1	2						
2004-30	SILVR SP	230	OCALA 1	230	1	2						
2004-30	RIO PINR	230	CURRY FD	230	1	2						
2004-30	STANTON	230	CURRY FD	230	1	2						
2004-30	OSCEOLA	230	LKAGNES	230	1	16						
2004-30	SHELD	230	LK TARPN	230	1	2						
2004-30	PEBB	230	CREWSLK	230	1	13						
2004-30	PEBB	230	N BARTOW	230	1	2						
2004-30	RECKER	230	LKAGNES	230	1	16						
2004-30	RECKER	230	ARIANA	230	1	16						
2004-30	RECKER	230	CREWSLK	230	1	13						
2004-30	B BEND	230	MANATEE	230	1	1						
2004-30	RUSKIN T	230	MANATEE	230	1	1						
2004-30	IND RIV	230	IND RIV	115	1	11						
2004-30	SHELD	230	SHELD-NW	69	1	16						
2004-30	LARGO	230	LARGO A	69	1	2						
2004-30	CLMT EST	230	CLMT EST	69	1	2						
2004-30	11TH AVE	230	ELEVEN-E	69	1	16						
2004-30	WINDERME	230	WINDERME	69	1	2						
2004-30	PASADENA	230	PASADENA	115	1	2						
2004-30	ARIANA	230	ARIANA-N	69	1	16						
2004-30	SELOSE	230	SELOSE-N	69	1	16						
2004-30	GAPWAY	230	GAPWAY	69	1	16						
2004-30	CREWSLK	230	CREWSLK	69	1	13						
2004-30	TENOROC	230	TENOROC	69	1	13						
2004-30	BARCOLA	230	WEST	230	1	2						
2004-30	EATON PK	230	CREWSLK	230	1	13						
2004-30	EATON PK	230	EATON PK	69	1	13						
2004-30	EATON PK	230	TENOROC	230	1	13						
2004-30	RECKER	230	GAPWAY	230	1	16						
2004-30	SN PLANT	115	TURNER	115	1	1						
2004-31	SN PLANT	230	SYLVAN	230	1	1						
2004-31	SYLVAN	230	N LONGWD	230	1	1						
2004-31	IND RIV	230	STANTON	230	1	11						
2004-31	SN PLANT	115	TURNER	115	1	1						
2004-31	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-31	SILVR SP	230	SILV SPN	230	1	2						
2004-31	SILVR SP	230	OCALA 1	230	1	2						
2004-31	RIO PINR	230	CURRY FD	230	1	2						
2004-31	STANTON	230	CURRY FD	230	1	2						
2004-31	OSCEOLA	230	LKAGNES	230	1	16						
2004-31	SHELD	230	LK TARPN	230	1	2						
2004-31	PEBB	230	CREWSLK	230	1	13						
2004-31	PEBB	230	N BARTOW	230	1	2						
2004-31	RECKER	230	LKAGNES	230	1	16						
2004-31	RECKER	230	ARIANA	230	1	16						
2004-31	RECKER	230	CREWSLK	230	1	13						
2004-31	B BEND	230	MANATEE	230	1	1						
2004-31	RUSKIN T	230	MANATEE	230	1	1						
2004-31	IND RIV	230	IND RIV	115	1	11						
2004-31	SHELD	230	SHELD-NW	69	1	16						
2004-31	LARGO	230	LARGO A	69	1	2						
2004-31	CLMT EST	230	CLMT EST	69	1	2						
2004-31	11TH AVE	230	ELEVEN-E	69	1	16						
2004-31	WINDERME	230	WINDERME	69	1	2						
2004-31	PASADENA	230	PASADENA	115	1	2						
2004-31	ARIANA	230	ARIANA-N	69	1	16						
2004-31	SELOSE	230	SELOSE-N	69	1	16						
2004-31	GAPWAY	230	GAPWAY	69	1	16						
2004-31	CREWSLK	230	CREWSLK	69	1	13						
2004-31	TENOROC	230	TENOROC	69	1	13						
2004-31	BARCOLA	230	WEST	230	1	2						
2004-31	EATON PK	230	CREWSLK	230	1	13						
2004-31	EATON PK	230	EATON PK	69	1	13						
2004-31	EATON PK	230	TENOROC	230	1	13						
2004-31	RECKER	230	GAPWAY	230	1	16						
2004-31	SN PLANT	115	TURNER	115	1	1						

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Following N-1 Disturbances
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100% Load Base Case

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Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-32	SN PLANT	230	SYLVAN	230	1	1						
2004-32	SYLVAN	230	N LONGWD	230	1	1						
2004-32	IND RIV	230	STANTON	230	1	11						
2004-32	SN PLANT	115	TURNER	115	1	1						
2004-32	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-32	SILVR SP	230	SILV SPN	230	1	2						
2004-32	SILVR SP	230	OCALA 1	230	1	2						
2004-32	RIO PINR	230	CURRY FD	230	1	2						
2004-32	STANTON	230	CURRY FD	230	1	2						
2004-32	OSCEOLA	230	LKAGNES	230	1	16						
2004-32	SHELD	230	LK TARPN	230	1	2						
2004-32	PEBB	230	CREWSLK	230	1	13						
2004-32	PEBB	230	N BARTOW	230	1	2						
2004-32	RECKER	230	LKAGNES	230	1	16						
2004-32	RECKER	230	ARIANA	230	1	16						
2004-32	RECKER	230	CREWSLK	230	1	13						
2004-32	B BEND	230	MANATEE	230	1	1						
2004-32	RUSKIN T	230	MANATEE	230	1	1						
2004-32	IND RIV	230	IND RIV	115	1	11						
2004-32	SHELD	230	SHELD-NW	69	1	16						
2004-32	LARGO	230	LARGO A	69	1	2						
2004-32	CLMT EST	230	CLMT EST	69	1	2						
2004-32	11TH AVE	230	ELEVEN-E	69	1	16						
2004-32	WINDERME	230	WINDERME	69	1	2						
2004-32	PASADENA	230	PASADENA	115	1	2						
2004-32	ARIANA	230	ARIANA-N	69	1	16						
2004-32	SELOSE	230	SELOSE-N	69	1	16						
2004-32	GAPWAY	230	GAPWAY	69	1	16						
2004-32	CREWSLK	230	CREWSLK	69	1	13						
2004-32	TENOROC	230	TENOROC	69	1	13						
2004-32	BARCOLA	230	WEST	230	1	2						
2004-32	EATON PK	230	CREWSLK	230	1	13						
2004-32	EATON PK	230	EATON PK	69	1	13						
2004-32	EATON PK	230	TENOROC	230	1	13						
2004-32	RECKER	230	GAPWAY	230	1	16						
2004-32	SN PLANT	115	TURNER	115	1	1						
2004-33	SN PLANT	230	SYLVAN	230	1	1						
2004-33	SYLVAN	230	N LONGWD	230	1	1						
2004-33	IND RIV	230	STANTON	230	1	11						
2004-33	SN PLANT	115	TURNER	115	1	1						
2004-33	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-33	SILVR SP	230	SILV SPN	230	1	2						
2004-33	SILVR SP	230	OCALA 1	230	1	2						
2004-33	RIO PINR	230	CURRY FD	230	1	2						
2004-33	STANTON	230	CURRY FD	230	1	2						
2004-33	OSCEOLA	230	LKAGNES	230	1	16						
2004-33	SHELD	230	LK TARPN	230	1	2						
2004-33	PEBB	230	CREWSLK	230	1	13						
2004-33	PEBB	230	N BARTOW	230	1	2						
2004-33	RECKER	230	LKAGNES	230	1	16						
2004-33	RECKER	230	ARIANA	230	1	16						
2004-33	RECKER	230	CREWSLK	230	1	13						
2004-33	B BEND	230	MANATEE	230	1	1						
2004-33	RUSKIN T	230	MANATEE	230	1	1						
2004-33	IND RIV	230	IND RIV	115	1	11						
2004-33	SHELD	230	SHELD-NW	69	1	16						
2004-33	LARGO	230	LARGO A	69	1	2						
2004-33	CLMT EST	230	CLMT EST	69	1	2						
2004-33	11TH AVE	230	ELEVEN-E	69	1	16						
2004-33	WINDERME	230	WINDERME	69	1	2						
2004-33	PASADENA	230	PASADENA	115	1	2						
2004-33	ARIANA	230	ARIANA-N	69	1	16						
2004-33	SELOSE	230	SELOSE-N	69	1	16						
2004-33	GAPWAY	230	GAPWAY	69	1	16						
2004-33	CREWSLK	230	CREWSLK	69	1	13						
2004-33	TENOROC	230	TENOROC	69	1	13						
2004-33	BARCOLA	230	WEST	230	1	2						
2004-33	EATON PK	230	CREWSLK	230	1	13						
2004-33	EATON PK	230	EATON PK	69	1	13						
2004-33	EATON PK	230	TENOROC	230	1	13						
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2004-33	SN PLANT	115	TURNER	115	1	1						

Table I

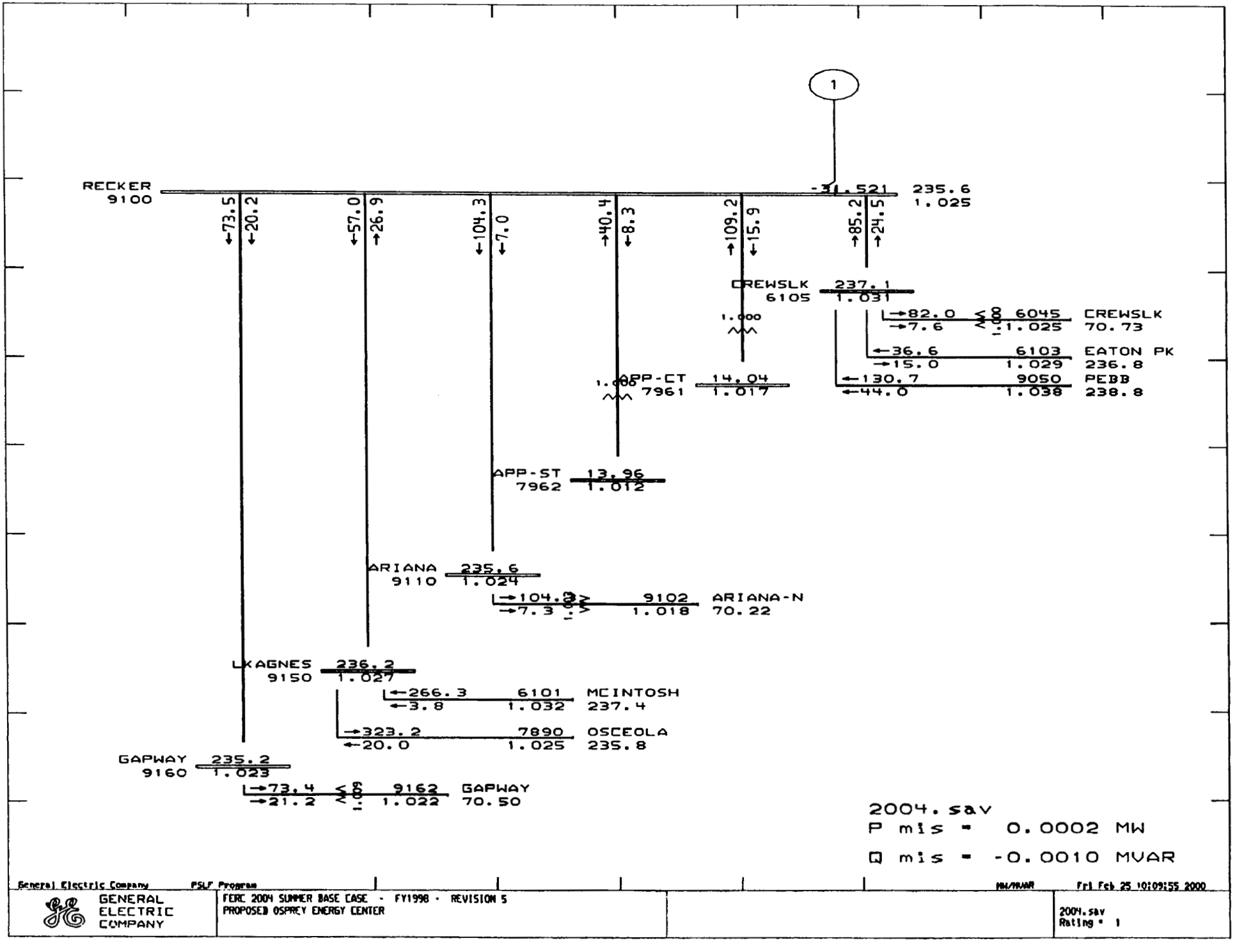
Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

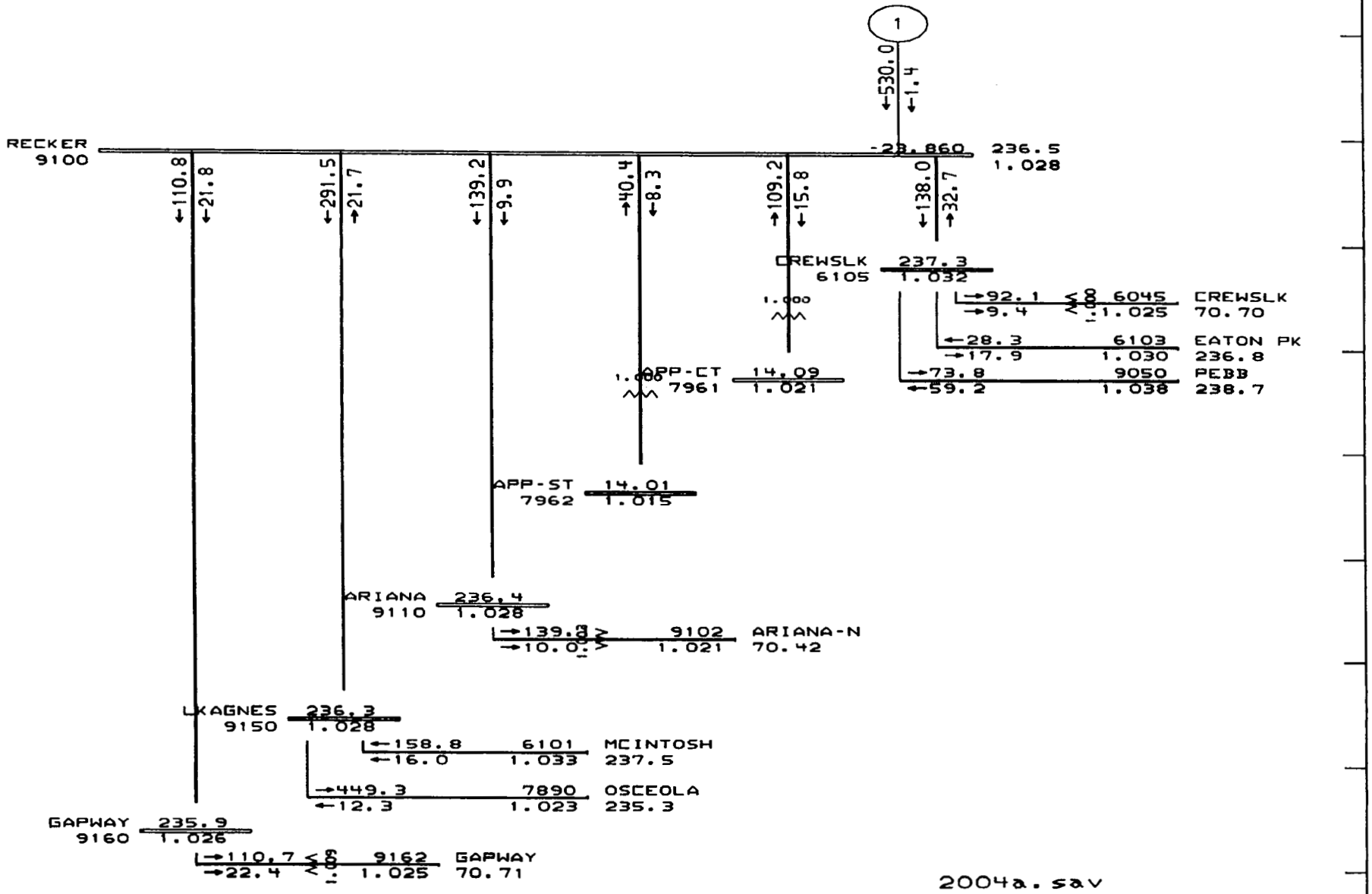
100% Load Base Case

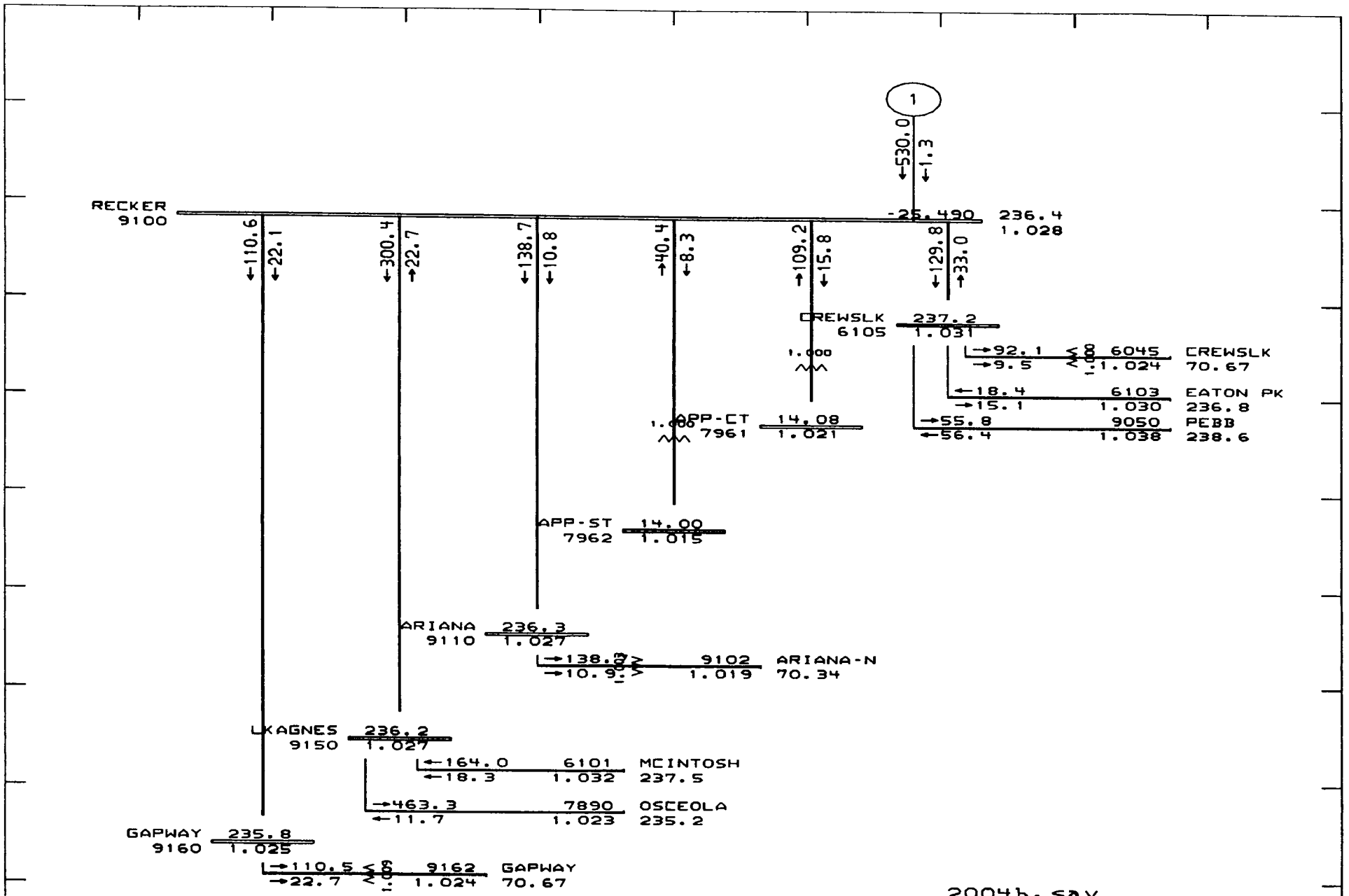
All Flows above 100% of Emergency rating are Shown

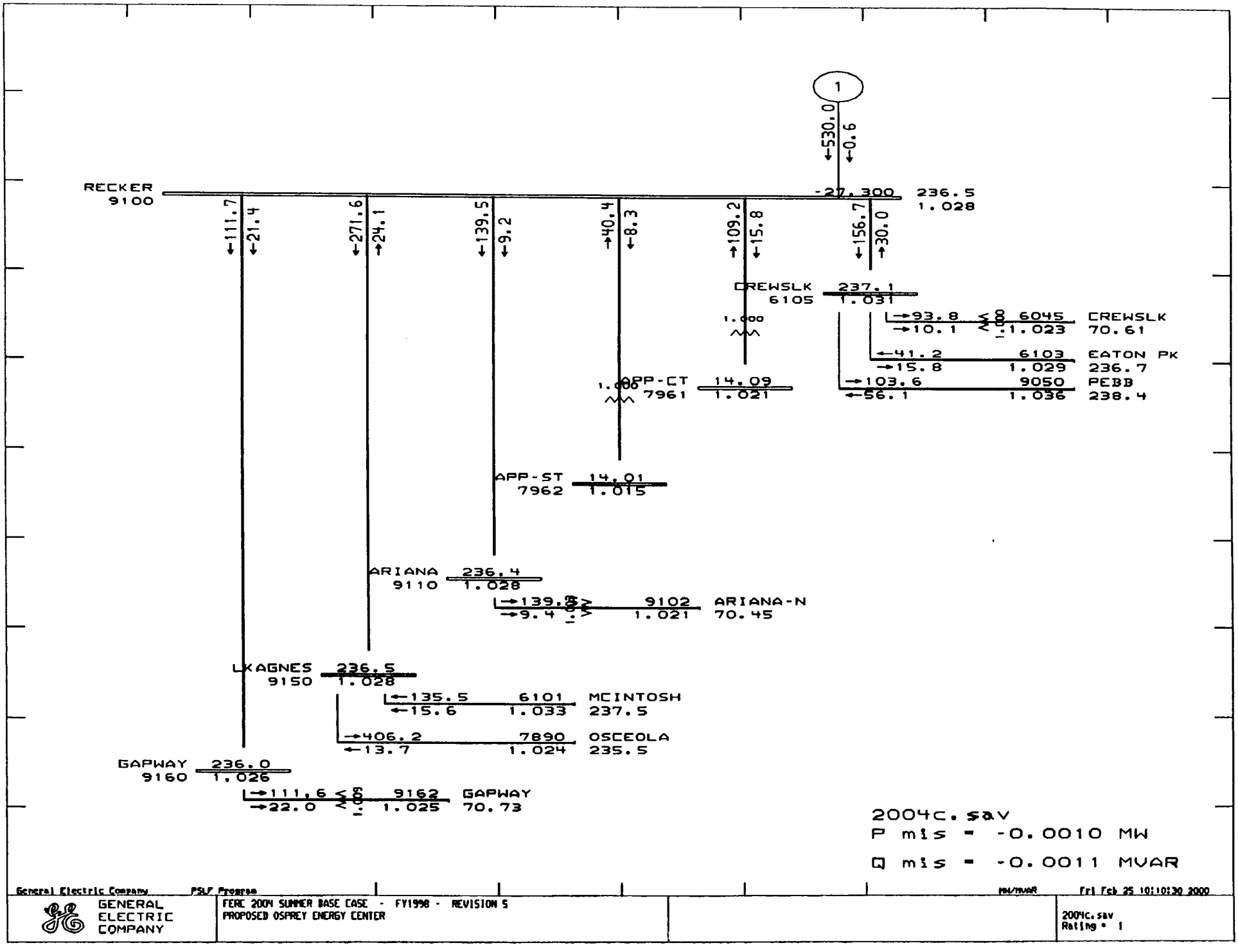
Monitored Branches							Case 2004 Base No OEC Gen	Case 2004A Sell to FPL	Case 2004B Sell to FPC	Case 2004C Sell to TEC	Case 2004D Sell to JEA	Case 2004E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-34	SN PLANT	230	SYLVAN	230	1	1						
2004-34	SYLVAN	230	N LONGWD	230	1	1						
2004-34	IND RIV	230	STANTON	230	1	11						
2004-34	SN PLANT	115	TURNER	115	1	1						
2004-34	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-34	SILVR SP	230	SILV SPN	230	1	2						
2004-34	SILVR SP	230	OCALA 1	230	1	2						
2004-34	RIO PINR	230	CURRY FD	230	1	2						
2004-34	STANTON	230	CURRY FD	230	1	2						
2004-34	OSCEOLA	230	LKAGNES	230	1	16						
2004-34	SHELD	230	LK TARPN	230	1	2						
2004-34	PEBB	230	CREWSLK	230	1	13						
2004-34	PEBB	230	N BARTOW	230	1	2						
2004-34	RECKER	230	LKAGNES	230	1	16						
2004-34	RECKER	230	ARIANA	230	1	16						
2004-34	RECKER	230	CREWSLK	230	1	13						
2004-34	B BEND	230	MANATEE	230	1	1						
2004-34	RUSKIN T	230	MANATEE	230	1	1						
2004-34	IND RIV	230	IND RIV	115	1	11						
2004-34	SHELD	230	SHELD-NW	69	1	16						
2004-34	LARGO	230	LARGO A	69	1	2						
2004-34	CLMT EST	230	CLMT EST	69	1	2						
2004-34	11TH AVE	230	ELEVEN-E	69	1	16						
2004-34	WINDERME	230	WINDERME	69	1	2						
2004-34	PASADENA	230	PASADENA	115	1	2						
2004-34	ARIANA	230	ARIANA-N	69	1	16						
2004-34	SELOSE	230	SELOSE-N	69	1	16						
2004-34	GAPWAY	230	GAPWAY	69	1	16						
2004-34	CREWSLK	230	CREWSLK	69	1	13						
2004-34	TENOROC	230	TENOROC	69	1	13						
2004-34	BARCOLA	230	WEST	230	1	2						
2004-34	EATON PK	230	CREWSLK	230	1	13						
2004-34	EATON PK	230	EATON PK	69	1	13						
2004-34	EATON PK	230	TENOROC	230	1	13						
2004-34	RECKER	230	GAPWAY	230	1	16						
2004-34	SN PLANT	115	TURNER	115	1	1						
2004-35	SN PLANT	230	SYLVAN	230	1	1						
2004-35	SYLVAN	230	N LONGWD	230	1	1						
2004-35	IND RIV	230	STANTON	230	1	11						
2004-35	SN PLANT	115	TURNER	115	1	1						
2004-35	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-35	SILVR SP	230	SILV SPN	230	1	2						
2004-35	SILVR SP	230	OCALA 1	230	1	2						
2004-35	RIO PINR	230	CURRY FD	230	1	2						
2004-35	STANTON	230	CURRY FD	230	1	2						
2004-35	OSCEOLA	230	LKAGNES	230	1	16						
2004-35	SHELD	230	LK TARPN	230	1	2						
2004-35	PEBB	230	CREWSLK	230	1	13						
2004-35	PEBB	230	N BARTOW	230	1	2						
2004-35	RECKER	230	LKAGNES	230	1	16						
2004-35	RECKER	230	ARIANA	230	1	16						
2004-35	RECKER	230	CREWSLK	230	1	13						
2004-35	B BEND	230	MANATEE	230	1	1						
2004-35	RUSKIN T	230	MANATEE	230	1	1						
2004-35	IND RIV	230	IND RIV	115	1	11						
2004-35	SHELD	230	SHELD-NW	69	1	16						
2004-35	LARGO	230	LARGO A	69	1	2						
2004-35	CLMT EST	230	CLMT EST	69	1	2						
2004-35	11TH AVE	230	ELEVEN-E	69	1	16						
2004-35	WINDERME	230	WINDERME	69	1	2						
2004-35	PASADENA	230	PASADENA	115	1	2						
2004-35	ARIANA	230	ARIANA-N	69	1	16						
2004-35	SELOSE	230	SELOSE-N	69	1	16						
2004-35	GAPWAY	230	GAPWAY	69	1	16						
2004-35	CREWSLK	230	CREWSLK	69	1	13						
2004-35	TENOROC	230	TENOROC	69	1	13						
2004-35	BARCOLA	230	WEST	230	1	2						
2004-35	EATON PK	230	CREWSLK	230	1	13						
2004-35	EATON PK	230	EATON PK	69	1	13						
2004-35	EATON PK	230	TENOROC	230	1	13						
2004-35	RECKER	230	GAPWAY	230	1	16						
2004-35	SN PLANT	115	TURNER	115	1	1						

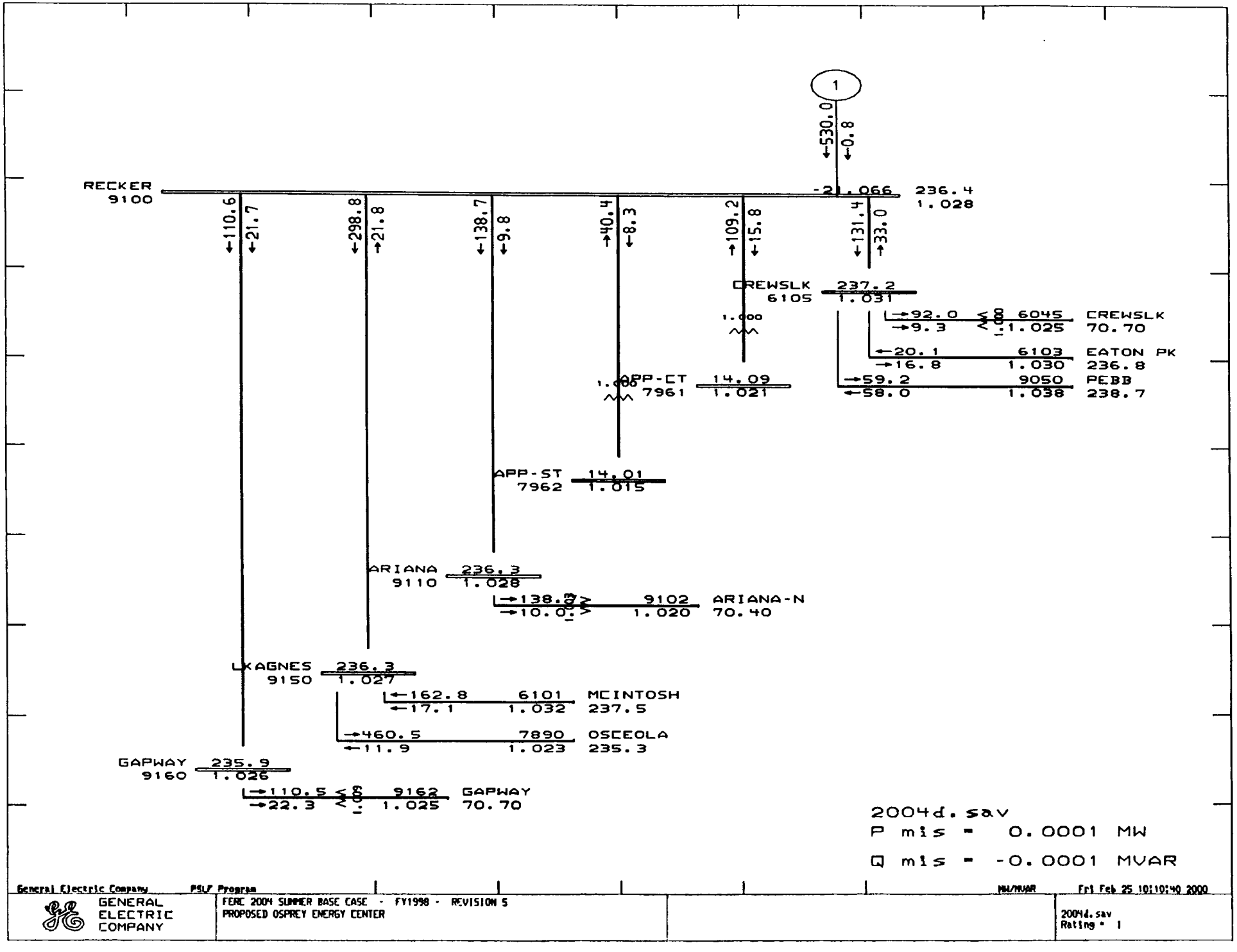
APPENDIX II-A

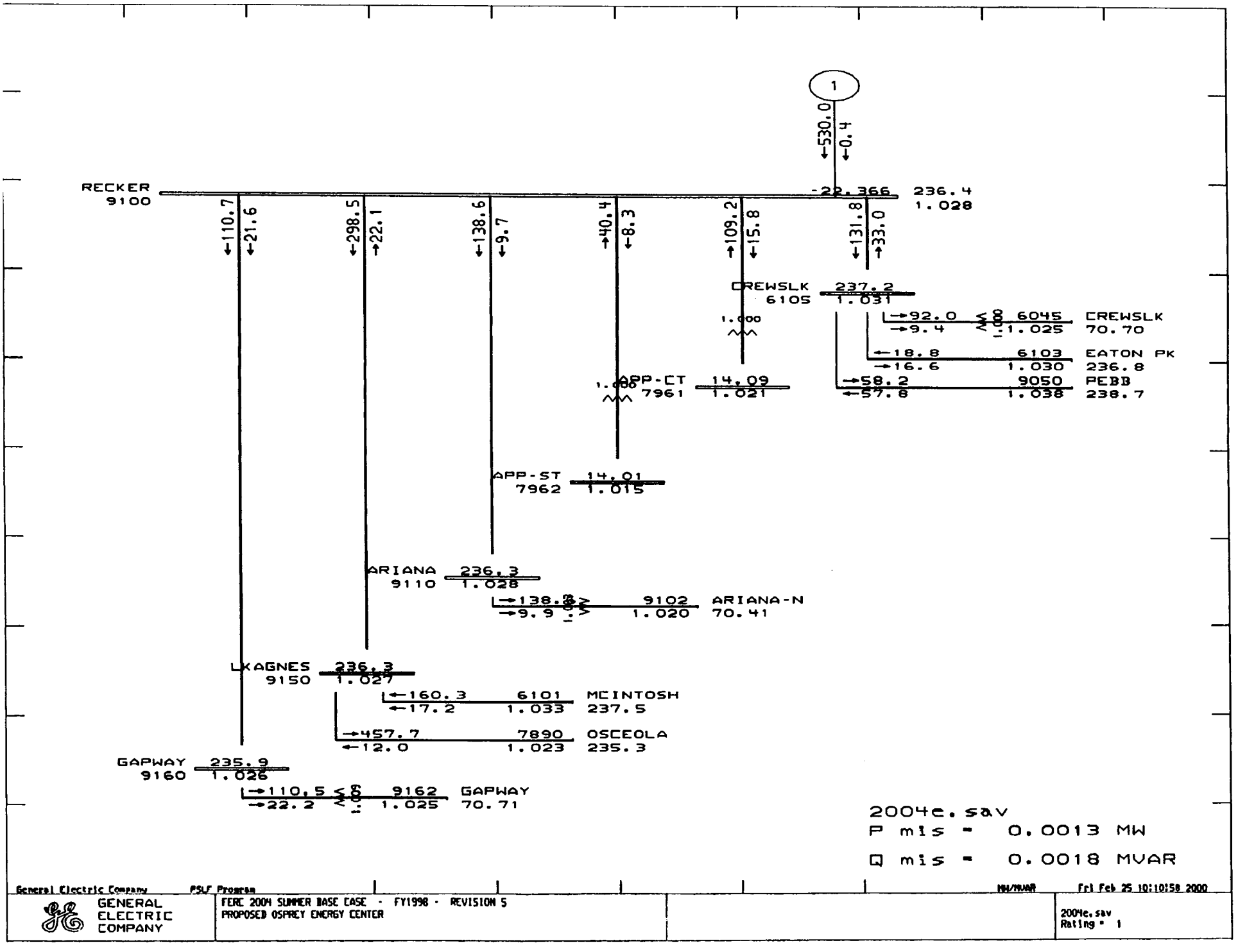

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←20.2
←57.0
→26.9
←104.3
←7.0
→40.4
←8.3
→109.2
←15.9
→85.2
→24.5
CREWSLK 237.1
6105 1.031
1.000
→82.0
→7.6
6045
1.025
CREWSLK
70.73
←36.6
→15.0
6103
1.029
EATON PK
236.8
1.000
APP-CT 14.04
7961 1.017
←130.7
←44.0
9050
1.038
PEBB
238.8
APP-ST 13.96
7962 1.012
ARIANA 235.6
9110 1.024
→104.3
→7.3
9102
1.018
ARIANA-N
70.22
LKAGNES 236.2
9150 1.027
←266.3
←3.8
6101
1.032
MCINTOSH
237.4
→323.2
←20.0
7890
1.025
OSCEOLA
235.8
GAPWAY 235.2
9160 1.023
→73.4
→21.2
9162
1.022
GAPWAY
70.50
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Q mis = -0.0010 MVAR
General Electric Company PSLF Program MW/MVAR Fri Feb 25 10:09:55 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004.sav
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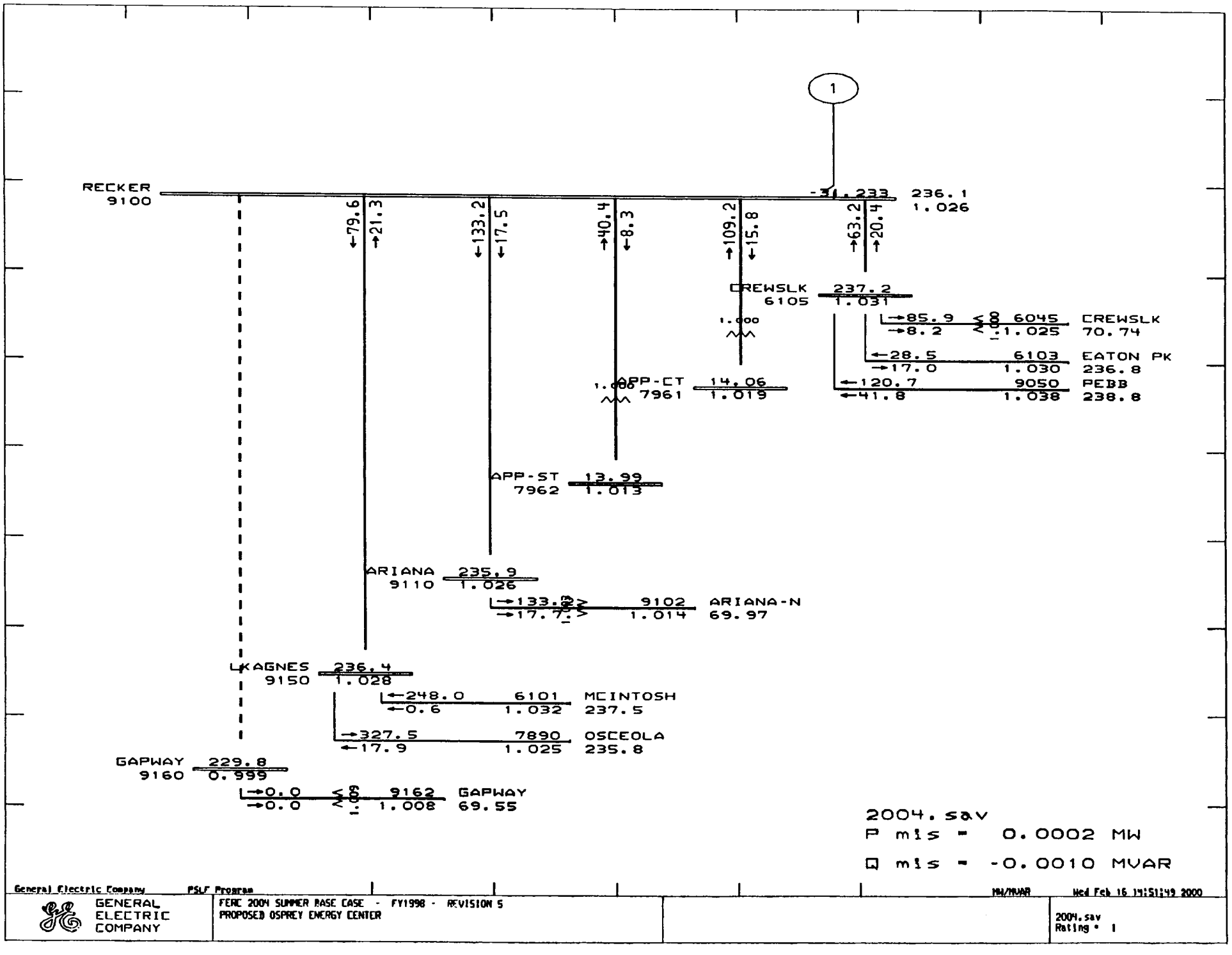

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→21.7
←139.2
←9.9
→40.4
←8.3
→109.2
←15.8
←138.0
→32.7
CREWSLK 237.3
6105 1.032
→92.1
→9.4
6045
1.025
CREWSLK
70.70
←28.3
→17.9
6103
1.030
EATON PK
236.8
1.000
APP-CT 14.09
7961 1.021
→73.8
←59.2
9050
1.038
PEBB
238.7
APP-ST 14.01
7962 1.015
ARIANA 236.4
9110 1.028
→139.8
→10.0
9102
1.021
ARIANA-N
70.42
LXAGNES 236.3
9150 1.028
←158.8
←16.0
6101
1.033
MCINTOSH
237.5
→449.3
←12.3
7890
1.023
OSCEOLA
235.3
GAPWAY 235.9
9160 1.026
→110.7
→22.4
9162
1.025
GAPWAY
70.71
2004a.sav
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Q mis = -0.0005 MVAR
General Electric Company PSLF Program MW/MVAR Fri Feb 25 10:10:05 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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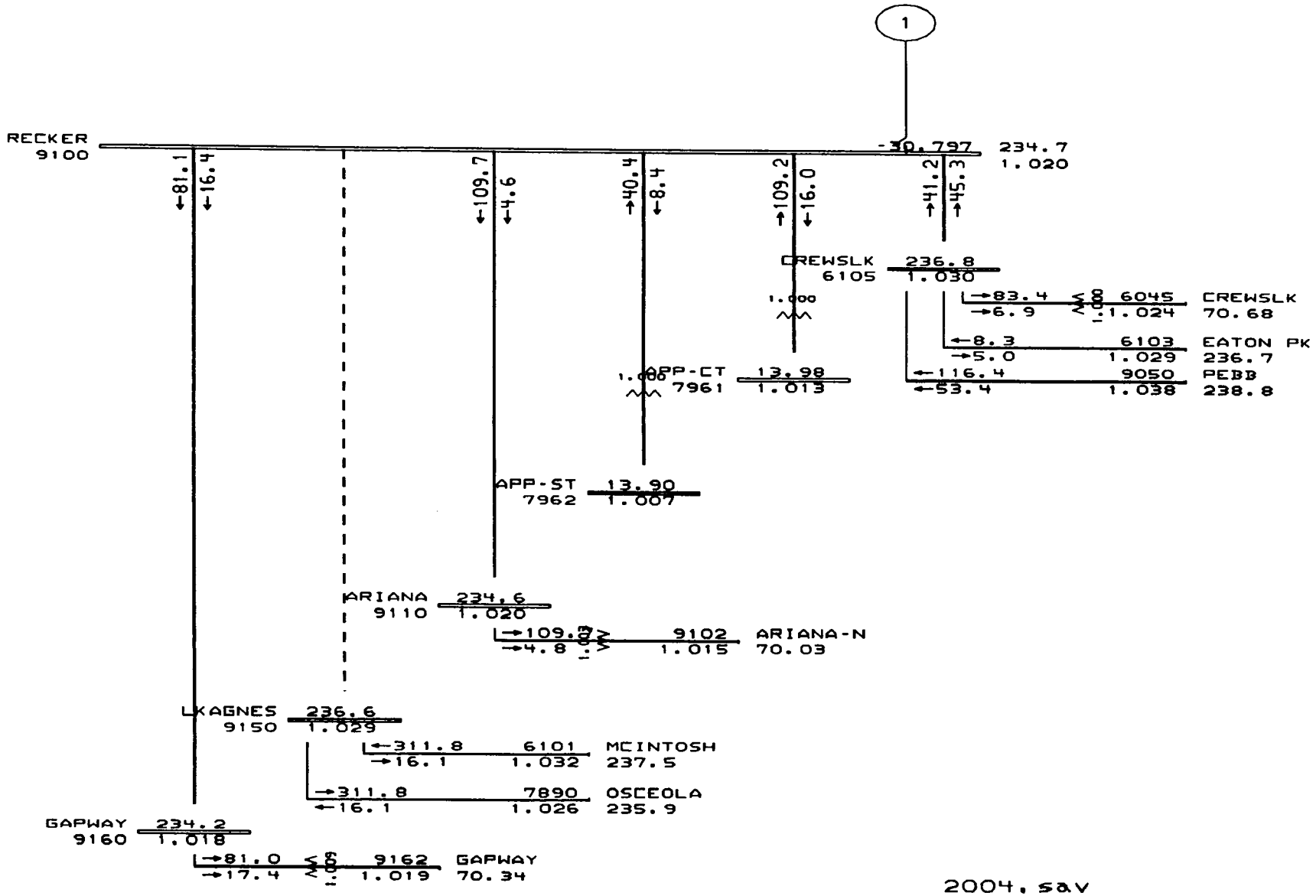

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1.028
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←1.3
1
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←22.1
←300.4
→22.7
←138.7
←10.8
→40.4
←8.3
→109.2
←15.8
←129.8
→33.0
CREWSLK 237.2
6105 1.031
1.000
→92.1
→9.5
6045
1.024
CREWSLK
70.67
←18.4
→15.1
6103
1.030
EATON PK
236.8
APP-CT 14.08
1.000 7961 1.021
→55.8
←56.4
9050
1.038
PEBB
238.6
APP-ST 14.00
7962 1.015
ARIANA 236.3
9110 1.027
→138.8
→10.9
9102
1.019
ARIANA-N
70.34
KAGNES 236.2
9150 1.027
←164.0
←18.3
6101
1.032
MCINTOSH
237.5
→463.3
←11.7
7890
1.023
OSCEOLA
235.2
GAPWAY 235.8
9160 1.025
→110.5
→22.7
9162
1.024
GAPWAY
70.67
2004b.sav
P mis = -0.0002 MW
Q mis = 0.0027 MVAR
General Electric Company PSLF Program
MW/MVAR Fri Feb 25 10:10:19 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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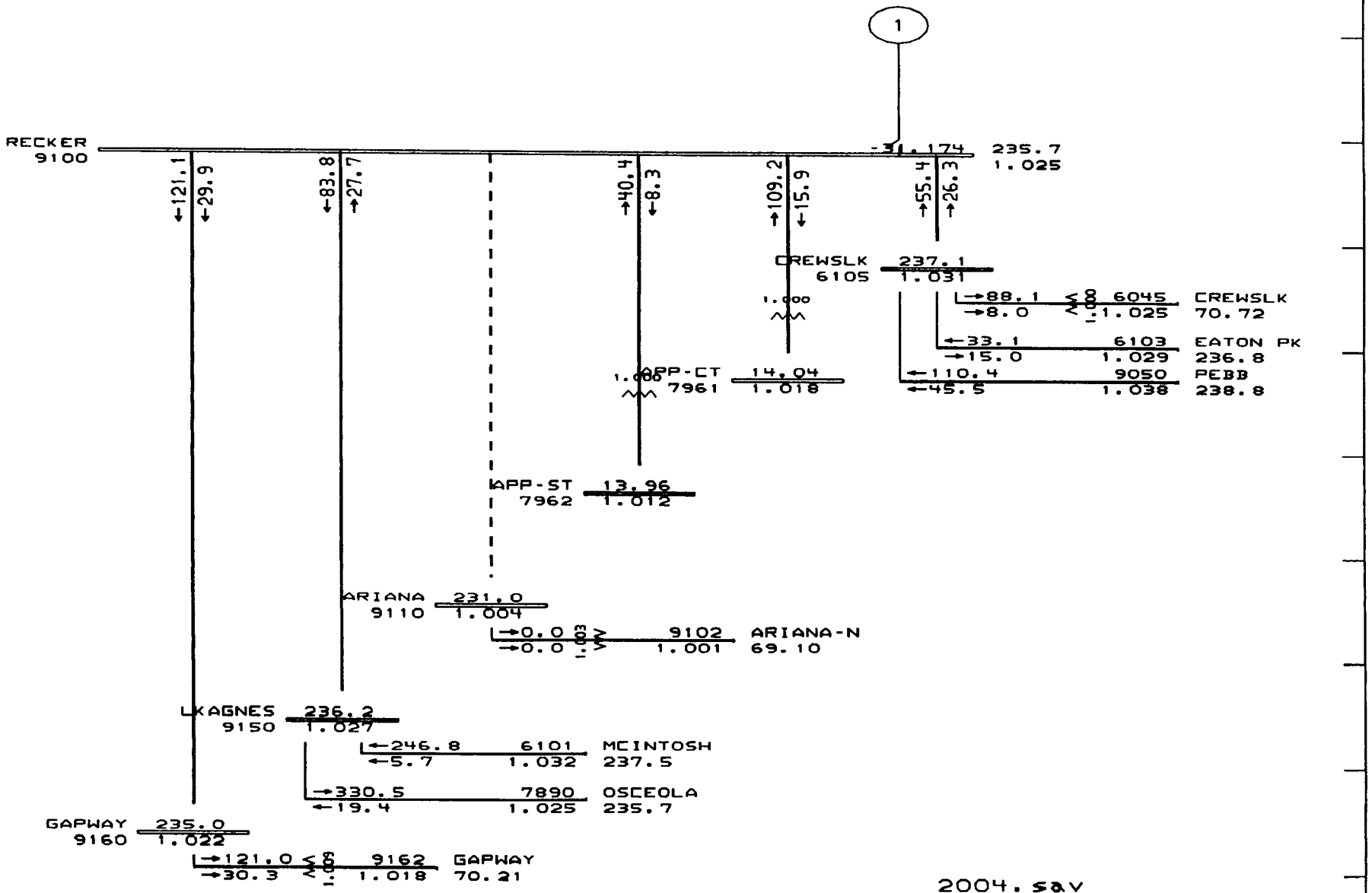

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RECKER
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1.028
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←21.4
←271.6
→24.1
←139.5
←9.2
→40.4
←8.3
→109.2
←15.8
←156.7
→30.0
CREWSLK 237.1
6105 1.031
→93.8
→10.1
6045
1.023
CREWSLK
70.61
←41.2
←15.8
6103
1.029
EATON PK
236.7
→103.6
←56.1
9050
1.036
PEBB
238.4
1.000
APP-CT 14.09
7961 1.021
1.000
APP-ST 14.01
7962 1.015
ARIANA 236.4
9110 1.028
→139.8
→9.4
9102
1.021
ARIANA-N
70.45
LKAGNES 236.5
9150 1.028
←135.5
←15.6
6101
1.033
MCINTOSH
237.5
→406.2
←13.7
7890
1.024
OSCEOLA
235.5
GAPWAY 236.0
9160 1.026
→111.6
→22.0
9162
1.025
GAPWAY
70.73
2004c.sav
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Q mis = -0.0011 MVAR
General Electric Company
PSLF Progress
MW/MVAR
Fri Feb 25 10:10:30 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004c.sav
Rating = 1

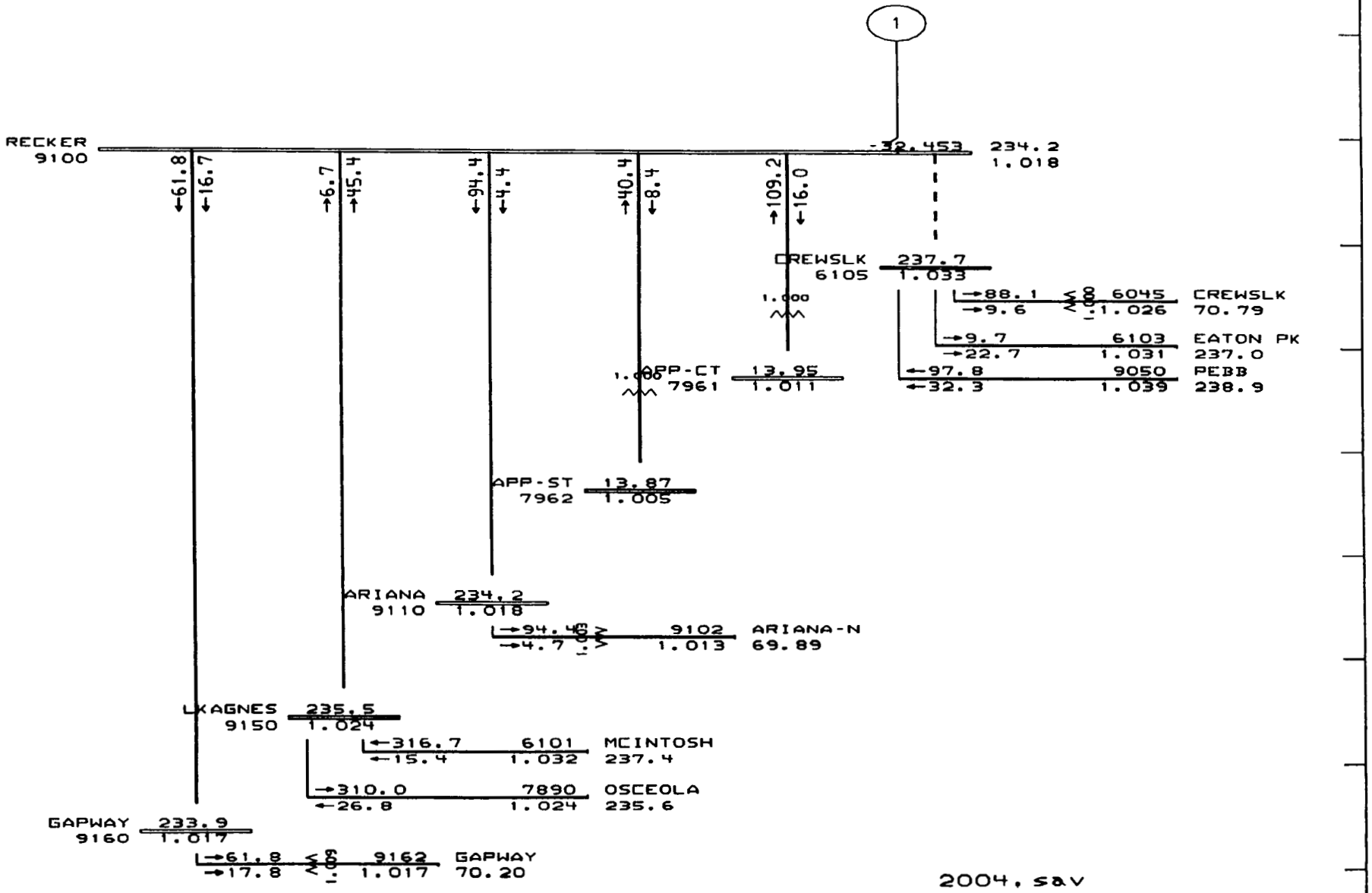

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RECKER
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298.8
21.8
138.7
9.8
40.4
8.3
109.2
15.8
131.4
33.0
CREWSLK 237.2
6105 1.031
92.0
9.3
6045
1.025
CREWSLK
70.70
20.1
16.8
6103
1.030
EATON PK
236.8
APP-CT 14.09
7961 1.021
59.2
58.0
9050
1.038
PEBB
238.7
APP-ST 14.01
7962 1.015
ARIANA 236.3
9110 1.028
138.7
10.0
9102
1.020
ARIANA-N
70.40
KAGNES 236.3
9150 1.027
162.8
17.1
6101
1.032
MCINTOSH
237.5
460.5
11.9
7890
1.023
OSCEOLA
235.3
GAPWAY 235.9
9160 1.026
110.5
22.3
9162
1.025
GAPWAY
70.70
2004d.sav
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Q mis = -0.0001 MVAR
General Electric Company
PSLF Program
MW/MVAR
Fri Feb 25 10:10:40 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004d.sav
Rating = 1


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←0.4
RECKER
9100
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236.4
1.028
←110.7
←21.6
←298.5
→22.1
←138.6
←9.7
→40.4
←8.3
→109.2
←15.8
←131.8
→33.0
CREWSLK 237.2
6105 1.031
→92.0 ≤ 6045 CREWSLK
→9.4 ≤ 1.025 70.70
←18.8 6103 EATON PK
→16.6 1.030 236.8
1.000
APP-CT 14.09
7961 1.021
→58.2 9050 PEBB
←57.8 1.038 238.7
APP-ST 14.01
7962 1.015
ARIANA 236.3
9110 1.028
→138.8 ≤ 9102 ARIANA-N
→9.9 ≤ 1.020 70.41
LKAGNES 236.3
9150 1.027
←160.3 6101 MCINTOSH
←17.2 1.033 237.5
→457.7 7890 OSCEOLA
←12.0 1.023 235.3
GAPWAY 235.9
9160 1.026
→110.5 ≤ 9162 GAPWAY
→22.2 ≤ 1.025 70.71
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Q mis = 0.0018 MVAR
General Electric Company
PSLF Program
MW/MVAR
Fri Feb 25 10:10:58 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004e.sav
Rating = 1


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1.026
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→21.3
←133.2
←17.5
→40.4
←8.3
→109.2
←15.8
→63.2
→20.4
CREWSLK 237.2
6105 1.031
1.000
→85.9
→8.2
6045
1.025
CREWSLK
70.74
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→17.0
6103
1.030
EATON PK
236.8
1.000
APP-CT 14.06
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←120.7
←41.8
9050
1.038
PEBB
238.8
APP-ST 13.99
7962 1.013
ARIANA 235.9
9110 1.026
→133.2
→17.7
9102
1.014
ARIANA-N
69.97
KAGNES 236.4
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←0.6
6101
1.032
MCINTOSH
237.5
→327.5
←17.9
7890
1.025
OSCEOLA
235.8
GAPWAY 229.8
9160 0.999
→0.0
→0.0
1.
9162
1.008
GAPWAY
69.55
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Q mis = -0.0010 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 19:51:49 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004.sav
Rating = 1


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-30.797
234.7
1.020
←81.1
←16.4
←109.7
←4.6
→40.4
←8.4
→109.2
←16.0
→41.2
→45.3
CREWSLK 236.8
6105 1.030
1.000
→83.4 ≤8 6045 CREWSLK
→6.9 1.024 70.68
←8.3 6103 EATON PK
→5.0 1.029 236.7
APP-CT 13.98
1.000 7961 1.013
←116.4 9050 PEBB
←53.4 1.038 238.8
APP-ST 13.90
7962 1.007
ARIANA 234.6
9110 1.020
→109.7 ≤8 9102 ARIANA-N
→4.8 1.015 70.03
LKAGNES 236.6
9150 1.029
←311.8 6101 MCINTOSH
→16.1 1.032 237.5
→311.8 7890 OSCEOLA
←16.1 1.026 235.9
GAPWAY 234.2
9160 1.018
→81.0 ≤8 9162 GAPWAY
→17.4 1.019 70.34
2004.sav
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Q mis = -0.0010 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 15:19:48 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004.sav
Rating = 1


1
RECKER
9100
-31.174
235.7
1.025
←121.1
←29.9
←83.8
←27.7
→40.4
←8.3
→109.2
←15.9
→55.4
→26.3
CREWSLK 237.1
6105 1.031
1.000
→88.1 ≤ 8 6045 CREWSLK
→8.0 ≤ 1.025 70.72
←33.1 6103 EATON PK
→15.0 1.029 236.8
1.000 APP-CT 14.04
7961 1.018
←110.4 9050 PEBB
←45.5 1.038 238.8
APP-ST 13.96
7962 1.012
ARIANA 231.0
9110 1.004
→0.0 ≤ 9102 ARIANA-N
→0.0 ≤ 1.001 69.10
LKAGNES 236.2
9150 1.027
←246.8 6101 MCINTOSH
←5.7 1.032 237.5
→330.5 7890 OSCEOLA
←19.4 1.025 235.7
GAPWAY 235.0
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→121.0 ≤ 9162 GAPWAY
→30.3 ≤ 1.018 70.21
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MW/MVAR
Wed Feb 16 15:15:07 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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Rating = 1

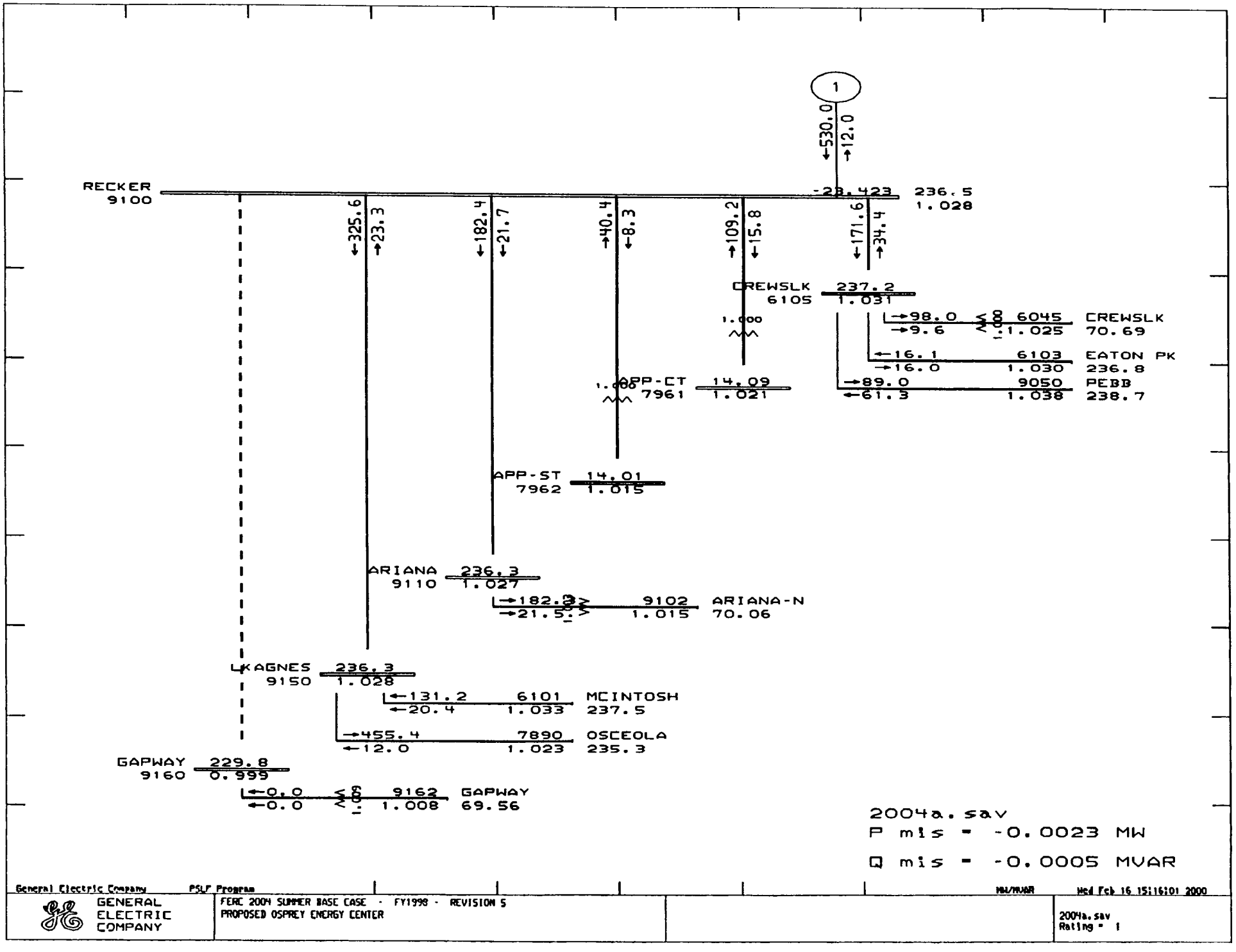


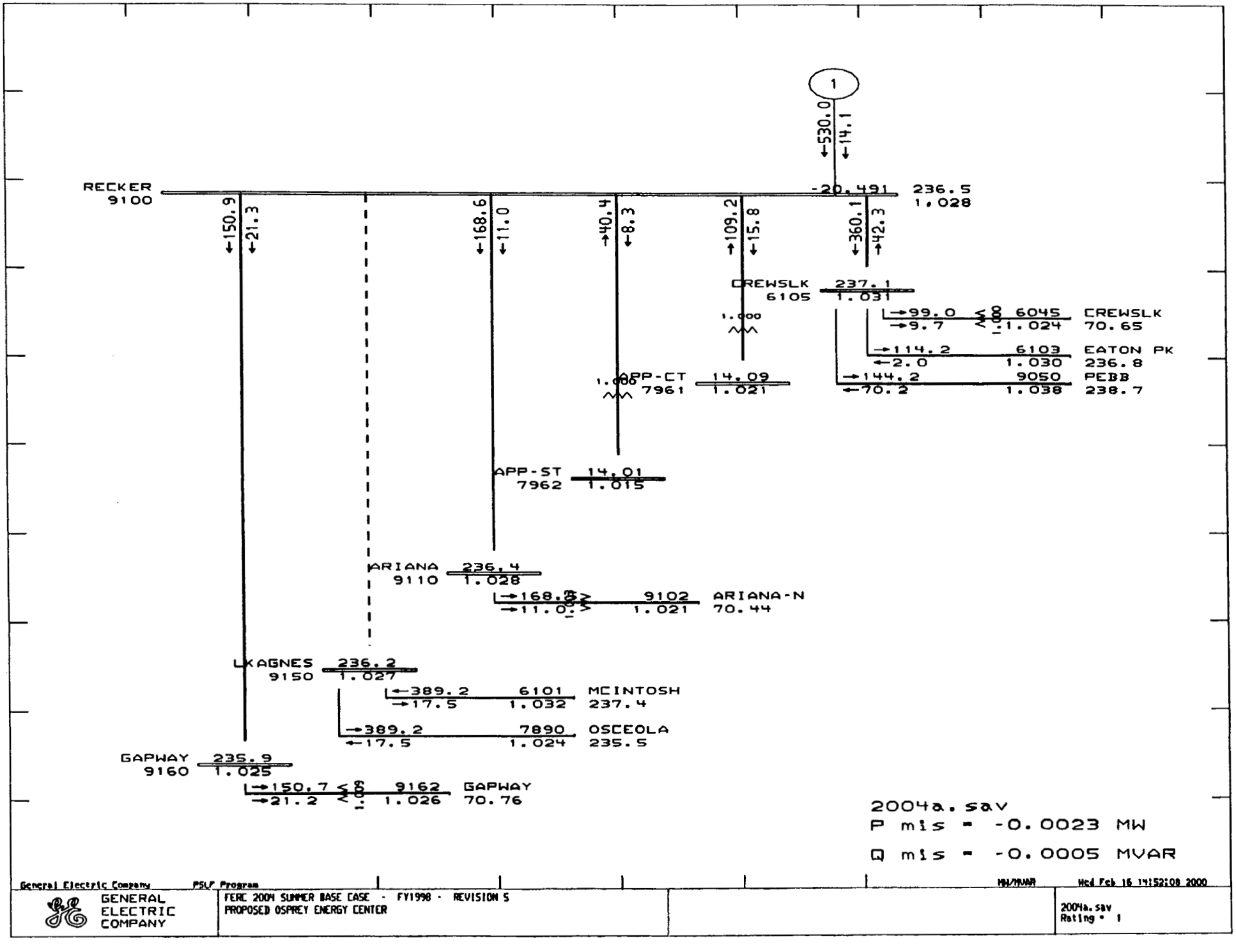
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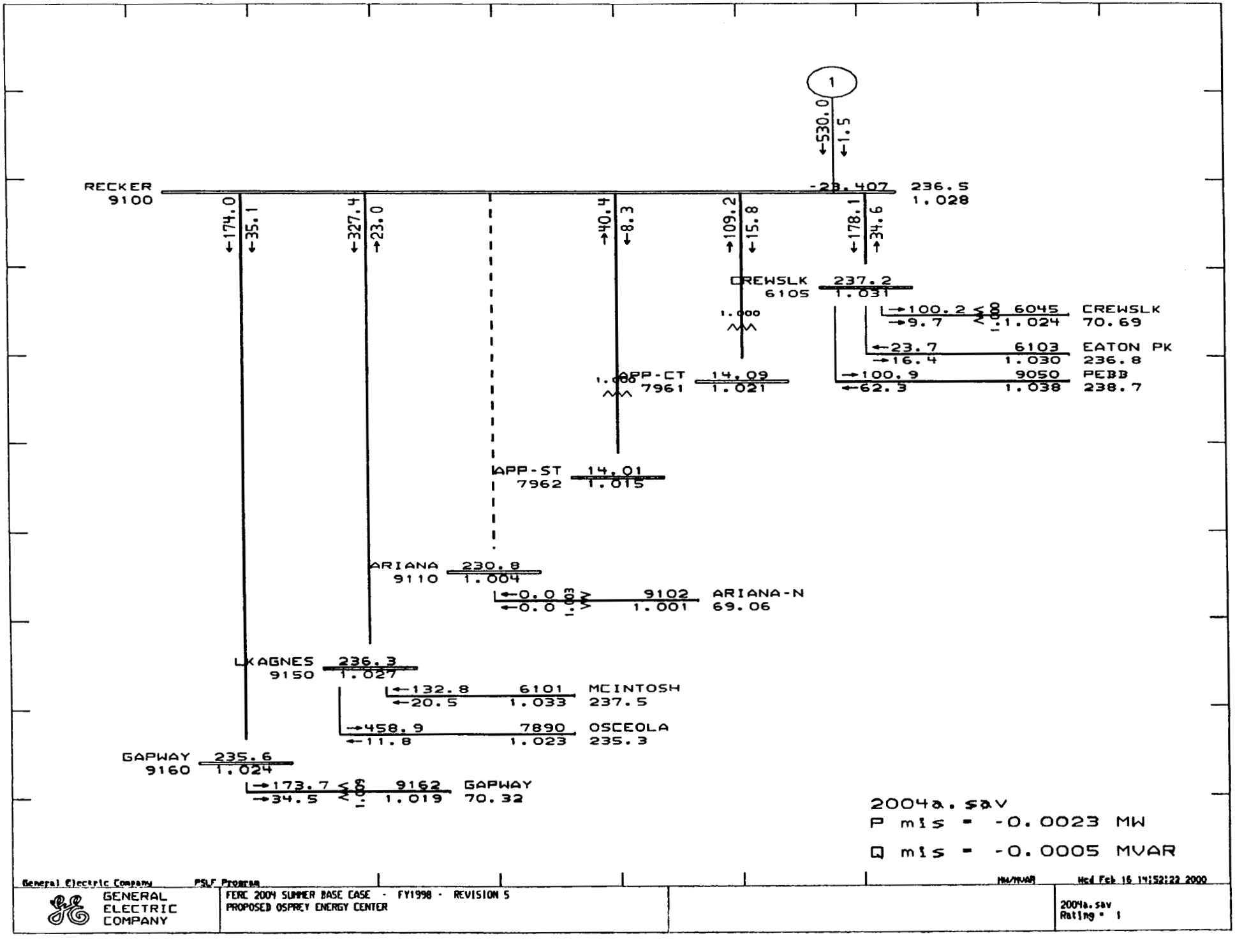
GENERAL ELECTRIC COMPANY

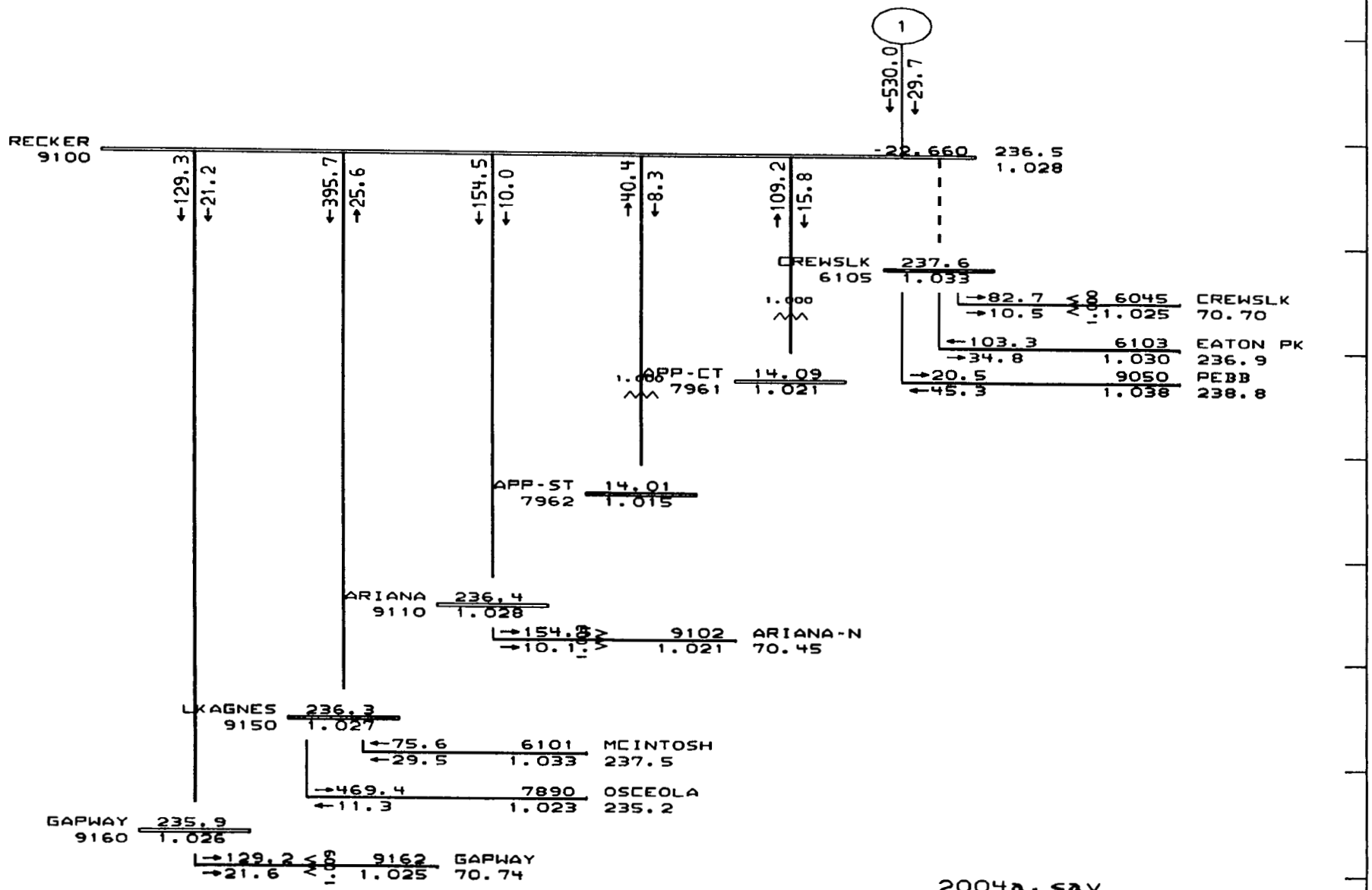
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PROPOSED OSPREY ENERGY CENTER

2004.sav
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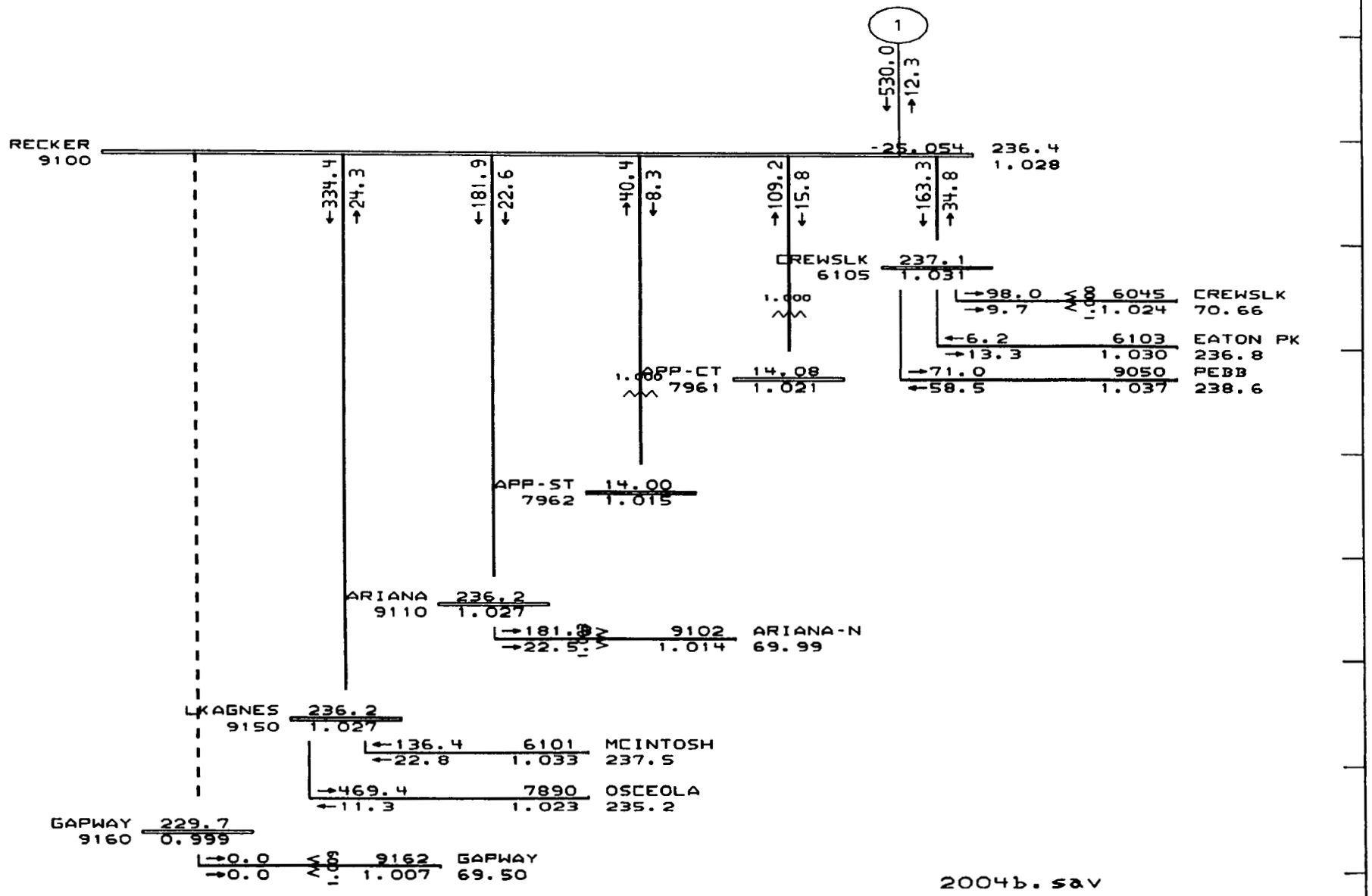

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182.4
21.7
40.4
8.3
109.2
15.8
171.6
34.4
CREWSLK 237.2
6105 1.031
98.0
9.6
6045
1.025
CREWSLK
70.69
16.1
16.0
6103
1.030
EATON PK
236.8
89.0
61.3
9050
1.038
PEBB
238.7
1.000
APP-CT 14.09
7961 1.021
APP-ST 14.01
7962 1.015
ARIANA 236.3
9110 1.027
182.3
21.5
9102
1.015
ARIANA-N
70.06
LKAGNES 236.3
9150 1.028
131.2
20.4
6101
1.033
MCINTOSH
237.5
455.4
12.0
7890
1.023
OSCEOLA
235.3
GAPWAY 229.8
9160 0.999
0.0
0.0
9162
1.008
GAPWAY
69.56
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Q mis = -0.0005 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 15:16:01 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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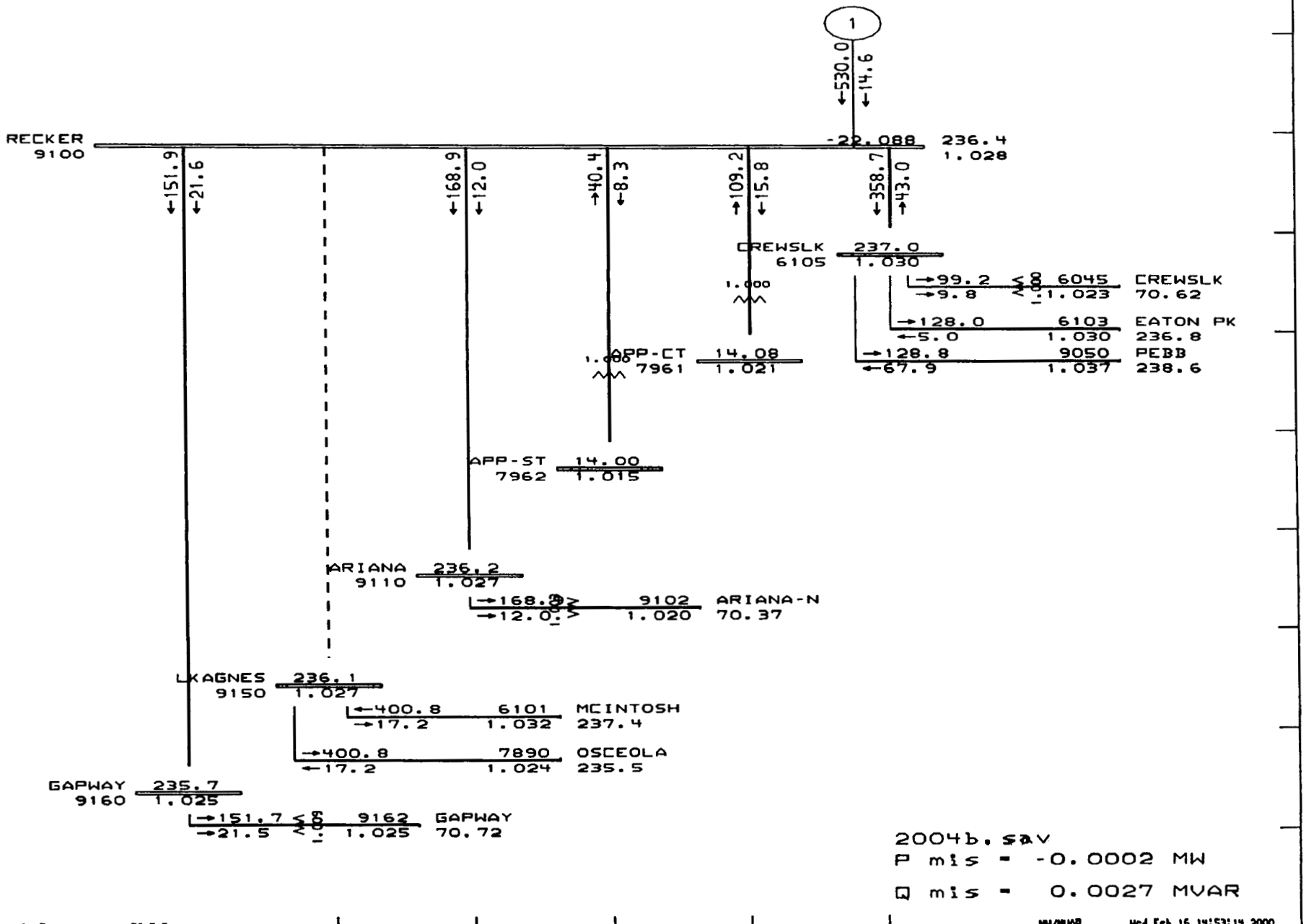

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←11.0
→40.4
←8.3
→109.2
←15.8
←360.1
→42.3
CREWSLK 237.1
6105 1.031
→99.0
→9.7
6045
1.024
CREWSLK
70.65
→114.2
←2.0
6103
1.030
EATON PK
236.8
1.000
APP-CT 14.09
7961 1.021
→144.2
←70.2
9050
1.038
PEBB
238.7
APP-ST 14.01
7962 1.015
ARIANA 236.4
9110 1.028
→168.8
→11.0
9102
1.021
ARIANA-N
70.44
LKAGNES 236.2
9150 1.027
←389.2
→17.5
6101
1.032
MCINTOSH
237.4
→389.2
←17.5
7890
1.024
OSCEOLA
235.5
GAPWAY 235.9
9160 1.025
→150.7
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9162
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GAPWAY
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Q mis = -0.0005 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:52:08 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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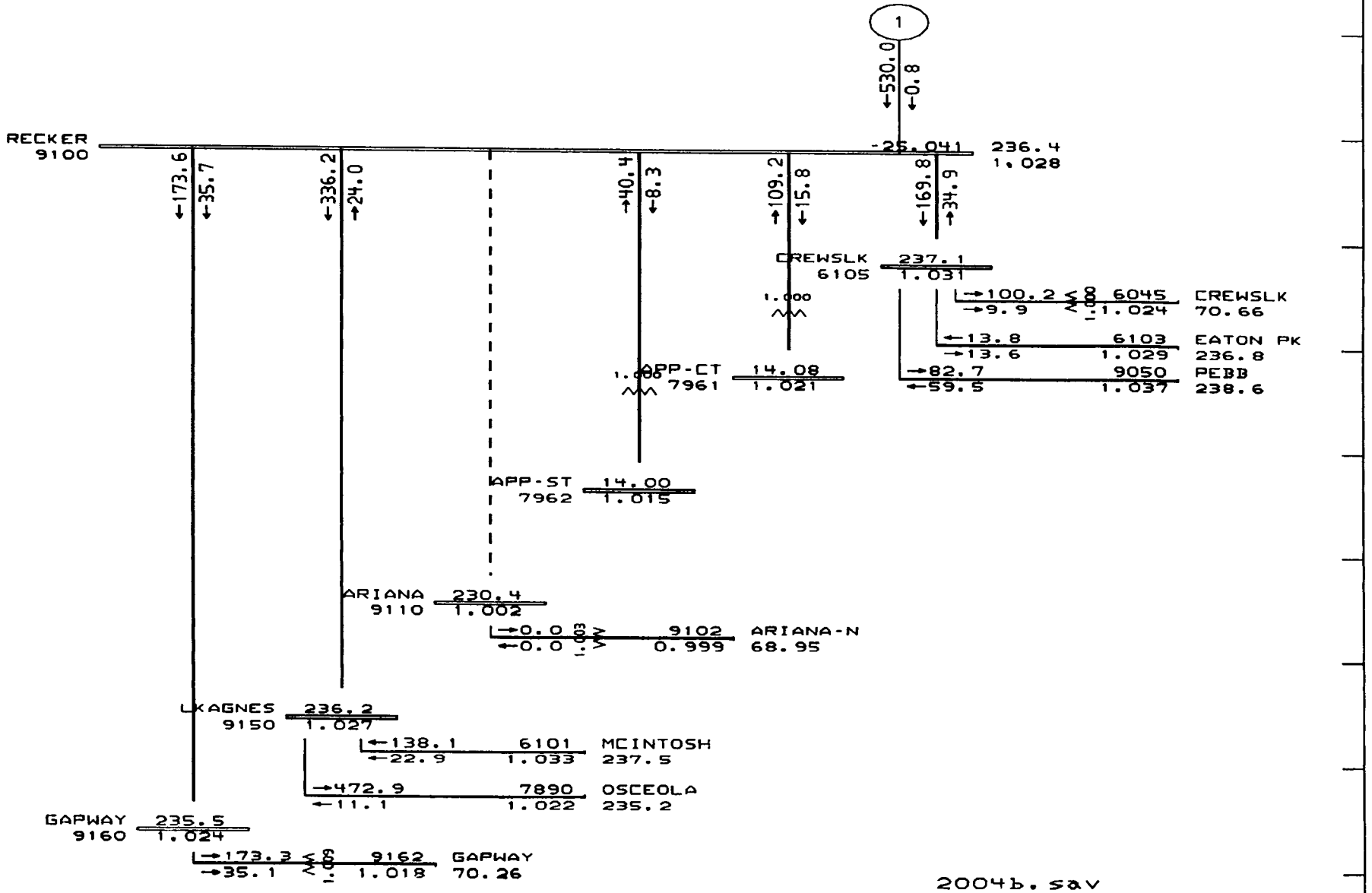

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236.5
1.028
←174.0
←35.1
←327.4
→23.0
→40.4
←8.3
→109.2
←15.8
←178.1
→34.6
CREWSLK 237.2
6105 1.031
1.000
→100.2 ≤ 6045 CREWSLK
→9.7 1.024 70.69
←23.7 6103 EATON PK
→16.4 1.030 236.8
APP-CT 14.09
1.000 7961 1.021
→100.9 9050 PEBB
←62.3 1.038 238.7
APP-ST 14.01
7962 1.015
ARIANA 230.8
9110 1.004
←0.0 ≤ 9102 ARIANA-N
←0.0 1.001 69.06
LXAGNES 236.3
9150 1.027
←132.8 6101 MCINTOSH
←20.5 1.033 237.5
→458.9 7890 OSCEOLA
←11.8 1.023 235.3
GAPWAY 235.6
9160 1.024
→173.7 ≤ 9162 GAPWAY
→34.5 1.019 70.32
2004a.sav
P mis = -0.0023 MW
Q mis = -0.0005 MVAR
General Electric Company PSLF Program MW/MVAR Wed Feb 16 14:52:22 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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Rating = 1

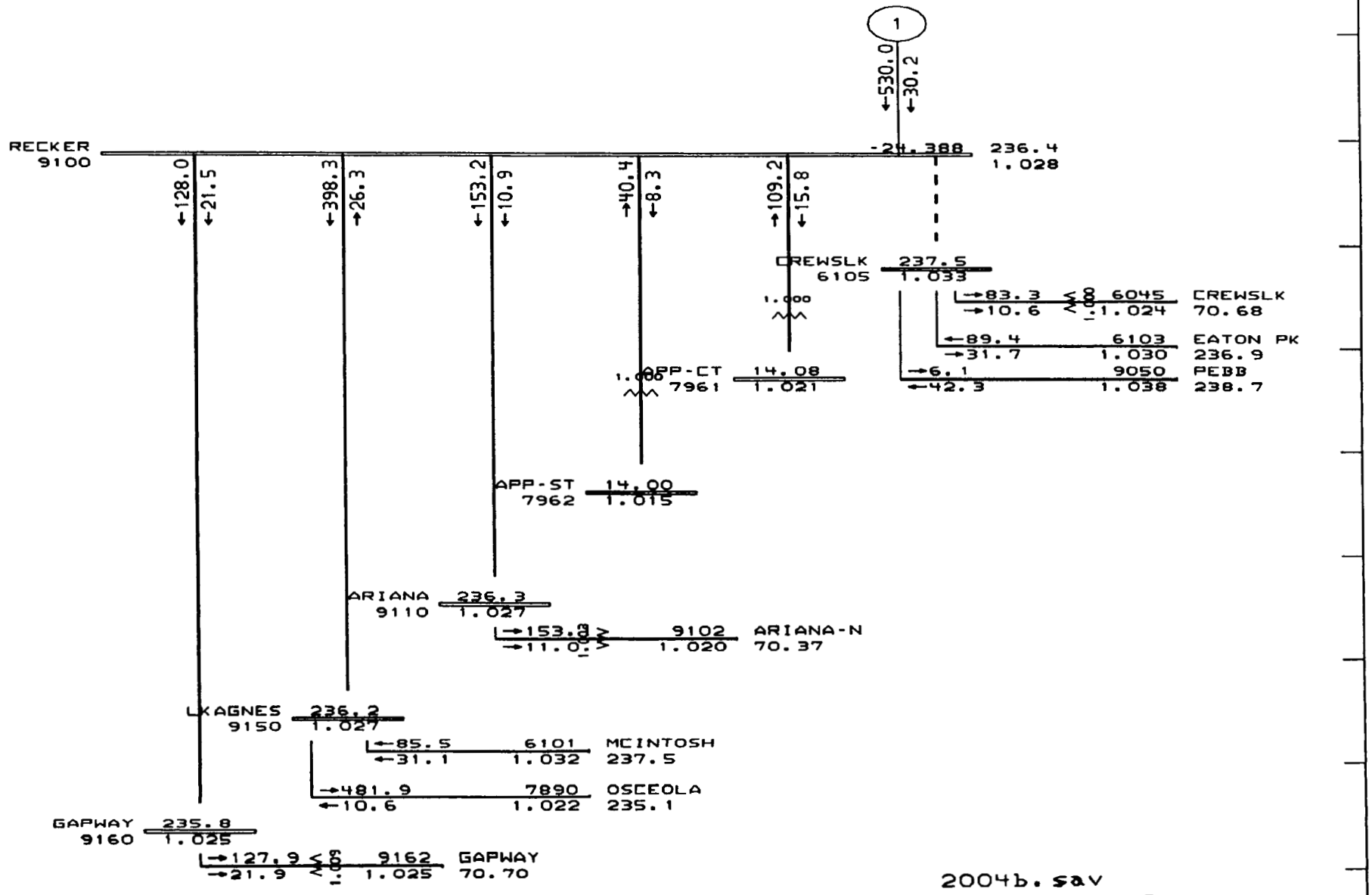


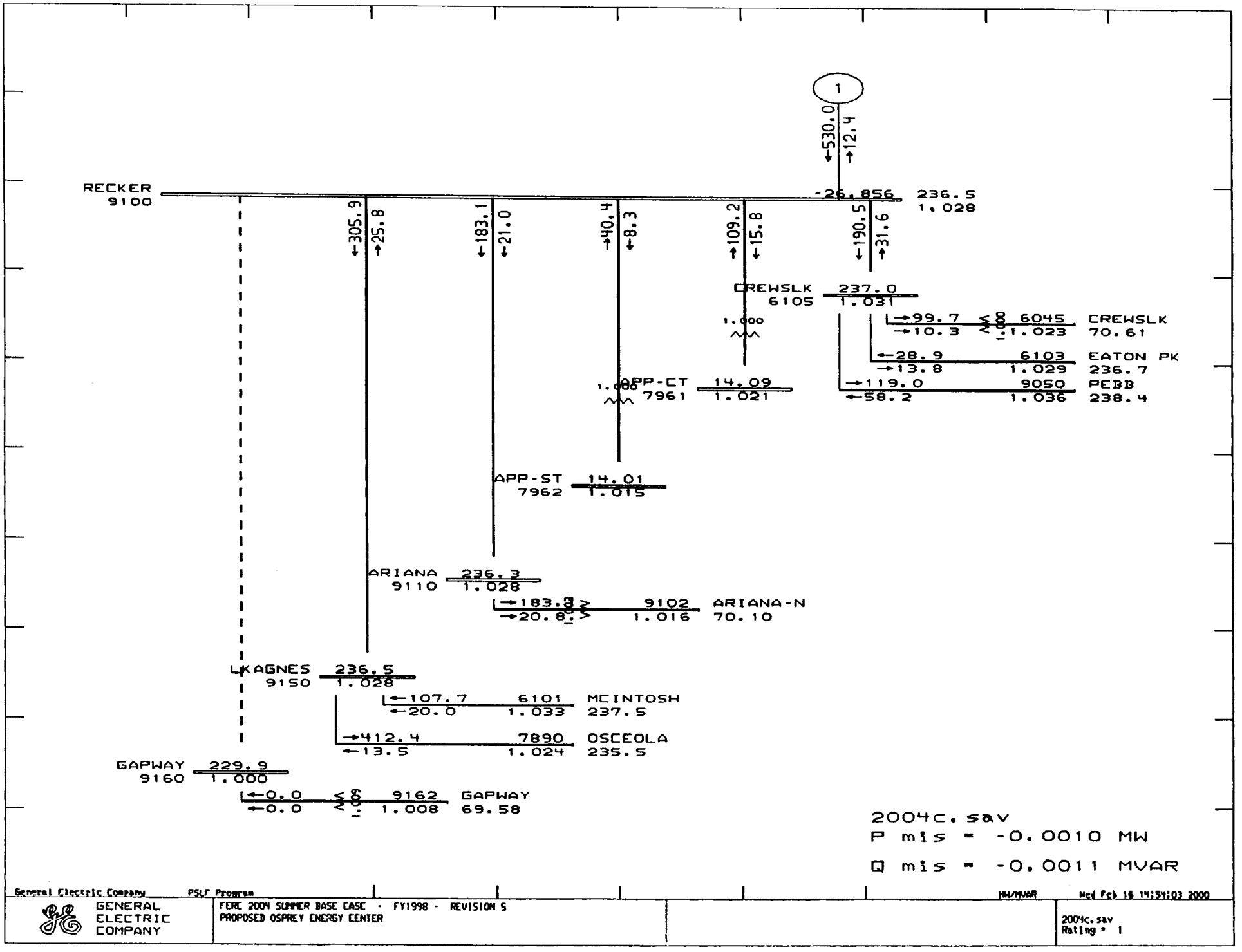
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Q mis = -0.0005 MVAR

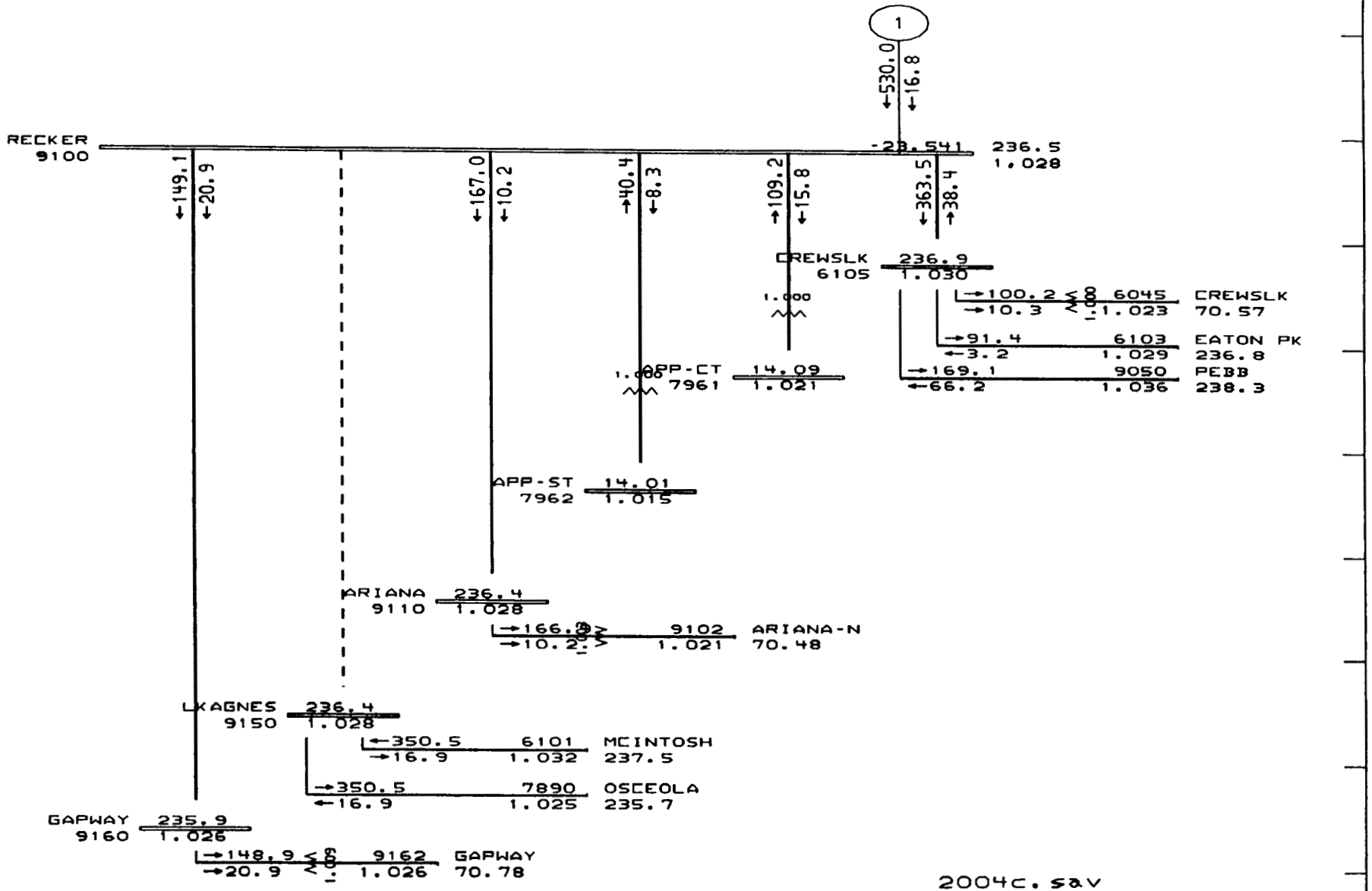

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→24.3
←181.9
→22.6
→40.4
←8.3
→109.2
←15.8
←163.3
→34.8
CREWSLK 237.1
6105 1.031
→98.0
→9.7
6045
1.024
CREWSLK
70.66
←6.2
→13.3
6103
1.030
EATON PK
236.8
1.000
APP-CT 14.08
7961 1.021
→71.0
←58.5
9050
1.037
PEBB
238.6
APP-ST 14.00
7962 1.015
ARIANA 236.2
9110 1.027
→181.8
→22.5
9102
1.014
ARIANA-N
69.99
LKAGNES 236.2
9150 1.027
←136.4
←22.8
6101
1.033
MCINTOSH
237.5
→469.4
←11.3
7890
1.023
OSCEOLA
235.2
GAPWAY 229.7
9160 0.999
→0.0
→0.0
9162
1.007
GAPWAY
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2004b.sav
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Q mis = 0.0027 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 14:52:59 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004b.sav
Rating = 1

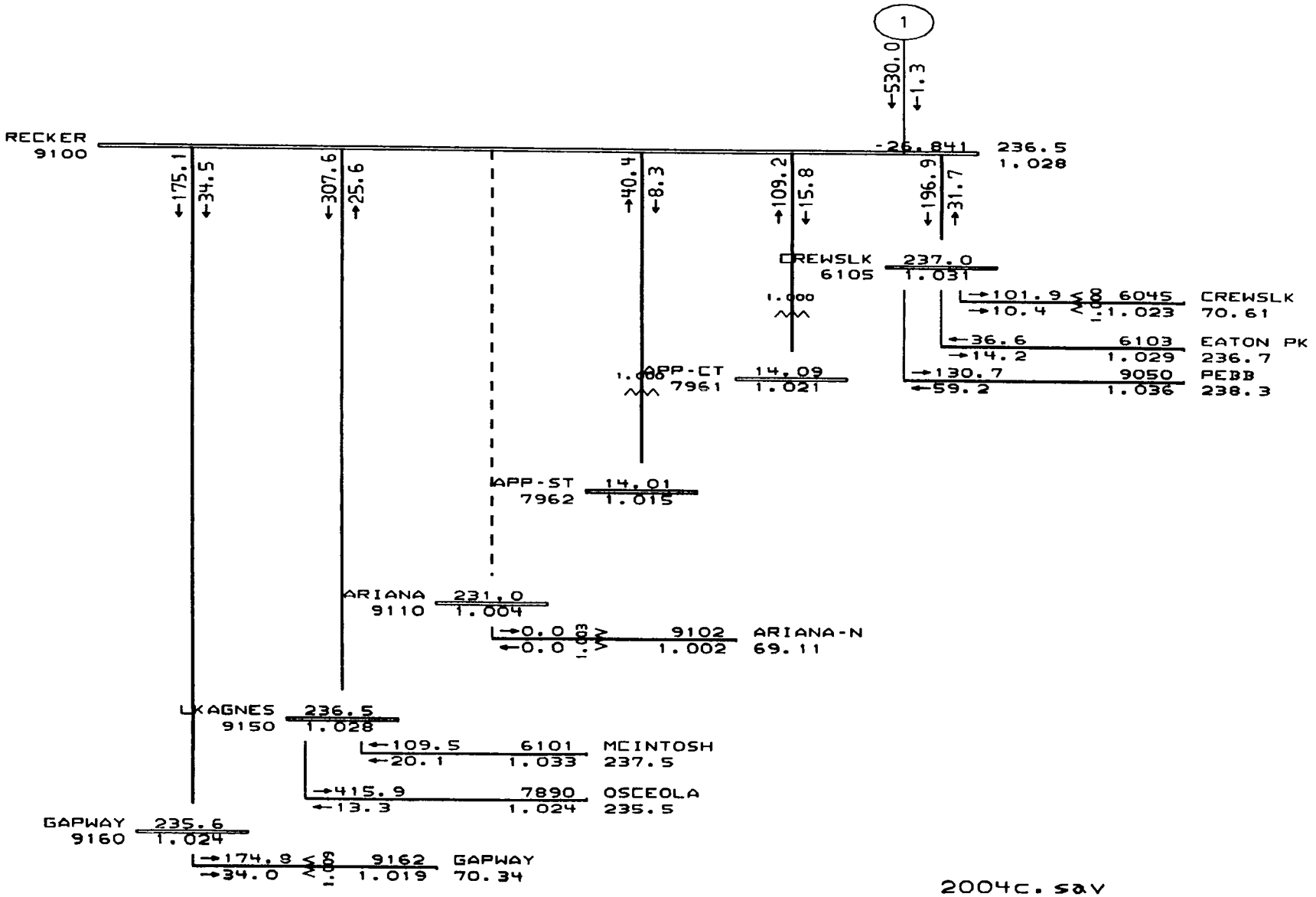

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←12.0
→40.4
←8.3
→109.2
←15.8
←358.7
→43.0
CREWSLK 237.0
6105 1.030
1.000
→99.2
→9.8
6045
1.023
CREWSLK
70.62
→128.0
←5.0
6103
1.030
EATON PK
236.8
APP-CT 14.08
7961 1.021
→128.8
←67.9
9050
1.037
PEBB
238.6
APP-ST 14.00
7962 1.015
ARIANA 236.2
9110 1.027
→168.9
→12.0
9102
1.020
ARIANA-N
70.37
LKAGNES 236.1
9150 1.027
←400.8
→17.2
6101
1.032
MCINTOSH
237.4
→400.8
←17.2
7890
1.024
OSCEOLA
235.5
GAPWAY 235.7
9160 1.025
→151.7
→21.5
9162
1.025
GAPWAY
70.72
2004b.sav
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Q mis = 0.0027 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:53:14 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004b.sav
Rating = 1

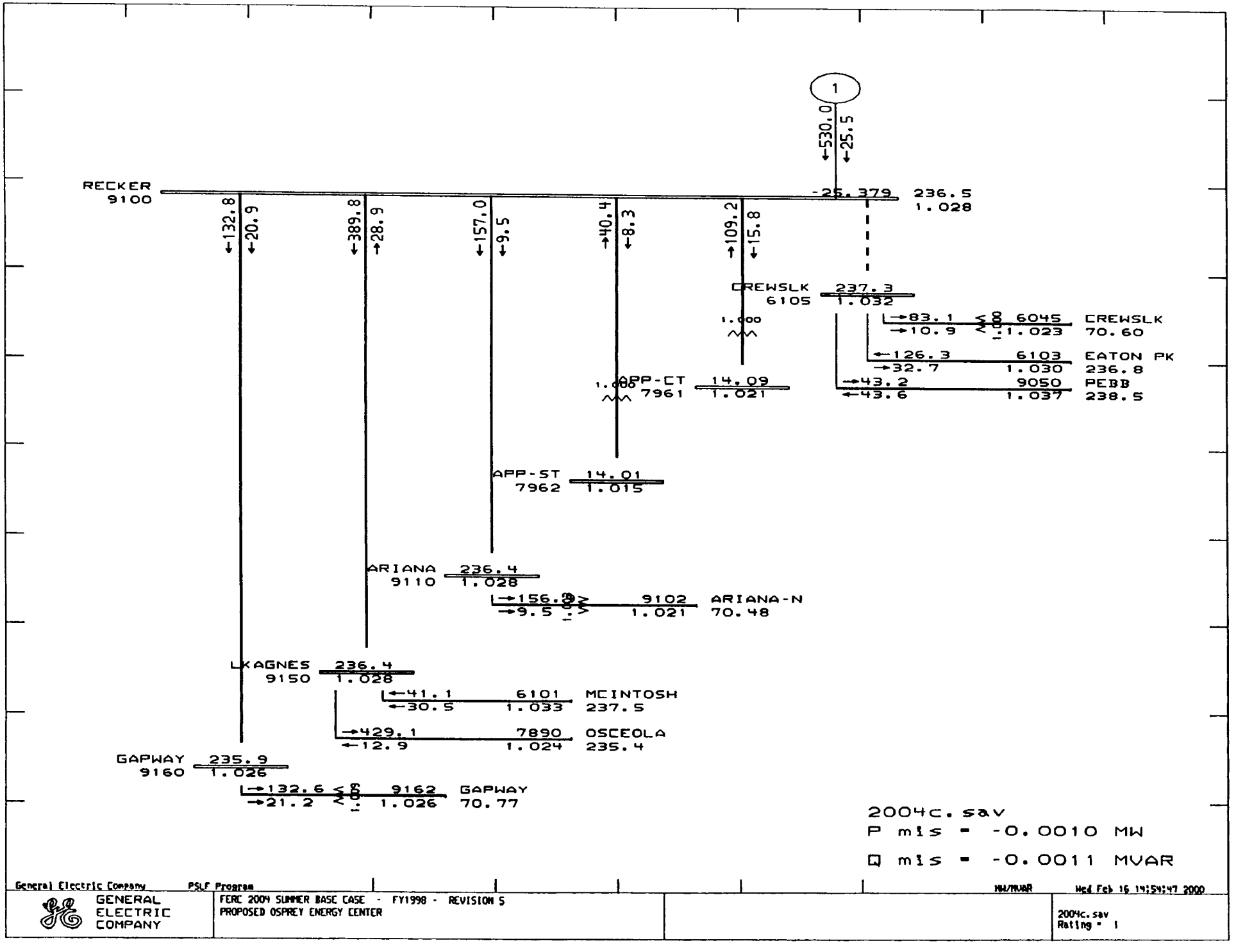

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→24.0
→40.4
←8.3
→109.2
←15.8
←169.8
→34.9
CREWSLK
6105
237.1
1.031
1.000
→100.2
→9.9
6045
1.024
CREWSLK
70.66
←13.8
→13.6
6103
1.029
EATON PK
236.8
APP-CT
7961
14.08
1.021
1.000
→82.7
←59.5
9050
1.037
PEBB
238.6
APP-ST
7962
14.00
1.015
ARIANA
9110
230.4
1.002
→0.0
←0.0
9102
0.999
ARIANA-N
68.95
LKAGNES
9150
236.2
1.027
←138.1
←22.9
6101
1.033
MCINTOSH
237.5
→472.9
←11.1
7890
1.022
OSCEOLA
235.2
GAPWAY
9160
235.5
1.024
→173.3
→35.1
9162
1.018
GAPWAY
70.26
2004b.sav
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Q mis = 0.0027 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:53:30 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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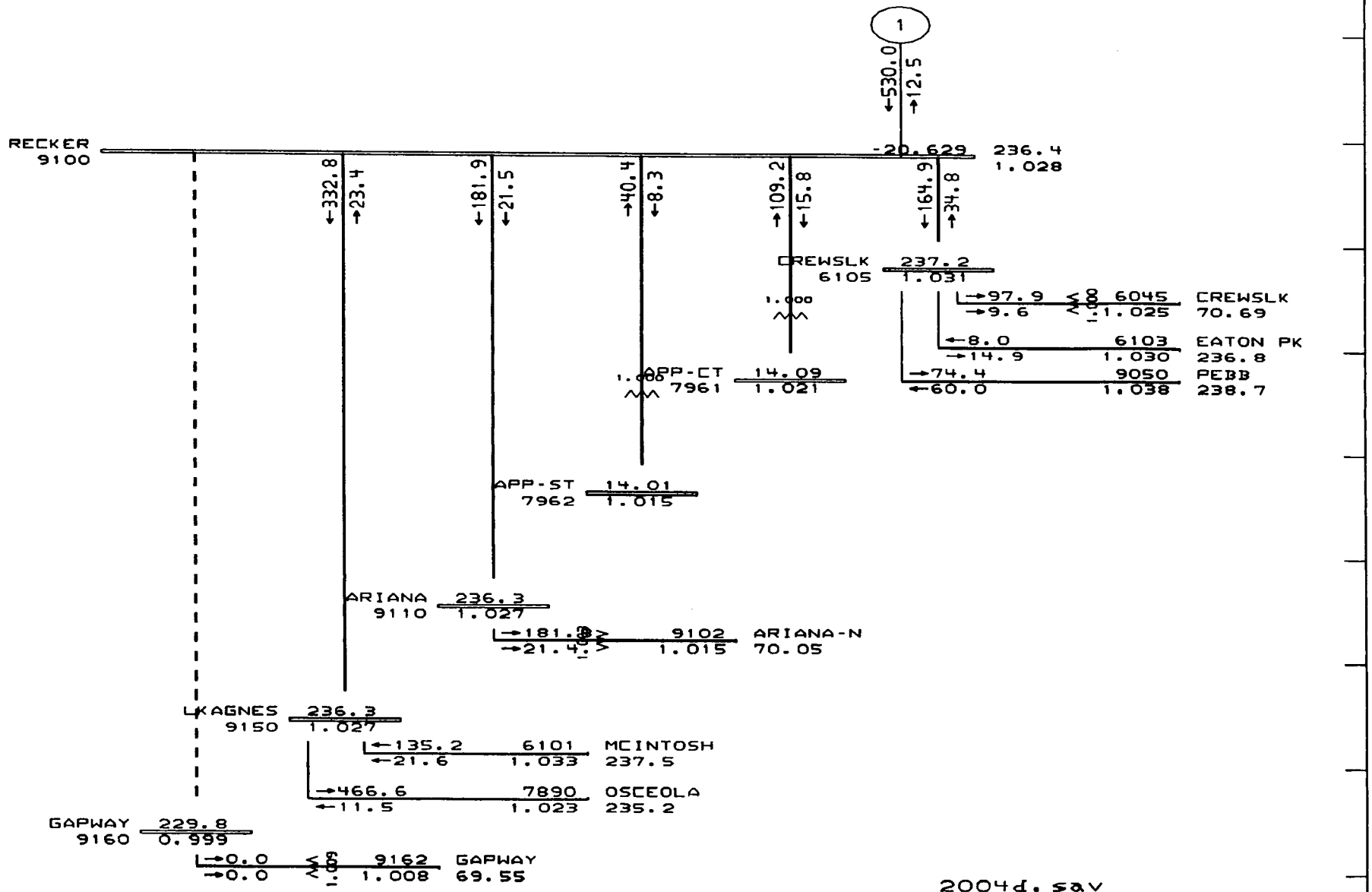

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←10.9
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→109.2
←15.8
CREWSLK 237.5
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1.000
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→10.6
6045
1.024
CREWSLK
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1.030
EATON PK
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1.000
APP-CT 14.08
7961 1.021
→6.1
←42.3
9050
1.038
PEBB
238.7
APP-ST 14.00
7962 1.015
ARIANA 236.3
9110 1.027
→153.8
→11.0
9102
1.020
ARIANA-N
70.37
LKAGNES 236.2
9150 1.027
←85.5
←31.1
6101
1.032
MCINTOSH
237.5
→481.9
←10.6
7890
1.022
OSCEOLA
235.1
GAPWAY 235.8
9160 1.025
→127.9
→21.9
9162
1.025
GAPWAY
70.70
2004b.sav
P mis = -0.0002 MW
Q mis = 0.0027 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:53:47 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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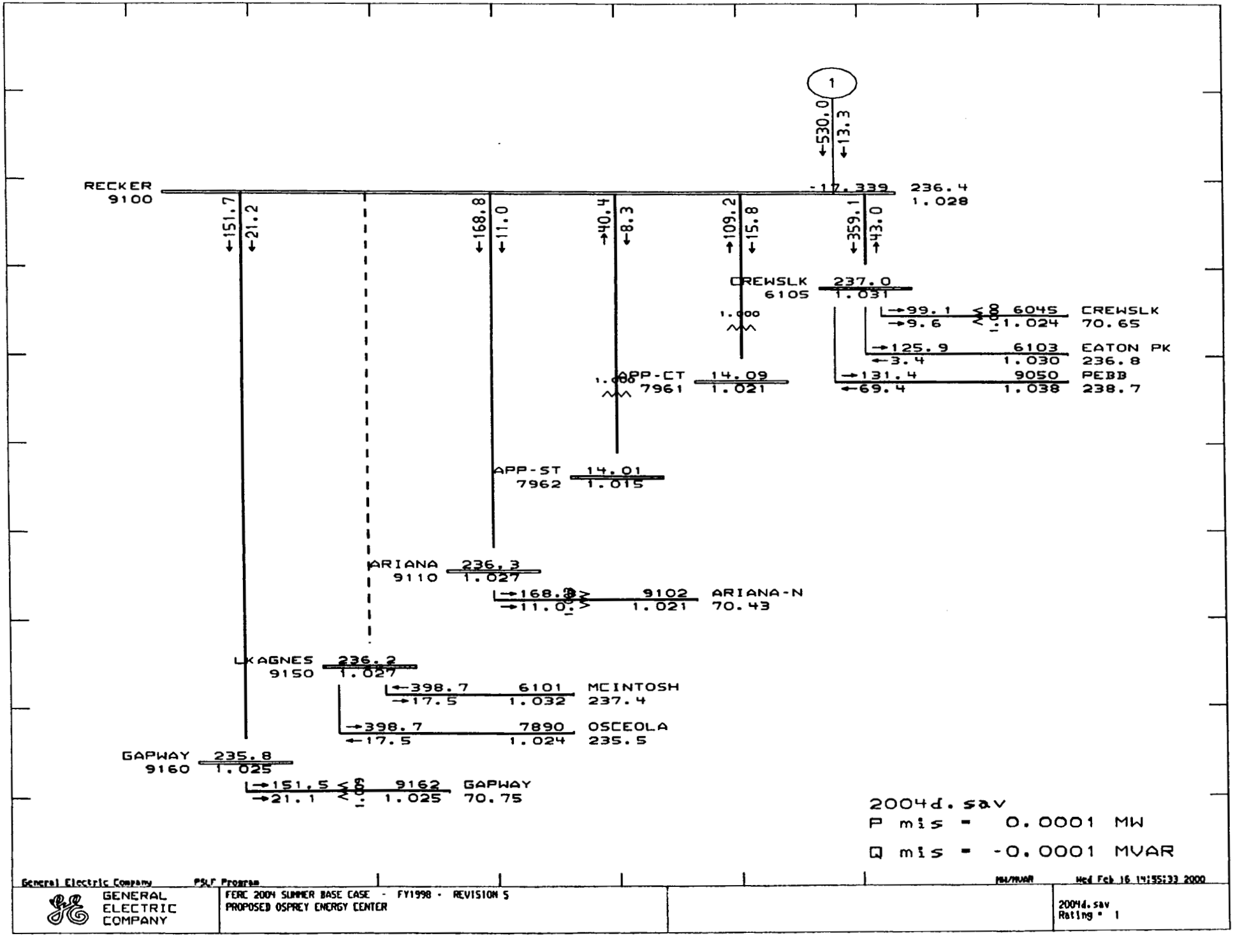

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→21.0
→40.4
←8.3
→109.2
←15.8
←190.5
→31.6
CREWSLK 237.0
6105 1.031
1.000
→99.7 ≤ 6045 CREWSLK
→10.3 ≤ 1.023 70.61
←28.9 6103 EATON PK
→13.8 1.029 236.7
APP-CT 14.09
1.000 7961 1.021
→119.0 9050 PEBB
←58.2 1.036 238.4
APP-ST 14.01
7962 1.015
ARIANA 236.3
9110 1.028
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→20.8 ≤ 1.016 70.10
LKAGNES 236.5
9150 1.028
←107.7 6101 MCINTOSH
←20.0 1.033 237.5
→412.4 7890 OSCEOLA
←13.5 1.024 235.5
GAPWAY 229.9
9160 1.000
←0.0 ≤ 9162 GAPWAY
←0.0 ≤ 1.008 69.58
2004c.sav
P mis = -0.0010 MW
Q mis = -0.0011 MVAR
General Electric Company PSLF Program
MW/MVAR
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GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004c.sav
Rating = 1

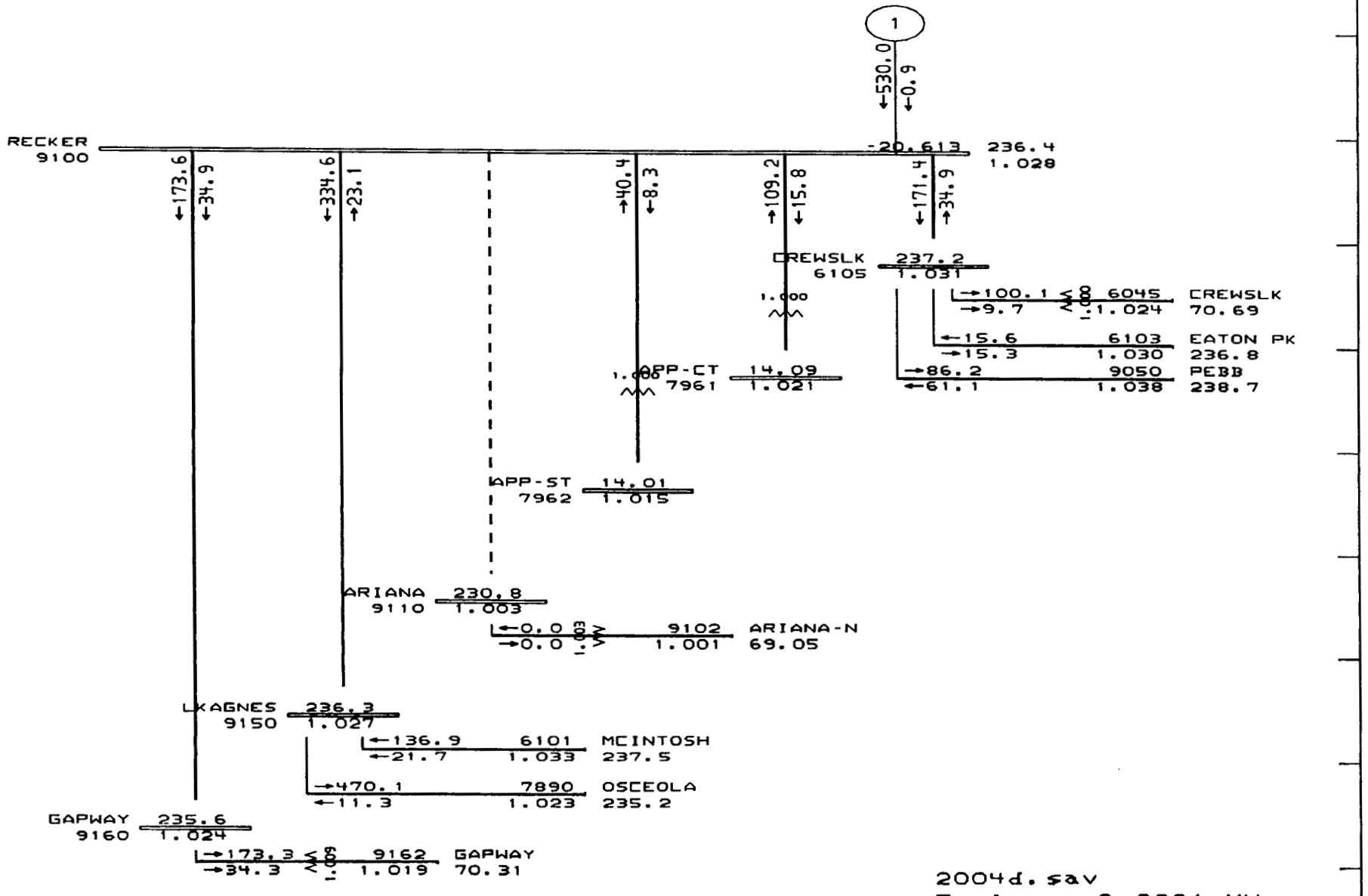

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←20.9
←167.0
←10.2
→40.4
←8.3
→109.2
←15.8
←363.5
→38.4
CREWSLK 236.9
6105 1.030
1.000
→100.2
→10.3
6045
1.023
CREWSLK
70.57
→91.4
←3.2
6103
1.029
EATON PK
236.8
1.000
APP-CT 14.09
7961 1.021
→169.1
←66.2
9050
1.036
PEBB
238.3
APP-ST 14.01
7962 1.015
ARIANA 236.4
9110 1.028
→166.8
→10.2
9102
1.021
ARIANA-N
70.48
LKAGNES 236.4
9150 1.028
←350.5
→16.9
6101
1.032
MCINTOSH
237.5
→350.5
←16.9
7890
1.025
OSCEOLA
235.7
GAPWAY 235.9
9160 1.026
→148.9
→20.9
9162
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GAPWAY
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2004c.sav
P mis = -0.0010 MW
Q mis = -0.0011 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:54:17 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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Rating = 1

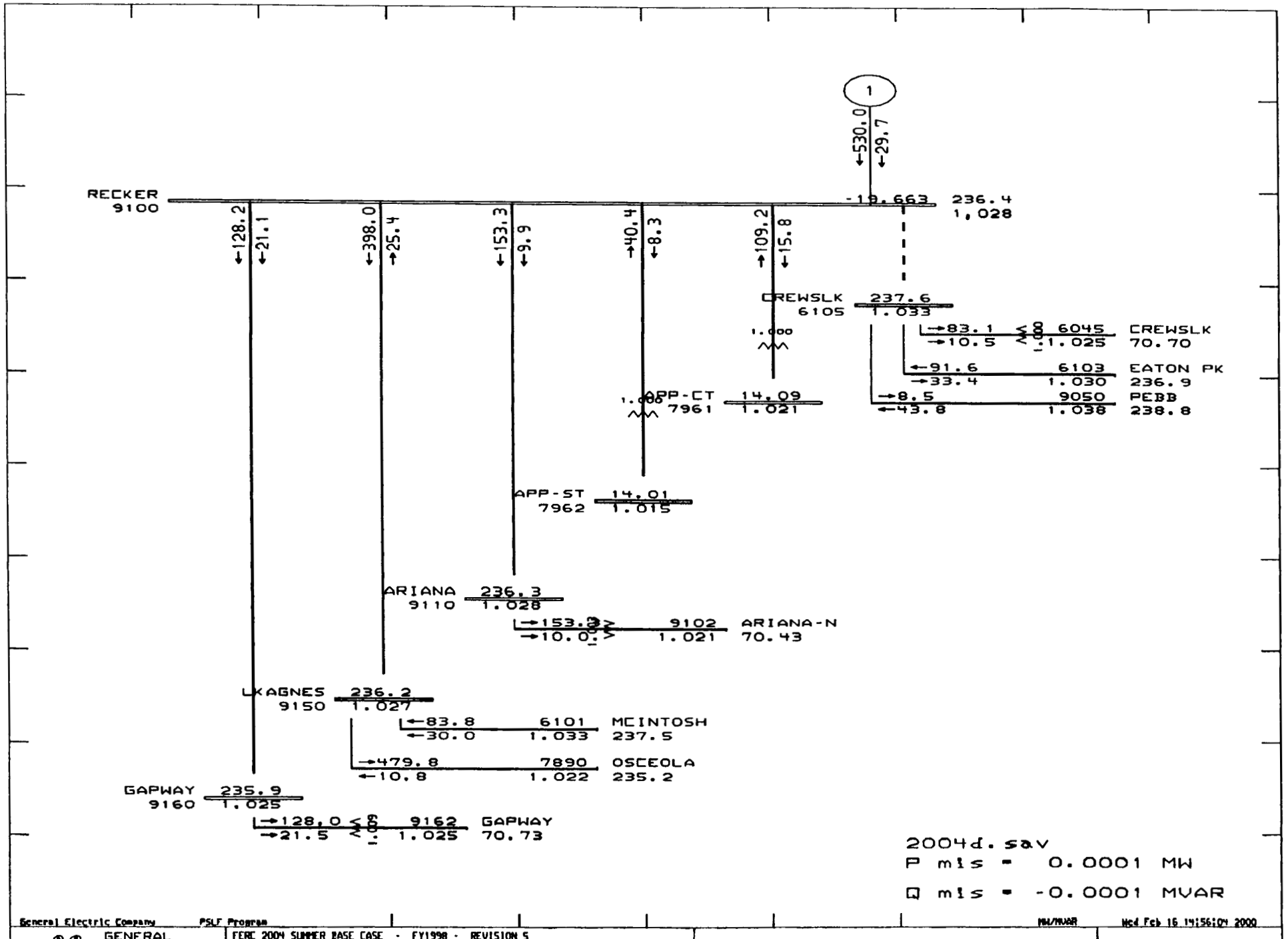

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1.028
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→25.6
→40.4
←8.3
→109.2
←15.8
←196.9
→31.7
CREWSLK 237.0
6105 1.031
1.000
→101.9 ≤ 8 6045 CREWSLK
→10.4 1.023 70.61
←36.6 6103 EATON PK
→14.2 1.029 236.7
APP-CT 14.09
1.000 7961 1.021
→130.7 9050 PEBB
←59.2 1.036 238.3
APP-ST 14.01
7962 1.015
ARIANA 231.0
9110 1.004
→0.0 ≤ 9102 ARIANA-N
←0.0 1.002 69.11
LKAGNES 236.5
9150 1.028
←109.5 6101 MCINTOSH
←20.1 1.033 237.5
→415.9 7890 OSCEOLA
←13.3 1.024 235.5
GAPWAY 235.6
9160 1.024
→174.8 ≤ 9162 GAPWAY
→34.0 1.019 70.34
2004c.sav
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Q mis = -0.0011 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 14:54:31 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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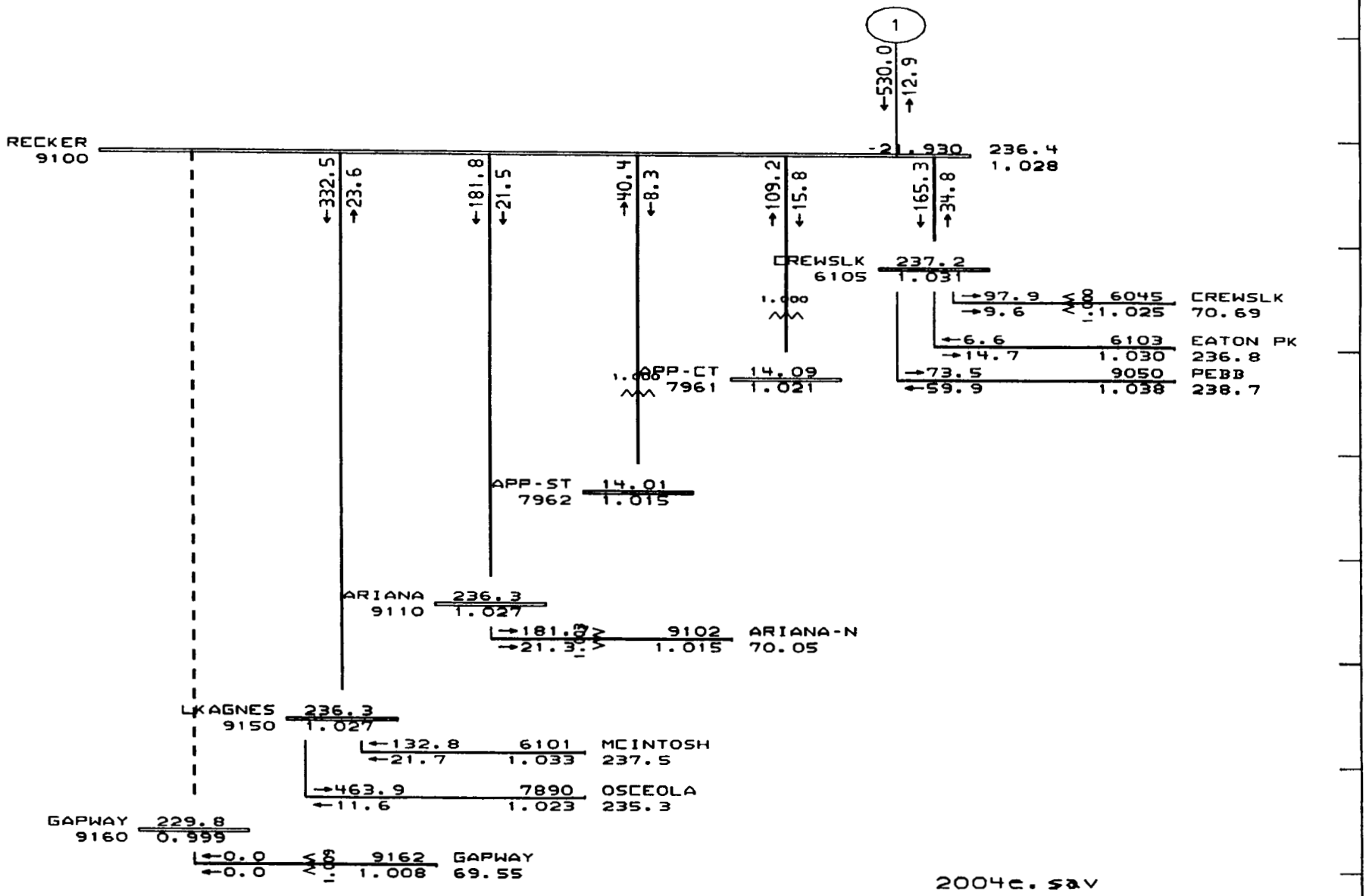

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1.028
←132.8
←20.9
←389.8
→28.9
←157.0
←9.5
→40.4
←8.3
→109.2
←15.8
CREWSLK
6105
237.3
1.032
1.000
→83.1
→10.9
6045
1.023
CREWSLK
70.60
←126.3
→32.7
6103
1.030
EATON PK
236.8
1.000
APP-CT
7961
14.09
1.021
→43.2
←43.6
9050
1.037
PEBB
238.5
APP-ST
7962
14.01
1.015
ARIANA
9110
236.4
1.028
→156.8
→9.5
9102
1.021
ARIANA-N
70.48
LKAGNES
9150
236.4
1.028
←41.1
←30.5
6101
1.033
MCINTOSH
237.5
→429.1
←12.9
7890
1.024
OSCEOLA
235.4
GAPWAY
9160
235.9
1.026
→132.6
→21.2
9162
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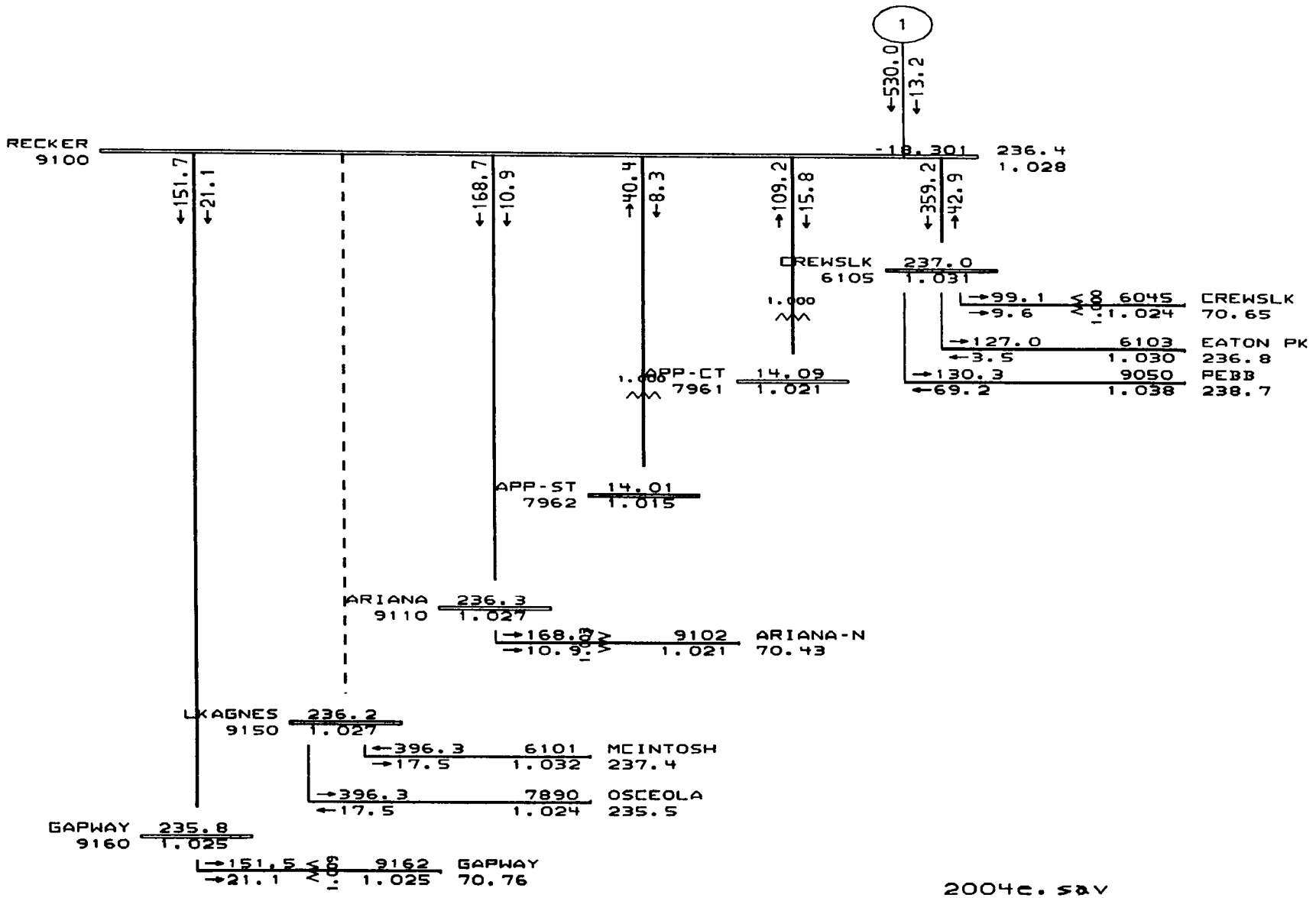

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→40.4
←8.3
→109.2
←15.8
←164.9
→34.8
CREWSLK
6105
237.2
1.031
→97.9
→9.6
6045
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CREWSLK
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←8.0
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6103
1.030
EATON PK
236.8
APP-CT
7961
14.09
1.021
→74.4
←60.0
9050
1.038
PEBB
238.7
APP-ST
7962
14.01
1.015
ARIANA
9110
236.3
1.027
→181.8
→21.4
9102
1.015
ARIANA-N
70.05
KAGNES
9150
236.3
1.027
←135.2
←21.6
6101
1.033
MCINTOSH
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OSCEOLA
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GAPWAY
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9162
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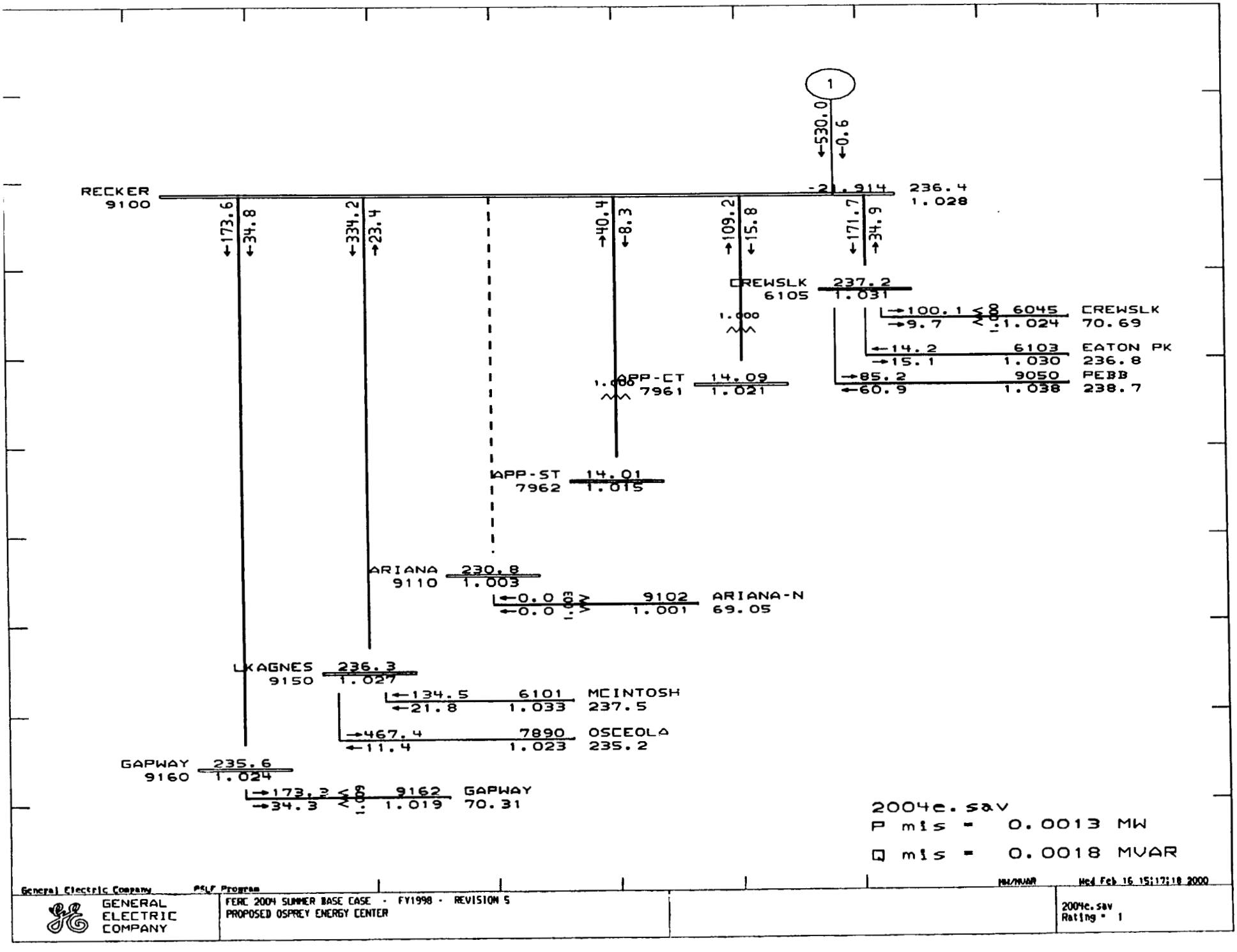

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←11.0
→40.4
←8.3
→109.2
←15.8
←359.1
→43.0
CREWSLK 237.0
6105 1.031
1.000
→99.1 ≤ 6045 CREWSLK
→9.6 ≤ 1.024 70.65
→125.9 6103 EATON PK
←3.4 1.030 236.8
1.000 APP-CT 14.09
7961 1.021
→131.4 9050 PEBB
←69.4 1.038 238.7
APP-ST 14.01
7962 1.015
ARIANA 236.3
9110 1.027
→168.8 ≤ 9102 ARIANA-N
→11.0 ≤ 1.021 70.43
LKAGNES 236.2
9150 1.027
←398.7 6101 MCINTOSH
→17.5 1.032 237.4
→398.7 7890 OSCEOLA
←17.5 1.024 235.5
GAPWAY 235.8
9160 1.025
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→21.1 ≤ 1.025 70.75
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MW/MVAR
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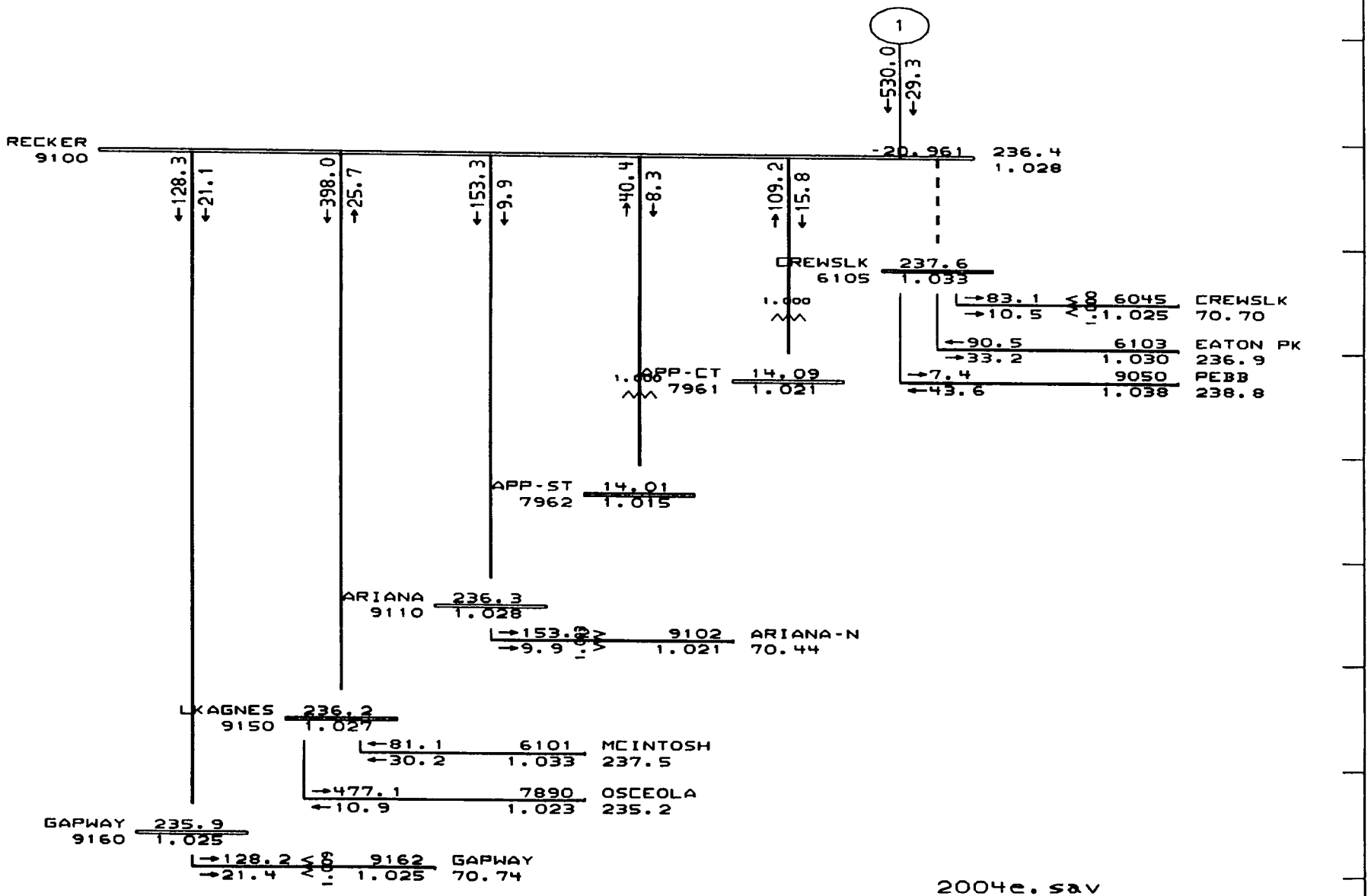

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CREWSLK 237.2
6105 1.031
→100.1
→9.7
6045
1.024
CREWSLK
70.69
←15.6
→15.3
6103
1.030
EATON PK
236.8
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9050
1.038
PEBB
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7961 1.021
APP-ST 14.01
7962 1.015
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9110 1.003
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1.003
9102
1.001
ARIANA-N
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LKAGNES 236.3
9150 1.027
←136.9
←21.7
6101
1.033
MCINTOSH
237.5
→470.1
←11.3
7890
1.023
OSCEOLA
235.2
GAPWAY 235.6
9160 1.024
→173.3
→34.3
1.008
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GAPWAY
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General Electric Company
PSLF Program
MW/MVAR
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
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RECKER
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←9.9
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←8.3
→109.2
←15.8
CREWSLK 237.6
6105 1.033
1.000
→83.1
→10.5
6045
1.025
CREWSLK
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→33.4
6103
1.030
EATON PK
236.9
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→8.5
←43.8
9050
1.038
PEBB
238.8
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7962 1.015
ARIANA 236.3
9110 1.028
→153.2
→10.0
9102
1.021
ARIANA-N
70.43
LKAGNES 236.2
9150 1.027
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6101
1.033
MCINTOSH
237.5
→479.8
←10.8
7890
1.022
OSCEOLA
235.2
GAPWAY 235.9
9160 1.025
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9162
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GAPWAY
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General Electric Company PSLF Program MW/MVAR Wed Feb 16 19:56:04 2000
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PROPOSED OSPREY ENERGY CENTER
2004d.sav
Rating = 1


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RECKER
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CREWSLK
6105
237.2
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6045
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CREWSLK
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6103
1.030
EATON PK
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1.021
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9050
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APP-ST
7962
14.01
1.015
ARIANA
9110
236.3
1.027
→181.8
→21.3
9102
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1.027
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6101
1.033
MCINTOSH
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7890
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PSLF Program
MW/MVAR
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6105 1.031
1.000
→99.1
→9.6
6045
1.024
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ARIANA-N
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1.024
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Q mis = 0.0018 MVAR


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RECKER
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→173.2 ≤ 8.0 9162 GAPWAY
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PROPOSED OSPREY ENERGY CENTER
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General Electric Company PSLF Program MW/MVAR Wed Feb 16 14:57:10 2000

GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

2004e.sav
Rating = 1

APPENDIX III

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-1	SN PLANT	230	SYLVAN	230	1	1						
2004-60-1	SYLVAN	230	N LONGWD	230	1	1						
2004-60-1	IND RIV	230	STANTON	230	1	11						
2004-60-1	SN PLANT	115	TURNER	115	1	1						
2004-60-1	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-1	SILVR SP	230	SILV SPN	230	1	2						
2004-60-1	SILVR SP	230	OCALA 1	230	1	2						
2004-60-1	RIO PINR	230	CURRY FD	230	1	2						
2004-60-1	STANTON	230	CURRY FD	230	1	2						
2004-60-1	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-1	SHELD	230	LK TARPN	230	1	2						
2004-60-1	PEBB	230	CREWSLK	230	1	13						
2004-60-1	PEBB	230	N BARTOW	230	1	2						
2004-60-1	RECKER	230	LKAGNES	230	1	16						
2004-60-1	RECKER	230	ARIANA	230	1	16						
2004-60-1	RECKER	230	CREWSLK	230	1	13						
2004-60-1	B BEND	230	MANATEE	230	1	1						
2004-60-1	RUSKIN T	230	MANATEE	230	1	1						
2004-60-1	IND RIV	230	IND RIV	115	1	11						
2004-60-1	SHELD	230	SHELD-NW	69	1	16						
2004-60-1	LARGO	230	LARGO A	69	1	2						
2004-60-1	CLMT EST	230	CLMT EST	69	1	2						
2004-60-1	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-1	WINDERME	230	WINDERME	69	1	2						
2004-60-1	PASADENA	230	PASADENA	115	1	2						
2004-60-1	ARIANA	230	ARIANA-N	69	1	16						
2004-60-1	SELOSE	230	SELOSE-N	69	1	16						
2004-60-1	GAPWAY	230	GAPWAY	69	1	16						
2004-60-1	CREWSLK	230	CREWSLK	69	1	13						
2004-60-1	TENOROC	230	TENOROC	69	1	13						
2004-60-1	BARCOLA	230	WEST	230	1	2						
2004-60-1	EATON PK	230	CREWSLK	230	1	13						
2004-60-1	EATON PK	230	EATON PK	69	1	13						
2004-60-1	EATON PK	230	TENOROC	230	1	13						
2004-60-1	RECKER	230	GAPWAY	230	1	16						
2004-60-1	SN PLANT	115	TURNER	115	1	1						
2004-60-2	SN PLANT	230	SYLVAN	230	1	1						
2004-60-2	SYLVAN	230	N LONGWD	230	1	1						
2004-60-2	IND RIV	230	STANTON	230	1	11						
2004-60-2	SN PLANT	115	TURNER	115	1	1						
2004-60-2	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-2	SILVR SP	230	SILV SPN	230	1	2						
2004-60-2	SILVR SP	230	OCALA 1	230	1	2						
2004-60-2	RIO PINR	230	CURRY FD	230	1	2						
2004-60-2	STANTON	230	CURRY FD	230	1	2						
2004-60-2	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-2	SHELD	230	LK TARPN	230	1	2						
2004-60-2	PEBB	230	CREWSLK	230	1	13						
2004-60-2	PEBB	230	N BARTOW	230	1	2						
2004-60-2	RECKER	230	LKAGNES	230	1	16						
2004-60-2	RECKER	230	ARIANA	230	1	16						
2004-60-2	RECKER	230	CREWSLK	230	1	13						
2004-60-2	B BEND	230	MANATEE	230	1	1						
2004-60-2	RUSKIN T	230	MANATEE	230	1	1						
2004-60-2	IND RIV	230	IND RIV	115	1	11						
2004-60-2	SHELD	230	SHELD-NW	69	1	16						
2004-60-2	LARGO	230	LARGO A	69	1	2						
2004-60-2	CLMT EST	230	CLMT EST	69	1	2						
2004-60-2	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-2	WINDERME	230	WINDERME	69	1	2						
2004-60-2	PASADENA	230	PASADENA	115	1	2						
2004-60-2	ARIANA	230	ARIANA-N	69	1	16						
2004-60-2	SELOSE	230	SELOSE-N	69	1	16						
2004-60-2	GAPWAY	230	GAPWAY	69	1	16						
2004-60-2	CREWSLK	230	CREWSLK	69	1	13						
2004-60-2	TENOROC	230	TENOROC	69	1	13						
2004-60-2	BARCOLA	230	WEST	230	1	2						
2004-60-2	EATON PK	230	CREWSLK	230	1	13						
2004-60-2	EATON PK	230	EATON PK	69	1	13						
2004-60-2	EATON PK	230	TENOROC	230	1	13						
2004-60-2	RECKER	230	GAPWAY	230	1	16						
2004-60-2	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-3	SN PLANT	230	SYLVAN	230	1	1						
2004-60-3	SYLVAN	230	N LONGWD	230	1	1						
2004-60-3	IND RIV	230	STANTON	230	1	11						
2004-60-3	SN PLANT	115	TURNER	115	1	1						
2004-60-3	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-3	SILVR SP	230	SILV SPN	230	1	2						
2004-60-3	SILVR SP	230	OCALA 1	230	1	2						
2004-60-3	RIO PINR	230	CURRY FD	230	1	2						
2004-60-3	STANTON	230	CURRY FD	230	1	2						
2004-60-3	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-3	SHELD	230	LK TARPN	230	1	2						
2004-60-3	PEBB	230	CREWSLK	230	1	13						
2004-60-3	PEBB	230	N BARTOW	230	1	2						
2004-60-3	RECKER	230	LKAGNES	230	1	16						
2004-60-3	RECKER	230	ARIANA	230	1	16						
2004-60-3	RECKER	230	CREWSLK	230	1	13						
2004-60-3	B BEND	230	MANATEE	230	1	1						
2004-60-3	RUSKIN T	230	MANATEE	230	1	1						
2004-60-3	IND RIV	230	IND RIV	115	1	11						
2004-60-3	SHELD	230	SHELD-NW	69	1	16						
2004-60-3	LARGO	230	LARGO A	69	1	2						
2004-60-3	CLMT EST	230	CLMT EST	69	1	2						
2004-60-3	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-3	WINDERME	230	WINDERME	69	1	2						
2004-60-3	PASADENA	230	PASADENA	115	1	2						
2004-60-3	ARIANA	230	ARIANA-N	69	1	16						
2004-60-3	SELOSE	230	SELOSE-N	69	1	16						
2004-60-3	GAPWAY	230	GAPWAY	69	1	16						
2004-60-3	CREWSLK	230	CREWSLK	69	1	13						
2004-60-3	TENOROC	230	TENOROC	69	1	13						
2004-60-3	BARCOLA	230	WEST	230	1	2						
2004-60-3	EATON PK	230	CREWSLK	230	1	13						
2004-60-3	EATON PK	230	EATON PK	69	1	13						
2004-60-3	EATON PK	230	TENOROC	230	1	13						
2004-60-3	RECKER	230	GAPWAY	230	1	16						
2004-60-3	SN PLANT	115	TURNER	115	1	1						
2004-60-4	SN PLANT	230	SYLVAN	230	1	1						
2004-60-4	SYLVAN	230	N LONGWD	230	1	1						
2004-60-4	IND RIV	230	STANTON	230	1	11						
2004-60-4	SN PLANT	115	TURNER	115	1	1						
2004-60-4	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-4	SILVR SP	230	SILV SPN	230	1	2						
2004-60-4	SILVR SP	230	OCALA 1	230	1	2						
2004-60-4	RIO PINR	230	CURRY FD	230	1	2						
2004-60-4	STANTON	230	CURRY FD	230	1	2						
2004-60-4	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-4	SHELD	230	LK TARPN	230	1	2						
2004-60-4	PEBB	230	CREWSLK	230	1	13						
2004-60-4	PEBB	230	N BARTOW	230	1	2						
2004-60-4	RECKER	230	LKAGNES	230	1	16						
2004-60-4	RECKER	230	ARIANA	230	1	16						
2004-60-4	RECKER	230	CREWSLK	230	1	13						
2004-60-4	B BEND	230	MANATEE	230	1	1						
2004-60-4	RUSKIN T	230	MANATEE	230	1	1						
2004-60-4	IND RIV	230	IND RIV	115	1	11						
2004-60-4	SHELD	230	SHELD-NW	69	1	16						
2004-60-4	LARGO	230	LARGO A	69	1	2						
2004-60-4	CLMT EST	230	CLMT EST	69	1	2						
2004-60-4	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-4	WINDERME	230	WINDERME	69	1	2						
2004-60-4	PASADENA	230	PASADENA	115	1	2						
2004-60-4	ARIANA	230	ARIANA-N	69	1	16						
2004-60-4	SELOSE	230	SELOSE-N	69	1	16						
2004-60-4	GAPWAY	230	GAPWAY	69	1	16						
2004-60-4	CREWSLK	230	CREWSLK	69	1	13						
2004-60-4	TENOROC	230	TENOROC	69	1	13						
2004-60-4	BARCOLA	230	WEST	230	1	2						
2004-60-4	EATON PK	230	CREWSLK	230	1	13						
2004-60-4	EATON PK	230	EATON PK	69	1	13						
2004-60-4	EATON PK	230	TENOROC	230	1	13						
2004-60-4	RECKER	230	GAPWAY	230	1	16						
2004-60-4	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-5	SN PLANT	230	SYLVAN	230	1	1						
2004-60-5	SYLVAN	230	N LONGWD	230	1	1						
2004-60-5	IND RIV	230	STANTON	230	1	11						
2004-60-5	SN PLANT	115	TURNER	115	1	1						
2004-60-5	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-5	SILVR SP	230	SILV SPN	230	1	2						
2004-60-5	SILVR SP	230	OCALA 1	230	1	2						
2004-60-5	RIO PINR	230	CURRY FD	230	1	2						
2004-60-5	STANTON	230	CURRY FD	230	1	2						
2004-60-5	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-5	SHELD	230	LK TARPN	230	1	2						
2004-60-5	PEBB	230	CREWSLK	230	1	13						
2004-60-5	PEBB	230	N BARTOW	230	1	2						
2004-60-5	RECKER	230	LKAGNES	230	1	16						
2004-60-5	RECKER	230	ARIANA	230	1	16						
2004-60-5	RECKER	230	CREWSLK	230	1	13						
2004-60-5	B BEND	230	MANATEE	230	1	1						
2004-60-5	RUSKIN T	230	MANATEE	230	1	1						
2004-60-5	IND RIV	230	IND RIV	115	1	11						
2004-60-5	SHELD	230	SHELD-NW	69	1	16						
2004-60-5	LARGO	230	LARGO A	69	1	2						
2004-60-5	CLMT EST	230	CLMT EST	69	1	2						
2004-60-5	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-5	WINDERME	230	WINDERME	69	1	2						
2004-60-5	PASADENA	230	PASADENA	115	1	2						
2004-60-5	ARIANA	230	ARIANA-N	69	1	16						
2004-60-5	SELOSE	230	SELOSE-N	69	1	16						
2004-60-5	GAPWAY	230	GAPWAY	69	1	16						
2004-60-5	CREWSLK	230	CREWSLK	69	1	13						
2004-60-5	TENOROC	230	TENOROC	69	1	13						
2004-60-5	BARCOLA	230	WEST	230	1	2						
2004-60-5	EATON PK	230	CREWSLK	230	1	13						
2004-60-5	EATON PK	230	EATON PK	69	1	13						
2004-60-5	EATON PK	230	TENOROC	230	1	13						
2004-60-5	RECKER	230	GAPWAY	230	1	16						
2004-60-5	SN PLANT	115	TURNER	115	1	1						
2004-60-6	SN PLANT	230	SYLVAN	230	1	1						
2004-60-6	SYLVAN	230	N LONGWD	230	1	1						
2004-60-6	IND RIV	230	STANTON	230	1	11						
2004-60-6	SN PLANT	115	TURNER	115	1	1						
2004-60-6	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-6	SILVR SP	230	SILV SPN	230	1	2						
2004-60-6	SILVR SP	230	OCALA 1	230	1	2						
2004-60-6	RIO PINR	230	CURRY FD	230	1	2						
2004-60-6	STANTON	230	CURRY FD	230	1	2						
2004-60-6	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-6	SHELD	230	LK TARPN	230	1	2						
2004-60-6	PEBB	230	CREWSLK	230	1	13						
2004-60-6	PEBB	230	N BARTOW	230	1	2						
2004-60-6	RECKER	230	LKAGNES	230	1	16						
2004-60-6	RECKER	230	ARIANA	230	1	16						
2004-60-6	RECKER	230	CREWSLK	230	1	13						
2004-60-6	B BEND	230	MANATEE	230	1	1						
2004-60-6	RUSKIN T	230	MANATEE	230	1	1						
2004-60-6	IND RIV	230	IND RIV	115	1	11						
2004-60-6	SHELD	230	SHELD-NW	69	1	16						
2004-60-6	LARGO	230	LARGO A	69	1	2						
2004-60-6	CLMT EST	230	CLMT EST	69	1	2						
2004-60-6	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-6	WINDERME	230	WINDERME	69	1	2						
2004-60-6	PASADENA	230	PASADENA	115	1	2						
2004-60-6	ARIANA	230	ARIANA-N	69	1	16						
2004-60-6	SELOSE	230	SELOSE-N	69	1	16						
2004-60-6	GAPWAY	230	GAPWAY	69	1	16						
2004-60-6	CREWSLK	230	CREWSLK	69	1	13						
2004-60-6	TENOROC	230	TENOROC	69	1	13						
2004-60-6	BARCOLA	230	WEST	230	1	2						
2004-60-6	EATON PK	230	CREWSLK	230	1	13						
2004-60-6	EATON PK	230	EATON PK	69	1	13						
2004-60-6	EATON PK	230	TENOROC	230	1	13						
2004-60-6	RECKER	230	GAPWAY	230	1	16						
2004-60-6	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-7	SN PLANT	230	SYLVAN	230	1	1						
2004-60-7	SYLVAN	230	N LONGWD	230	1	1						
2004-60-7	IND RIV	230	STANTON	230	1	11						
2004-60-7	SN PLANT	115	TURNER	115	1	1						
2004-60-7	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-7	SILVR SP	230	SILV SPN	230	1	2						
2004-60-7	SILVR SP	230	OCALA 1	230	1	2						
2004-60-7	RIO PINR	230	CURRY FD	230	1	2						
2004-60-7	STANTON	230	CURRY FD	230	1	2						
2004-60-7	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-7	SHELD	230	LK TARPN	230	1	2						
2004-60-7	PEBB	230	CREWSLK	230	1	13						
2004-60-7	PEBB	230	N BARTOW	230	1	2						
2004-60-7	RECKER	230	LKAGNES	230	1	16						
2004-60-7	RECKER	230	ARIANA	230	1	16						
2004-60-7	RECKER	230	CREWSLK	230	1	13						
2004-60-7	B BEND	230	MANATEE	230	1	1						
2004-60-7	RUSKIN T	230	MANATEE	230	1	1						
2004-60-7	IND RIV	230	IND RIV	115	1	11						
2004-60-7	SHELD	230	SHELD-NW	69	1	16						
2004-60-7	LARGO	230	LARGO A	69	1	2						
2004-60-7	CLMT EST	230	CLMT EST	69	1	2						
2004-60-7	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-7	WINDERME	230	WINDERME	69	1	2						
2004-60-7	PASADENA	230	PASADENA	115	1	2						
2004-60-7	ARIANA	230	ARIANA-N	69	1	16						
2004-60-7	SELOSE	230	SELOSE-N	69	1	16						
2004-60-7	GAPWAY	230	GAPWAY	69	1	16						
2004-60-7	CREWSLK	230	CREWSLK	69	1	13						
2004-60-7	TENOROC	230	TENOROC	69	1	13						
2004-60-7	BARCOLA	230	WEST	230	1	2						
2004-60-7	EATON PK	230	CREWSLK	230	1	13						
2004-60-7	EATON PK	230	EATON PK	69	1	13						
2004-60-7	EATON PK	230	TENOROC	230	1	13						
2004-60-7	RECKER	230	GAPWAY	230	1	16						
2004-60-7	SN PLANT	115	TURNER	115	1	1						
2004-60-8	SN PLANT	230	SYLVAN	230	1	1						
2004-60-8	SYLVAN	230	N LONGWD	230	1	1						
2004-60-8	IND RIV	230	STANTON	230	1	11						
2004-60-8	SN PLANT	115	TURNER	115	1	1						
2004-60-8	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-8	SILVR SP	230	SILV SPN	230	1	2						
2004-60-8	SILVR SP	230	OCALA 1	230	1	2						
2004-60-8	RIO PINR	230	CURRY FD	230	1	2						
2004-60-8	STANTON	230	CURRY FD	230	1	2						
2004-60-8	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-8	SHELD	230	LK TARPN	230	1	2						
2004-60-8	PEBB	230	CREWSLK	230	1	13						
2004-60-8	PEBB	230	N BARTOW	230	1	2						
2004-60-8	RECKER	230	LKAGNES	230	1	16						
2004-60-8	RECKER	230	ARIANA	230	1	16						
2004-60-8	RECKER	230	CREWSLK	230	1	13						
2004-60-8	B BEND	230	MANATEE	230	1	1						
2004-60-8	RUSKIN T	230	MANATEE	230	1	1						
2004-60-8	IND RIV	230	IND RIV	115	1	11						
2004-60-8	SHELD	230	SHELD-NW	69	1	16						
2004-60-8	LARGO	230	LARGO A	69	1	2						
2004-60-8	CLMT EST	230	CLMT EST	69	1	2						
2004-60-8	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-8	WINDERME	230	WINDERME	69	1	2						
2004-60-8	PASADENA	230	PASADENA	115	1	2						
2004-60-8	ARIANA	230	ARIANA-N	69	1	16						
2004-60-8	SELOSE	230	SELOSE-N	69	1	16						
2004-60-8	GAPWAY	230	GAPWAY	69	1	16						
2004-60-8	CREWSLK	230	CREWSLK	69	1	13						
2004-60-8	TENOROC	230	TENOROC	69	1	13						
2004-60-8	BARCOLA	230	WEST	230	1	2						
2004-60-8	EATON PK	230	CREWSLK	230	1	13						
2004-60-8	EATON PK	230	EATON PK	69	1	13						
2004-60-8	EATON PK	230	TENOROC	230	1	13						
2004-60-8	RECKER	230	GAPWAY	230	1	16						
2004-60-8	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-9	SN PLANT	230	SYLVAN	230	1	1						
2004-60-9	SYLVAN	230	N LONGWD	230	1	1						
2004-60-9	IND RIV	230	STANTON	230	1	11						
2004-60-9	SN PLANT	115	TURNER	115	1	1						
2004-60-9	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-9	SILVR SP	230	SILV SPN	230	1	2						
2004-60-9	SILVR SP	230	OCALA 1	230	1	2						
2004-60-9	RIO PINR	230	CURRY FD	230	1	2						
2004-60-9	STANTON	230	CURRY FD	230	1	2						
2004-60-9	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-9	SHELD	230	LK TARPN	230	1	2						
2004-60-9	PEBB	230	CREWSLK	230	1	13						
2004-60-9	PEBB	230	N BARTOW	230	1	2						
2004-60-9	RECKER	230	LKAGNES	230	1	16						
2004-60-9	RECKER	230	ARIANA	230	1	16						
2004-60-9	RECKER	230	CREWSLK	230	1	13						
2004-60-9	B BEND	230	MANATEE	230	1	1						
2004-60-9	RUSKIN T	230	MANATEE	230	1	1						
2004-60-9	IND RIV	230	IND RIV	115	1	11						
2004-60-9	SHELD	230	SHELD-NW	69	1	16						
2004-60-9	LARGO	230	LARGO A	69	1	2						
2004-60-9	CLMT EST	230	CLMT EST	69	1	2						
2004-60-9	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-9	WINDERME	230	WINDERME	69	1	2						
2004-60-9	PASADENA	230	PASADENA	115	1	2						
2004-60-9	ARIANA	230	ARIANA-N	69	1	16						
2004-60-9	SELOSE	230	SELOSE-N	69	1	16						
2004-60-9	GAPWAY	230	GAPWAY	69	1	16						
2004-60-9	CREWSLK	230	CREWSLK	69	1	13						
2004-60-9	TENOROC	230	TENOROC	69	1	13						
2004-60-9	BARCOLA	230	WEST	230	1	2						
2004-60-9	EATON PK	230	CREWSLK	230	1	13						
2004-60-9	EATON PK	230	EATON PK	69	1	13						
2004-60-9	EATON PK	230	TENOROC	230	1	13						
2004-60-9	RECKER	230	GAPWAY	230	1	16						
2004-60-9	SN PLANT	115	TURNER	115	1	1						
2004-60-10	SN PLANT	230	SYLVAN	230	1	1						
2004-60-10	SYLVAN	230	N LONGWD	230	1	1						
2004-60-10	IND RIV	230	STANTON	230	1	11						
2004-60-10	SN PLANT	115	TURNER	115	1	1						
2004-60-10	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-10	SILVR SP	230	SILV SPN	230	1	2						
2004-60-10	SILVR SP	230	OCALA 1	230	1	2						
2004-60-10	RIO PINR	230	CURRY FD	230	1	2						
2004-60-10	STANTON	230	CURRY FD	230	1	2						
2004-60-10	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-10	SHELD	230	LK TARPN	230	1	2						
2004-60-10	PEBB	230	CREWSLK	230	1	13						
2004-60-10	PEBB	230	N BARTOW	230	1	2						
2004-60-10	RECKER	230	LKAGNES	230	1	16						
2004-60-10	RECKER	230	ARIANA	230	1	16						
2004-60-10	RECKER	230	CREWSLK	230	1	13						
2004-60-10	B BEND	230	MANATEE	230	1	1						
2004-60-10	RUSKIN T	230	MANATEE	230	1	1						
2004-60-10	IND RIV	230	IND RIV	115	1	11						
2004-60-10	SHELD	230	SHELD-NW	69	1	16						
2004-60-10	LARGO	230	LARGO A	69	1	2						
2004-60-10	CLMT EST	230	CLMT EST	69	1	2						
2004-60-10	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-10	WINDERME	230	WINDERME	69	1	2						
2004-60-10	PASADENA	230	PASADENA	115	1	2						
2004-60-10	ARIANA	230	ARIANA-N	69	1	16						
2004-60-10	SELOSE	230	SELOSE-N	69	1	16						
2004-60-10	GAPWAY	230	GAPWAY	69	1	16						
2004-60-10	CREWSLK	230	CREWSLK	69	1	13						
2004-60-10	TENOROC	230	TENOROC	69	1	13						
2004-60-10	BARCOLA	230	WEST	230	1	2						
2004-60-10	EATON PK	230	CREWSLK	230	1	13						
2004-60-10	EATON PK	230	EATON PK	69	1	13						
2004-60-10	EATON PK	230	TENOROC	230	1	13						
2004-60-10	RECKER	230	GAPWAY	230	1	16						
2004-60-10	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-11	SN PLANT	230	SYLVAN	230	1	1						
2004-60-11	SYLVAN	230	N LONGWD	230	1	1						
2004-60-11	IND RIV	230	STANTON	230	1	11						
2004-60-11	SN PLANT	115	TURNER	115	1	1						
2004-60-11	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-11	SILVR SP	230	SILV SPN	230	1	2						
2004-60-11	SILVR SP	230	OCALA 1	230	1	2						
2004-60-11	RIO PINR	230	CURRY FD	230	1	2						
2004-60-11	STANTON	230	CURRY FD	230	1	2						
2004-60-11	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-11	SHELD	230	LK TARPN	230	1	2						
2004-60-11	PEBB	230	CREWSLK	230	1	13						
2004-60-11	PEBB	230	N BARTOW	230	1	2						
2004-60-11	RECKER	230	LKAGNES	230	1	16						
2004-60-11	RECKER	230	ARIANA	230	1	16						
2004-60-11	RECKER	230	CREWSLK	230	1	13						
2004-60-11	B BEND	230	MANATEE	230	1	1						
2004-60-11	RUSKIN T	230	MANATEE	230	1	1						
2004-60-11	IND RIV	230	IND RIV	115	1	11						
2004-60-11	SHELD	230	SHELD-NW	69	1	16						
2004-60-11	LARGO	230	LARGO A	69	1	2						
2004-60-11	CLMT EST	230	CLMT EST	69	1	2						
2004-60-11	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-11	WINDERME	230	WINDERME	69	1	2						
2004-60-11	PASADENA	230	PASADENA	115	1	2						
2004-60-11	ARIANA	230	ARIANA-N	69	1	16						
2004-60-11	SELOSE	230	SELOSE-N	69	1	16						
2004-60-11	GAPWAY	230	GAPWAY	69	1	16						
2004-60-11	CREWSLK	230	CREWSLK	69	1	13						
2004-60-11	TENOROC	230	TENOROC	69	1	13						
2004-60-11	BARCOLA	230	WEST	230	1	2						
2004-60-11	EATON PK	230	CREWSLK	230	1	13						
2004-60-11	EATON PK	230	EATON PK	69	1	13						
2004-60-11	EATON PK	230	TENOROC	230	1	13						
2004-60-11	RECKER	230	GAPWAY	230	1	16						
2004-60-11	SN PLANT	115	TURNER	115	1	1						
2004-60-12	SN PLANT	230	SYLVAN	230	1	1						
2004-60-12	SYLVAN	230	N LONGWD	230	1	1						
2004-60-12	IND RIV	230	STANTON	230	1	11						
2004-60-12	SN PLANT	115	TURNER	115	1	1						
2004-60-12	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-12	SILVR SP	230	SILV SPN	230	1	2						
2004-60-12	SILVR SP	230	OCALA 1	230	1	2						
2004-60-12	RIO PINR	230	CURRY FD	230	1	2						
2004-60-12	STANTON	230	CURRY FD	230	1	2						
2004-60-12	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-12	SHELD	230	LK TARPN	230	1	2						
2004-60-12	PEBB	230	CREWSLK	230	1	13						
2004-60-12	PEBB	230	N BARTOW	230	1	2						
2004-60-12	RECKER	230	LKAGNES	230	1	16						
2004-60-12	RECKER	230	ARIANA	230	1	16						
2004-60-12	RECKER	230	CREWSLK	230	1	13						
2004-60-12	B BEND	230	MANATEE	230	1	1						
2004-60-12	RUSKIN T	230	MANATEE	230	1	1						
2004-60-12	IND RIV	230	IND RIV	115	1	11						
2004-60-12	SHELD	230	SHELD-NW	69	1	16						
2004-60-12	LARGO	230	LARGO A	69	1	2						
2004-60-12	CLMT EST	230	CLMT EST	69	1	2						
2004-60-12	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-12	WINDERME	230	WINDERME	69	1	2						
2004-60-12	PASADENA	230	PASADENA	115	1	2						
2004-60-12	ARIANA	230	ARIANA-N	69	1	16						
2004-60-12	SELOSE	230	SELOSE-N	69	1	16						
2004-60-12	GAPWAY	230	GAPWAY	69	1	16						
2004-60-12	CREWSLK	230	CREWSLK	69	1	13						
2004-60-12	TENOROC	230	TENOROC	69	1	13						
2004-60-12	BARCOLA	230	WEST	230	1	2						
2004-60-12	EATON PK	230	CREWSLK	230	1	13						
2004-60-12	EATON PK	230	EATON PK	69	1	13						
2004-60-12	EATON PK	230	TENOROC	230	1	13						
2004-60-12	RECKER	230	GAPWAY	230	1	16						
2004-60-12	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-13	SN PLANT	230	SYLVAN	230	1	1						
2004-60-13	SYLVAN	230	N LONGWD	230	1	1						
2004-60-13	IND RIV	230	STANTON	230	1	11						
2004-60-13	SN PLANT	115	TURNER	115	1	1						
2004-60-13	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-13	SILVR SP	230	SILV SPN	230	1	2						
2004-60-13	SILVR SP	230	OCALA 1	230	1	2						
2004-60-13	RIO PINR	230	CURRY FD	230	1	2						
2004-60-13	STANTON	230	CURRY FD	230	1	2						
2004-60-13	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-13	SHELD	230	LK TARPN	230	1	2						
2004-60-13	PEBB	230	CREWSLK	230	1	13						
2004-60-13	PEBB	230	N BARTOW	230	1	2						
2004-60-13	RECKER	230	LKAGNES	230	1	16						
2004-60-13	RECKER	230	ARIANA	230	1	16						
2004-60-13	RECKER	230	CREWSLK	230	1	13						
2004-60-13	B BEND	230	MANATEE	230	1	1						
2004-60-13	RUSKIN T	230	MANATEE	230	1	1						
2004-60-13	IND RIV	230	IND RIV	115	1	11						
2004-60-13	SHELD	230	SHELD-NW	69	1	16						
2004-60-13	LARGO	230	LARGO A	69	1	2						
2004-60-13	CLMT EST	230	CLMT EST	69	1	2						
2004-60-13	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-13	WINDERME	230	WINDERME	69	1	2						
2004-60-13	PASADENA	230	PASADENA	115	1	2						
2004-60-13	ARIANA	230	ARIANA-N	69	1	16						
2004-60-13	SELOSE	230	SELOSE-N	69	1	16						
2004-60-13	GAPWAY	230	GAPWAY	69	1	16						
2004-60-13	CREWSLK	230	CREWSLK	69	1	13						
2004-60-13	TENOROC	230	TENOROC	69	1	13						
2004-60-13	BARCOLA	230	WEST	230	1	2						
2004-60-13	EATON PK	230	CREWSLK	230	1	13						
2004-60-13	EATON PK	230	EATON PK	69	1	13						
2004-60-13	EATON PK	230	TENOROC	230	1	13						
2004-60-13	RECKER	230	GAPWAY	230	1	16						
2004-60-13	SN PLANT	115	TURNER	115	1	1						
2004-60-15	SN PLANT	230	SYLVAN	230	1	1						
2004-60-15	SYLVAN	230	N LONGWD	230	1	1						
2004-60-15	IND RIV	230	STANTON	230	1	11						
2004-60-15	SN PLANT	115	TURNER	115	1	1						
2004-60-15	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-15	SILVR SP	230	SILV SPN	230	1	2						
2004-60-15	SILVR SP	230	OCALA 1	230	1	2						
2004-60-15	RIO PINR	230	CURRY FD	230	1	2						
2004-60-15	STANTON	230	CURRY FD	230	1	2						
2004-60-15	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-15	SHELD	230	LK TARPN	230	1	2						
2004-60-15	PEBB	230	CREWSLK	230	1	13						
2004-60-15	PEBB	230	N BARTOW	230	1	2						
2004-60-15	RECKER	230	LKAGNES	230	1	16						
2004-60-15	RECKER	230	ARIANA	230	1	16						
2004-60-15	RECKER	230	CREWSLK	230	1	13						
2004-60-15	B BEND	230	MANATEE	230	1	1						
2004-60-15	RUSKIN T	230	MANATEE	230	1	1						
2004-60-15	IND RIV	230	IND RIV	115	1	11						
2004-60-15	SHELD	230	SHELD-NW	69	1	16						
2004-60-15	LARGO	230	LARGO A	69	1	2						
2004-60-15	CLMT EST	230	CLMT EST	69	1	2						
2004-60-15	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-15	WINDERME	230	WINDERME	69	1	2						
2004-60-15	PASADENA	230	PASADENA	115	1	2						
2004-60-15	ARIANA	230	ARIANA-N	69	1	16						
2004-60-15	SELOSE	230	SELOSE-N	69	1	16						
2004-60-15	GAPWAY	230	GAPWAY	69	1	16						
2004-60-15	CREWSLK	230	CREWSLK	69	1	13						
2004-60-15	TENOROC	230	TENOROC	69	1	13						
2004-60-15	BARCOLA	230	WEST	230	1	2						
2004-60-15	EATON PK	230	CREWSLK	230	1	13						
2004-60-15	EATON PK	230	EATON PK	69	1	13						
2004-60-15	EATON PK	230	TENOROC	230	1	13						
2004-60-15	RECKER	230	GAPWAY	230	1	16						
2004-60-15	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-16	SN PLANT	230	SYLVAN	230	1	1						
2004-60-16	SYLVAN	230	N LONGWD	230	1	1						
2004-60-16	IND RIV	230	STANTON	230	1	11						
2004-60-16	SN PLANT	115	TURNER	115	1	1						
2004-60-16	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-16	SILVR SP	230	SILV SPN	230	1	2						
2004-60-16	SILVR SP	230	OCALA 1	230	1	2						
2004-60-16	RIO PINR	230	CURRY FD	230	1	2						
2004-60-16	STANTON	230	CURRY FD	230	1	2						
2004-60-16	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-16	SHELD	230	LK TARPN	230	1	2						
2004-60-16	PEBB	230	CREWSLK	230	1	13						
2004-60-16	PEBB	230	N BARTOW	230	1	2						
2004-60-16	RECKER	230	LKAGNES	230	1	16						
2004-60-16	RECKER	230	ARIANA	230	1	16						
2004-60-16	RECKER	230	CREWSLK	230	1	13						
2004-60-16	B BEND	230	MANATEE	230	1	1						
2004-60-16	RUSKIN T	230	MANATEE	230	1	1						
2004-60-16	IND RIV	230	IND RIV	115	1	11						
2004-60-16	SHELD	230	SHELD-NW	69	1	16						
2004-60-16	LARGO	230	LARGO A	69	1	2						
2004-60-16	CLMT EST	230	CLMT EST	69	1	2						
2004-60-16	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-16	WINDERME	230	WINDERME	69	1	2						
2004-60-16	PASADENA	230	PASADENA	115	1	2						
2004-60-16	ARIANA	230	ARIANA-N	69	1	16						
2004-60-16	SELOSE	230	SELOSE-N	69	1	16						
2004-60-16	GAPWAY	230	GAPWAY	69	1	16						
2004-60-16	CREWSLK	230	CREWSLK	69	1	13						
2004-60-16	TENOROC	230	TENOROC	69	1	13						
2004-60-16	BARCOLA	230	WEST	230	1	2						
2004-60-16	EATON PK	230	CREWSLK	230	1	13						
2004-60-16	EATON PK	230	EATON PK	69	1	13						
2004-60-16	EATON PK	230	TENOROC	230	1	13						
2004-60-16	RECKER	230	GAPWAY	230	1	16						
2004-60-16	SN PLANT	115	TURNER	115	1	1						
2004-60-17	SN PLANT	230	SYLVAN	230	1	1						
2004-60-17	SYLVAN	230	N LONGWD	230	1	1						
2004-60-17	IND RIV	230	STANTON	230	1	11						
2004-60-17	SN PLANT	115	TURNER	115	1	1						
2004-60-17	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-17	SILVR SP	230	SILV SPN	230	1	2						
2004-60-17	SILVR SP	230	OCALA 1	230	1	2						
2004-60-17	RIO PINR	230	CURRY FD	230	1	2						
2004-60-17	STANTON	230	CURRY FD	230	1	2						
2004-60-17	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-17	SHELD	230	LK TARPN	230	1	2						
2004-60-17	PEBB	230	CREWSLK	230	1	13						
2004-60-17	PEBB	230	N BARTOW	230	1	2						
2004-60-17	RECKER	230	LKAGNES	230	1	16						
2004-60-17	RECKER	230	ARIANA	230	1	16						
2004-60-17	RECKER	230	CREWSLK	230	1	13						
2004-60-17	B BEND	230	MANATEE	230	1	1						
2004-60-17	RUSKIN T	230	MANATEE	230	1	1						
2004-60-17	IND RIV	230	IND RIV	115	1	11						
2004-60-17	SHELD	230	SHELD-NW	69	1	16						
2004-60-17	LARGO	230	LARGO A	69	1	2						
2004-60-17	CLMT EST	230	CLMT EST	69	1	2						
2004-60-17	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-17	WINDERME	230	WINDERME	69	1	2						
2004-60-17	PASADENA	230	PASADENA	115	1	2						
2004-60-17	ARIANA	230	ARIANA-N	69	1	16						
2004-60-17	SELOSE	230	SELOSE-N	69	1	16						
2004-60-17	GAPWAY	230	GAPWAY	69	1	16						
2004-60-17	CREWSLK	230	CREWSLK	69	1	13						
2004-60-17	TENOROC	230	TENOROC	69	1	13						
2004-60-17	BARCOLA	230	WEST	230	1	2						
2004-60-17	EATON PK	230	CREWSLK	230	1	13						
2004-60-17	EATON PK	230	EATON PK	69	1	13						
2004-60-17	EATON PK	230	TENOROC	230	1	13						
2004-60-17	RECKER	230	GAPWAY	230	1	16						
2004-60-17	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows Following N-1 Disturbances for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-18	SN PLANT	230	SYLVAN	230	1	1						
2004-60-18	SYLVAN	230	N LONGWD	230	1	1						
2004-60-18	IND RIV	230	STANTON	230	1	11						
2004-60-18	SN PLANT	115	TURNER	115	1	1						
2004-60-18	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-18	SILVR SP	230	SILV SPN	230	1	2						
2004-60-18	SILVR SP	230	OCALA 1	230	1	2						
2004-60-18	RIO PINR	230	CURRY FD	230	1	2						
2004-60-18	STANTON	230	CURRY FD	230	1	2						
2004-60-18	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-18	SHELD	230	LK TARPN	230	1	2						
2004-60-18	PEBB	230	CREWSLK	230	1	13						
2004-60-18	PEBB	230	N BARTOW	230	1	2						
2004-60-18	RECKER	230	LKAGNES	230	1	16						
2004-60-18	RECKER	230	ARIANA	230	1	16						
2004-60-18	RECKER	230	CREWSLK	230	1	13						
2004-60-18	B BEND	230	MANATEE	230	1	1						
2004-60-18	RUSKIN T	230	MANATEE	230	1	1						
2004-60-18	IND RIV	230	IND RIV	115	1	11						
2004-60-18	SHELD	230	SHELD-NW	69	1	16						
2004-60-18	LARGO	230	LARGO A	69	1	2						
2004-60-18	CLMT EST	230	CLMT EST	69	1	2						
2004-60-18	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-18	WINDERME	230	WINDERME	69	1	2						
2004-60-18	PASADENA	230	PASADENA	115	1	2						
2004-60-18	ARIANA	230	ARIANA-N	69	1	16						
2004-60-18	SELOSE	230	SELOSE-N	69	1	16						
2004-60-18	GAPWAY	230	GAPWAY	69	1	16						
2004-60-18	CREWSLK	230	CREWSLK	69	1	13						
2004-60-18	TENOROC	230	TENOROC	69	1	13						
2004-60-18	BARCOLA	230	WEST	230	1	2						
2004-60-18	EATON PK	230	CREWSLK	230	1	13						
2004-60-18	EATON PK	230	EATON PK	69	1	13						
2004-60-18	EATON PK	230	TENOROC	230	1	13						
2004-60-18	RECKER	230	GAPWAY	230	1	16						
2004-60-18	SN PLANT	115	TURNER	115	1	1						
2004-60-19	SN PLANT	230	SYLVAN	230	1	1						
2004-60-19	SYLVAN	230	N LONGWD	230	1	1						
2004-60-19	IND RIV	230	STANTON	230	1	11						
2004-60-19	SN PLANT	115	TURNER	115	1	1						
2004-60-19	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-19	SILVR SP	230	SILV SPN	230	1	2						
2004-60-19	SILVR SP	230	OCALA 1	230	1	2						
2004-60-19	RIO PINR	230	CURRY FD	230	1	2						
2004-60-19	STANTON	230	CURRY FD	230	1	2						
2004-60-19	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-19	SHELD	230	LK TARPN	230	1	2						
2004-60-19	PEBB	230	CREWSLK	230	1	13						
2004-60-19	PEBB	230	N BARTOW	230	1	2						
2004-60-19	RECKER	230	LKAGNES	230	1	16						
2004-60-19	RECKER	230	ARIANA	230	1	16						
2004-60-19	RECKER	230	CREWSLK	230	1	13						
2004-60-19	B BEND	230	MANATEE	230	1	1						
2004-60-19	RUSKIN T	230	MANATEE	230	1	1						
2004-60-19	IND RIV	230	IND RIV	115	1	11						
2004-60-19	SHELD	230	SHELD-NW	69	1	16						
2004-60-19	LARGO	230	LARGO A	69	1	2						
2004-60-19	CLMT EST	230	CLMT EST	69	1	2						
2004-60-19	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-19	WINDERME	230	WINDERME	69	1	2						
2004-60-19	PASADENA	230	PASADENA	115	1	2						
2004-60-19	ARIANA	230	ARIANA-N	69	1	16						
2004-60-19	SELOSE	230	SELOSE-N	69	1	16						
2004-60-19	GAPWAY	230	GAPWAY	69	1	16						
2004-60-19	CREWSLK	230	CREWSLK	69	1	13						
2004-60-19	TENOROC	230	TENOROC	69	1	13						
2004-60-19	BARCOLA	230	WEST	230	1	2						
2004-60-19	EATON PK	230	CREWSLK	230	1	13						
2004-60-19	EATON PK	230	EATON PK	69	1	13						
2004-60-19	EATON PK	230	TENOROC	230	1	13						
2004-60-19	RECKER	230	GAPWAY	230	1	16						
2004-60-19	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-20	SN PLANT	230	SYLVAN	230	1	1						
2004-60-20	SYLVAN	230	N LONGWD	230	1	1						
2004-60-20	IND RIV	230	STANTON	230	1	11						
2004-60-20	SN PLANT	115	TURNER	115	1	1						
2004-60-20	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-20	SILVR SP	230	SILV SPN	230	1	2						
2004-60-20	SILVR SP	230	OCALA 1	230	1	2						
2004-60-20	RIO PINR	230	CURRY FD	230	1	2						
2004-60-20	STANTON	230	CURRY FD	230	1	2						
2004-60-20	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-20	SHELD	230	LK TARPN	230	1	2						
2004-60-20	PEBB	230	CREWSLK	230	1	13						
2004-60-20	PEBB	230	N BARTOW	230	1	2						
2004-60-20	RECKER	230	LKAGNES	230	1	16						
2004-60-20	RECKER	230	ARIANA	230	1	16						
2004-60-20	RECKER	230	CREWSLK	230	1	13						
2004-60-20	B BEND	230	MANATEE	230	1	1						
2004-60-20	RUSKIN T	230	MANATEE	230	1	1						
2004-60-20	IND RIV	230	IND RIV	115	1	11						
2004-60-20	SHELD	230	SHELD-NW	69	1	16						
2004-60-20	LARGO	230	LARGO A	69	1	2						
2004-60-20	CLMT EST	230	CLMT EST	69	1	2						
2004-60-20	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-20	WINDERME	230	WINDERME	69	1	2						
2004-60-20	PASADENA	230	PASADENA	115	1	2						
2004-60-20	ARIANA	230	ARIANA-N	69	1	16						
2004-60-20	SELOSE	230	SELOSE-N	69	1	16						
2004-60-20	GAPWAY	230	GAPWAY	69	1	16						
2004-60-20	CREWSLK	230	CREWSLK	69	1	13						
2004-60-20	TENOROC	230	TENOROC	69	1	13						
2004-60-20	BARCOLA	230	WEST	230	1	2						
2004-60-20	EATON PK	230	CREWSLK	230	1	13						
2004-60-20	EATON PK	230	EATON PK	69	1	13						
2004-60-20	EATON PK	230	TENOROC	230	1	13						
2004-60-20	RECKER	230	GAPWAY	230	1	16						
2004-60-20	SN PLANT	115	TURNER	115	1	1						
2004-60-21	SN PLANT	230	SYLVAN	230	1	1						
2004-60-21	SYLVAN	230	N LONGWD	230	1	1						
2004-60-21	IND RIV	230	STANTON	230	1	11						
2004-60-21	SN PLANT	115	TURNER	115	1	1						
2004-60-21	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-21	SILVR SP	230	SILV SPN	230	1	2						
2004-60-21	SILVR SP	230	OCALA 1	230	1	2						
2004-60-21	RIO PINR	230	CURRY FD	230	1	2						
2004-60-21	STANTON	230	CURRY FD	230	1	2						
2004-60-21	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-21	SHELD	230	LK TARPN	230	1	2						
2004-60-21	PEBB	230	CREWSLK	230	1	13						
2004-60-21	PEBB	230	N BARTOW	230	1	2						
2004-60-21	RECKER	230	LKAGNES	230	1	16						
2004-60-21	RECKER	230	ARIANA	230	1	16						
2004-60-21	RECKER	230	CREWSLK	230	1	13						
2004-60-21	B BEND	230	MANATEE	230	1	1						
2004-60-21	RUSKIN T	230	MANATEE	230	1	1						
2004-60-21	IND RIV	230	IND RIV	115	1	11						
2004-60-21	SHELD	230	SHELD-NW	69	1	16						
2004-60-21	LARGO	230	LARGO A	69	1	2						
2004-60-21	CLMT EST	230	CLMT EST	69	1	2						
2004-60-21	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-21	WINDERME	230	WINDERME	69	1	2						
2004-60-21	PASADENA	230	PASADENA	115	1	2						
2004-60-21	ARIANA	230	ARIANA-N	69	1	16						
2004-60-21	SELOSE	230	SELOSE-N	69	1	16						
2004-60-21	GAPWAY	230	GAPWAY	69	1	16						
2004-60-21	CREWSLK	230	CREWSLK	69	1	13						
2004-60-21	TENOROC	230	TENOROC	69	1	13						
2004-60-21	BARCOLA	230	WEST	230	1	2						
2004-60-21	EATON PK	230	CREWSLK	230	1	13						
2004-60-21	EATON PK	230	EATON PK	69	1	13						
2004-60-21	EATON PK	230	TENOROC	230	1	13						
2004-60-21	RECKER	230	GAPWAY	230	1	16						
2004-60-21	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-22	SN PLANT	230	SYLVAN	230	1	1						
2004-60-22	SYLVAN	230	N LONGWD	230	1	1						
2004-60-22	IND RIV	230	STANTON	230	1	11						
2004-60-22	SN PLANT	115	TURNER	115	1	1						
2004-60-22	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-22	SILVR SP	230	SILV SPN	230	1	2						
2004-60-22	SILVR SP	230	OCALA 1	230	1	2						
2004-60-22	RIO PINR	230	CURRY FD	230	1	2						
2004-60-22	STANTON	230	CURRY FD	230	1	2						
2004-60-22	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-22	SHELD	230	LK TARPN	230	1	2						
2004-60-22	PEBB	230	CREWSLK	230	1	13						
2004-60-22	PEBB	230	N BARTOW	230	1	2						
2004-60-22	RECKER	230	LKAGNES	230	1	16						
2004-60-22	RECKER	230	ARIANA	230	1	16						
2004-60-22	RECKER	230	CREWSLK	230	1	13						
2004-60-22	B BEND	230	MANATEE	230	1	1						
2004-60-22	RUSKIN T	230	MANATEE	230	1	1						
2004-60-22	IND RIV	230	IND RIV	115	1	11						
2004-60-22	SHELD	230	SHELD-NW	69	1	16						
2004-60-22	LARGO	230	LARGO A	69	1	2						
2004-60-22	CLMT EST	230	CLMT EST	69	1	2						
2004-60-22	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-22	WINDERME	230	WINDERME	69	1	2						
2004-60-22	PASADENA	230	PASADENA	115	1	2						
2004-60-22	ARIANA	230	ARIANA-N	69	1	16						
2004-60-22	SELOSE	230	SELOSE-N	69	1	16						
2004-60-22	GAPWAY	230	GAPWAY	69	1	16						
2004-60-22	CREWSLK	230	CREWSLK	69	1	13						
2004-60-22	TENOROC	230	TENOROC	69	1	13						
2004-60-22	BARCOLA	230	WEST	230	1	2						
2004-60-22	EATON PK	230	CREWSLK	230	1	13						
2004-60-22	EATON PK	230	EATON PK	69	1	13						
2004-60-22	EATON PK	230	TENOROC	230	1	13						
2004-60-22	RECKER	230	GAPWAY	230	1	16						
2004-60-22	SN PLANT	115	TURNER	115	1	1						
2004-60-23	SN PLANT	230	SYLVAN	230	1	1						
2004-60-23	SYLVAN	230	N LONGWD	230	1	1						
2004-60-23	IND RIV	230	STANTON	230	1	11						
2004-60-23	SN PLANT	115	TURNER	115	1	1						
2004-60-23	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-23	SILVR SP	230	SILV SPN	230	1	2						
2004-60-23	SILVR SP	230	OCALA 1	230	1	2						
2004-60-23	RIO PINR	230	CURRY FD	230	1	2						
2004-60-23	STANTON	230	CURRY FD	230	1	2						
2004-60-23	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-23	SHELD	230	LK TARPN	230	1	2						
2004-60-23	PEBB	230	CREWSLK	230	1	13						
2004-60-23	PEBB	230	N BARTOW	230	1	2						
2004-60-23	RECKER	230	LKAGNES	230	1	16						
2004-60-23	RECKER	230	ARIANA	230	1	16						
2004-60-23	RECKER	230	CREWSLK	230	1	13						
2004-60-23	B BEND	230	MANATEE	230	1	1						
2004-60-23	RUSKIN T	230	MANATEE	230	1	1						
2004-60-23	IND RIV	230	IND RIV	115	1	11						
2004-60-23	SHELD	230	SHELD-NW	69	1	16						
2004-60-23	LARGO	230	LARGO A	69	1	2						
2004-60-23	CLMT EST	230	CLMT EST	69	1	2						
2004-60-23	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-23	WINDERME	230	WINDERME	69	1	2						
2004-60-23	PASADENA	230	PASADENA	115	1	2						
2004-60-23	ARIANA	230	ARIANA-N	69	1	16						
2004-60-23	SELOSE	230	SELOSE-N	69	1	16						
2004-60-23	GAPWAY	230	GAPWAY	69	1	16						
2004-60-23	CREWSLK	230	CREWSLK	69	1	13						
2004-60-23	TENOROC	230	TENOROC	69	1	13						
2004-60-23	BARCOLA	230	WEST	230	1	2						
2004-60-23	EATON PK	230	CREWSLK	230	1	13						
2004-60-23	EATON PK	230	EATON PK	69	1	13						
2004-60-23	EATON PK	230	TENOROC	230	1	13						
2004-60-23	RECKER	230	GAPWAY	230	1	16						
2004-60-23	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-24	SN PLANT	230	SYLVAN	230	1	1						
2004-60-24	SYLVAN	230	N LONGWD	230	1	1						
2004-60-24	IND RIV	230	STANTON	230	1	11						
2004-60-24	SN PLANT	115	TURNER	115	1	1						
2004-60-24	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-24	SILVR SP	230	SILV SPN	230	1	2						
2004-60-24	SILVR SP	230	OCALA 1	230	1	2						
2004-60-24	RIO PINR	230	CURRY FD	230	1	2						
2004-60-24	STANTON	230	CURRY FD	230	1	2						
2004-60-24	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-24	SHELD	230	LK TARPN	230	1	2						
2004-60-24	PEBB	230	CREWSLK	230	1	13						
2004-60-24	PEBB	230	N BARTOW	230	1	2						
2004-60-24	RECKER	230	LKAGNES	230	1	16						
2004-60-24	RECKER	230	ARIANA	230	1	16						
2004-60-24	RECKER	230	CREWSLK	230	1	13						
2004-60-24	B BEND	230	MANATEE	230	1	1						
2004-60-24	RUSKIN T	230	MANATEE	230	1	1						
2004-60-24	IND RIV	230	IND RIV	115	1	11						
2004-60-24	SHELD	230	SHELD-NW	69	1	16						
2004-60-24	LARGO	230	LARGO A	69	1	2						
2004-60-24	CLMT EST	230	CLMT EST	69	1	2						
2004-60-24	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-24	WINDERME	230	WINDERME	69	1	2						
2004-60-24	PASADENA	230	PASADENA	115	1	2						
2004-60-24	ARIANA	230	ARIANA-N	69	1	16						
2004-60-24	SELOSE	230	SELOSE-N	69	1	16						
2004-60-24	GAPWAY	230	GAPWAY	69	1	16						
2004-60-24	CREWSLK	230	CREWSLK	69	1	13						
2004-60-24	TENOROC	230	TENOROC	69	1	13						
2004-60-24	BARCOLA	230	WEST	230	1	2						
2004-60-24	EATON PK	230	CREWSLK	230	1	13						
2004-60-24	EATON PK	230	EATON PK	69	1	13						
2004-60-24	EATON PK	230	TENOROC	230	1	13						
2004-60-24	RECKER	230	GAPWAY	230	1	16						
2004-60-24	SN PLANT	115	TURNER	115	1	1						
2004-60-25	SN PLANT	230	SYLVAN	230	1	1						
2004-60-25	SYLVAN	230	N LONGWD	230	1	1						
2004-60-25	IND RIV	230	STANTON	230	1	11						
2004-60-25	SN PLANT	115	TURNER	115	1	1						
2004-60-25	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-25	SILVR SP	230	SILV SPN	230	1	2						
2004-60-25	SILVR SP	230	OCALA 1	230	1	2						
2004-60-25	RIO PINR	230	CURRY FD	230	1	2						
2004-60-25	STANTON	230	CURRY FD	230	1	2						
2004-60-25	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-25	SHELD	230	LK TARPN	230	1	2						
2004-60-25	PEBB	230	CREWSLK	230	1	13						
2004-60-25	PEBB	230	N BARTOW	230	1	2						
2004-60-25	RECKER	230	LKAGNES	230	1	16						
2004-60-25	RECKER	230	ARIANA	230	1	16						
2004-60-25	RECKER	230	CREWSLK	230	1	13						
2004-60-25	B BEND	230	MANATEE	230	1	1						
2004-60-25	RUSKIN T	230	MANATEE	230	1	1						
2004-60-25	IND RIV	230	IND RIV	115	1	11						
2004-60-25	SHELD	230	SHELD-NW	69	1	16						
2004-60-25	LARGO	230	LARGO A	69	1	2						
2004-60-25	CLMT EST	230	CLMT EST	69	1	2						
2004-60-25	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-25	WINDERME	230	WINDERME	69	1	2						
2004-60-25	PASADENA	230	PASADENA	115	1	2						
2004-60-25	ARIANA	230	ARIANA-N	69	1	16						
2004-60-25	SELOSE	230	SELOSE-N	69	1	16						
2004-60-25	GAPWAY	230	GAPWAY	69	1	16						
2004-60-25	CREWSLK	230	CREWSLK	69	1	13						
2004-60-25	TENOROC	230	TENOROC	69	1	13						
2004-60-25	BARCOLA	230	WEST	230	1	2						
2004-60-25	EATON PK	230	CREWSLK	230	1	13						
2004-60-25	EATON PK	230	EATON PK	69	1	13						
2004-60-25	EATON PK	230	TENOROC	230	1	13						
2004-60-25	RECKER	230	GAPWAY	230	1	16						
2004-60-25	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-26	SN PLANT	230	SYLVAN	230	1	1						
2004-60-26	SYLVAN	230	N LONGWD	230	1	1						
2004-60-26	IND RIV	230	STANTON	230	1	11						
2004-60-26	SN PLANT	115	TURNER	115	1	1						
2004-60-26	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-26	SILVR SP	230	SILV SPN	230	1	2						
2004-60-26	SILVR SP	230	OCALA 1	230	1	2						
2004-60-26	RIO PINR	230	CURRY FD	230	1	2						
2004-60-26	STANTON	230	CURRY FD	230	1	2						
2004-60-26	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-26	SHELD	230	LK TARPN	230	1	2						
2004-60-26	PEBB	230	CREWSLK	230	1	13						
2004-60-26	PEBB	230	N BARTOW	230	1	2						
2004-60-26	RECKER	230	LKAGNES	230	1	16						
2004-60-26	RECKER	230	ARIANA	230	1	16						
2004-60-26	RECKER	230	CREWSLK	230	1	13						
2004-60-26	B BEND	230	MANATEE	230	1	1						
2004-60-26	RUSKIN T	230	MANATEE	230	1	1						
2004-60-26	IND RIV	230	IND RIV	115	1	11						
2004-60-26	SHELD	230	SHELD-NW	69	1	16						
2004-60-26	LARGO	230	LARGO A	69	1	2						
2004-60-26	CLMT EST	230	CLMT EST	69	1	2						
2004-60-26	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-26	WINDERME	230	WINDERME	69	1	2						
2004-60-26	PASADENA	230	PASADENA	115	1	2						
2004-60-26	ARIANA	230	ARIANA-N	69	1	16						
2004-60-26	SELOSE	230	SELOSE-N	69	1	16						
2004-60-26	GAPWAY	230	GAPWAY	69	1	16						
2004-60-26	CREWSLK	230	CREWSLK	69	1	13						
2004-60-26	TENOROC	230	TENOROC	69	1	13						
2004-60-26	BARCOLA	230	WEST	230	1	2						
2004-60-26	EATON PK	230	CREWSLK	230	1	13						
2004-60-26	EATON PK	230	EATON PK	69	1	13						
2004-60-26	EATON PK	230	TENOROC	230	1	13						
2004-60-26	RECKER	230	GAPWAY	230	1	16						
2004-60-26	SN PLANT	115	TURNER	115	1	1						
2004-60-27	SN PLANT	230	SYLVAN	230	1	1						
2004-60-27	SYLVAN	230	N LONGWD	230	1	1						
2004-60-27	IND RIV	230	STANTON	230	1	11						
2004-60-27	SN PLANT	115	TURNER	115	1	1						
2004-60-27	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-27	SILVR SP	230	SILV SPN	230	1	2						
2004-60-27	SILVR SP	230	OCALA 1	230	1	2						
2004-60-27	RIO PINR	230	CURRY FD	230	1	2						
2004-60-27	STANTON	230	CURRY FD	230	1	2						
2004-60-27	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-27	SHELD	230	LK TARPN	230	1	2						
2004-60-27	PEBB	230	CREWSLK	230	1	13						
2004-60-27	PEBB	230	N BARTOW	230	1	2						
2004-60-27	RECKER	230	LKAGNES	230	1	16						
2004-60-27	RECKER	230	ARIANA	230	1	16						
2004-60-27	RECKER	230	CREWSLK	230	1	13						
2004-60-27	B BEND	230	MANATEE	230	1	1						
2004-60-27	RUSKIN T	230	MANATEE	230	1	1						
2004-60-27	IND RIV	230	IND RIV	115	1	11						
2004-60-27	SHELD	230	SHELD-NW	69	1	16						
2004-60-27	LARGO	230	LARGO A	69	1	2						
2004-60-27	CLMT EST	230	CLMT EST	69	1	2						
2004-60-27	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-27	WINDERME	230	WINDERME	69	1	2						
2004-60-27	PASADENA	230	PASADENA	115	1	2						
2004-60-27	ARIANA	230	ARIANA-N	69	1	16						
2004-60-27	SELOSE	230	SELOSE-N	69	1	16						
2004-60-27	GAPWAY	230	GAPWAY	69	1	16						
2004-60-27	CREWSLK	230	CREWSLK	69	1	13						
2004-60-27	TENOROC	230	TENOROC	69	1	13						
2004-60-27	BARCOLA	230	WEST	230	1	2						
2004-60-27	EATON PK	230	CREWSLK	230	1	13						
2004-60-27	EATON PK	230	EATON PK	69	1	13						
2004-60-27	EATON PK	230	TENOROC	230	1	13						
2004-60-27	RECKER	230	GAPWAY	230	1	16						
2004-60-27	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-28	SN PLANT	230	SYLVAN	230	1	1						
2004-60-28	SYLVAN	230	N LONGWD	230	1	1						
2004-60-28	IND RIV	230	STANTON	230	1	11						
2004-60-28	SN PLANT	115	TURNER	115	1	1						
2004-60-28	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-28	SILVR SP	230	SILV SPN	230	1	2						
2004-60-28	SILVR SP	230	OCALA 1	230	1	2						
2004-60-28	RIO PINR	230	CURRY FD	230	1	2						
2004-60-28	STANTON	230	CURRY FD	230	1	2						
2004-60-28	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-28	SHELD	230	LK TARPN	230	1	2						
2004-60-28	PEBB	230	CREWSLK	230	1	13						
2004-60-28	PEBB	230	N BARTOW	230	1	2						
2004-60-28	RECKER	230	LKAGNES	230	1	16						
2004-60-28	RECKER	230	ARIANA	230	1	16						
2004-60-28	RECKER	230	CREWSLK	230	1	13						
2004-60-28	B BEND	230	MANATEE	230	1	1						
2004-60-28	RUSKIN T	230	MANATEE	230	1	1						
2004-60-28	IND RIV	230	IND RIV	115	1	11						
2004-60-28	SHELD	230	SHELD-NW	69	1	16						
2004-60-28	LARGO	230	LARGO A	69	1	2						
2004-60-28	CLMT EST	230	CLMT EST	69	1	2						
2004-60-28	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-28	WINDERME	230	WINDERME	69	1	2						
2004-60-28	PASADENA	230	PASADENA	115	1	2						
2004-60-28	ARIANA	230	ARIANA-N	69	1	16						
2004-60-28	SELOSE	230	SELOSE-N	69	1	16						
2004-60-28	GAPWAY	230	GAPWAY	69	1	16						
2004-60-28	CREWSLK	230	CREWSLK	69	1	13						
2004-60-28	TENOROC	230	TENOROC	69	1	13						
2004-60-28	BARCOLA	230	WEST	230	1	2						
2004-60-28	EATON PK	230	CREWSLK	230	1	13						
2004-60-28	EATON PK	230	EATON PK	69	1	13						
2004-60-28	EATON PK	230	TENOROC	230	1	13						
2004-60-28	RECKER	230	GAPWAY	230	1	16						
2004-60-28	SN PLANT	115	TURNER	115	1	1						
2004-60-29	SN PLANT	230	SYLVAN	230	1	1						
2004-60-29	SYLVAN	230	N LONGWD	230	1	1						
2004-60-29	IND RIV	230	STANTON	230	1	11						
2004-60-29	SN PLANT	115	TURNER	115	1	1						
2004-60-29	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-29	SILVR SP	230	SILV SPN	230	1	2						
2004-60-29	SILVR SP	230	OCALA 1	230	1	2						
2004-60-29	RIO PINR	230	CURRY FD	230	1	2						
2004-60-29	STANTON	230	CURRY FD	230	1	2						
2004-60-29	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-29	SHELD	230	LK TARPN	230	1	2						
2004-60-29	PEBB	230	CREWSLK	230	1	13						
2004-60-29	PEBB	230	N BARTOW	230	1	2						
2004-60-29	RECKER	230	LKAGNES	230	1	16						
2004-60-29	RECKER	230	ARIANA	230	1	16						
2004-60-29	RECKER	230	CREWSLK	230	1	13						
2004-60-29	B BEND	230	MANATEE	230	1	1						
2004-60-29	RUSKIN T	230	MANATEE	230	1	1						
2004-60-29	IND RIV	230	IND RIV	115	1	11						
2004-60-29	SHELD	230	SHELD-NW	69	1	16						
2004-60-29	LARGO	230	LARGO A	69	1	2						
2004-60-29	CLMT EST	230	CLMT EST	69	1	2						
2004-60-29	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-29	WINDERME	230	WINDERME	69	1	2						
2004-60-29	PASADENA	230	PASADENA	115	1	2						
2004-60-29	ARIANA	230	ARIANA-N	69	1	16						
2004-60-29	SELOSE	230	SELOSE-N	69	1	16						
2004-60-29	GAPWAY	230	GAPWAY	69	1	16						
2004-60-29	CREWSLK	230	CREWSLK	69	1	13						
2004-60-29	TENOROC	230	TENOROC	69	1	13						
2004-60-29	BARCOLA	230	WEST	230	1	2						
2004-60-29	EATON PK	230	CREWSLK	230	1	13						
2004-60-29	EATON PK	230	EATON PK	69	1	13						
2004-60-29	EATON PK	230	TENOROC	230	1	13						
2004-60-29	RECKER	230	GAPWAY	230	1	16						
2004-60-29	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-30	SN PLANT	230	SYLVAN	230	1	1						
2004-60-30	SYLVAN	230	N LONGWD	230	1	1						
2004-60-30	IND RIV	230	STANTON	230	1	11						
2004-60-30	SN PLANT	115	TURNER	115	1	1						
2004-60-30	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-30	SILVR SP	230	SILV SPN	230	1	2						
2004-60-30	SILVR SP	230	OCALA 1	230	1	2						
2004-60-30	RIO PINR	230	CURRY FD	230	1	2						
2004-60-30	STANTON	230	CURRY FD	230	1	2						
2004-60-30	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-30	SHELD	230	LK TARPN	230	1	2						
2004-60-30	PEBB	230	CREWSLK	230	1	13						
2004-60-30	PEBB	230	N BARTOW	230	1	2						
2004-60-30	RECKER	230	LKAGNES	230	1	16						
2004-60-30	RECKER	230	ARIANA	230	1	16						
2004-60-30	RECKER	230	CREWSLK	230	1	13						
2004-60-30	B BEND	230	MANATEE	230	1	1						
2004-60-30	RUSKIN T	230	MANATEE	230	1	1						
2004-60-30	IND RIV	230	IND RIV	115	1	11						
2004-60-30	SHELD	230	SHELD-NW	69	1	16						
2004-60-30	LARGO	230	LARGO A	69	1	2						
2004-60-30	CLMT EST	230	CLMT EST	69	1	2						
2004-60-30	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-30	WINDERME	230	WINDERME	69	1	2						
2004-60-30	PASADENA	230	PASADENA	115	1	2						
2004-60-30	ARIANA	230	ARIANA-N	69	1	16						
2004-60-30	SELOSE	230	SELOSE-N	69	1	16						
2004-60-30	GAPWAY	230	GAPWAY	69	1	16						
2004-60-30	CREWSLK	230	CREWSLK	69	1	13						
2004-60-30	TENOROC	230	TENOROC	69	1	13						
2004-60-30	BARCOLA	230	WEST	230	1	2						
2004-60-30	EATON PK	230	CREWSLK	230	1	13						
2004-60-30	EATON PK	230	EATON PK	69	1	13						
2004-60-30	EATON PK	230	TENOROC	230	1	13						
2004-60-30	RECKER	230	GAPWAY	230	1	16						
2004-60-30	SN PLANT	115	TURNER	115	1	1						
2004-60-31	SN PLANT	230	SYLVAN	230	1	1						
2004-60-31	SYLVAN	230	N LONGWD	230	1	1						
2004-60-31	IND RIV	230	STANTON	230	1	11						
2004-60-31	SN PLANT	115	TURNER	115	1	1						
2004-60-31	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-31	SILVR SP	230	SILV SPN	230	1	2						
2004-60-31	SILVR SP	230	OCALA 1	230	1	2						
2004-60-31	RIO PINR	230	CURRY FD	230	1	2						
2004-60-31	STANTON	230	CURRY FD	230	1	2						
2004-60-31	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-31	SHELD	230	LK TARPN	230	1	2						
2004-60-31	PEBB	230	CREWSLK	230	1	13						
2004-60-31	PEBB	230	N BARTOW	230	1	2						
2004-60-31	RECKER	230	LKAGNES	230	1	16						
2004-60-31	RECKER	230	ARIANA	230	1	16						
2004-60-31	RECKER	230	CREWSLK	230	1	13						
2004-60-31	B BEND	230	MANATEE	230	1	1						
2004-60-31	RUSKIN T	230	MANATEE	230	1	1						
2004-60-31	IND RIV	230	IND RIV	115	1	11						
2004-60-31	SHELD	230	SHELD-NW	69	1	16						
2004-60-31	LARGO	230	LARGO A	69	1	2						
2004-60-31	CLMT EST	230	CLMT EST	69	1	2						
2004-60-31	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-31	WINDERME	230	WINDERME	69	1	2						
2004-60-31	PASADENA	230	PASADENA	115	1	2						
2004-60-31	ARIANA	230	ARIANA-N	69	1	16						
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2004-60-31	RECKER	230	GAPWAY	230	1	16						
2004-60-31	SN PLANT	115	TURNER	115	1	1						

Table III

Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

60% Load Base Case

All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-32	SN PLANT	230	SYLVAN	230	1	1						
2004-60-32	SYLVAN	230	N LONGWD	230	1	1						
2004-60-32	IND RIV	230	STANTON	230	1	11						
2004-60-32	SN PLANT	115	TURNER	115	1	1						
2004-60-32	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-32	SILVR SP	230	SILV SPN	230	1	2						
2004-60-32	SILVR SP	230	OCALA 1	230	1	2						
2004-60-32	RIO PINR	230	CURRY FD	230	1	2						
2004-60-32	STANTON	230	CURRY FD	230	1	2						
2004-60-32	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-32	SHELD	230	LK TARPN	230	1	2						
2004-60-32	PEBB	230	CREWSLK	230	1	13						
2004-60-32	PEBB	230	N BARTOW	230	1	2						
2004-60-32	RECKER	230	LKAGNES	230	1	16						
2004-60-32	RECKER	230	ARIANA	230	1	16						
2004-60-32	RECKER	230	CREWSLK	230	1	13						
2004-60-32	B BEND	230	MANATEE	230	1	1						
2004-60-32	RUSKIN T	230	MANATEE	230	1	1						
2004-60-32	IND RIV	230	IND RIV	115	1	11						
2004-60-32	SHELD	230	SHELD-NW	69	1	16						
2004-60-32	LARGO	230	LARGO A	69	1	2						
2004-60-32	CLMT EST	230	CLMT EST	69	1	2						
2004-60-32	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-32	WINDERME	230	WINDERME	69	1	2						
2004-60-32	PASADENA	230	PASADENA	115	1	2						
2004-60-32	ARIANA	230	ARIANA-N	69	1	16						
2004-60-32	SELOSE	230	SELOSE-N	69	1	16						
2004-60-32	GAPWAY	230	GAPWAY	69	1	16						
2004-60-32	CREWSLK	230	CREWSLK	69	1	13						
2004-60-32	TENOROC	230	TENOROC	69	1	13						
2004-60-32	BARCOLA	230	WEST	230	1	2						
2004-60-32	EATON PK	230	CREWSLK	230	1	13						
2004-60-32	EATON PK	230	EATON PK	69	1	13						
2004-60-32	EATON PK	230	TENOROC	230	1	13						
2004-60-32	RECKER	230	GAPWAY	230	1	16						
2004-60-32	SN PLANT	115	TURNER	115	1	1						
2004-60-33	SN PLANT	230	SYLVAN	230	1	1						
2004-60-33	SYLVAN	230	N LONGWD	230	1	1						
2004-60-33	IND RIV	230	STANTON	230	1	11						
2004-60-33	SN PLANT	115	TURNER	115	1	1						
2004-60-33	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-33	SILVR SP	230	SILV SPN	230	1	2						
2004-60-33	SILVR SP	230	OCALA 1	230	1	2						
2004-60-33	RIO PINR	230	CURRY FD	230	1	2						
2004-60-33	STANTON	230	CURRY FD	230	1	2						
2004-60-33	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-33	SHELD	230	LK TARPN	230	1	2						
2004-60-33	PEBB	230	CREWSLK	230	1	13						
2004-60-33	PEBB	230	N BARTOW	230	1	2						
2004-60-33	RECKER	230	LKAGNES	230	1	16						
2004-60-33	RECKER	230	ARIANA	230	1	16						
2004-60-33	RECKER	230	CREWSLK	230	1	13						
2004-60-33	B BEND	230	MANATEE	230	1	1						
2004-60-33	RUSKIN T	230	MANATEE	230	1	1						
2004-60-33	IND RIV	230	IND RIV	115	1	11						
2004-60-33	SHELD	230	SHELD-NW	69	1	16						
2004-60-33	LARGO	230	LARGO A	69	1	2						
2004-60-33	CLMT EST	230	CLMT EST	69	1	2						
2004-60-33	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-33	WINDERME	230	WINDERME	69	1	2						
2004-60-33	PASADENA	230	PASADENA	115	1	2						
2004-60-33	ARIANA	230	ARIANA-N	69	1	16						
2004-60-33	SELOSE	230	SELOSE-N	69	1	16						
2004-60-33	GAPWAY	230	GAPWAY	69	1	16						
2004-60-33	CREWSLK	230	CREWSLK	69	1	13						
2004-60-33	TENOROC	230	TENOROC	69	1	13						
2004-60-33	BARCOLA	230	WEST	230	1	2						
2004-60-33	EATON PK	230	CREWSLK	230	1	13						
2004-60-33	EATON PK	230	EATON PK	69	1	13						
2004-60-33	EATON PK	230	TENOROC	230	1	13						
2004-60-33	RECKER	230	GAPWAY	230	1	16						
2004-60-33	SN PLANT	115	TURNER	115	1	1						

Table III

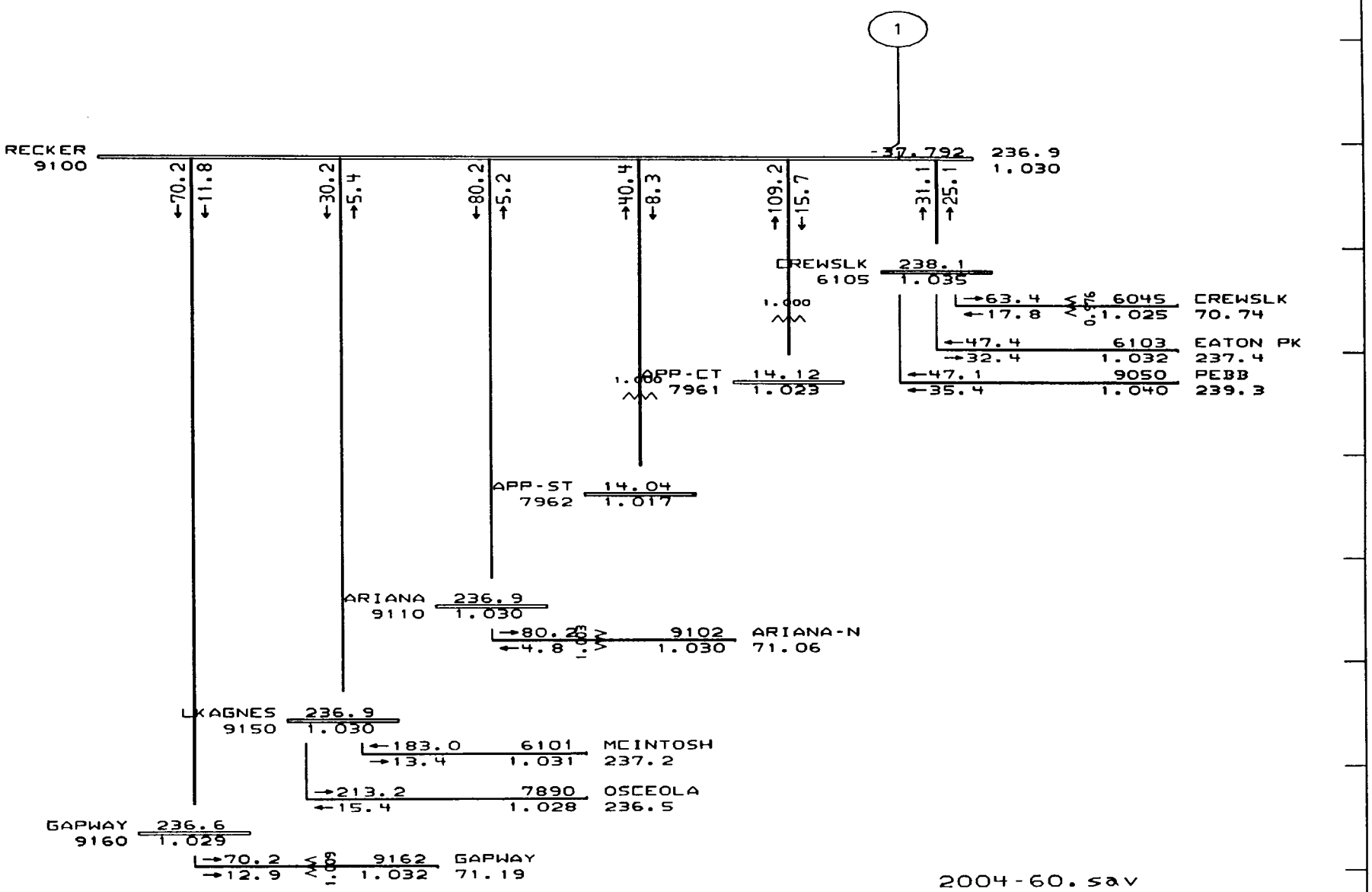
Comparison of Line & Transformer Flows
Following N-1 Disturbances
for Various OEC 500 MW Generation Alternatives

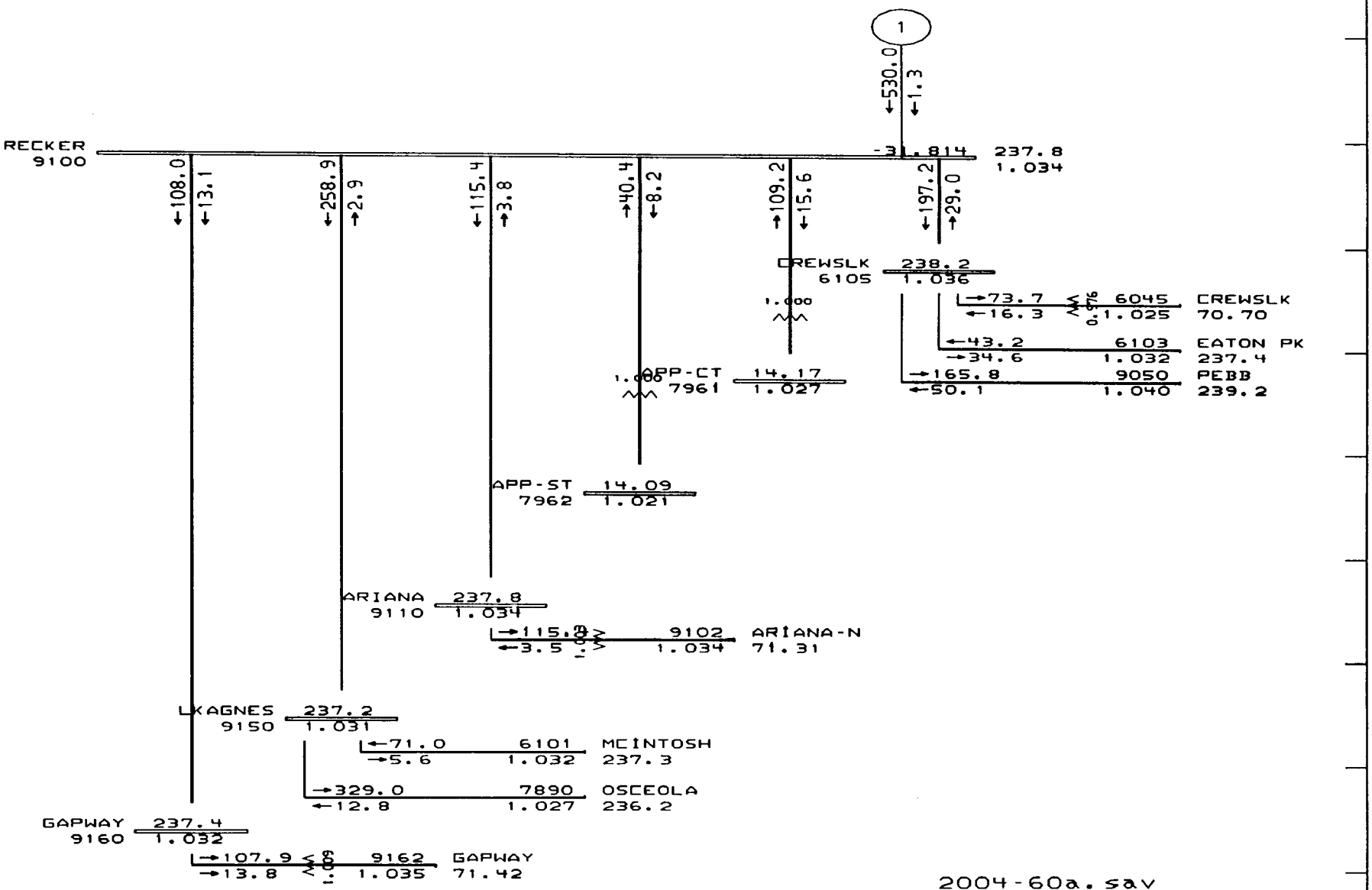
60% Load Base Case

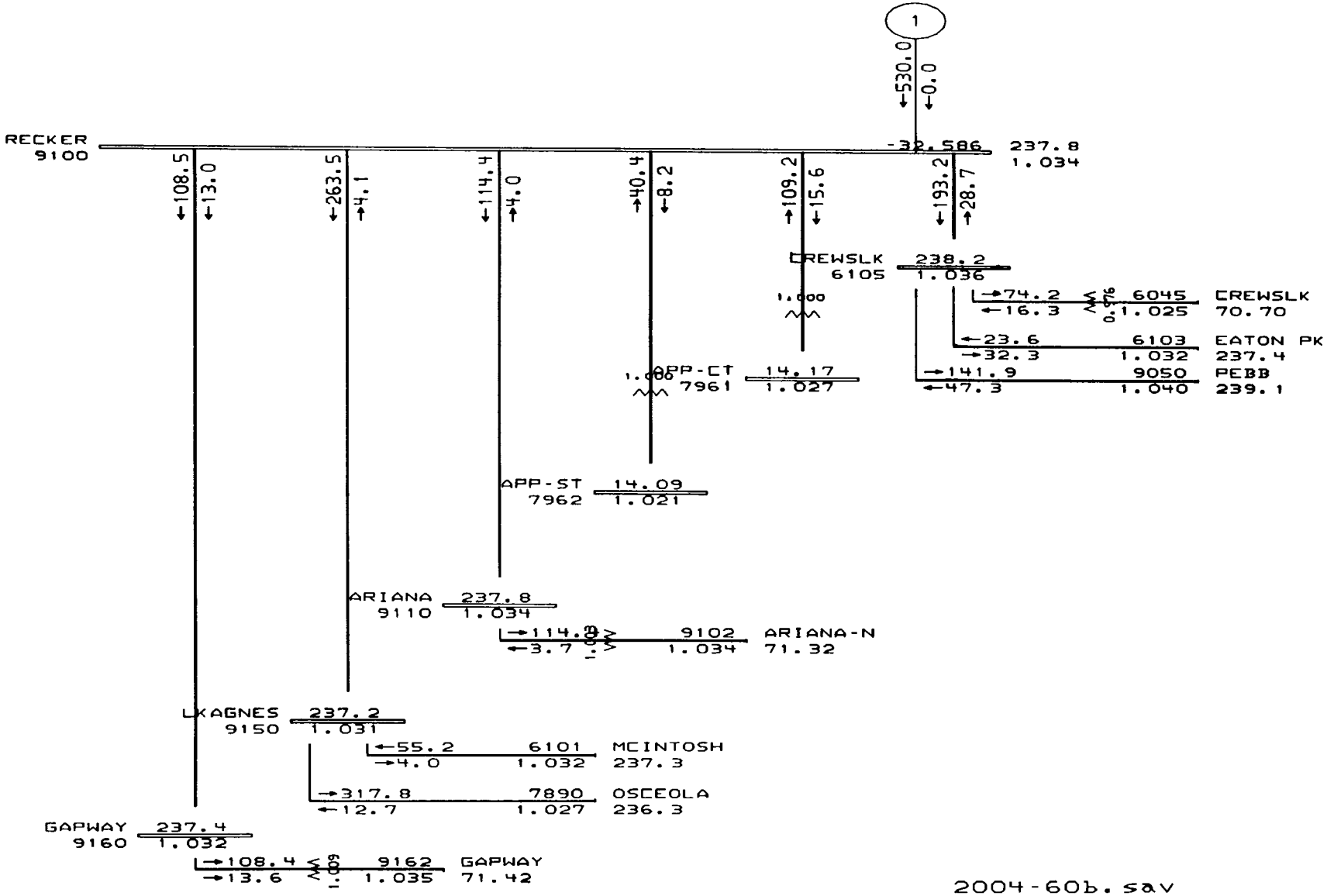
All Flows above 100% of Emergency rating are Shown

Monitored Branches							Case 2004-60 Base No OEC Gen	Case 2004-60A Sell to FPL	Case 2004-60B Sell to FPC	Case 2004-60C Sell to TEC	Case 2004-60D Sell to JEA	Case 2004-60E Sell to SEM
Case	Bus 1	kV 1	Bus 2	kV 2	ckt	Area	Percent	Percent	Percent	Percent	Percent	Percent
2004-60-34	SN PLANT	230	SYLVAN	230	1	1						
2004-60-34	SYLVAN	230	N LONGWD	230	1	1						
2004-60-34	IND RIV	230	STANTON	230	1	11						
2004-60-34	SN PLANT	115	TURNER	115	1	1						
2004-60-34	BUCKEYE	230	RUSKMTR8	230	1	1						
2004-60-34	SILVR SP	230	SILV SPN	230	1	2						
2004-60-34	SILVR SP	230	OCALA 1	230	1	2						
2004-60-34	RIO PINR	230	CURRY FD	230	1	2						
2004-60-34	STANTON	230	CURRY FD	230	1	2						
2004-60-34	OSCEOLA	230	LKAGNES	230	1	16						
2004-60-34	SHELD	230	LK TARPN	230	1	2						
2004-60-34	PEBB	230	CREWSLK	230	1	13						
2004-60-34	PEBB	230	N BARTOW	230	1	2						
2004-60-34	RECKER	230	LKAGNES	230	1	16						
2004-60-34	RECKER	230	ARIANA	230	1	16						
2004-60-34	RECKER	230	CREWSLK	230	1	13						
2004-60-34	B BEND	230	MANATEE	230	1	1						
2004-60-34	RUSKIN T	230	MANATEE	230	1	1						
2004-60-34	IND RIV	230	IND RIV	115	1	11						
2004-60-34	SHELD	230	SHELD-NW	69	1	16						
2004-60-34	LARGO	230	LARGO A	69	1	2						
2004-60-34	CLMT EST	230	CLMT EST	69	1	2						
2004-60-34	11TH AVE	230	ELEVEN-E	69	1	16						
2004-60-34	WINDERME	230	WINDERME	69	1	2						
2004-60-34	PASADENA	230	PASADENA	115	1	2						
2004-60-34	ARIANA	230	ARIANA-N	69	1	16						
2004-60-34	SELOSE	230	SELOSE-N	69	1	16						
2004-60-34	GAPWAY	230	GAPWAY	69	1	16						
2004-60-34	CREWSLK	230	CREWSLK	69	1	13						
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2004-60-35	IND RIV	230	STANTON	230	1	11						
2004-60-35	SN PLANT	115	TURNER	115	1	1						
2004-60-35	BUCKEYE	230	RUSKMTR8	230	1	1						
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2004-60-35	RECKER	230	CREWSLK	230	1	13						
2004-60-35	B BEND	230	MANATEE	230	1	1						
2004-60-35	RUSKIN T	230	MANATEE	230	1	1						
2004-60-35	IND RIV	230	IND RIV	115	1	11						
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2004-60-35	CLMT EST	230	CLMT EST	69	1	2						
2004-60-35	11TH AVE	230	ELEVEN-E	69	1	16						
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2004-60-35	GAPWAY	230	GAPWAY	69	1	16						
2004-60-35	CREWSLK	230	CREWSLK	69	1	13						
2004-60-35	TENOROC	230	TENOROC	69	1	13						
2004-60-35	BARCOLA	230	WEST	230	1	2						
2004-60-35	EATON PK	230	CREWSLK	230	1	13						
2004-60-35	EATON PK	230	EATON PK	69	1	13						
2004-60-35	EATON PK	230	TENOROC	230	1	13						
2004-60-35	RECKER	230	GAPWAY	230	1	16						
2004-60-35	SN PLANT	115	TURNER	115	1	1						

APPENDIX III-A


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MW/MVAR
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GENERAL ELECTRIC COMPANY
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PROPOSED OSPREY ENERGY CENTER
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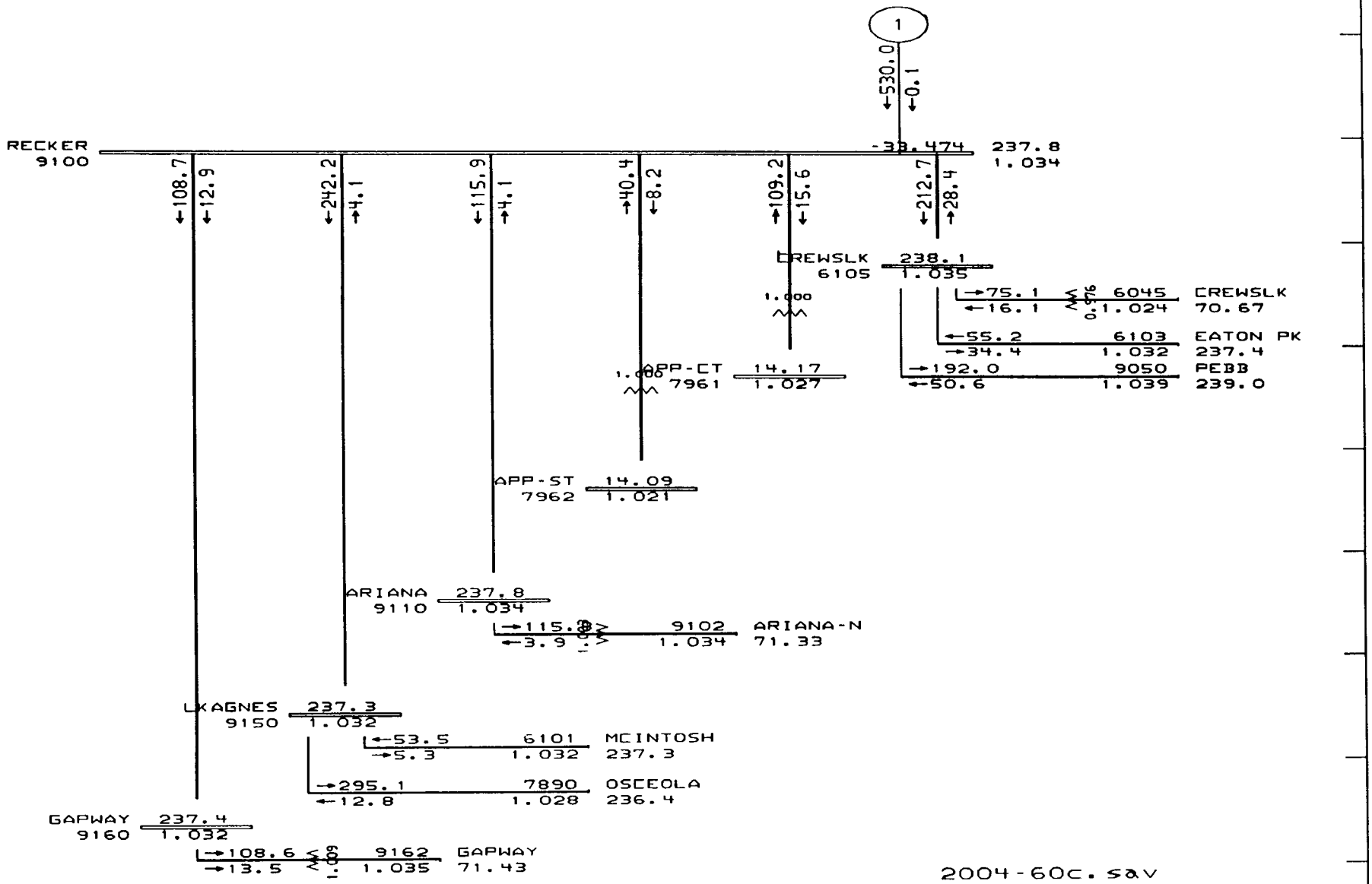


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GENERAL ELECTRIC COMPANY

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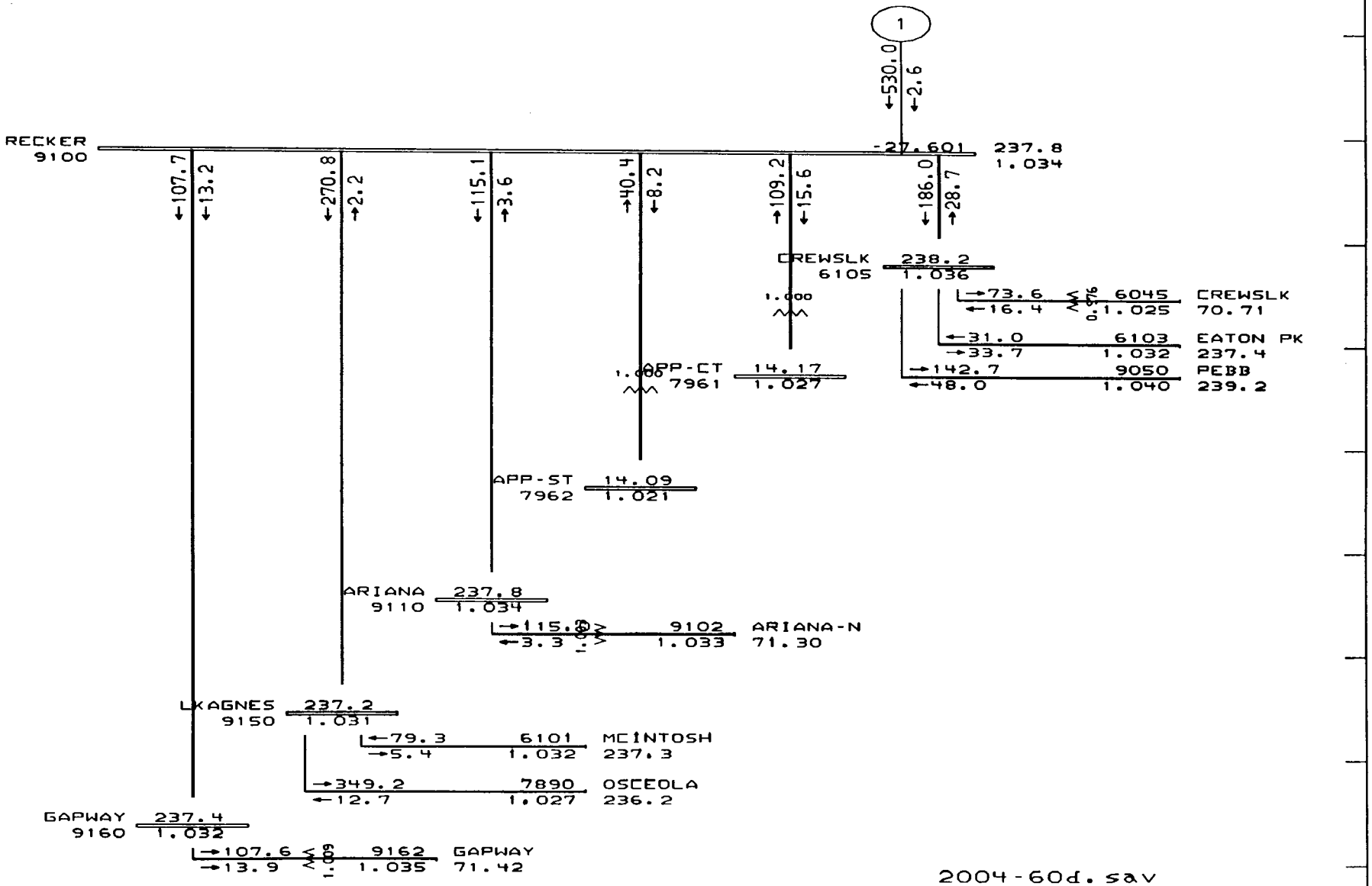


General Electric Company PSLF Program

GENERAL ELECTRIC COMPANY

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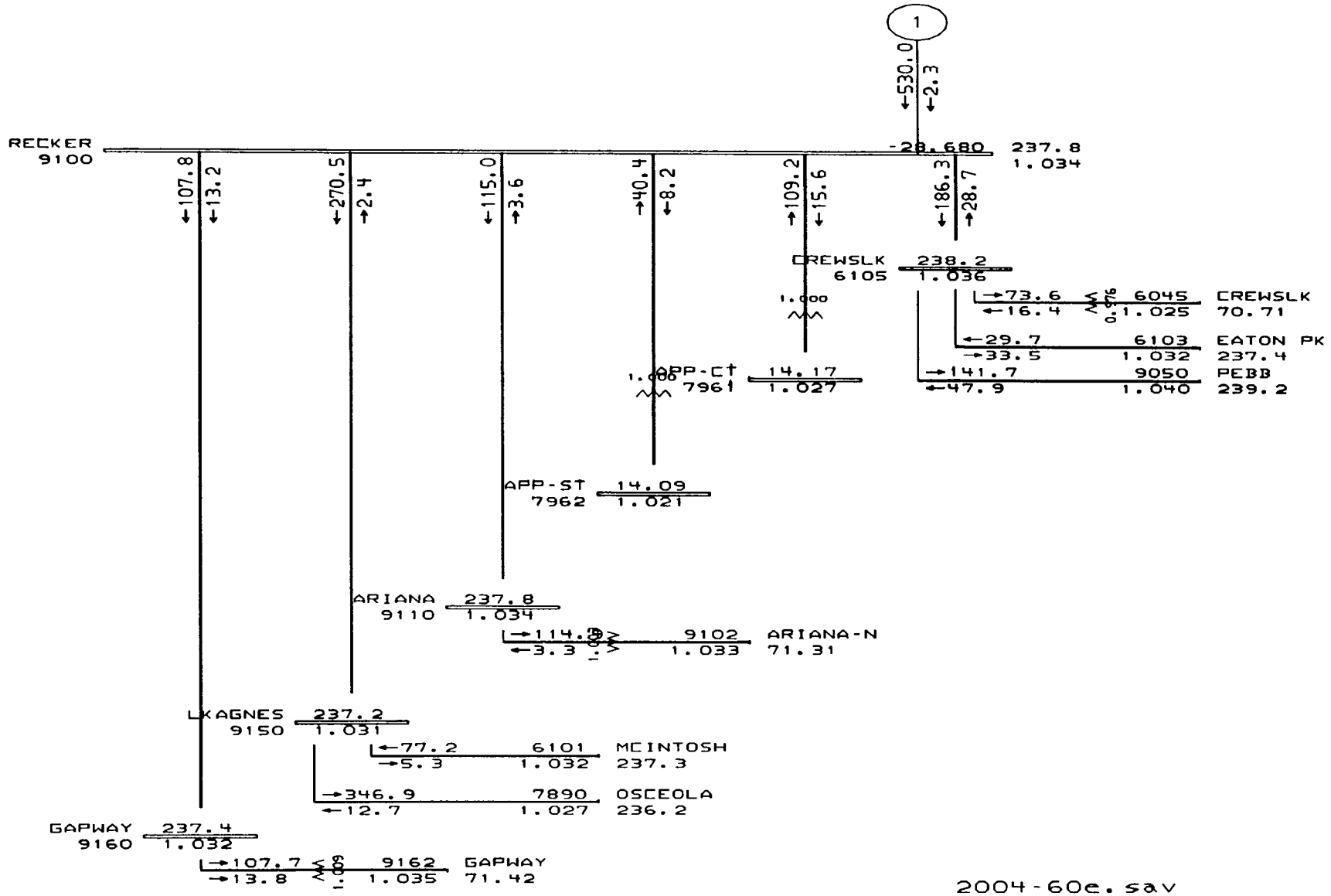


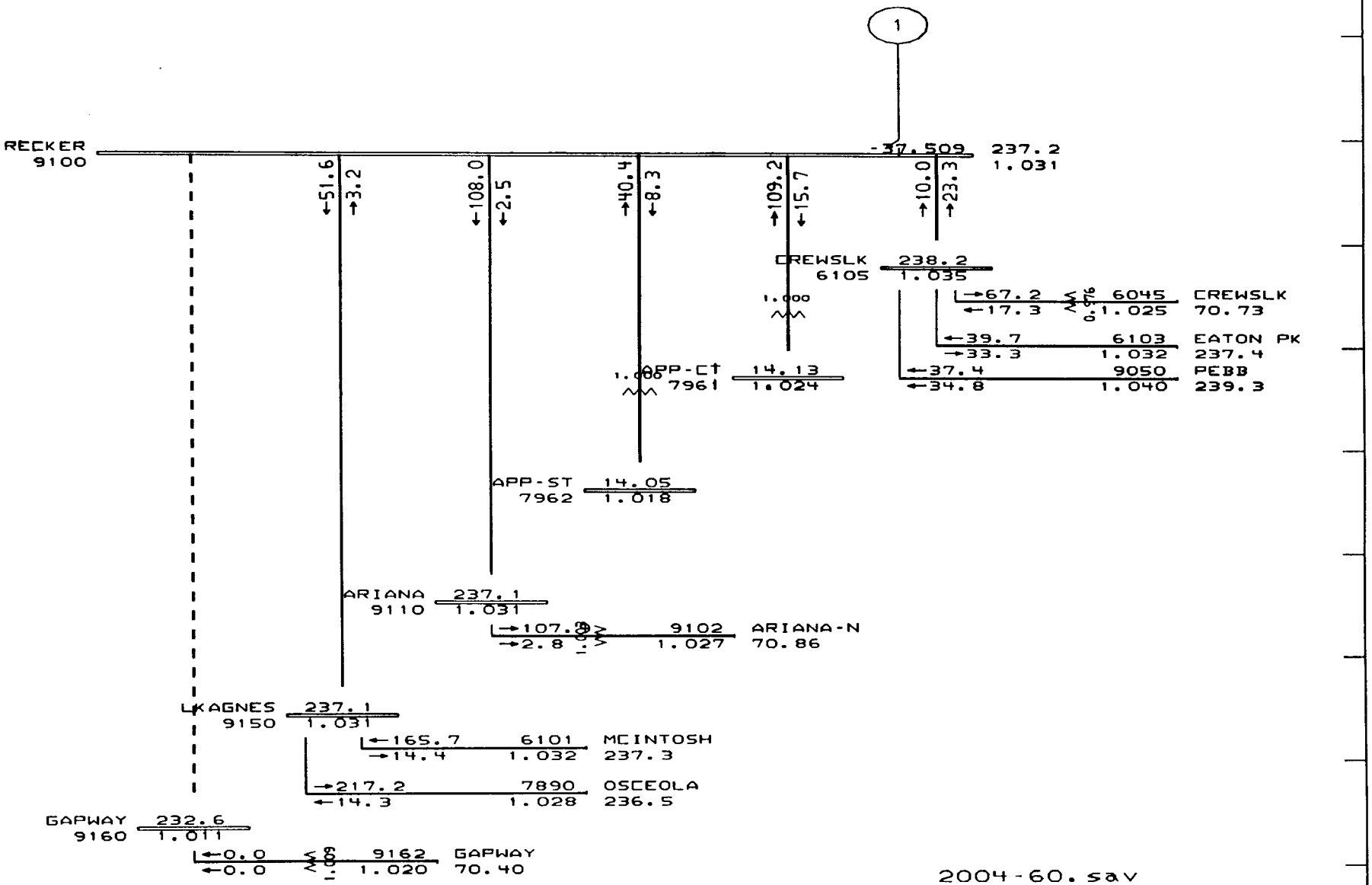
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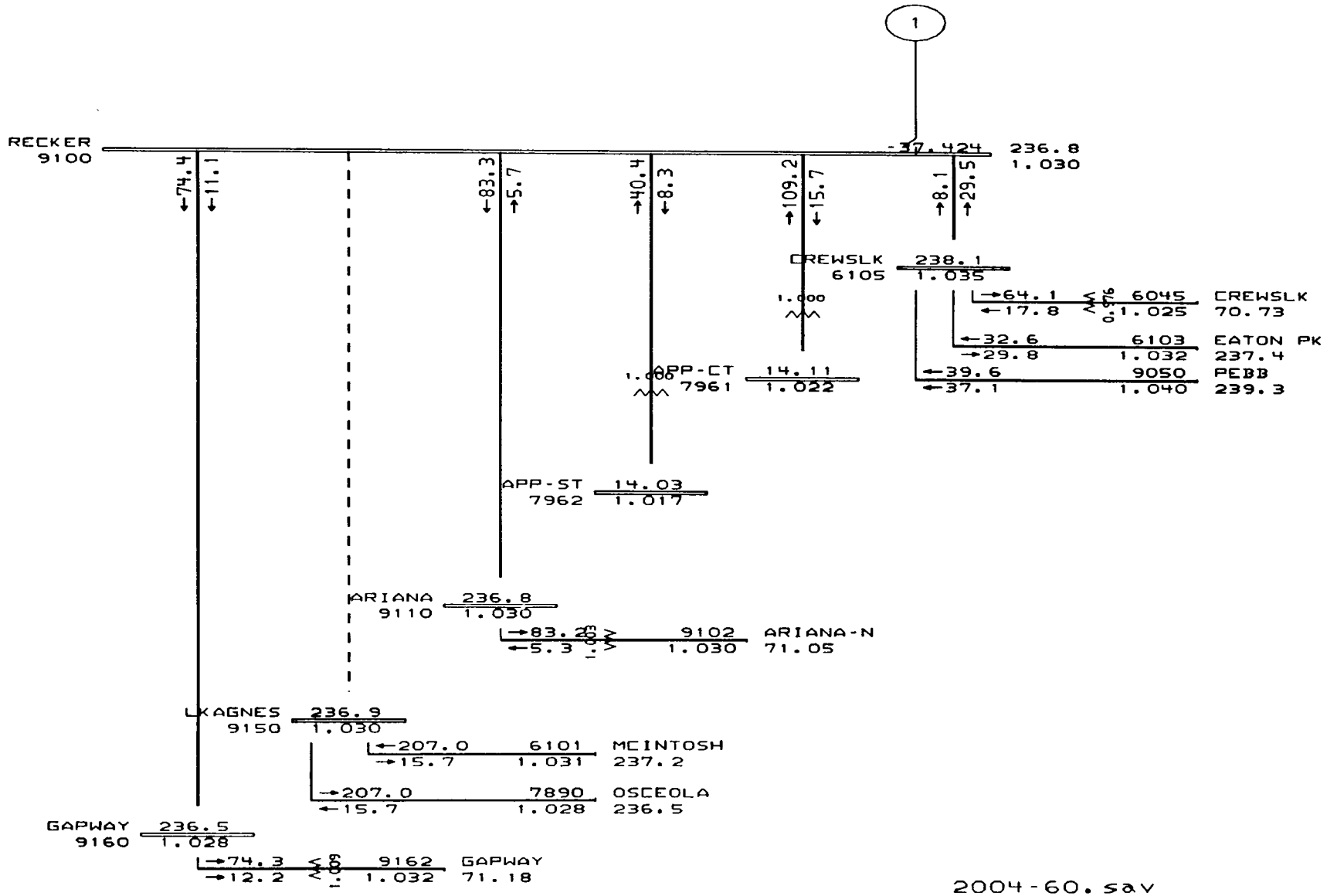
GENERAL ELECTRIC COMPANY

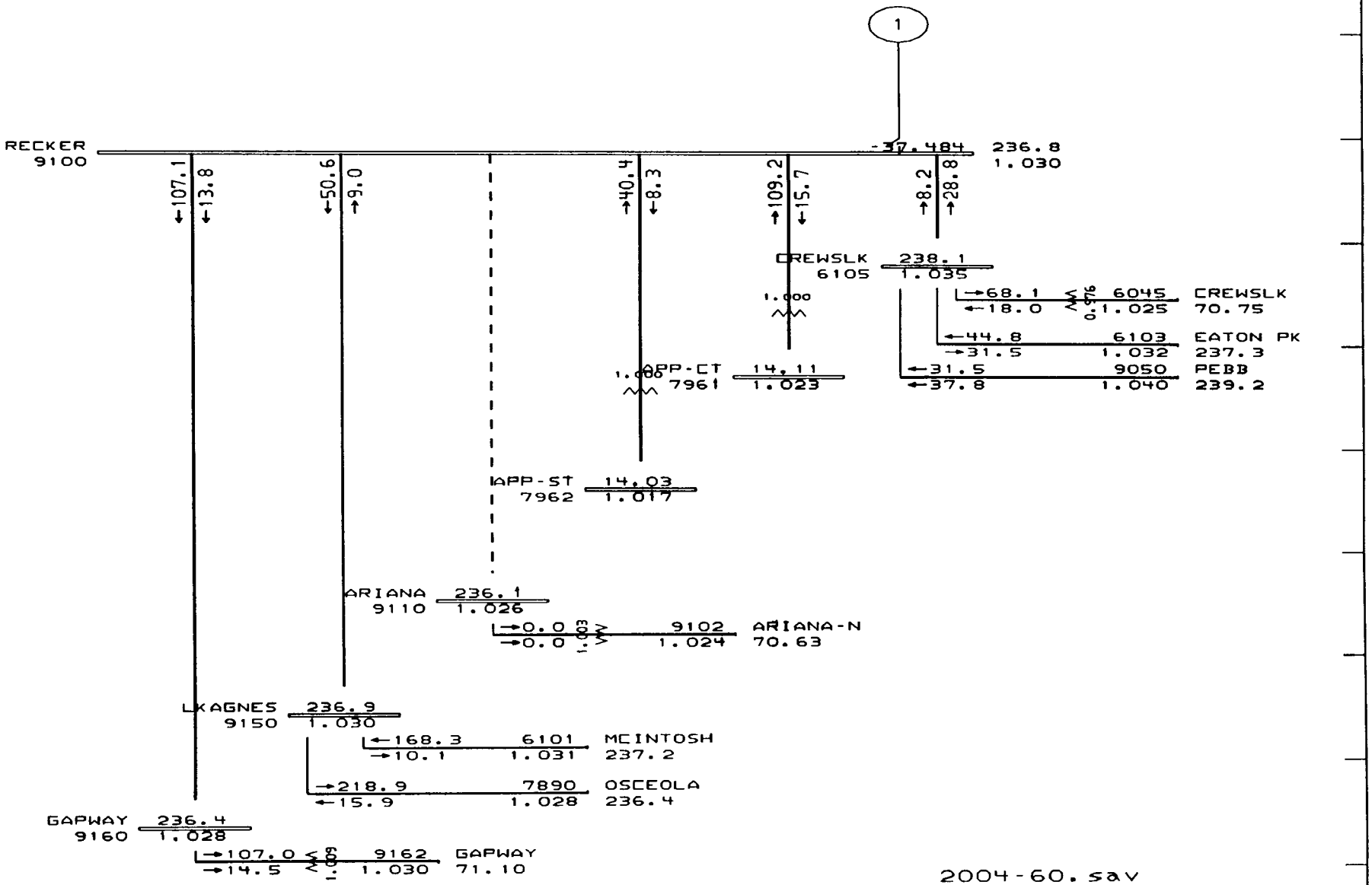
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

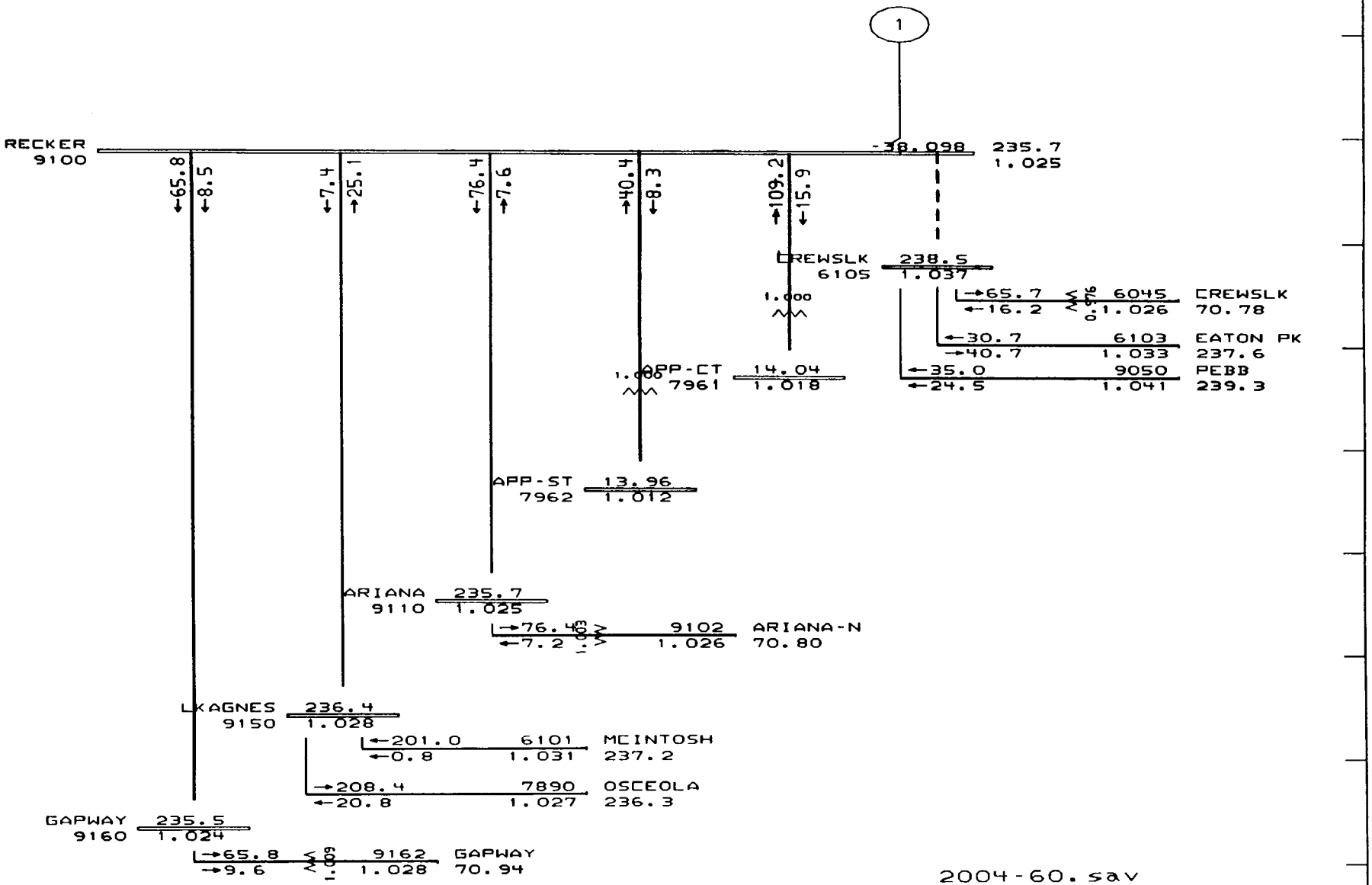
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Rating = 1

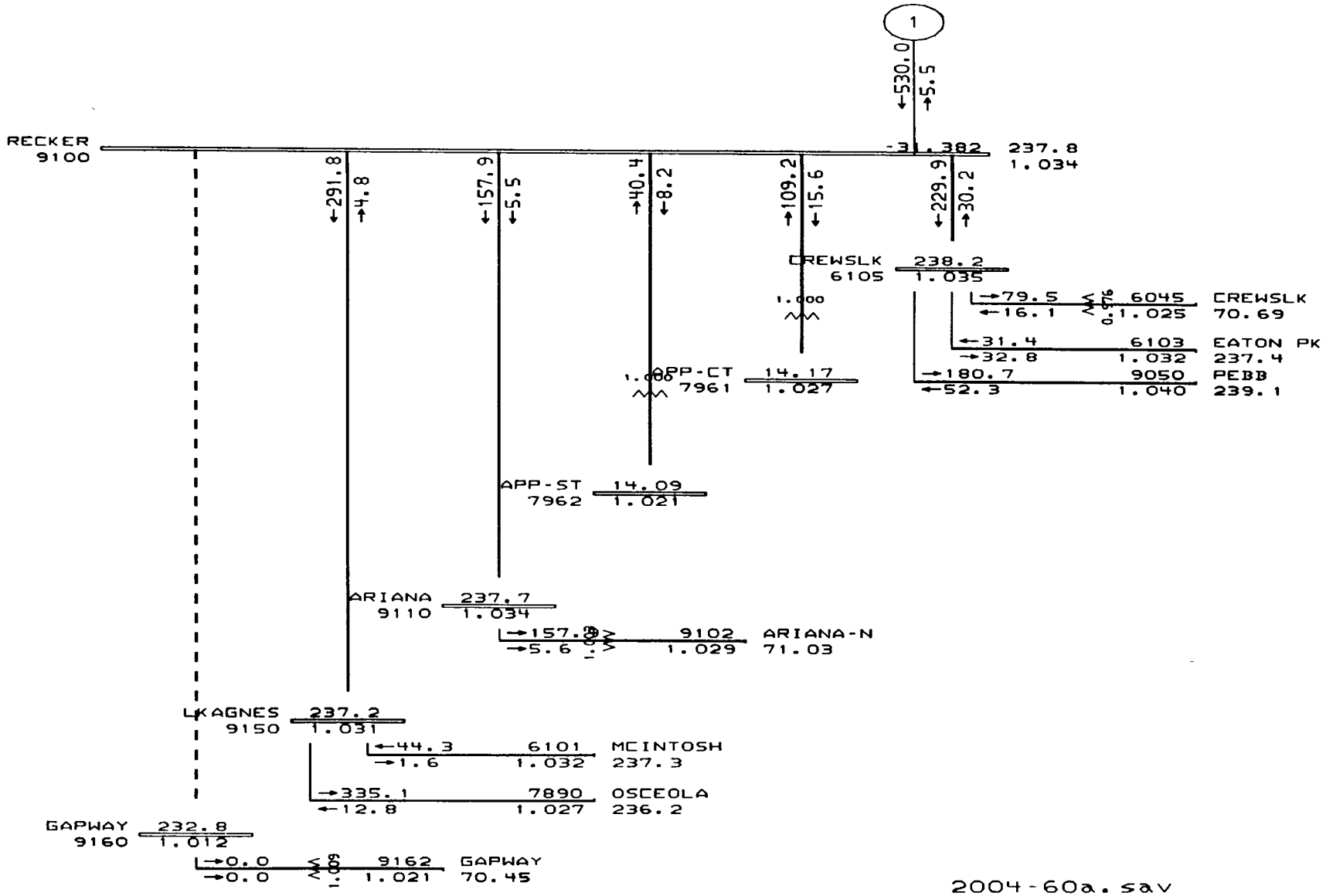

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←2.3
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9100
-28.680
237.8
1.034
←107.8
←13.2
←270.5
→2.4
←115.0
→3.6
→40.4
←8.2
→109.2
←15.6
←186.3
→28.7
CREWSLK 238.2
6105 1.036
1.000
→73.6
←16.4
0.976
6045 CREWSLK
1.025 70.71
←29.7
→33.5
6103 EATON PK
1.032 237.4
APP-CT 14.17
1.000 7961 1.027
→141.7
←47.9
9050 PEBB
1.040 239.2
APP-ST 14.09
7962 1.021
ARIANA 237.8
9110 1.034
→114.8
←3.3
1.000
9102 ARIANA-N
1.033 71.31
LKAGNES 237.2
9150 1.031
←77.2
→5.3
6101 MCINTOSH
1.032 237.3
→346.9
←12.7
7890 OSCEOLA
1.027 236.2
GAPWAY 237.4
9160 1.032
→107.7
→13.8
1.000
9162 GAPWAY
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Q mis = 0.0005 MVAR

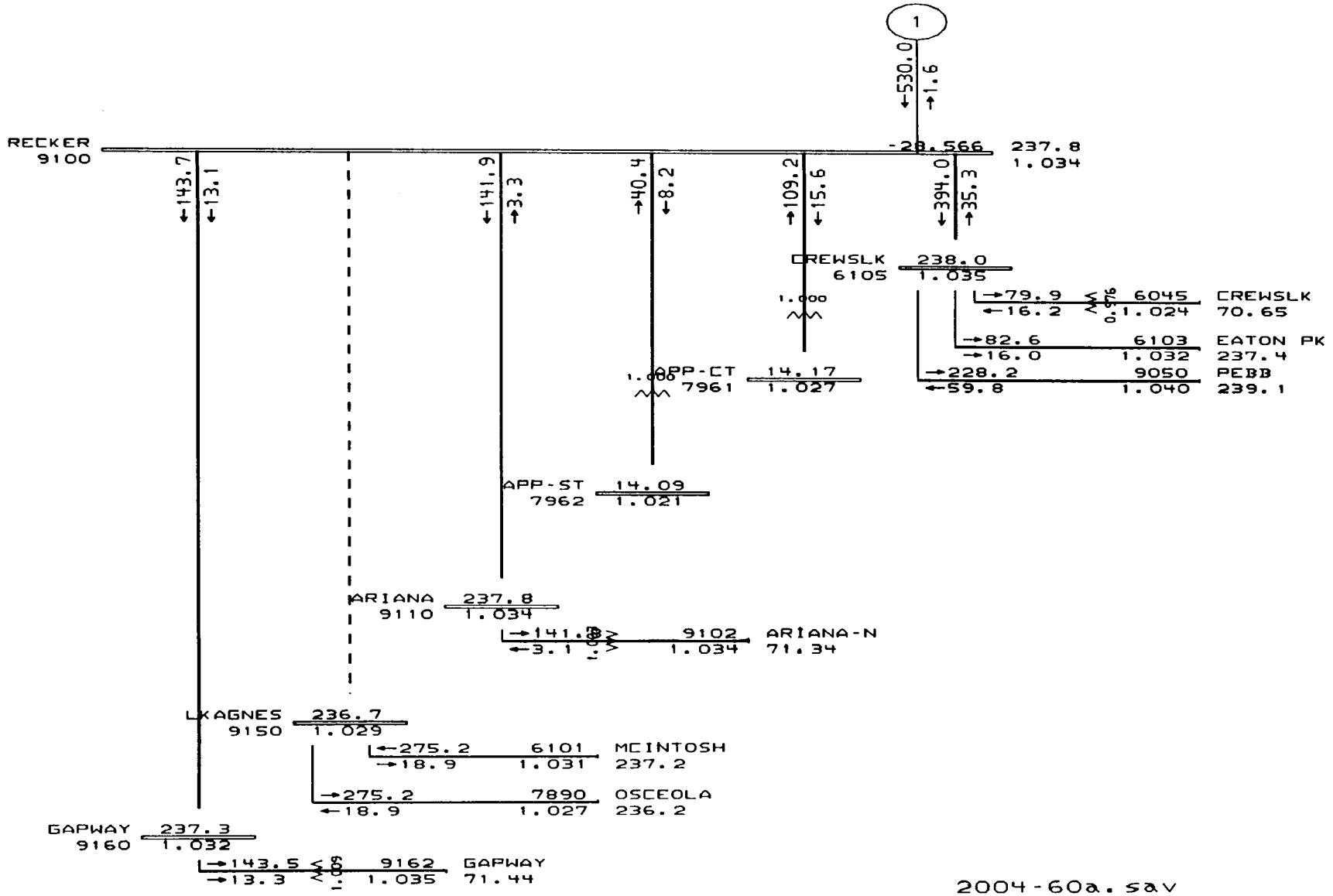

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51.6
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40.4
8.3
109.2
15.7
10.0
23.3
CREWSLK
6105
238.2
1.035
67.2
17.3
6045
CREWSLK
1.025
70.73
39.7
33.3
6103
EATON PK
1.032
237.4
1.000
APP-CT
7961
14.13
1.024
37.4
34.8
9050
PEBB
1.040
239.3
APP-ST
7962
14.05
1.018
ARIANA
9110
237.1
1.031
107.8
2.8
9102
ARIANA-N
1.027
70.86
LKAGNES
9150
237.1
1.031
165.7
14.4
6101
MCINTOSH
1.032
237.3
217.2
14.3
7890
OSCEOLA
1.028
236.5
GAPWAY
9160
232.6
1.011
0.0
0.0
9162
GAPWAY
1.020
70.40
2004-60.sav
P mis = 0.0007 MW
Q mis = -0.0029 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:43:21 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60.sav
Rating = 1

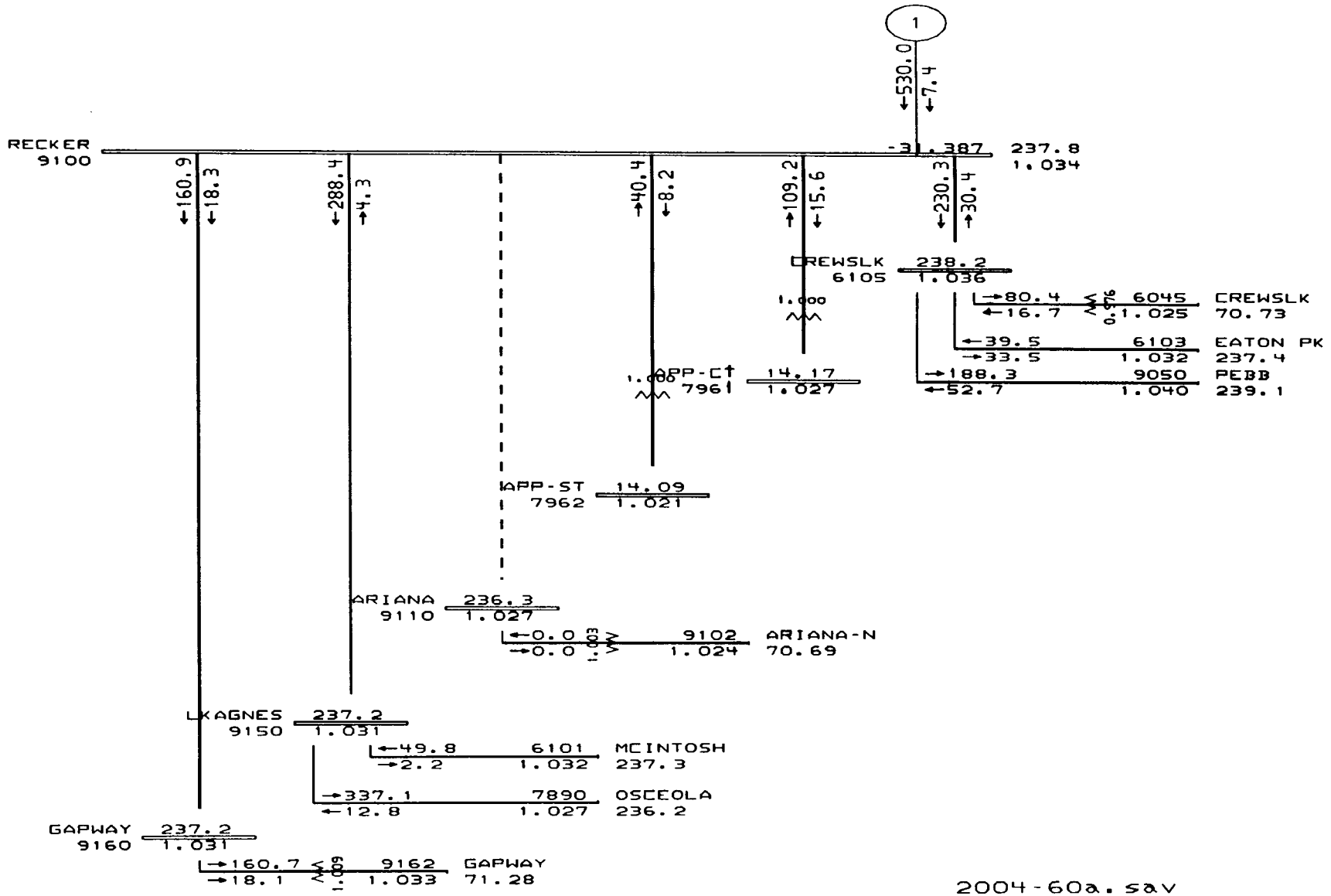

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RECKER
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1.030
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←83.3
→5.7
→40.4
←8.3
→109.2
←15.7
→8.1
→29.5
CREWSLK 238.1
6105 1.035
1.000
→64.1
←17.8
0.976
6045
1.025
CREWSLK
70.73
←32.6
→29.8
6103
1.032
EATON PK
237.4
APP-CT 14.11
1.000 7961 1.022
←39.6
←37.1
9050
1.040
PEBB
239.3
APP-ST 14.03
7962 1.017
ARIANA 236.8
9110 1.030
→83.2
←5.3
0.976
9102
1.030
ARIANA-N
71.05
LKAGNES 236.9
9150 1.030
←207.0
→15.7
6101
1.031
MCINTOSH
237.2
→207.0
←15.7
7890
1.028
OSCEOLA
236.5
GAPWAY 236.5
9160 1.028
→74.3
→12.2
0.98
9162
1.032
GAPWAY
71.18
2004-60.sav
P mis = 0.0007 MW
Q mis = -0.0029 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:43:39 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60.sav
Rating = 1

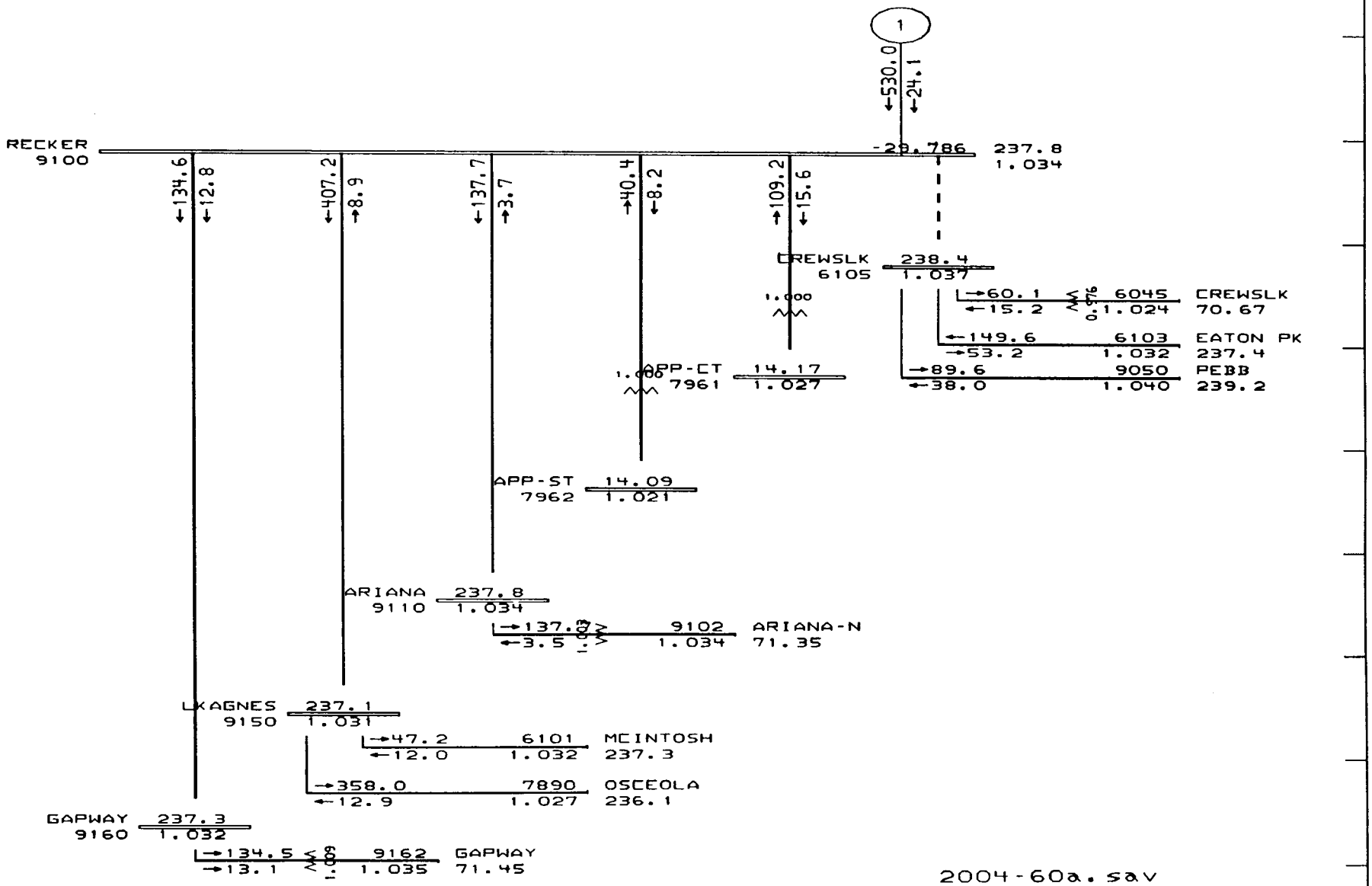

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RECKER
9100
-37.484
236.8
1.030
←107.1
←13.8
←50.6
→9.0
→40.4
←8.3
→109.2
←15.7
→8.2
→28.8
CREWSLK 238.1
6105 1.035
1.000
→68.1 6045 CREWSLK
←18.0 0.1.025 70.75
0.5%
←44.8 6103 EATON PK
→31.5 1.032 237.3
APP-CT 14.11
1.000 7961 1.023
←31.5 9050 PEBB
←37.8 1.040 239.2
APP-ST 14.03
7962 1.017
ARIANA 236.1
9110 1.026
→0.0 9102 ARIANA-N
→0.0 1.024 70.63
1.0%
LKAGNES 236.9
9150 1.030
←168.3 6101 MCINTOSH
→10.1 1.031 237.2
→218.9 7890 OSCEOLA
←15.9 1.028 236.4
GAPWAY 236.4
9160 1.028
→107.0 9162 GAPWAY
→14.5 1.0% 1.030 71.10
2004-60.sav
P mis = 0.0007 MW
Q mis = -0.0029 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:43:54 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60.sav
Rating = 1


1
RECKER
9100
-38.098
235.7
1.025
←65.8
←8.5
←7.4
→25.1
←76.4
→7.6
→40.4
←8.3
→109.2
←15.9
CREWSLK 238.5
6105 1.037
1.000
←65.7
←16.2
1.026
6045
CREWSLK
70.78
←30.7
→40.7
6103
1.033
EATON PK
237.6
←35.0
←24.5
9050
1.041
PEBB
239.3
APP-CT 14.04
7961 1.018
1.000
APP-ST 13.96
7962 1.012
ARIANA 235.7
9110 1.025
→76.4
←7.2
9102
1.026
ARIANA-N
70.80
LKAGNES 236.4
9150 1.028
←201.0
←0.8
6101
1.031
MCINTOSH
237.2
→208.4
←20.8
7890
1.027
OSCEOLA
236.3
GAPWAY 235.5
9160 1.024
→65.8
→9.6
9162
1.028
GAPWAY
70.94
2004-60.sav
P mis = 0.0007 MW
Q mis = -0.0029 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:44:10 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60.sav
Rating = 1


1
←530.0
→5.5
RECKER
9100
-31.382
237.8
1.034
←291.8
→4.8
←157.9
→5.5
→40.4
←8.2
→109.2
←15.6
←229.9
→30.2
CREWSLK 238.2
6105 1.035
1.000
→79.5
←16.1
0.976
6045
1.025
CREWSLK
70.69
←31.4
→32.8
6103
1.032
EATON PK
237.4
1.000
APP-CT 14.17
7961 1.027
→180.7
←52.3
9050
1.040
PEBB
239.1
APP-ST 14.09
7962 1.021
ARIANA 237.7
9110 1.034
→157.8
→5.6
9102
1.029
ARIANA-N
71.03
LKAGNES 237.2
9150 1.031
←44.3
→1.6
6101
1.032
MCINTOSH
237.3
→335.1
←12.8
7890
1.027
OSCEOLA
236.2
GAPWAY 232.8
9160 1.012
→0.0
→0.0
9162
1.021
GAPWAY
70.45
2004-60a.sav
P mis = 0.0029 MW
Q mis = 0.0003 MVAR
General Electric Company PSLF Program
MW/MVAR
Wed Feb 16 14:45:07 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60a.sav
Rating = 1


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←530.0
→1.6
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9100
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←143.7
←13.1
←141.9
→3.3
→40.4
←8.2
→109.2
←15.6
←394.0
→35.3
CREWSLK 238.0
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1.000
→79.9
←16.2
0.976
6045
1.024
CREWSLK
70.65
→82.6
→16.0
6103
1.032
EATON PK
237.4
1.000
APP-CT 14.17
7961 1.027
→228.2
←59.8
9050
1.040
PEBB
239.1
APP-ST 14.09
7962 1.021
ARIANA 237.8
9110 1.034
→141.8
←3.1
1.000
9102
1.034
ARIANA-N
71.34
LXAGNES 236.7
9150 1.029
←275.2
→18.9
6101
1.031
MCINTOSH
237.2
→275.2
←18.9
7890
1.027
OSCEOLA
236.2
GAPWAY 237.3
9160 1.032
→143.5
→13.3
1.000
9162
1.035
GAPWAY
71.44
2004-60a.sav
P mis = 0.0029 MW
Q mis = 0.0003 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:45:36 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60a.sav
Rating = 1


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7.4
RECKER
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230.3
30.4
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80.4
16.7
6045
1.025
CREWSLK
70.73
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6103
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EATON PK
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52.7
9050
1.040
PEBB
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APP-CT
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APP-ST
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LKAGNES
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2.2
6101
1.032
MCINTOSH
237.3
337.1
12.8
7890
1.027
OSCEOLA
236.2
GAPWAY
9160
237.2
1.031
160.7
18.1
9162
1.033
GAPWAY
71.28
2004-60a.sav
P mis = 0.0029 MW
Q mis = 0.0003 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:45:56 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60a.sav
Rating = 1



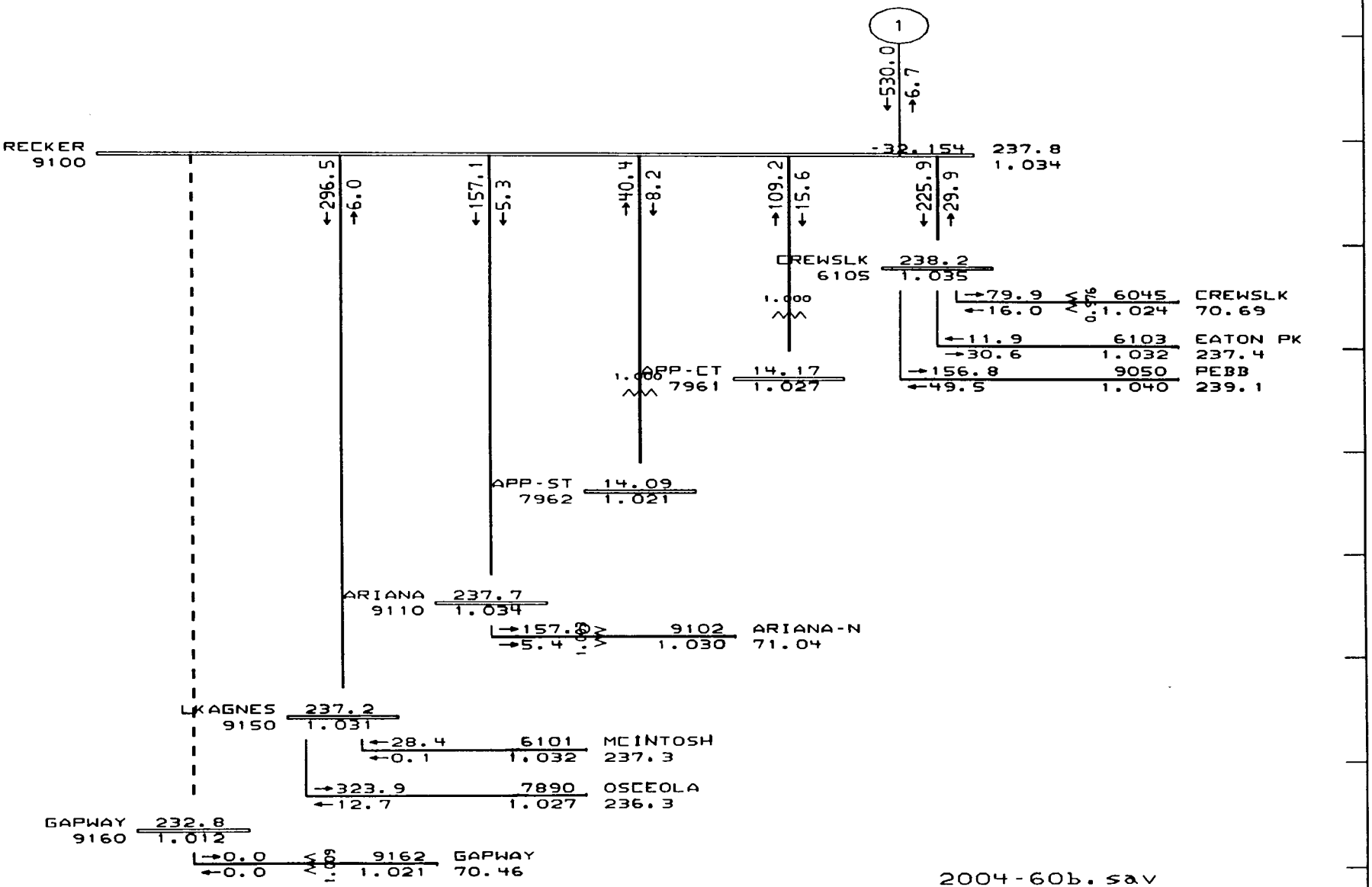
2004-60a.sav
P mis = 0.0029 MW
Q mis = 0.0003 MVAR

General Electric Company PSLF Program MW/MVAR Wed Feb 16 14:46:18 2000

GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

2004-60a.sav
Rating = 1

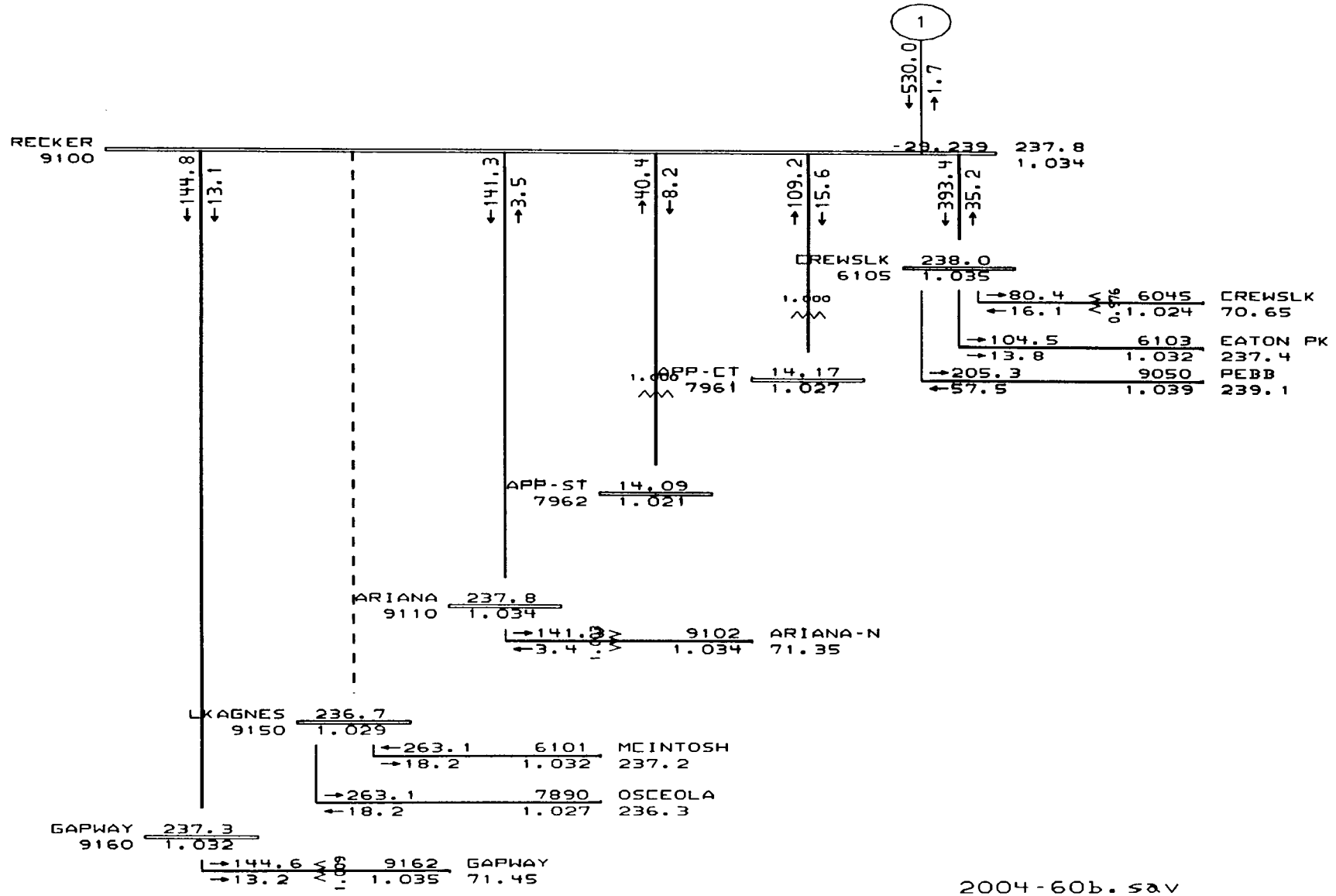


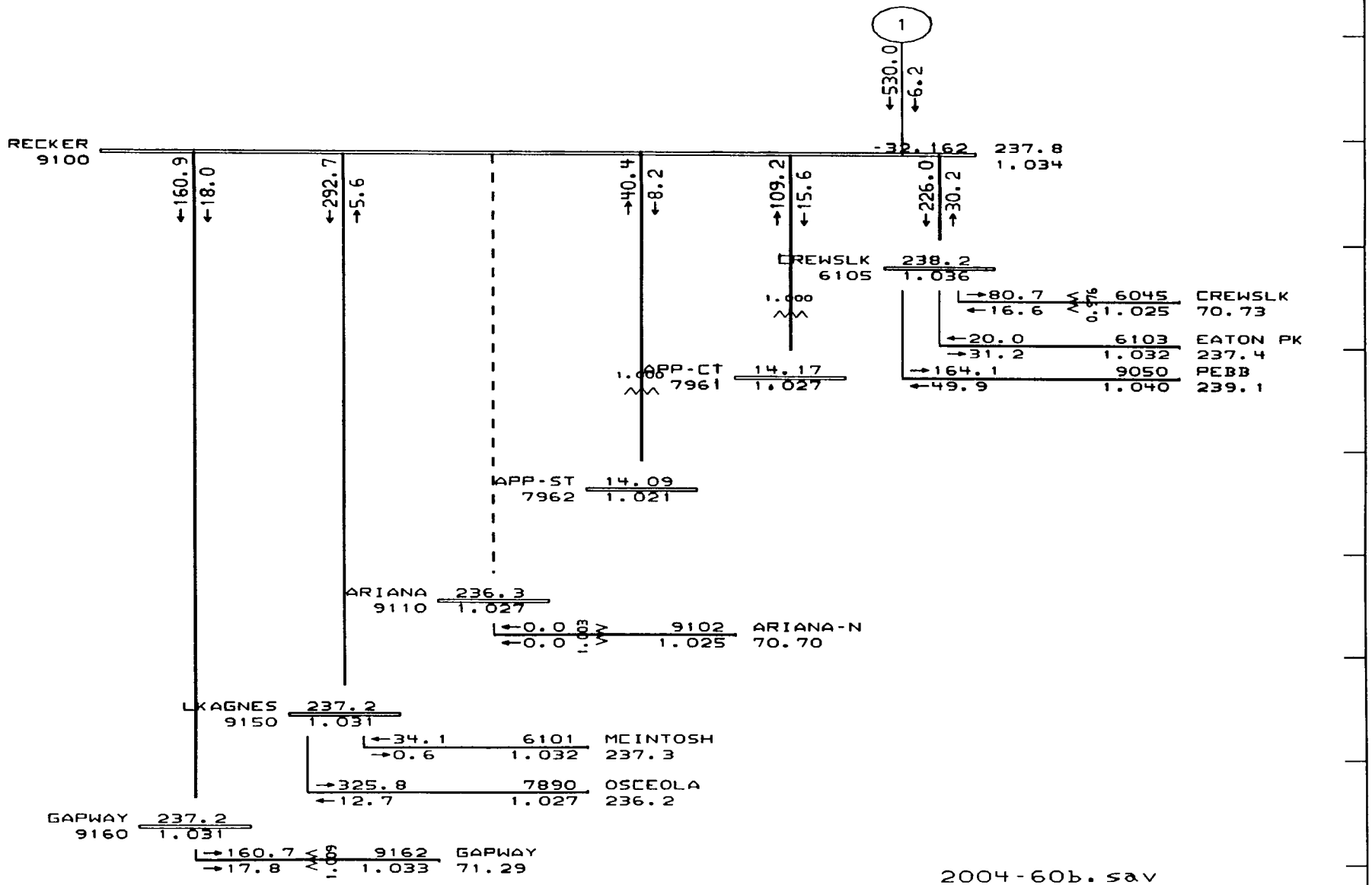
General Electric Company PSLF Program MW/MVAR Wed Feb 16 14:46:39 2000

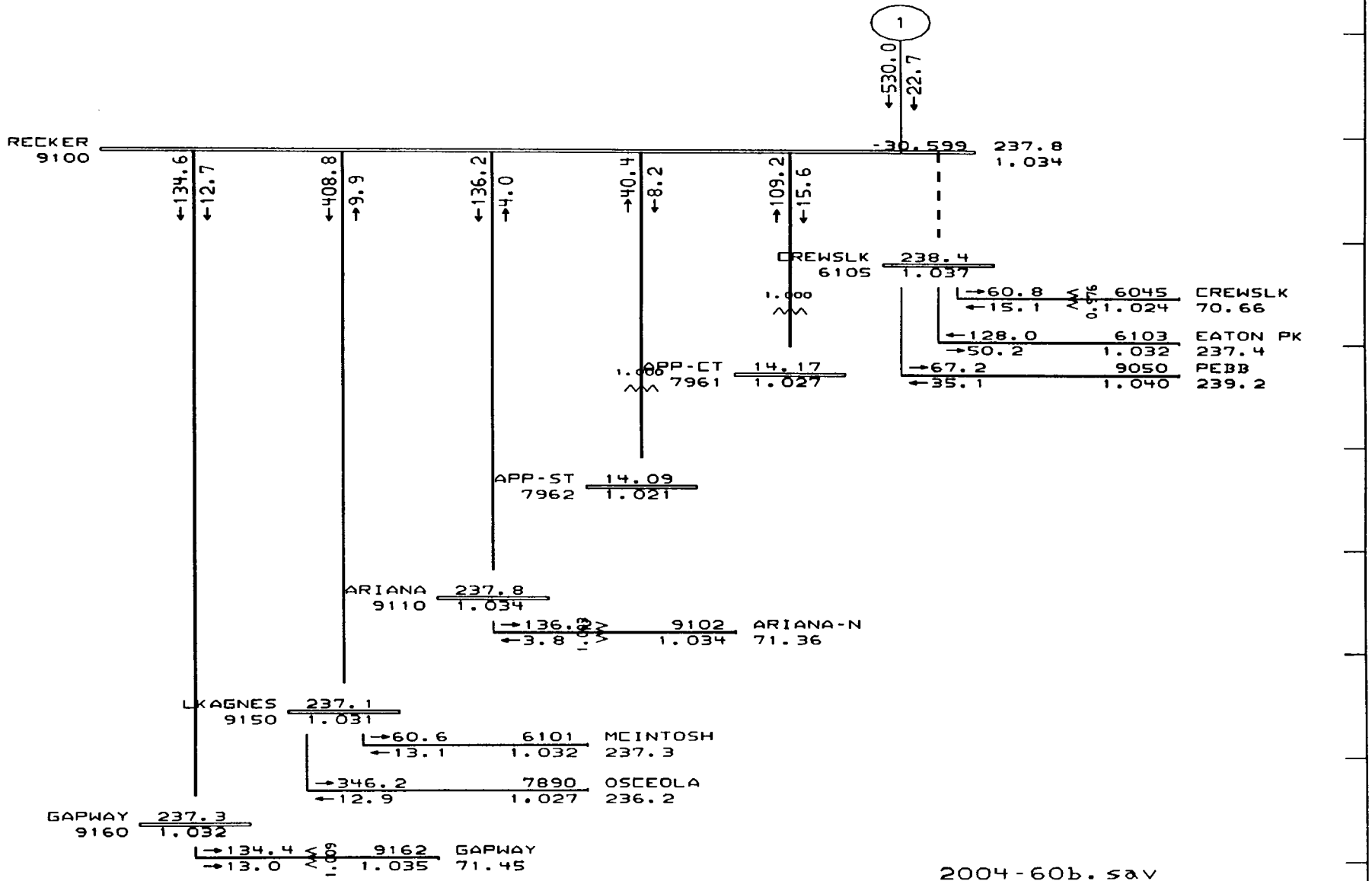
GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

2004-60b.sav
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RECKER
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237.8
1.034
144.8
13.1
141.3
3.5
40.4
8.2
109.2
15.6
393.4
35.2
CREWSLK 238.0
6105 1.035
1.000
80.4
16.1
0.5%
6045
0.1.024
CREWSLK
70.65
104.5
13.8
6103
1.032
EATON PK
237.4
APP-CT 14,17
7961 1.027
1.000
205.3
57.5
9050
1.039
PEBB
239.1
APP-ST 14,09
7962 1.021
ARIANA 237.8
9110 1.034
141.3
3.4
1.0%
9102
1.034
ARIANA-N
71.35
LKAGNES 236.7
9150 1.029
263.1
18.2
6101
1.032
MCINTOSH
237.2
263.1
18.2
7890
1.027
OSCEOLA
236.3
GAPWAY 237.3
9160 1.032
144.6
13.2
1.0%
9162
1.035
GAPWAY
71.45
2004-60b.sav
P mis = -0.0047 MW
Q mis = -0.0007 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:46:57 2000
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60b.sav
Rating = 1


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RECKER
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237.8
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292.7
5.6
40.4
8.2
109.2
15.6
226.0
30.2
CREWSLK
6105
238.2
1.036
80.7
16.6
6045
1.025
CREWSLK
70.73
20.0
31.2
6103
1.032
EATON PK
237.4
164.1
49.9
9050
1.040
PEBB
239.1
APP-CT
7961
14.17
1.027
APP-ST
7962
14.09
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ARIANA
9110
236.3
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ARIANA-N
70.70
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9150
237.2
1.031
34.1
0.6
6101
1.032
MCINTOSH
237.3
325.8
12.7
7890
1.027
OSCEOLA
236.2
GAPWAY
9160
237.2
1.031
160.7
17.8
9162
1.033
GAPWAY
71.29
2004-60b.sav
P mis = -0.0047 MW
Q mis = -0.0007 MVAR
General Electric Company
PSLF Program
MW/MVAR
Wed Feb 16 14:47:12 2000
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
2004-60b.sav
Rating = 1

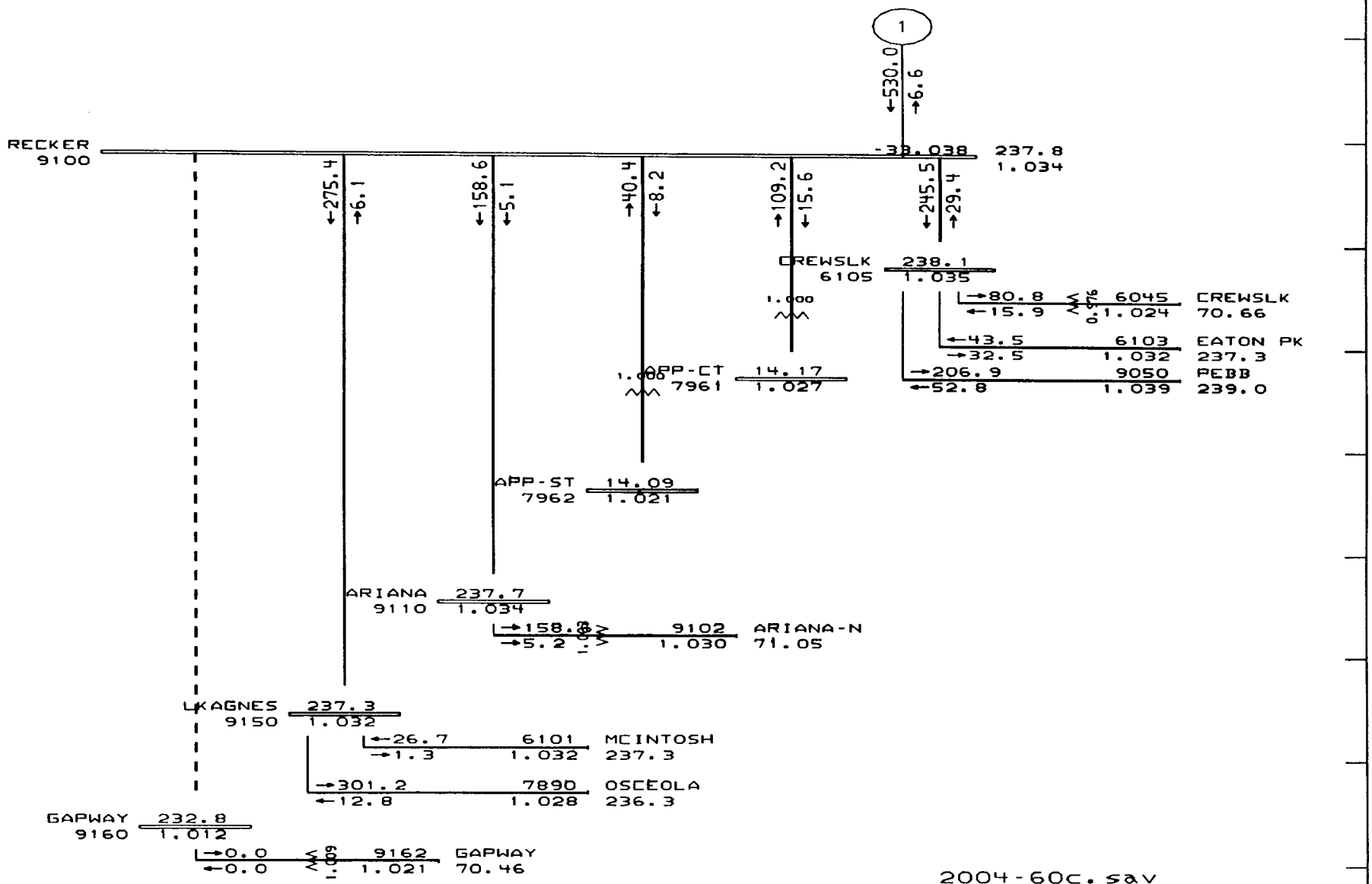


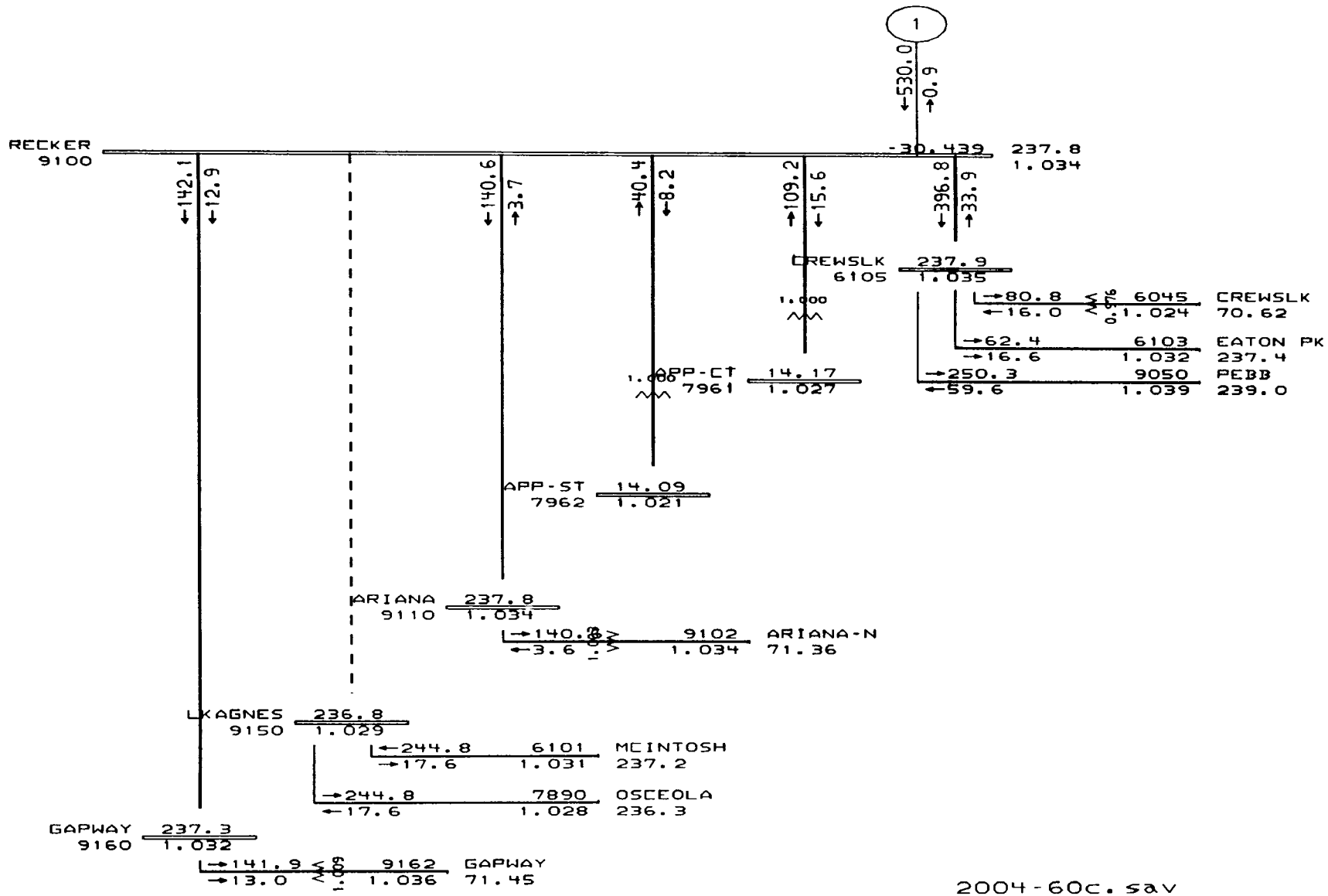
General Electric Company PSLF Program MW/MVAR Wed Feb 16 14:47:31 2000

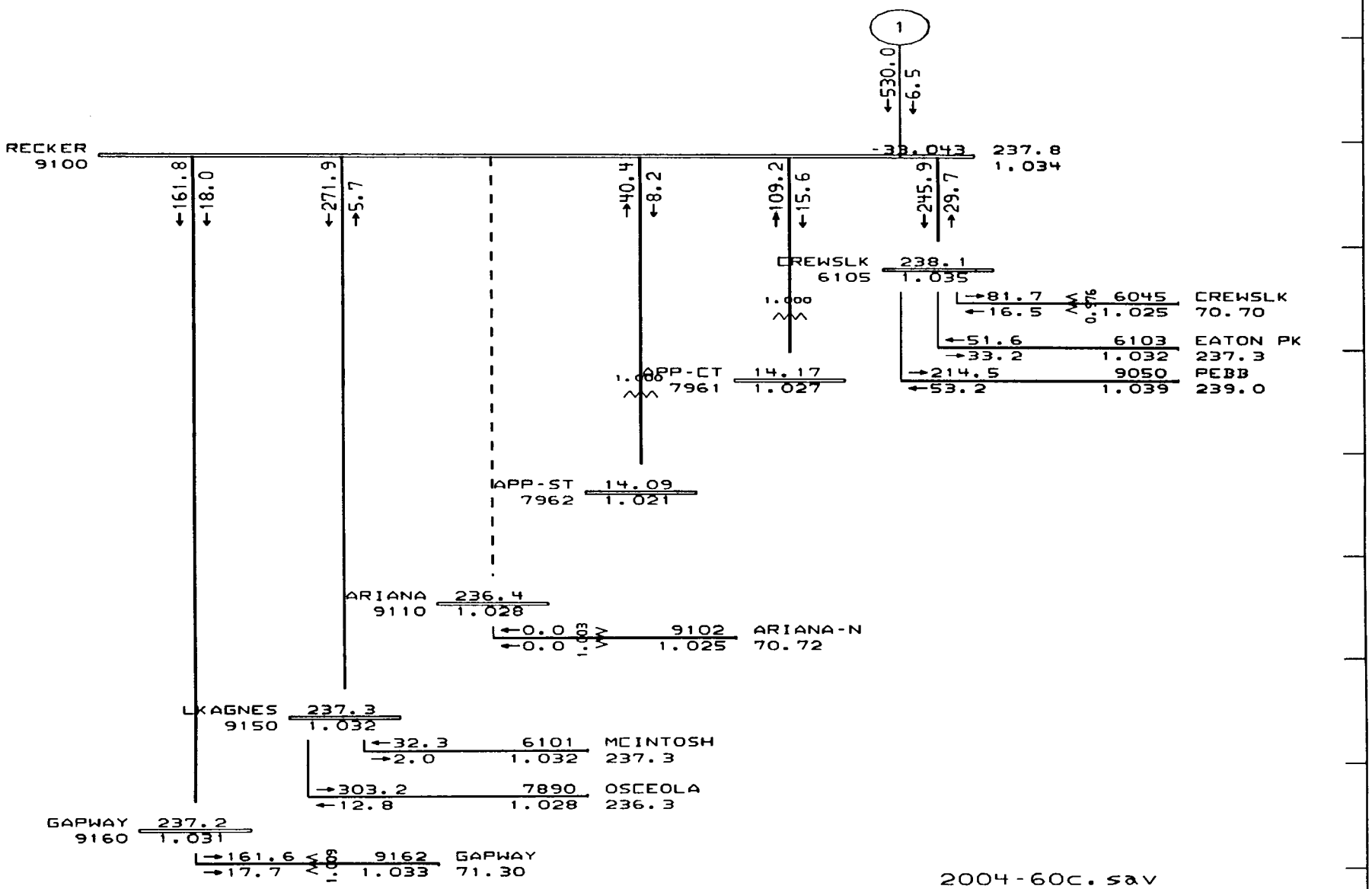
GENERAL ELECTRIC COMPANY

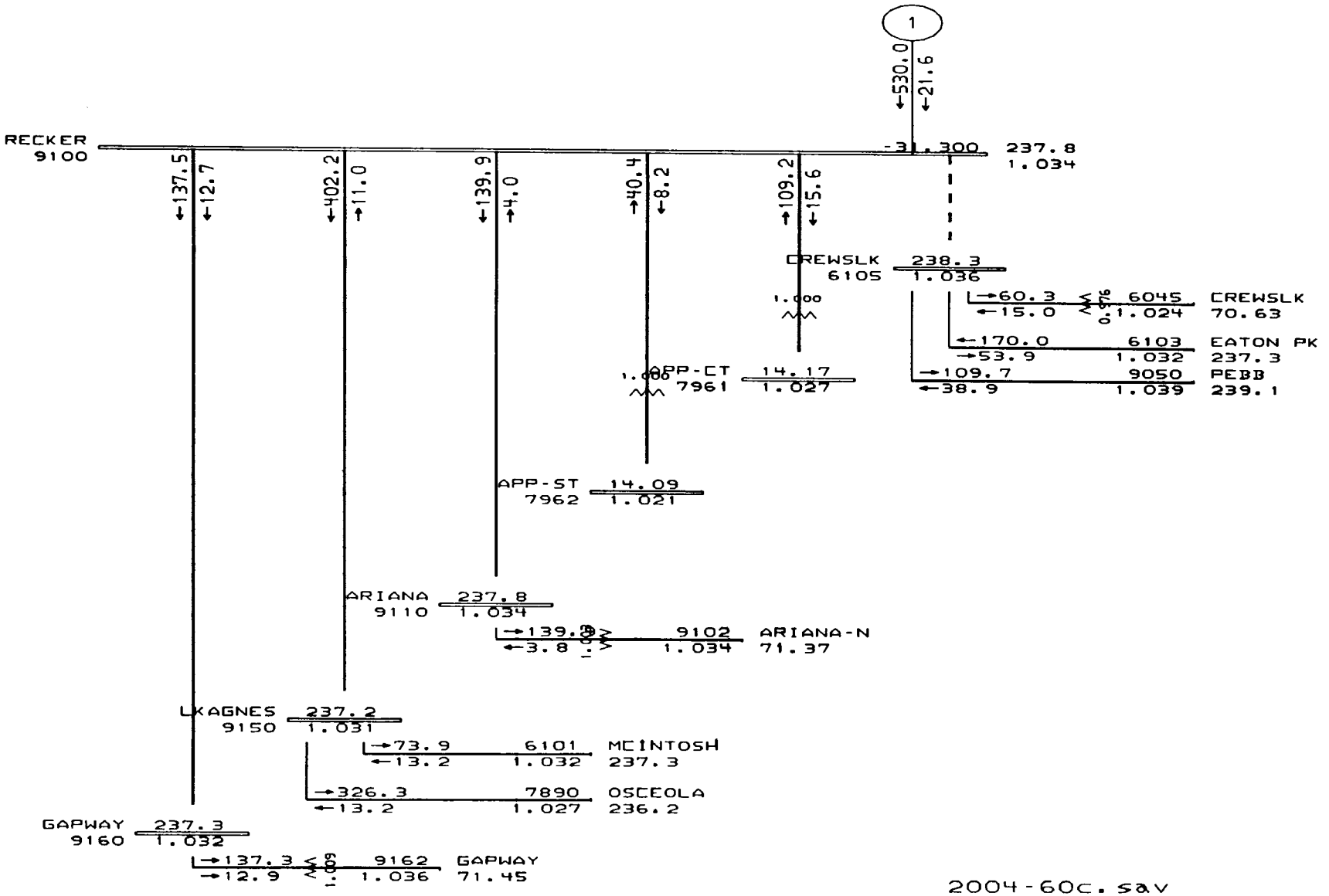
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

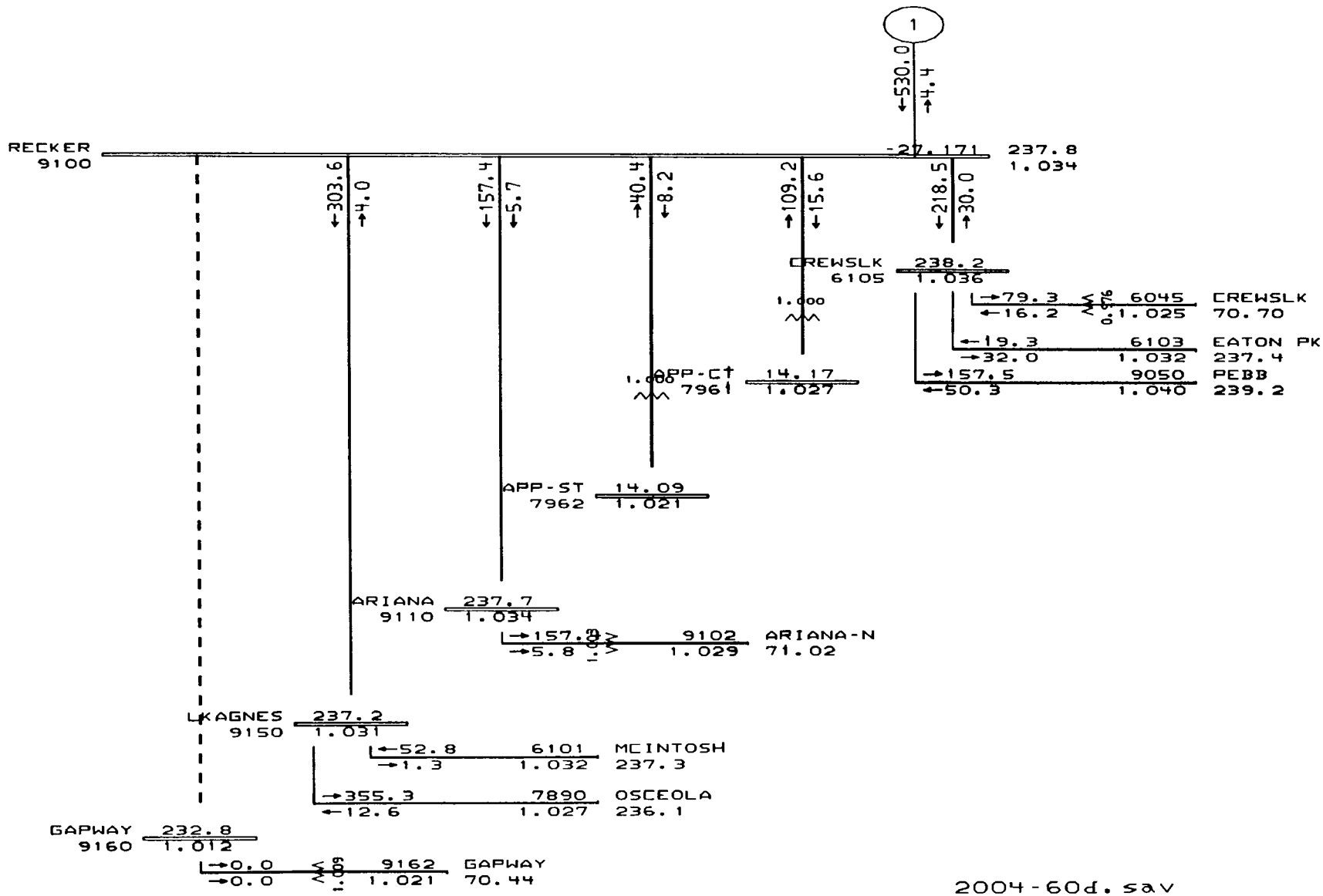
2004-60b.sav
Rating = 1

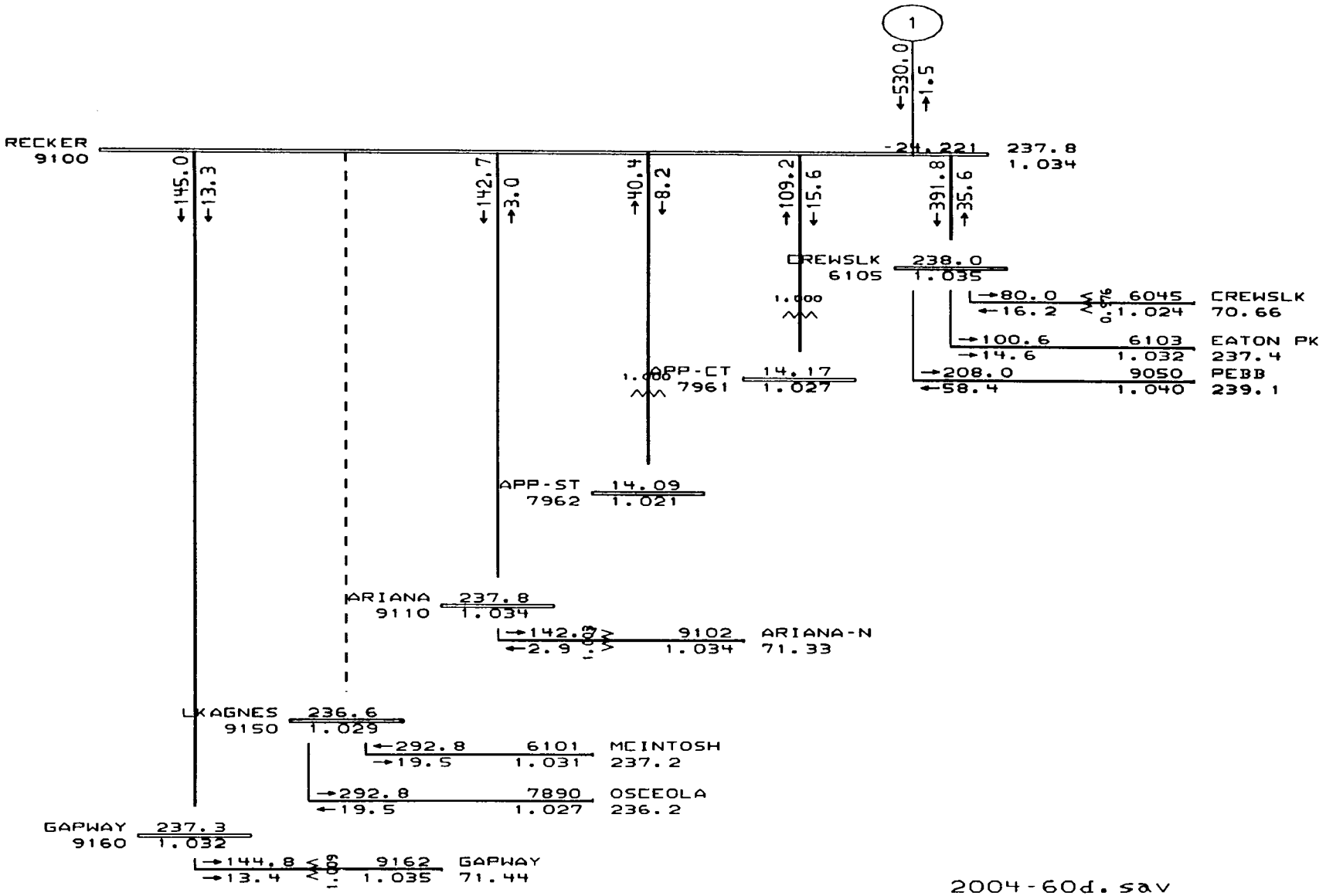

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6.6
RECKER
9100
38.038
237.8
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275.4
6.1
158.6
5.1
40.4
8.2
109.2
15.6
245.5
29.4
CREWSLK
6105
238.1
1.035
1.000
80.8
15.9
6045
1.024
CREWSLK
70.66
43.5
32.5
6103
1.032
EATON PK
237.3
APP-CT
7961
14.17
1.027
206.9
52.8
9050
1.039
PEBB
239.0
APP-ST
7962
14.09
1.021
ARIANA
9110
237.7
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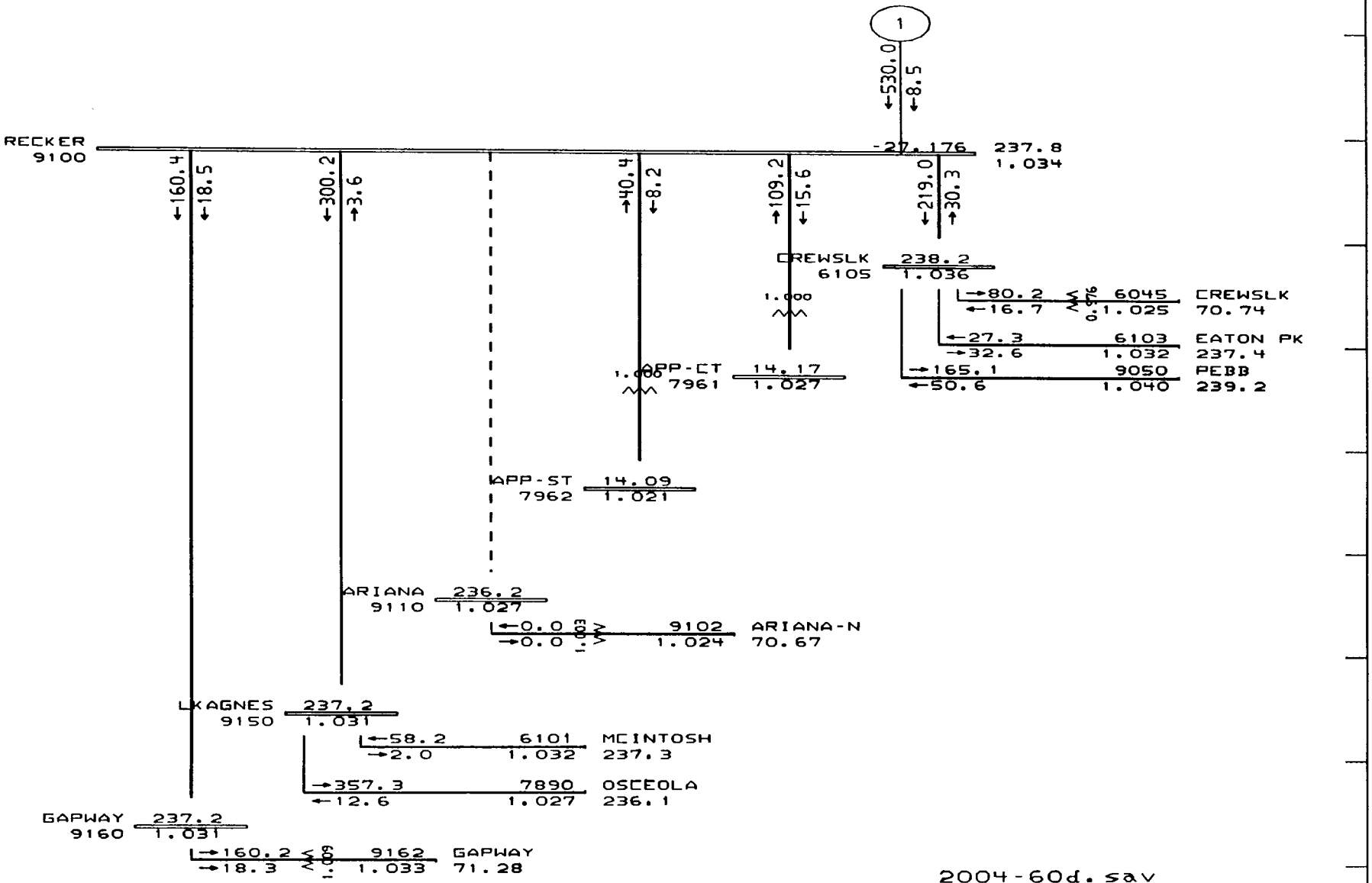

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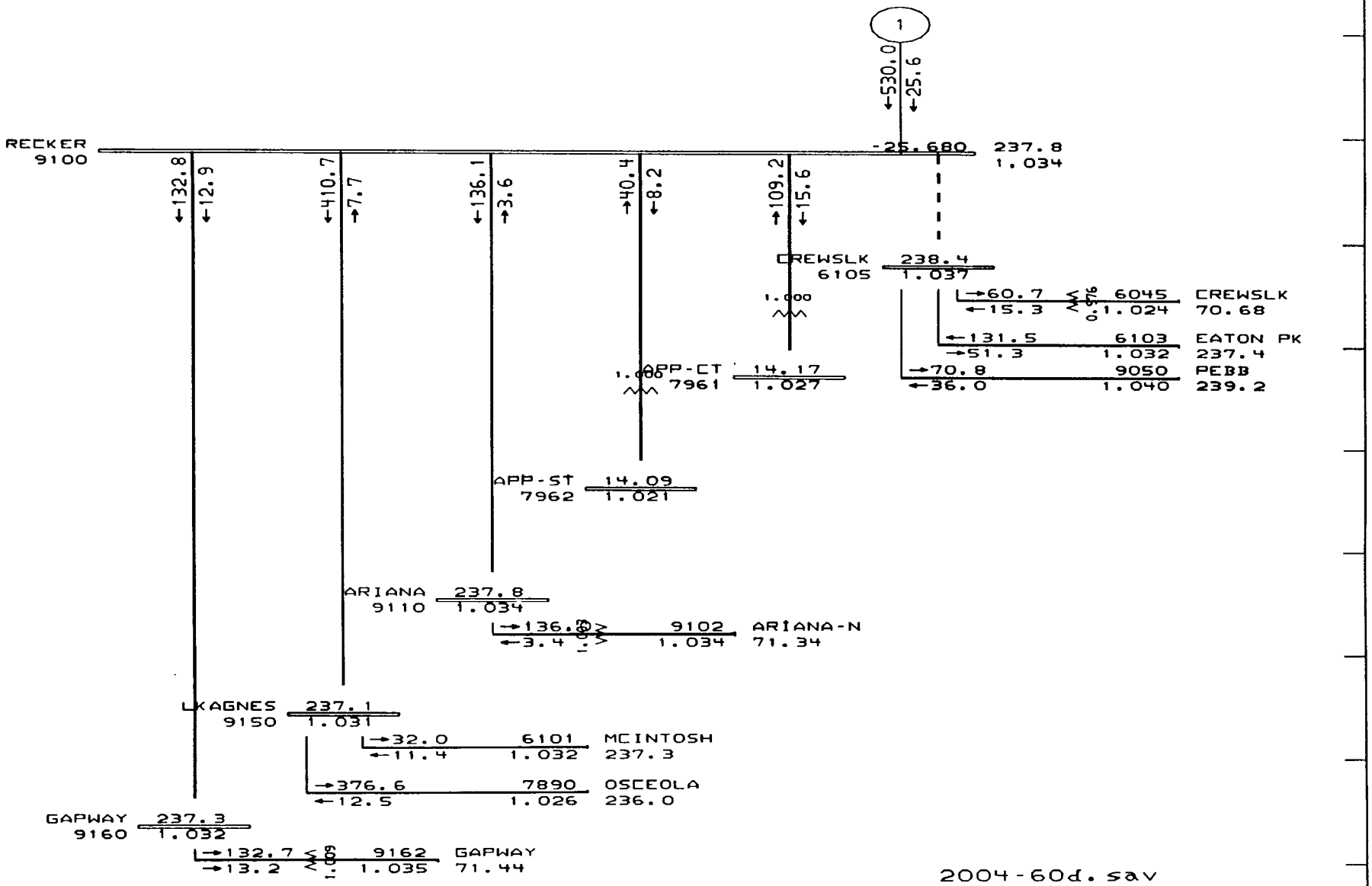


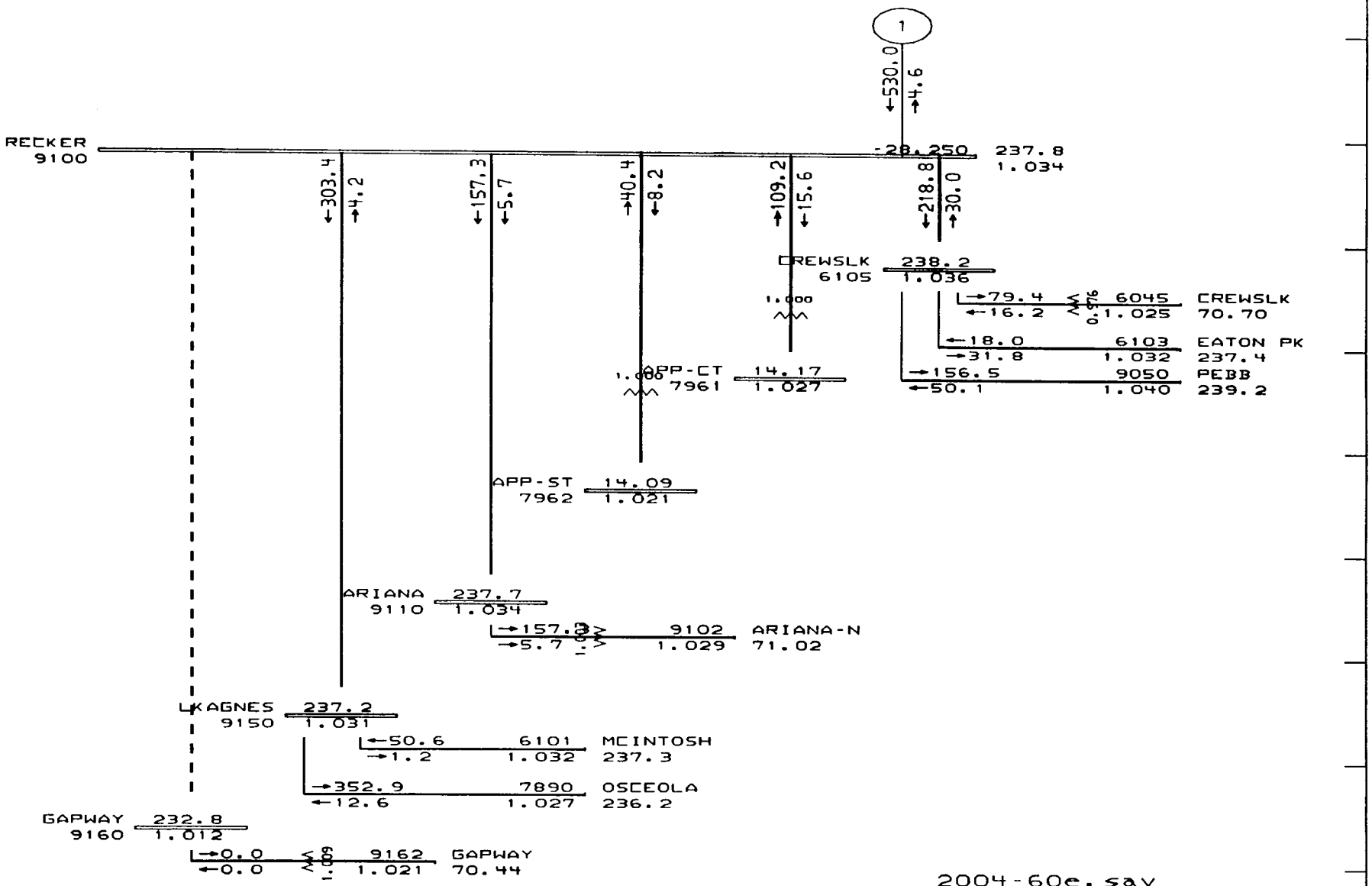
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GENERAL ELECTRIC COMPANY

FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

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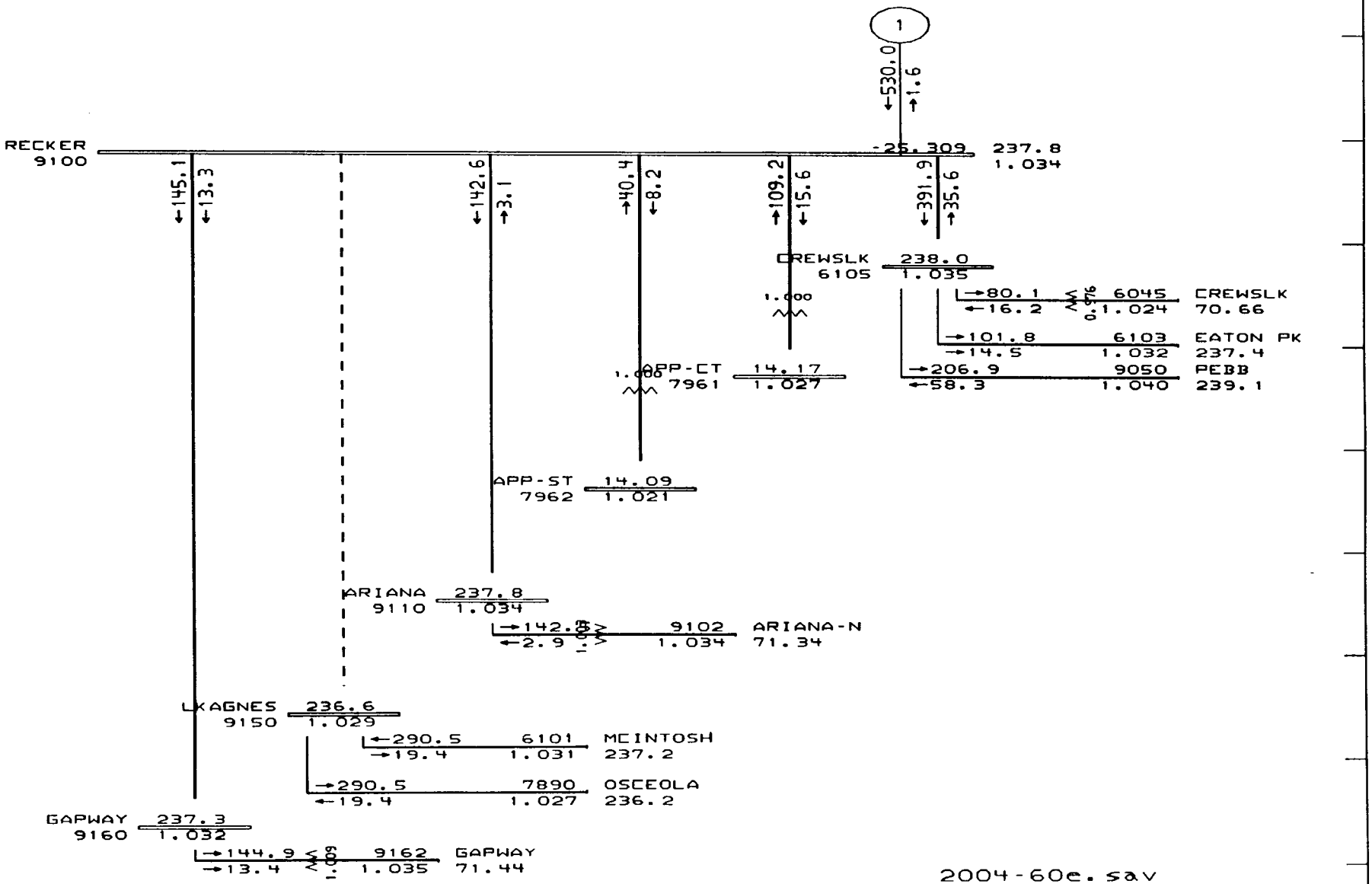


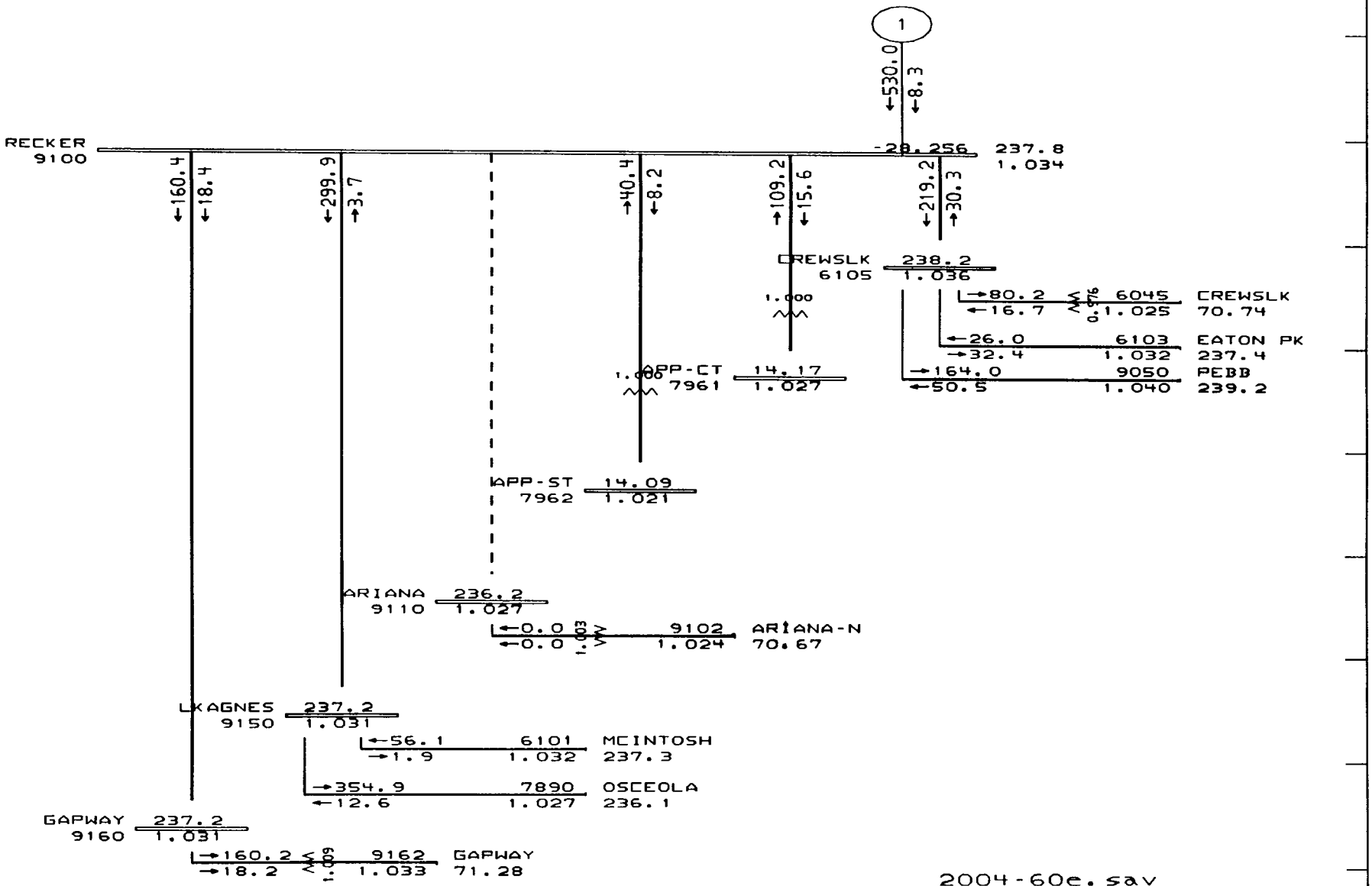
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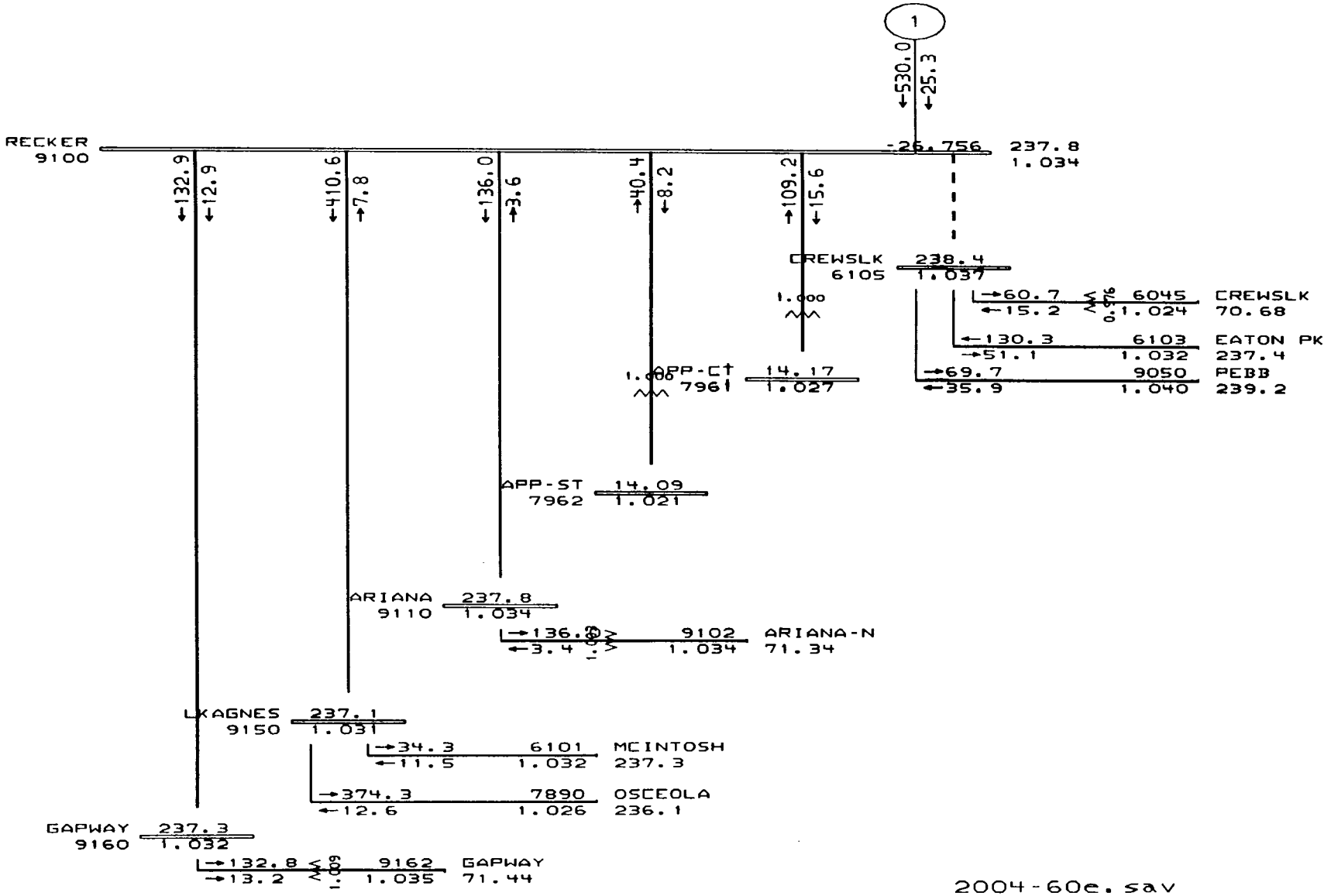
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FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER

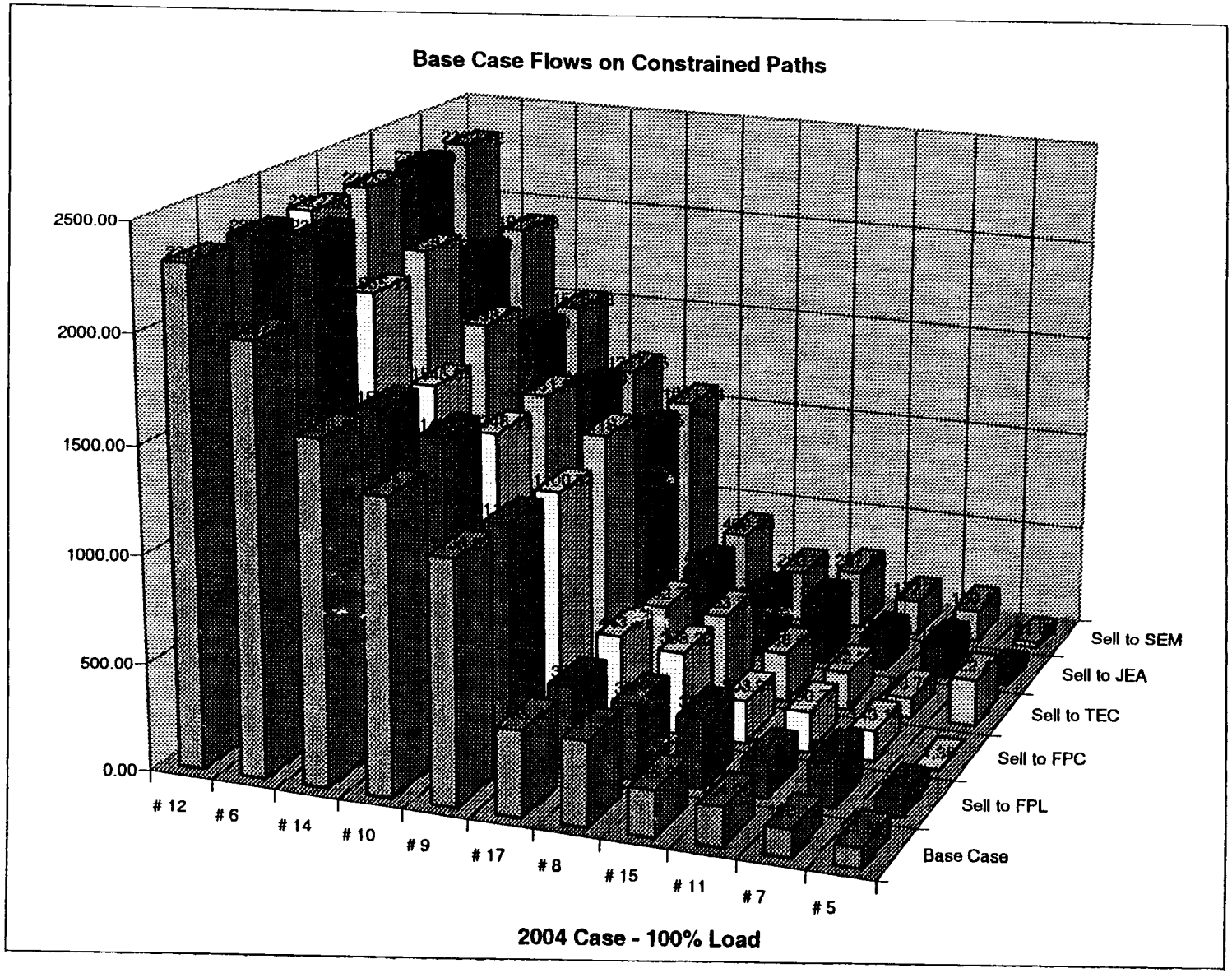
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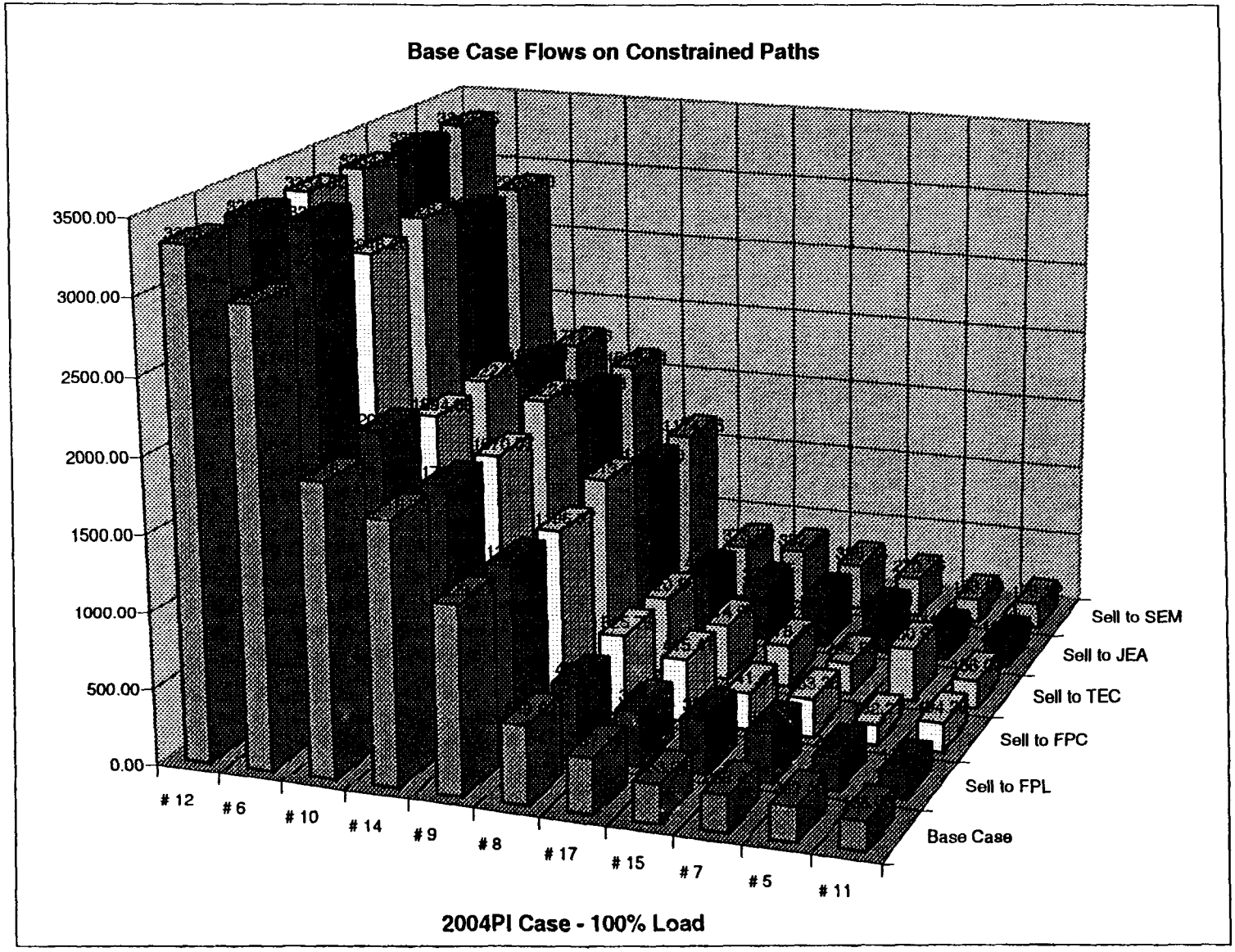

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PROPOSED OSPREY ENERGY CENTER
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APPENDIX IV


Base Case Flows on Constrained Paths
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1500.00
1000.00
500.00
0.00
12
6
14
10
9
17
8
15
11
7
5
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2004 Case - 100% Load


Base Case Flows on Constrained Paths
3500.00
3000.00
2500.00
2000.00
1500.00
1000.00
500.00
0.00
12
6
10
14
9
8
17
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Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2004PI Case - 100% Load

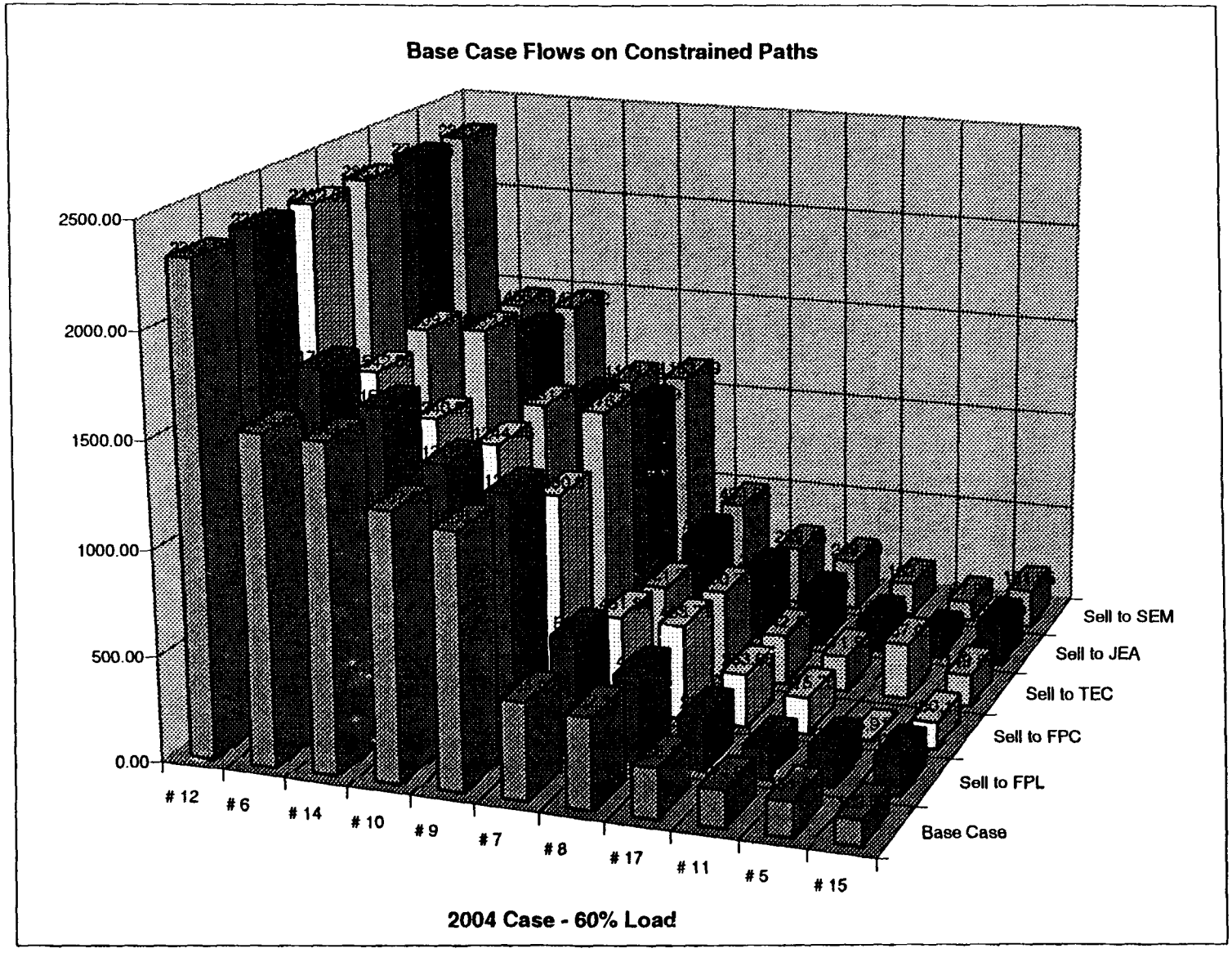

Base Case Flows on Constrained Paths
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14
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9
7
8
17
11
5
15
Sell to SEM
Sell to JEA
Sell to TEC
Sell to FPC
Sell to FPL
Base Case
2004 Case - 60% Load

Table 1
Summary of Constrained Paths
in Base Case & OEC Alternatives

	Case 2004	OEC Sell 500 MW to :				
		Case 2004A	Case 2004B	Case 2004C	Case 2004D	Case 2004E
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
# 12	2314.17	2320.28	2322.50	2325.21	2330.50	2332.42
# 6	1997.09	2344.98	1955.11	2038.61	1903.84	1912.43
# 14	1596.51	1578.06	1545.64	1698.67	1535.50	1526.48
# 10	1373.65	1483.49	1348.16	1381.96	1273.29	1217.95
# 9	1136.02	1121.98	1100.54	1219.46	1088.65	1081.64
# 17	395.20	391.21	443.31	402.78	406.67	409.93
# 8	391.70	350.70	398.20	393.24	300.83	250.92
# 15	215.94	328.18	203.94	238.97	303.16	287.24
# 11	184.08	169.91	190.72	182.29	164.78	172.71
# 7	128.19	204.39	143.14	93.76	164.33	160.21
# 5	94.52	86.08	1.38	222.41	40.76	31.62

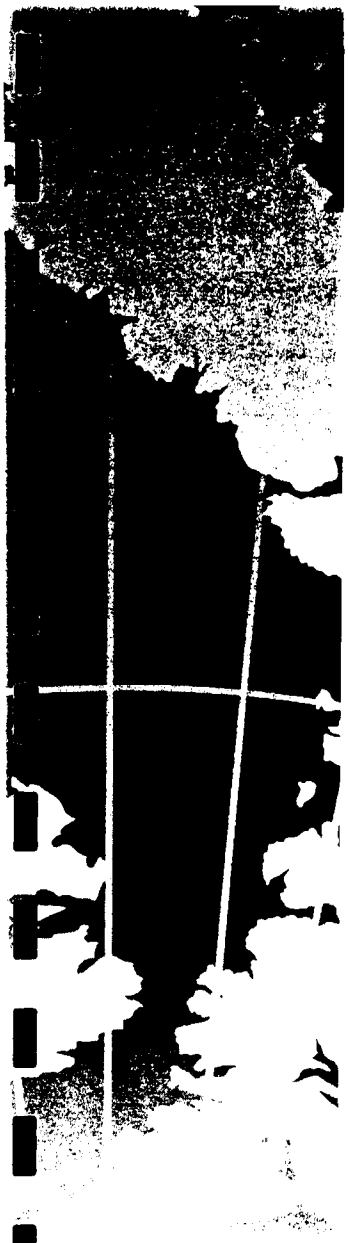
Table 2
Summary of Constrained Paths
in Base Case & OEC Alternatives

	Case 2004PI	OEC Sell 500 MW to :				
	Case 2004PI	Case 2004PIA	Case 2004PIB	Case 2004PIC	Case 2004PID	Case 2004PIE
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
# 12	3328.22	3333.06	3334.80	3334.25	3337.70	3343.05
# 6	2985.61	3332.69	2946.20	3026.09	2898.11	2905.90
# 10	1916.15	2008.69	1894.00	1922.86	1830.74	1772.86
# 14	1718.75	1706.43	1670.07	1822.92	1655.43	1646.84
# 9	1229.97	1220.86	1196.37	1313.92	1181.00	1174.06
# 8	519.82	483.65	525.76	520.56	423.80	373.66
# 17	367.14	363.04	415.41	374.06	378.78	382.17
# 15	253.01	357.05	241.41	278.43	341.67	325.34
# 7	239.25	323.59	253.35	205.55	274.10	270.26
# 5	222.42	220.80	132.21	350.91	167.19	158.60
# 11	188.06	174.06	194.39	186.00	168.72	176.32

Table 3
Summary of Constrained Paths
in Base Case & OEC Alternatives

	Case 2004-60	OEC Sell 500 MW to :				
	Case 2004-60	Case 2004-60A	Case 2004-60B	Case 2004-60C	Case 2004-60D	Case 2004-60E
	Base Case	Sell to FPL	Sell to FPC	Sell to TEC	Sell to JEA	Sell to SEM
# 12	2324.79	2336.76	2332.36	2333.64	2341.56	2341.01
# 6	1554.62	1705.13	1542.08	1609.81	1458.73	1466.53
# 14	1549.13	1549.36	1340.28	1632.35	1485.41	1477.82
# 10	1267.60	1313.02	1244.46	1281.31	1169.55	1109.54
# 9	1208.88	1209.82	1030.01	1276.56	1159.69	1153.29
# 7	464.02	560.89	461.34	421.32	497.47	494.05
# 8	432.14	412.76	453.71	430.39	341.46	289.45
# 17	236.16	251.67	253.68	242.40	246.50	249.80
# 11	174.03	144.22	175.70	171.52	154.69	162.51
# 5	161.86	174.15	5.91	267.02	105.74	97.97
# 15	122.54	179.14	130.19	149.89	207.59	191.95

Osprey Energy Center
Calpine
Witness: Michel P. Armand
Exhibit _____ (MPA-3)



ANALYSIS OF TRANSMISSION SYSTEM IMPROVEMENTS IN SUPPORT OF OSPREY ENERGY CENTER

APRIL 18, 2000

Prepared For

CALPINE EASTERN CORPORATION

UNPUBLISHED WORK © APRIL 2000

Navigant™

Navigant
CONSULTING, INC.

April 18, 2000

Mr. Paul A. Barnett
Calpine Eastern Corporation
The Pilot House, Lewis Wharf
Boston, MA 02110

Subject: Final Report on Transmission System Upgrade Study for Osprey Energy Center

Dear Mr. Barnett:

Enclosed are three copies of the final report on the transmission system upgrade study performed by Navigant Consulting, Inc. (Navigant Consulting) for the Osprey Energy Center. As we discussed last week, the transmission lines impacted will need to be rebuilt using stronger single pole, spun concrete structures to support the larger conductors required to increase line capacity. Calculations performed to make this determination and associated construction cost estimates are included in the report.

Three technically feasible options emerged for increasing the capacity of the existing 150-MVA transformer at Ariana Substation. Two of these options are: adding auxiliary cooling equipment to the existing transformer and adding a second transformer at the substation. Analyses performed to evaluate these options are included in the report along with associated construction cost estimates.

A third option involves no physical changes to the existing substation or transformer. It involves negotiating with Tampa Electric Cooperative to allow the intermittent, short term overloading of the existing transformer, thus incurring a measured loss in the life expectancy of the transformer. Calpine would then reimburse Tampa Electric Company for the loss of life of the transformer at a pre-determined rate. The actual cost of this option could not be determined at this time, and would depend on the amount of transformer loss of life and the negotiated rate of reimbursement agreed to between Calpine and Tampa Electric Company. However, assuming a reasonable rate can be agreed upon, the overall cost for this option should be much less than either of the other two options.

We hope this report and accompanying documents provide you with the information you needed. If you have any questions regarding the report or any other related issue, please call me.

Sincerely,

Frank Alonso

Frank Alonso, P.E.

ANALYSIS OF TRANSMISSION SYSTEM IMPROVEMENTS IN SUPPORT OF OSPREY ENERGY CENTER

APRIL 18, 2000

Prepared For

CALPINE EASTERN CORPORATION

Prepared By



Navigant™
CONSULTING, INC.

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SECTION 1 INTRODUCTION

In support of the proposed Osprey Energy Center, Calpine Eastern Corporation (Calpine), the project's developer, contracted Navigant Consulting, Inc. (NCI) to perform a load flow analysis to determine the capacity of the surrounding transmission system to effectively transform and transmit the center's generated electric power to its customers via the Florida transmission grid. The results of that analysis initially indicated that under certain conditions, four existing facilities would restrict the flow of power out from the energy center. The four critical facilities identified in the analysis are owned by Tampa Electric Company (TECO) and are described as follows:

- The Recker to Lake Agnes 230-kV Transmission Line
- The Recker to Crews Lake 230-kV Transmission Line
- The Crews Lake to Pebbledale 230-kV Transmission Line
- The 150-MVA, 225Y/130 - 69Y/38.8 kV transformer at Ariana Substation.

These lines and substation transformer are located in Polk County, Florida near the City of Auburndale, Florida. A schematic diagram of these lines is shown in Drawing No. 1 in Appendix C.

The analysis conducted by NCI indicates that under maximum loading conditions and single contingency failure of related facilities, the transmission lines interconnecting the energy center with the Florida transmission grid should be rated a minimum of 478-MVA. According to TECO, the overall load carrying capacity of the critical transmission lines is to 398-MVA.

The NCI analysis also indicates that under maximum loading conditions and single contingency failure of associated facilities, the transformer at TECO's Ariana Substation will be overloaded to 220-MVA or 47% above its nominal rating of 150-MVA.

Under certain equipment failure scenarios and maximum loading conditions, the existing transmission system does not have the capacity to accommodate the proposed Osprey Energy Center.

In view of the impact the transmission lines and substation transformer could have on the ability of Calpine to operate the generation units at the Osprey Energy Center at full capacity, Calpine has contracted with NCI to perform this analysis of potential transmission system modifications to increase the capacities of these critical facilities.

The scope of this analysis includes a feasibility study to determine how these facilities could be modified, improved, or replaced so that they are able to carry the additional anticipated loads. Cost estimates are provided for recommended modifications and improvements.

SECTION 2 BACKGROUND

PROBLEM DEFINITION

Most of the Recker to Lake Agnes 230-kV Transmission Line uses tubular steel pole construction with 1590-kcmil, ACSR conductor. However, according to the original information provided by TECO, there was a short line section of old wood pole, H-frame construction with 954-kcmil, ACSR conductors. That section of line was responsible for limiting the overall load carrying capacity of the line to 398-MVA. The rest of the line is rated for 550-MVA. According to more recent information received from TECO, these old sections of the line have been upgraded so that the entire line is now rated 550-MVA.

The Recker to Crews Lake 230-kV Transmission Line is approximately 17 miles long. A major portion of the line uses H-frame structures and 1590-kcmil, ACSR conductor, which provides a load carrying capacity of 550-MVA. However, two short sections of the line, totaling 1.4 miles, located immediately north of Crews Lake Substation, use 954-kcmil, ACSR conductors on wood, H-frame structures. These two short line sections limit the overall capacity of the line to 398-MVA. The capacity of these two line sections needs to be upgraded to match the rest of the line.

The Crews Lake to Pebbledale 230-kV Transmission Line is approximately 6.3 miles long. The entire line uses 954-kcmil, ACSR conductor which limits its load carrying capacity to 398-MVA. The first line section out of Crews Lake Substation is approximately 2.2 miles long and uses wood, H-frame structures. The middle section is approximately 3.1 miles long and uses tubular steel poles with long spans; some exceeding 1000'. The last section of the line is approximately one mile long and uses single pole wood structures. The entire line must be upgraded to 1590-kcmil, ACSR conductor to provide the additional capacity required for the new energy center.

The 230/69-kV auto-transformer at Ariana Substation has a nominal, liquid-immersed, self-cooled (OA) rating of 150-MVA and a liquid-immersed, forced liquid-cooling, forced air-cooled (FOA) rating of 168-MVA (12% over OA rating) with a 55°C/65°C temperature rise. Because of the additional generation at the Osprey Energy Center, under certain load flow conditions, this transformer will be overloaded by almost 50% to 220-MVA. Although this overload condition is not projected to be long lasting, TECO has indicated that they are not willing to operate their transformer above the FOA rating of 168-MVA. Given that constraint, additional transformer capacity will be required at Ariana Substation.

SITE INSPECTION AND DATA GATHERING

On March 22, 2000, representatives from TECO and NCI met at TECO's Recker Substation. The TECO representatives provided line design information and criteria for the two lines under consideration. In addition, they provided nameplate information for the transformer at Ariana Substation. A cursory inspection of the transmission lines near Recker and Ariana Substation was conducted. A visit to Ariana Substation provided a close-up inspection of the 150-MVA transformer.

Photographs taken during the site inspection are included in Appendix B.

SECTION 3 ANALYSIS

TRANSMISSION LINE OPTIONS

There are only two possible option for increasing the capacity of a power transmission line: increase the line operating voltage or increasing the current carrying capacity of the line by installing a larger conductor or bundling two or more conductors per phase.

For existing lines that are already interconnected within an existing transmission grid, the option to increase the line operating voltage is not cost effective. It involves:

- Voltage transformations at both ends of the line -- from the transmission grid voltage to the new line voltage at one end and back from the line voltage to the grid voltage at the other end (The large transformers required makes this option very costly.),
- Replacement of all line structures to accommodate the increased line to ground clearances, conductor to structure clearances, and structure strength requirements, and
- Acquisition of additional right-of-way for operating the line at a higher voltage.

Therefore, in this situation, this option is not cost effective.

Upgrading the transmission line's capacity by increasing the size of the line conductors can sometimes be accomplished with minimal costs. Such would be the case if only the conductors are replaced and all the other hardware and equipment are reused with minor structure adjustments for ground clearances and for the increased loading resulting from the larger conductors. However, typically, the structures are old or not originally designed to handle the increased loading resulting from the larger conductors. Also, in some cases the insulators have to be changed to higher strength type insulators. In most cases, the conductor and shield wire attachment points on the structures will have to be raised to accommodate the greater sag associated with the larger conductors.

TRANSMISSION LINE DESIGN CRITERIA

The Recker to Crews Lake and the Crews lake to Pebbledale 230-kV Transmission Lines were designed and constructed in the 1960's and use old wood, H-frame structures with suspension insulators or single pole wood structures with post insulators to support the 954 or 1590-kcmil, ACSR conductors. A 3.1-mile section of the Crews Lake to Pebbledale Line uses tubular steel poles with 954-kcmil, ACSR conductor.

The original design met the requirements of the then applicable edition of the National Electrical Safety Code. Any future modifications or improvements to the lines will have to comply with the requirements in the current edition of the same code. Drawing No. 2 in

Appendix C shows TECO's original wood, H-frame structure design used for the major portions of these lines.

A summary of the original design criteria used for the existing H-frame, wood pole line is presented in Table 1 along with TECO's current line design criteria applicable to future lines.

Table 1

	Design Criteria for Existing Lines	Design Criteria for New Lines
CONDUCTOR	954-kcmil, ACSR-S, Code Name "Cardinal"	1590-kcmil, ACSR, Code Name "Lapwing"
OHGW	3/8" HS steel	3/8" HS steel
INSULATION	For wood, H-frame: 11 units 5-3/4" X 10"suspension type For single wood poles: 230-kV post insulators For tubular steel poles: polymer insulators in braced post arrangement	If exiting H-frames reused, 11 units 5-3/4" X 10" high strength suspension type If structures are changed to concrete or tubular steel poles, use polymer insulators in a braced post arrangement
LOADING CONDITIONS	Not known.	NESC Light with following limiting conditions: 75^{0}F with 45psf wind (TECO Extreme) 212^{0}F with no-wind (Maximum Sag) 30^{0}F with no-wind (Minimum Sag)
CONDUCTOR SPACING	For H-frame construction: 17' - 6" with 36' crossarm 19' - 6" with 40' crossarm For single pole construction: 10' between phase conductors 12' between top phase conductor and OHGW.	For H-frame construction: 17' - 6" with 36' crossarm 19' - 6" with 40' crossarm For concrete or steel pole construction: 10' between phase conductors 12' between top phase conductor and OHGW.
BASIC POLE HEIGHT	70' - 75' for H-frames 80' - 85' for single poles	70' - 75' for H-frames 80' - 85' for single poles
CLEARANCE TO GROUND	25'	25'

Both sets of design criteria were used in this analysis to evaluate the feasibility of the various options considered for upgrading the transmission lines to 550-MVA capacity. The design criteria for existing lines were used to determine the design loading of the existing transmission lines. The design criteria for new lines were used to determine if the existing lines can support the larger sized conductor and to determine the required strength of new concrete or steel poles to be used if lines had to be rebuilt.

TRANSMISSION LINE OPTIONS FOR INCREASING CONDUCTOR SIZE

Increasing the size of the phase conductors on the existing transmission lines can be accomplished by re-framing the existing wood, H-frame structures or by replacing them with concrete or tubular steel poles. In either case, we assumed the spans lengths and structure alignments remain the same. If the existing structures are reused, obviously, they will be re-framed in place. If new concrete or steel structures are used, they will be installed in close proximity to the existing structures and along the same centerline. With this approach, no additional right-of-way will be required.

Three options were considered in this analysis for increasing the line conductor size to 1590-kcmil. The three options are described as follows:

Option L1: Reuse the existing wood, H-frame or single pole, wood structures. Modify structures as required and install new 1590-kcmil conductor.

Option L2: Rebuild line in place using spun concrete poles. Install new 1590-kcmil, ACSR conductors on new concrete poles. Then, remove existing wood H-frame structures with 954-kcmil ACSR conductors.

Option L3: Rebuild line in place using tubular steel poles. Install new 1590-kcmil, ACSR conductors on new steel poles. Then, remove existing wood H-frame structures with 954-kcmil ACSR conductors.

TRANSMISSION LINE TECHNICAL FEASIBILITY ANALYSIS

Table 2 lists the basic line criteria, conductor data, conductor loads, preliminary structure loading criteria and capacity factors, and resultant vertical and horizontal loads for H-frame, spun concrete, and tubular steel structures proposed for the three options being considered. Overload factors and safety factors are in accordance with applicable sections of the National Electrical Safety Code (NESC).

Table 2

Basic Line Criteria

Max. Wind (psf)	45	(Extreme wind condition on cylindrical surfaces per TECO)
Average Span (ft.)	457	
Max Wind Span (ft.)	571	
Max Weight Span (ft.)	686	
Conductor Loading Const.	0.05	(in lbs./LF from NESC Table 251-1)
Cylindrical Shape Factor	1.0	(Per NESC 252.B.2.a)

Conductor Data

Conductor Type	954 ACSR	1590 ACSR	3/8" HS Steel	7#10 AW
Weight (lbs./LF)	1.229	1.792	0.237	0.1647
Diameter (in.)	1.196	1.504	0.12	0.306

Conductor Loading per NESC 251

Conductor Type	954 ACSR	1590 ACSR	3/8" HS Steel	7#10 AW
Vertical Load (lbs.)	842	1228	187	113
Horizontal Loads (lbs.)	2562	3222	257	656
Resultant Load (lbs.)	2697	3448	318	665
Total Load (lbs.)	2720	3471	341	688

(Total loads include NESC Loading Constant.)

Structure Loading Criteria and Capacity Factors per NESC 252

(Assumed H-frame structures use Class 1 type wood poles.)

	H-Frame W/954	H-Frame w/1590	Concrete Pole	Tubular Steel Pole
Overload Capacity Factors				
Vertical Loads	2.20	2.20	1.50	1.50
Transverse Loads	4.00	4.00	2.50	2.50
Longitudinal Loads	1.33	1.33	1.10	1.10
Average Pole Height (ft.)	70	70	85	85
Setting Depth (ft.)	10.0	10.0	10.5	10.5
Pole Length Exposed to Wind Load (ft.)	60.0	60.0	74.5	74.5
Pole Top Diameter (in.)	8.6	8.6	18.0	13.0
Pole Diameter at Ground Line (in.)	15.76	15.76	32.9	27.9
Pole Wind Load Area (sq. ft.)	63.1	63.1	158.0	127.0

Table 2
(Continued)

Resultant Vertical and Horizontal Loads

	H-Frame W/954	H-Frame w/1590	Concrete Pole	Tubular Steel Pole
Conductor Vertical Load/Phase (lbs.)	1869	2720	1855	1855
OHGW Vertical Load/Wire (lbs.)	257	441	301	301
Weight of Insulators/Phase (lbs.)	363	165	113	113
Conductor Wind Load/Phase (lbs.)	10335	12973	8108	8108
OHGW Wind Load/Wire (lbs.)	2712	1102	689	689
Wind Load on Poles (lbs.)	2839	2839	7110	5713

TECHNICAL FEASIBILITY OF OPTION L1

The main consideration when increasing the size of line conductors is to determine if the existing structures can support the increased loading resulting from the higher weight and wind loading associated with the larger conductors.

Inherently, wood, H-frame structures are relatively strong and provide greater flexibility than single pole steel or concrete structures. However, they are statically indeterminate structures and difficult to analyze. There are various techniques available for analyzing H-frame structures: (1) classical indeterminate structural analysis, (2) matrix method of structural analysis, and (3) approximate method. The approximate method will be used for this feasibility analysis for the following reasons:

- Wood is a variable product. More accurate analysis techniques do not always mean assured safety,
- Classical indeterminate analysis and matrix methods are too cumbersome,
- Loading inputs for the classical indeterminate analysis and matrix methods cannot be predicted or determined with a high degree of accuracy.

The approximate method was used to analyze the strength of the existing H-frame structures to determine if they can withstand the additional loading resulting from the use of 1590-kcmil ACSR phase conductors. The calculations, included in Appendix A, show the maximum span limitations resulting from comparing the resultant moment from wind loading on poles and conductors at selected critical points along the length of the poles with the available moment capacity of the poles at that same point. The results of the calculations show the following:

- The resultant moment at the point of crossarm attachment allows a maximum span of 352 ft. This is much less than the existing average span of 457 ft.
- The resultant moment at the top cross brace attachment point allows a maximum span of 448 ft. Again, this is less than the existing average span.
- The resultant moment at the bottom cross brace attachment point allows a maximum span of 105 ft. It is also well below the existing average span.
- The resultant ground line moment allows for a maximum span of 203 ft.

Single pole wood structures are easier to analyze than H-frame structures. The typical structure strength calculations are included in Appendix A. They show that the maximum span resulting from comparing the resultant moment from wind loading on the pole and conductors with the ultimate ground line moment of the pole is 14.49 feet which is much less than the existing average span of 275.4 feet.

Clearly, from the results of the H-frame and single pole maximum allowable spans calculations, the existing H-frame and single wood pole structures cannot support the 1590-kcmil, ACSR conductors without major modifications that would be more costly than total line replacement. For this reason, this option was eliminated from further consideration.

TECHNICAL FEASIBILITY OF OPTIONS L2 AND L3

The technical analysis of these two options can be combined because they are very similar in construction and appearance. The loading analysis for these structures is very similar. Currently TECO uses both spun cast concrete poles and tubular steel poles for 230-kV transmission lines throughout their system. The technical feasibility of using either of these types of structures for upgrading the lines has been proven by other existing TECO lines that use 1590-kcmil, ACSR conductors. (See Pictures 12 through 14, 18 through 21, and 24 in Appendix B.)

Generally, tubular steel poles are stronger than wood or concrete poles. They are typically used in situations where guying is required, but not possible, or where longer spans are desired or required. Self supported angle and corner structures are typically made from tubular steel. Tubular steel poles are fabricated and shipped in sections that are assembled at the job site. Thus, they require smaller cranes and erection equipment during construction. Because they are fabricated in sections, they are also better suited for lines built along right-of-ways with difficult or limited access. The smaller pole sections are easier to maneuver through difficult turns and restricted areas.

The major disadvantages of tubular steel poles are higher initial cost, corrosion, the need for foundations and anchor bolts, and they are difficult to modify in the field.

Although steel galvanizing processes have improved, the section joints and other bolted connections on tubular steel poles are prone to corrosion problems. These can be minimized by careful installation procedures that minimize the damaged to the galvanizing coating. Because they are susceptible to corrosion, most utilities avoid direct burial of tubular steel poles. Typically, they are provided with a concrete foundation that requires precise placement, spacing, and embedment of anchor bolts. The foundations and anchor bolts also increase overall line construction costs.

Modification of tubular steel pole structures in the field is very difficult because they cannot be field drilled. They are shipped from the factory complete with welded flanges and other provisions for the installation of insulators and other hardware. Any field modifications are usually accomplished with steel bands around the pole or by having factory personnel come out to the field to make the required modifications. Any field changes that involve removing and replacing the galvanizing coat on the steel becomes a potential source for corrosion.

The initial cost of tubular steel poles can be 30 to 50% higher than concrete poles. However, because they are stronger, the average span of the line can be increased thereby reducing the total number of poles required and bringing the overall constructed cost of the line down to the same range as with concrete poles. Since we will not be changing the existing span lengths for the existing transmission lines, the ability to go longer spans is not applicable negating the strength advantage tubular steel poles have over concrete poles.

Spun cast concrete poles are heavier than but not as strong or as expensive as tubular steel poles. They provide sufficient strength for average transmission line spans of 400 to 600 feet, depending on the size of the conductors, maximum wind loading conditions, and soil conditions. Concrete poles can be directly buried requiring no foundation or anchor bolts. Where soil conditions require it, they are provided with a concrete footing to spread the bearing load at the bottom of the pole and with concrete backfill to provide greater distribution of side bearing loads on the sides of the hole.

With certain limitations, spun concrete poles can be field drilled by construction crews making it possible to make framing modifications during construction.

For upgrading the existing transmission lines, we recommend the use of spun concrete poles. They are currently used by TECO on other transmission lines and they provide the strength and versatility required for such a project. Most of the structures will have a tangent conductor alignment. Where guying is required, the existing right-of-way is wide enough to allow it. In fact, the existing structures are guyed at angle locations.

The cost estimate for increasing the electrical load carrying capacity of the existing transmission lines from Recker to Crews Lake and from Crews Lake to Pebbledale were prepared based on the use of spun cast concrete poles.

SUBSTATION TRANSFORMER OPTIONS

There are two options for increasing the capacity of the transformer at Ariana Substation. They are described as follows:

Option T1: Increase the capacity of the existing transformer by adding auxiliary cooling equipment, or

Option T2: Adding a second transformer at the substation.

EXISTING TRANSFORMER RATINGS

The nameplate information for the existing transformer was provided by TECO and is summarized in the following Table 3.

Table 3

Manufacturer:	McGraw-Edison Power Systems Division
Serial Number:	C04020-5-1
Class:	FOA
Number of Phases:	3
Frequency:	60-Hz
KVA Rating:	150000/168000 kVA
Voltage Ratings:	225000GRD.Y/129904-69000GRD.Y/39837 Volts
Temperature Rise:	55⁰/65⁰C Rise @ Full Load Continuously
Percent Impedance:	8.6% at 150000-kVA
Basic Lightning Impulse Insulation Level:	825-kV high voltage side 350-kV low voltage side 150-kV neutral bushings
Approximate Total Mass:	318,400 Lbs.
Insulating Liquid:	Mineral Oil

TRANSFORMER TECHNICAL FEASIBILITY ANALYSIS

The autotransformer at Ariana Substation has a nominal, OA rating of 150-MVA. To reach its FOA rating of 168-MVA, it has two sets of radiators, oil pumps, and fans mounted on the north side of the transformer as shown in Pictures 2, 3, 6 and 7 in Appendix B. It is not clear, if the FOA rating is achieved in stages or if the cooling fans and pumps all come on at the same time. They seem to be separate, independent systems.

The substation layout provides space for the future addition of a second transformer next to the existing one.

The American National Standards Institute (ANSI) Standard C57.92, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers Up to and Including 100-MVA with 55 °C or 65 °C Average Winding Rise, provides transformer loading limits for normal operation and for moderate sacrifice of life. Although intended for transformers rated less than 100-MVA the Standard can be applicable to this transformer with certain restrictions. The standard says:

> *"Loading of transformers larger than 100-MVA may be limited by factors other than insulation aging such as stray flux, etc. When it is known that such limitations do not exist and insulation aging rather than oil temperature, gassing, tank heating, etc is the controlling factor, this guide may be used."*

Assuming the loading of the transformer at Ariana Substation is not restricted by any of the limiting factors referred to in ANSI Standard C57.92 and that the original transformer design was performed in accordance with ANSI Standard C57.12.00, then its loading limitations can be determined using the information provided in ANSI Standard C57.92.

According to Table 5(l) of ANSI C57.92, with ambient temperature of 30 °C (86 °F), the Ariana transformer can be continuously loaded to 100% of its FOA rating. Under those loading conditions, according to the ANSI Standard, the transformer will reach its normal life expectancy of 6.5 X 10^4 hours (7.4 years) which represents a normal daily loss of life of 0.0369%. The actual life expectancy of the transformer should be considerably greater than 6.5 X 10^4 hours since it is not fully loaded 100% of the time and ambient temperature is not always 30°C. For most transformers, actual life expectancy is 30 to 35 years.

To stay within the temperature rise limitations of the transformer, the continuous load has to be reduced whenever the ambient temperature increases above 30 °C. For example, at 40 °C (104 °F), the continuous load has to be reduced to 91% of the FOA rating or 153-MVA so as not to shorten the life expectancy of the transformer.

At the 30°C ambient temperature, the transformer can be loaded as follows:

Duration	Peak Load (MVA)	Percent of FOA Rating	Percent Loss of Life
½ Hour	274	163	0.25
1 Hour	250	149	0.25
2 Hours	232	138	0.25
4 Hours	217	129	0.25
8 Hours	207	123	0.25
24 Hours	193	1.15	0.25

The table shows that for a 0.25% reduction in the normal life expectancy of the transformer it can be loaded for over 4 hours at 220-MVA which is the overload condition projected by the NCI study for the transformer at Ariana.

This points to an option that cannot be quantified at this time, but one we recommend pursuing with TECO. According to the NCI study, the transformer overload condition is expected to last less than one-hour. Since it will be of such short duration, the anticipated loss of life will be less than 0.25%. We have extrapolated the data provided in Table 5 (l) in ANSI Standard C57.92 and determined that the projected loss of life for operating the transformer at 220-MVA for one-hour each day would be 0.16%. That equates to a reduction of 4.3 days from the normal life expectancy of the transformer for each occurrence of this overload condition.

It should be possible, and probably less costly to negotiate a price with TECO for this projected loss of life so that they would be made whole in case such an overload condition occurred. This would eliminate the need to pursue the options being considered.

TECHNICAL FEASIBILITY OF OPTION T1

Before considering the detailed technical feasibility of this option, the construction sequence for its implementation should be reviewed. Replacing the radiator, cooling fans and oil circulating pumps on the existing transformer will require its removal from service for a long time. Since this is the only transformer at Ariana Substation, removing it from service essentially shuts down the entire substation and removes one source feeding TECO's 69-kV system. Therefore, to perform the required transformer modifications, the installation of a temporary transformer may be required to maintain the substation operational while the transformer is being modified.

This requirement will be included in the cost assessment of this option.

To increase the forced cooled loading capacity of the existing transformer to 220-MVA (50% above its OA rating), additional auxiliary cooling equipment such as fans, external forced-oil coolers, or water spray equipment will have to be provided. The amount of additional loading capacity resulting from the addition of auxiliary cooling equipment varies widely, depending upon:

- Design characteristics of the transformer
- Type of auxiliary cooling equipment provided

No general rules can be given for such supplemental cooling. Each transformer must be evaluated individually.

The standard levels of overload capacity using auxiliary cooling equipment are 125%, 133%, and 166% of the transformer's OA rating, corresponding to 187.5, 199.5, and 249-MVA respectively for the Ariana Substation transformer. These levels are industry wide standards. Therefore, an increase to 220-MVA rating for the Ariana transformer is within standard industry practice.

However, unless provisions were made in the original transformer design for the future addition of cooling equipment, retrofitting such equipment on an existing transformer can be expensive and limited by the original design criteria. And, the effectiveness of such modifications is not always predictable.

Internal limitations may also exist that are difficult to evaluate without additional information about the detailed design of the transformer. Some of these are:

- Capacity for oil expansion
- Size of internal leads
- Tap Changer current carrying capacity
- Stray flux heating.

In addition, there are external limitations that must also be considered such as the thermal capability of associated equipment such as busses, conductors, cables, circuit breakers, disconnecting switches, and current transformers.

At 69-kV, the original design provided for a minimum of 1400-A per phase at the FOA loading level. At the projected load of 220-MVA, the phase current would be 1840-A. That represents an additional 440-A per phase on the 69-kV side of the transformer. All external 230-kV and 69-kV equipment associated with the transformer should be capable of carrying the additional current.

Assuming there are no internal or external limitations to increasing the rating of the transformer to 220-MVA, adding cooling fans to the existing transformer would require major modifications. The existing radiators would have to be replaced with much larger units with greater surface area to make the fans more efficient. Additional radiators would be required. They could be installed on the west side of the transformer, which is the only unencumbered side. The potential transformers and air-break switches north of the transformer will have to be relocated along with their associated support structures and foundations. (See Pictures 6, 7, 10, 11, 16, and 17 in Appendix B.)

The existing fans and oil circulating pumps are fed from an auxiliary transformer rated 75-kVA. It will not have sufficient capacity to provide a viable source of power for the larger number of fans and oil circulating pumps required. The associated power distribution panelboard will also have to be replaced to provide a greater number of circuits for the new fans and pumps.

Pumping the oil through the radiators would reduce the number of fans required. However, the efficiency of forced oil circulation is limited by diminishing returns. In order to release the optimum amount of heat the oil has to be in contact with the cooled radiator surfaces for a given period of time. The length of contact time required is determined by the ambient temperature and humidity, the heat exchange ratios between the oil and the radiators, and the amount of heat the external fans can remove from the radiators.

Forcing the flow of oil through the radiators faster than the required amount of time it takes for optimum heat removal is not cost effective. Typically, oil-pumping equipment can provide between a 12% and 20% increase in the rating of the transformer. That would provide a boost of 18 to 30-MVA. The remaining 40 to 52-MVA required over the OA rating will have to be provided by cooling fans.

In conclusion, while the addition of auxiliary cooling equipment to increase the rating of the existing transformer at Ariana Substation is technically feasible, it will require extensive modifications to the transformer and the surrounding equipment. It will also require the installation of a temporary transformer to maintain the substation in service during construction.

The proposed modifications will include the following as minimum:

- Coordinating with TECO and transformer manufacturer to verify that the rating increase is not limited by the internal transformer limitations discussed previously,
- Verifying that the ratings and capacities of associated equipment and hardware are high enough to accept the increased currents and associated heating,
- Installing a temporary transformer with associated busses, disconnect switches, and with self contained metering and relaying devices,
- If required, replacing external equipment that is undersized for the increased current flows,
- Relocating existing air-break switches and potential transformers with associated supports,
- Removing existing radiators with associated fans, oil circulating pumps, and associated piping and replacing with larger radiators with new fans, oil circulating pumps, and piping, and
- Relocating existing lightning arrestors currently located directly over the existing radiators.

TECHNICAL FEASIBILITY OF OPTION T2

The approach for adding a second transformer at the Ariana Substation includes providing a new transformer bay adjacent to the existing transformer. The substation layout provides space for a second transformer to be added at a future date. There are no technical limitations for the implementation of this option.

SECTION 4 COST ESTIMATES

Prices for equipment, materials, and labor were obtained from past NCI projects, local contractors, vendors, manufacturers, and other utilities. All prices were adjusted to 1999 prices using the "handy-Whitman Index of Public Utility Construction Costs". The 1999 prices were increased by 3% to approximate Y2000 prices. This increase is based on an assumed annual inflation rate of 3%.

Table 4 provides a breakdown of the estimated construction cost for upgrading the two short sections of the Recker to Crews Lake Line that currently uses 954-kcmil, ACSR conductor. Table 5 provides a breakdown of the estimated cost for upgrading the structures and conductors in the wood pole sections of the Crews Lake to Pebbledale Line and the conductor in the existing section of he line that currently uses single pole tubular steel structures. Table 6 provides a breakdown of the estimated construction costs for adding auxiliary cooling equipment to the existing 150-MVA transformer at Ariana Substation. Finally, Table 7 provides a breakdown of the estimated construction cost for adding a second transformer at Ariana Substation.

The following budget level construction cost estimates have an accuracy of ± 15%.

Table 4

Construction Cost Estimate for
Upgrading Sections of the
Recker to Crews Lake 230-kV Transmission Line

Assumptions:

Flat terrain
Normal access
1590-kcmil ACSR conductor
3/8" overhead ground wire
Existing right-of-way is adequate
No environmental statement required
Poles are spun cast concrete
Line is single circuit
Line section length is 7387' (= 1.4 miles)
Number of tangent structures = 14
Number of corner structures = 4
Number of deadend structures = 1

Table 4
(Continued)

Cost Estimate:

Concrete Poles	104,710
Guying	23,000
Conductor	209,860
Overhead Ground Wire	34,010
Insulators and Hardware	53,120
Demolition	12,470
Surveying	4,200
Geological Investigation	7,000
Engineering	67,260
Construction Services	53,800
TOTAL	**$569,430**

Table 5

Construction Cost Estimate for
Upgrading the Crews Lake to Pebbledale 230-kV Transmission Line

Assumptions:

Flat terrain
Normal access
1590-kcmil ACSR conductor
3/8" overhead ground wire
Existing right-of-way is adequate
No environmental statement required
New poles will be spun cast concrete
Line is single circuit
Line length is 33,088' (= 6.3 miles)
Number of tangent structures = 47
Number of corner structures = 10
Number of deadend structures = 2
Number of angle structures = 6

Cost Estimate:

Concrete Poles	155,340
Guying	50,600
Conductor	710,940
Overhead Ground Wire	110,420
Insulators and Hardware	83,900
Demolition	40,440
Surveying	9,600
Geological Investigation	16,000
Engineering	129,500
Construction Services	117,720
TOTAL	**$1,424,460**

Table 6

**Construction Cost Estimate for
Adding Auxiliary Cooling Equipment to
Existing Transformer at Ariana Substation**

Assumptions:

No site work required
Normal access
Soil is adequate for new equipment foundations
No additional land required
No control building required
No environmental statement required
Existing transformer suitable for upgrading

Cost Estimate:

Auxiliary Cooling Equipment	370,330
Modifications to Existing Transformer	166,650
Installation of Cooling Equipment	53,700
Adjustments and Relocation of Surrounding Equipment	113,130
Temporary Transformer	281,420
Demolition	83,770
Surveying	7,200
Engineering	160,350
Construction Services	128,280
TOTAL	**$1,364,830**

Table 7

Construction Cost Estimate for
Adding a Second Transformer at Ariana Substation

Assumptions:
No site work required
Normal access
Soil is adequate for new foundations
No additional land required
No control building required
No environmental statement required
Existing transformer stays
New transformer is 150-MVA, FOA to match existing

Cost Estimate:

New Transformer	2,574,690
Circuit Protection Device (Breaker)	187,720
Switches	58,740
Control and Protection Systems	83,010
Bus Systems (230-kV and 69-kV)	126,420
Equipment Support Foundations	152,390
Surveying	12,000
Engineering	477,450
Construction Services	381,960
TOTAL	**$4,054,380**

SECTION 5 CONCLUSIONS AND RECOMMENDATIONS

The existing wood, H-frame and single pole structures in sections of the Recker to Crews Lake and Crews Lake to Pebbledale 230-kV Transmission Lines are not strong enough to support the larger 1590-kcmil, ACSR conductors. Therefore, those line sections should be upgraded using spun cast concrete poles. Upgrading the line sections in the Recker to Crews Lake Line will cost approximately $549,880. Upgrading the sections of the Crews Lake to Pebbledale Line will cost approximately $1,424,460.

To resolve the transformer overloading problem at Ariana Substation we looked at two conventional options and one potential option that requires no physical modifications to the Substation; but does require entering into negotiations with TECO regarding compensation for the planned loss of life of the transformer.

For obvious economic and scheduling reasons, we recommend pursuing the following options in the order in which they are:

- Making no changes at the substation and entering negotiations with TECO to arrive at an equitable method for reimbursing them for the loss of life of the transformer resulting from the short periods of overloading above its FOA rating.

- Adding auxiliary cooling equipment to the existing transformer to increase its capacity by 50% to 220-MVA. While this is technically feasible and less costly than installing a new larger transformer at the Substation, it is subject to many limitations including those limitations imposed by the original transformer design. These limitations are not apparent from a physical inspection of the transformer. Therefore, we were not able to evaluate them. This option requires the installation of a temporary second transformer at the substation to maintain the station in service while the modifications are made to the existing transformer.

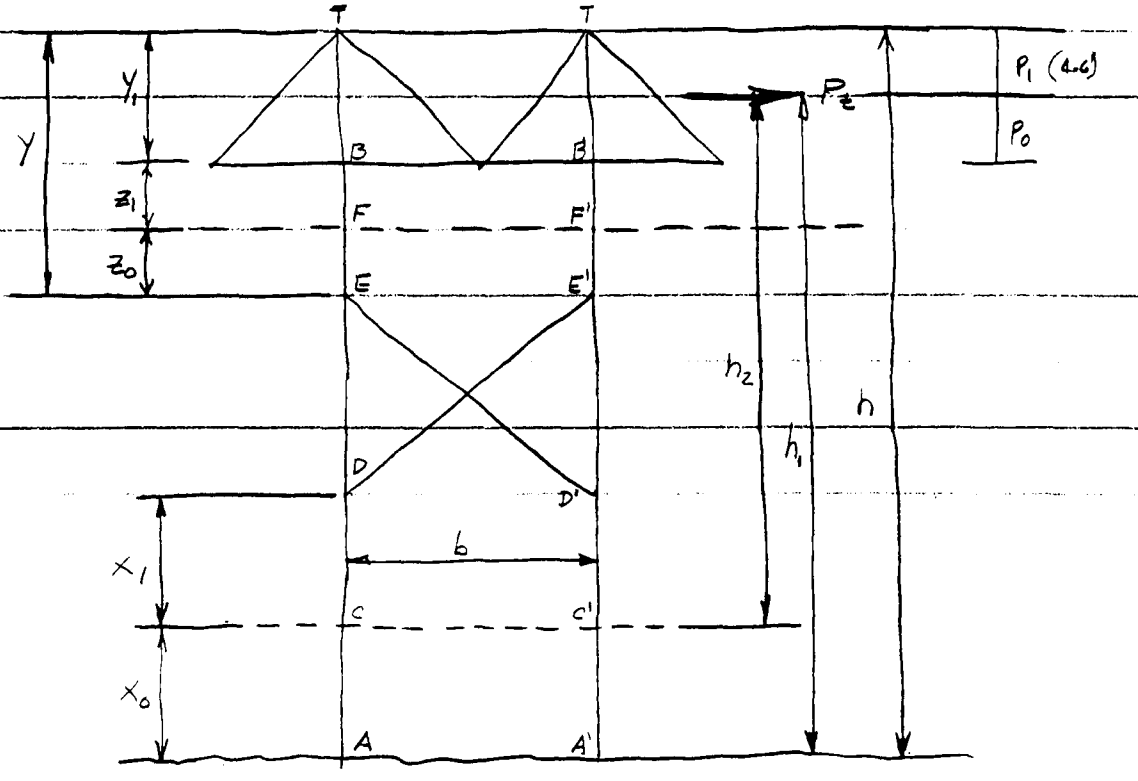
- Adding a second transformer at Ariana Substation is the most costly option. While it does not carry any of the caveats that the two previous options have, it is three times more costly than the addition of cooling equipment to the existing transformer. It requires the installation of a new transformer bay at the station with associated breakers, bus, and switches.

APPENDICES

APPENDIX A CALCULATIONS

Calculation of Max Horiz Spans for H-Frame, Wood Pole Structure

Conductor is 1590 ACSR



For the TECO Structure:

$Y = 19'$ $\quad x_1 + x_0 = 21'$

$Y_1 = 10'$ $\quad z_1 + z_0 = 9'$

$h = 59'-6''$ $\quad P_1 + P_0 = 10'$

$b = 19'-6''$ $\quad h_1 = 60' - 4.6' = 55.4'$

$$\frac{x_0}{x_1 + x_0} = \frac{C_A(2C_A + C_D)}{2(C_A^2 + C_A C_D + C_D^2)}$$

$h_2 = h_1 - x_0 = 55.4' - 11.3$

$h_2 = 44.1'$

Where: C_A = circumference at point A = 49.5"

C_D = circumference at point D = 44"

$$x_o = \left[\frac{49.5\left[(2\times 49.5)+44\right]}{2\left[(49.5)^2+(49.5\times 44)+(44^2)\right]}\right] \times 21'$$

$$\underset{143}{49.5\left[(2\times 49.5)+44\right]} \qquad \underset{6564.25}{2\left[(49.5)^2+(49.5\times 44)+(44^2)\right]}$$

$x_o = 11.3' \Rightarrow x_1 = 9.7'$

Also

$$\frac{Z_o}{Z_1+Z_o} = \frac{C_E\left(2C_E+C_B\right)}{2\left(C_E^2+C_E C_B+C_B^2\right)}$$

Where: C_E = circumference at point E = 34"

C_B = circumference at point B = 30"

$$Z_o = \left[\frac{34.5\left[(2\times 34.5)+30.8\right]}{2\left[(34.5)^2+(34.5\times 30.8)+(30.8)^2\right]}\right] 9$$

$$\underset{3443.1}{34.5\left[(2\times 34.5)+30.8\right]} \qquad \underset{6402.98}{2\left[(34.5)^2+(34.5\times 30.8)+(30.8)^2\right]}$$

$Z_o = 4.8 \Rightarrow Z_1 = 4.2'$

$$\frac{P_o}{P_1+P_o} = \frac{C_B\left(2C_B+C_T\right)}{2\left(C_B^2+C_B C_T+C_T^2\right)}$$

C_B = circumference at point B = 30.8"

C_T = circumference at point T = 27"

$$P_o = \left[\frac{30.8\left[(2\times 30.8)+27\right]}{2\left[(30.8)^2+(30.8\times 27)+(27)^2\right]}\right] 10'$$

$$\underset{2728.88}{30.8\left[(2\times 30.8)+27\right]} \qquad \underset{5018.48}{2\left[(30.8)^2+(30.8\times 27)+(27)^2\right]}$$

$P_o = 5.4' \Rightarrow P_1 = 4.6'$

Max Horizontal Spans (w/ 1590 ACSR Cond. on H-Frames)

$$HS_B = \left[M_B - \frac{(OCF)(F)(Y - Z_0)(d_t + d_F)(Z_1)}{2} \right] / \left[\frac{(OCF)(P_t)(Z_1)}{2} \right]$$

Where: HS_B = Max. Horiz. Span due to moments at point B

M_B = Moment capacity at point B (ft-lbs)

OCF = Overload capacity factor

F = Wind pressure on cylindrical surface (psf)

Y = 19'

Z_0 = 4.8'

d_t = Pole diameter at pole top (ft)

d_F = Pole diameter at point F (ft)

Z_1 = 4.2'

P_t = Total horiz force/LF due to wind on conductors & OHGW (lbs/ft)

In this case: M_B = 61,400 (ft-lbs) from REA Bulletin 1724E-200, Appendix F Page F-11

OCF = 4.0 from NESC

F = 45 (psf)

d_t = 8.6/12 (ft)

d_F = 10.97/12 (ft)

P_t = (5.64 lbs/ft x 3) + (45 lbs/LF x 2)

= 17.82

So:

$$HS_B = \frac{\left[61{,}900 - \frac{4.0 \times 45 \times 14.2 \times 1.63 \times 4.2}{2}\right]}{\left[\frac{4.0 \times 17.82 \times 4.2}{2}\right]}$$

$$HS_B = \frac{61{,}900 - 8749.19}{149.69} = \underline{351.73'} < 457' \text{ Exist. Avg. Spd.}$$

$$HS_E = \left[M_E - \frac{(OCF)(F)(Y - z_o)(d_t + d_f)(z_o)}{2}\right] / \left[\frac{(OCF)(P_T)(z_o)}{2}\right]$$

Where: HS_E = Max. Horiz. Span due to moments at point E

M_E = Moment capacity at point E (ft-lbs)

All other variables are the same

In this case: $M_E = 86{,}700$ (ft-lbs)

$$HS_E = \left[86{,}700 - \frac{4.0 \times 45 \times 14.2 \times 1.63 \times 4.8}{2}\right] / \left[\frac{4.0 \times 17.82 \times 4.8}{2}\right]$$

$$HS_E = \frac{86{,}700 - 9999.07}{171.07} = \underline{448.36'} < 457' \text{ Avg. Span}$$

$$HS_D = \left[M_D - \frac{(OCF)(F)(h-x_o)(x_1)(d_t+d_c)}{2} \right] / \left[\frac{(OCF)(P_t)(x_1)}{2} \right]$$

Where: HS_D = Max. Horiz. Span due to moments at point D

M_D = Moment capacity at point D (ft-lbs)

d_c = Pole diameter at Point C (ft)

In this case: M_D = 152,200 (ft-lbs)

d_c = 14.08/12 ft

All other variables have the same meanings & values

So:

$$HS_D = \left[152,200 - \frac{4 \times 45 \times 48.2 \times 9.7 \times 1.89}{2} \right] / \left[\frac{4 \times 17.82 \times 9.7}{2} \right]$$

$$HS_D = \frac{152,200 - 79,528.55}{691.42} = \underline{105.1'} << 457' \text{ Exist Avg Sp}$$

$$HS_A = \left[M_A - \frac{(OCF)(F)(h-X_o)(X_o)(d_t-d_c)}{2} \right] / \left[\frac{(OCF)(P_t)(X_o)}{2} \right]$$

Where: HS_A = Max. Horiz. Span due to moments at point A, ground line moments.

M_A = Moment capacity at point A (ft-lbs)

In this case: $M_A = 256,000$ (ft-lbs)

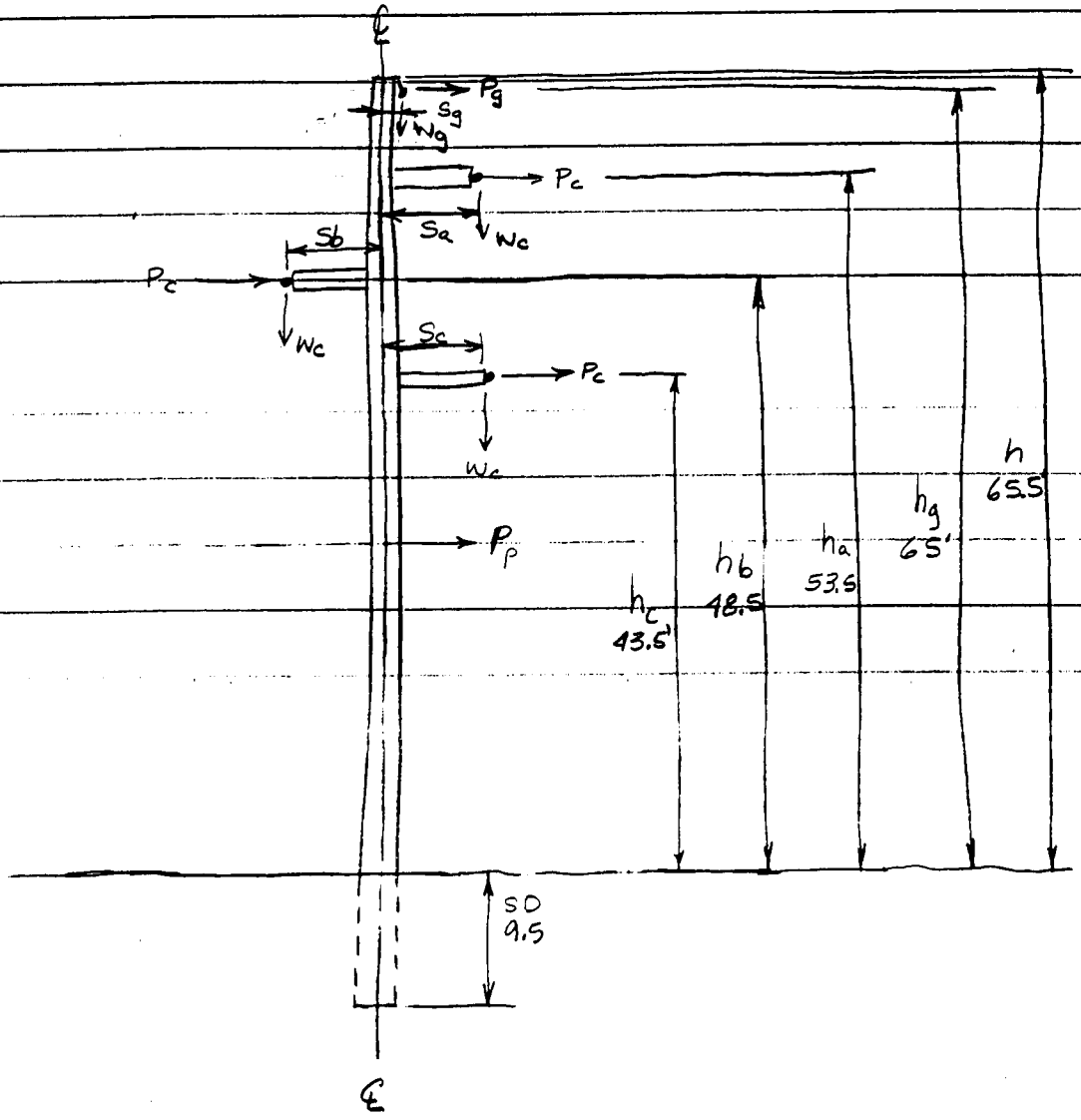
All other variables have the same meanings & values

So:

$$HS_A = \left[256000 - \frac{4.0 \times 45 \times 48.2 \times 11.3 \times 1.89}{2} \right] / \left[\frac{4 \times 17.82 \times 11.3}{2} \right]$$

$$HS_A = \frac{256,000 - 92,646.67}{805.46} = \underline{202.8' < 457'}$$

Calculation of Max Horiz Spans for Single, Wood Pole Structure



Assume: Pole is 75' tall

Conductors are Δ configuration

Max wind loading 45psf

Horiz. Span = 280'

Vertical Span = 300'

Ruling Span = 275.4' (Calculated)

No adjustment Required for additional sag.

Assume Poles are Class H-1

Max Horiz. Span (w/1590 ACSR Cond.)

$$HS = \frac{M_A - (OCF)(M_{wp})}{(OCF)\left[(P_c)(h_a + h_b + h_c) + (P_g)(h_g)\right] + (OCF)\left[(W_c)(S_a + S_b + S_c) + (W_g)(S_g)\right]}$$

Where: M_A = Ultimate Groundline Moment Capacity of Pole

OCF = Overload Capacity Factor (from NESC)

$M_{wp} = \frac{(P_p)(2d_t + d_a)(h)^2}{6}$ = Moment Due to Wind on pole (ft-lbs)

Where: P_p = Wind Press. on Pole (psf)

d_t = Pole Top Diameter (ft)

d_a = Pole Groundline Diameter (ft)

h = Pole Height Above Groundline (ft)

HS = Horizontal Span (ft)

P_c = Wind Pressure on Conductor per Unit Length (lbs/ft)

h_a = Height of A Phase (ft)

h_b = " " B Phase (ft)

h_c = Height of C Phase (ft)

P_g = Wind Press. on OHGW per Unit Length (lbs/ft)

h_g = Height of OHGW (ft)

W_c = Weight of Cond. per Unit Length (lbs/ft)

S_a = Horiz. Dist. from Pole Center to A Phase (ft)

S_b = " " " " " " B Phase (ft)

S_c = " " " " " " C Phase (ft)

W_g = Weight of OHGW per Unit Length (lbs/ft)

S_g = Horiz. Dist. from Pole Center to OHGW (ft)

In this case:

M_A = 331,700 ft-lbs (from REA Bulletin 1724E-200, App. F, Pg F-1

OCF = 4.0 (from NESC)

P_p = 45 psf

d_t = .769 ft

d_a = 1.43 ft

h = 65.5 ft

P_c = 5.64 lbs/ft

h_a = 53.5 ft

h_b = 48.5 ft

h_c = 43.5 ft

P_g = .45 lbs/ft

h_g = 65 ft

W_c = 1.792 lbs/ft

S_a = 5 ft

S_b = 5 ft

S_c = 5 ft

W_g = .273 lbs/ft

S_g = .63 ft

So:

$$M_{wp} = \frac{45 \times (2 \times .769 + 1.43)(65.5)^2}{6} = \underline{95,501} \text{ ft-lbs}$$

$$HS = \frac{331,700 - (4 \times 95,501)}{4[5.64 \times (53.5 + 48.5 + 43.5) + .45 \times 65] + 4[1.792(10) + .273 \times (.63)]}$$

(145.5; 29.25; 17.92; .17199)

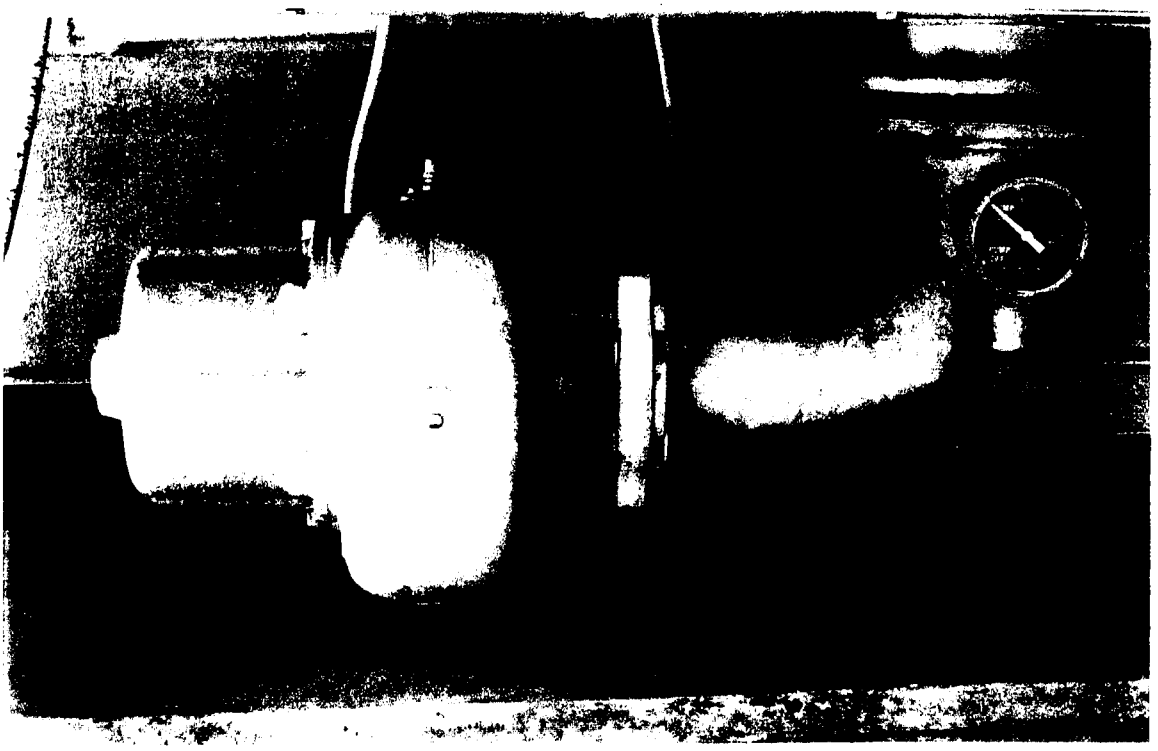
$$HS = \frac{331,700 - 382,004}{3399.48 + 72.37} = -\frac{50,304}{3471.85} = \underline{-14.49'}$$

Negative No. implies pole is not strong enough to carry 1590 kcmil conductors.

APPENDIX B PICTURES



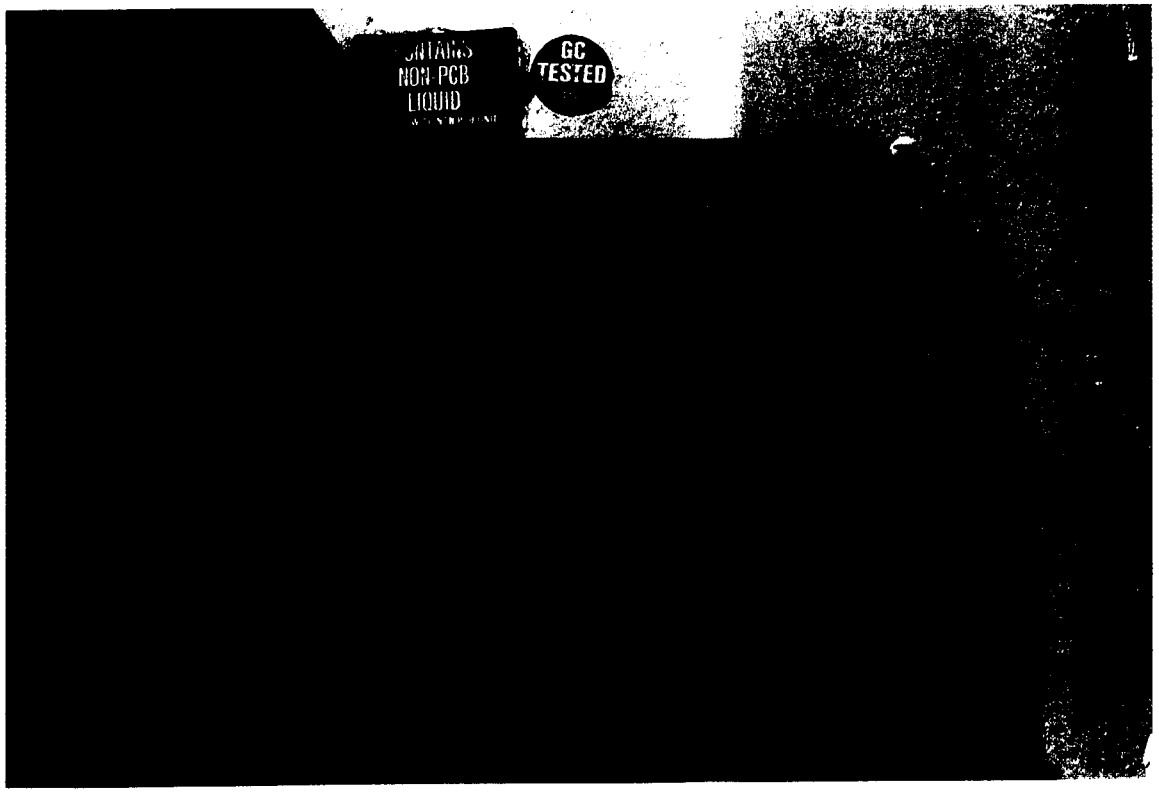
Picture 1: Nameplate for 75-KVA station power transformer mounted on 150-MVA transformer at Ariana Substation.



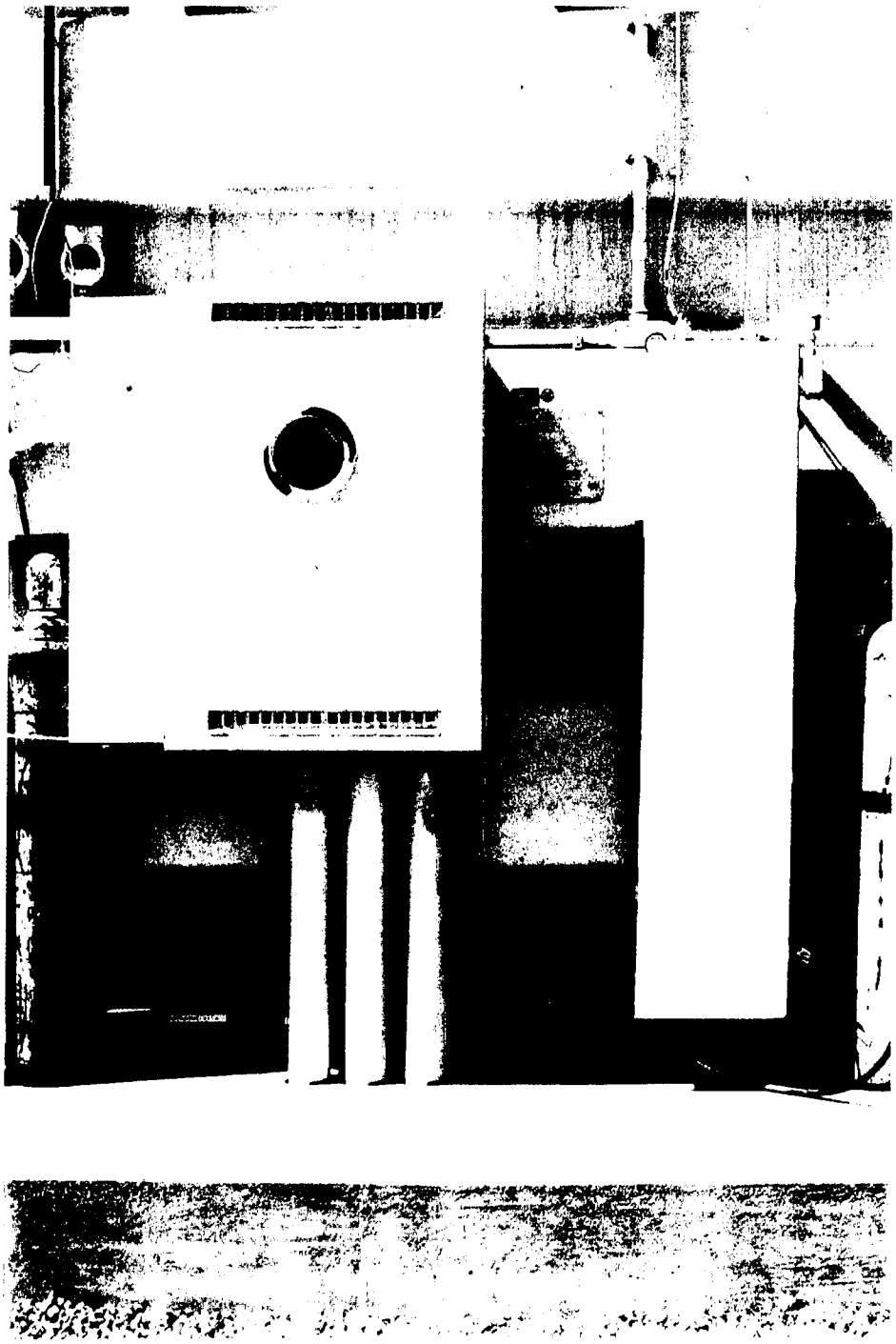
Picture 2: Oil pump for west radiator on 150-MVA transformer



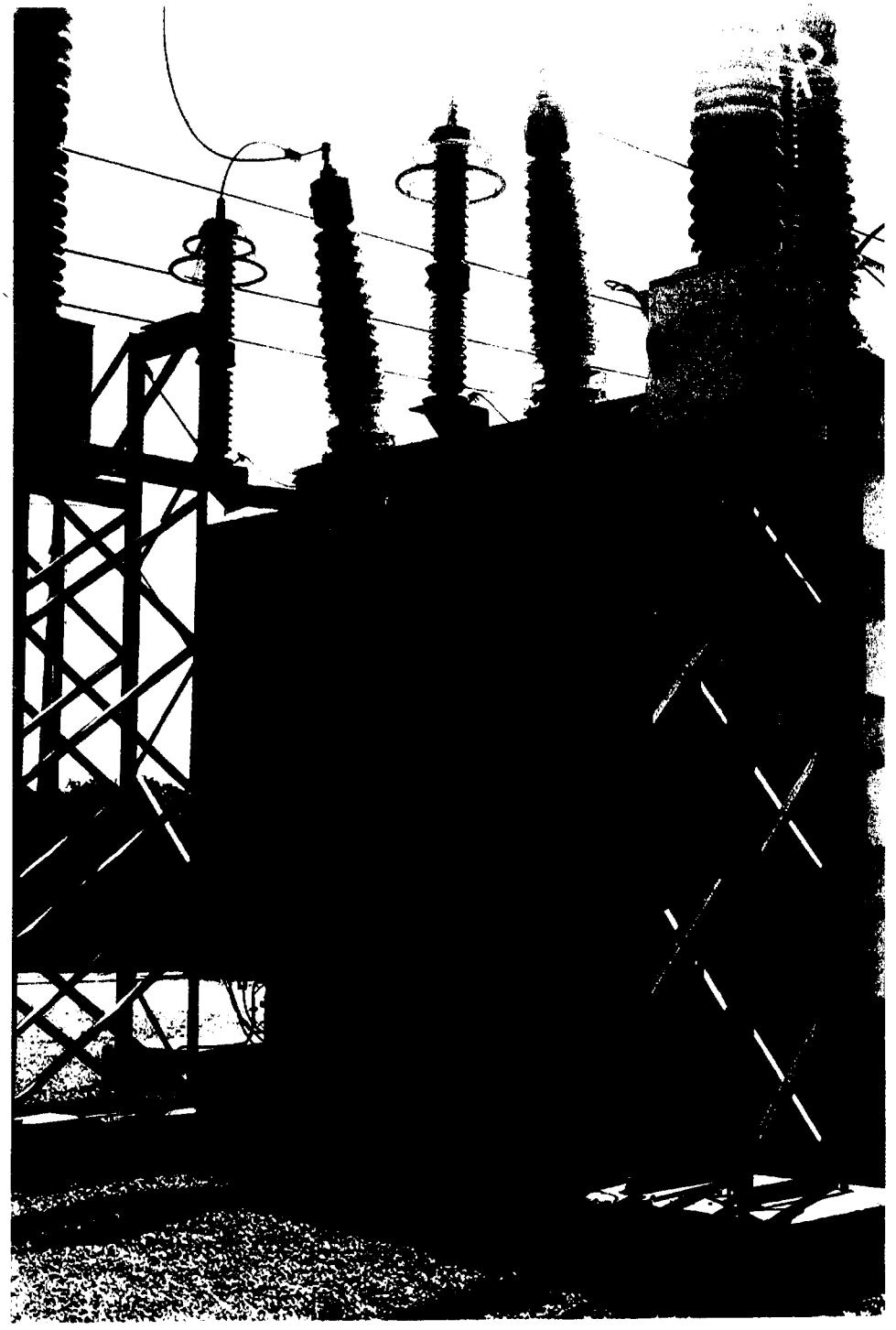
Picture 3: Oil pump for east radiator on 150-MVA transformer



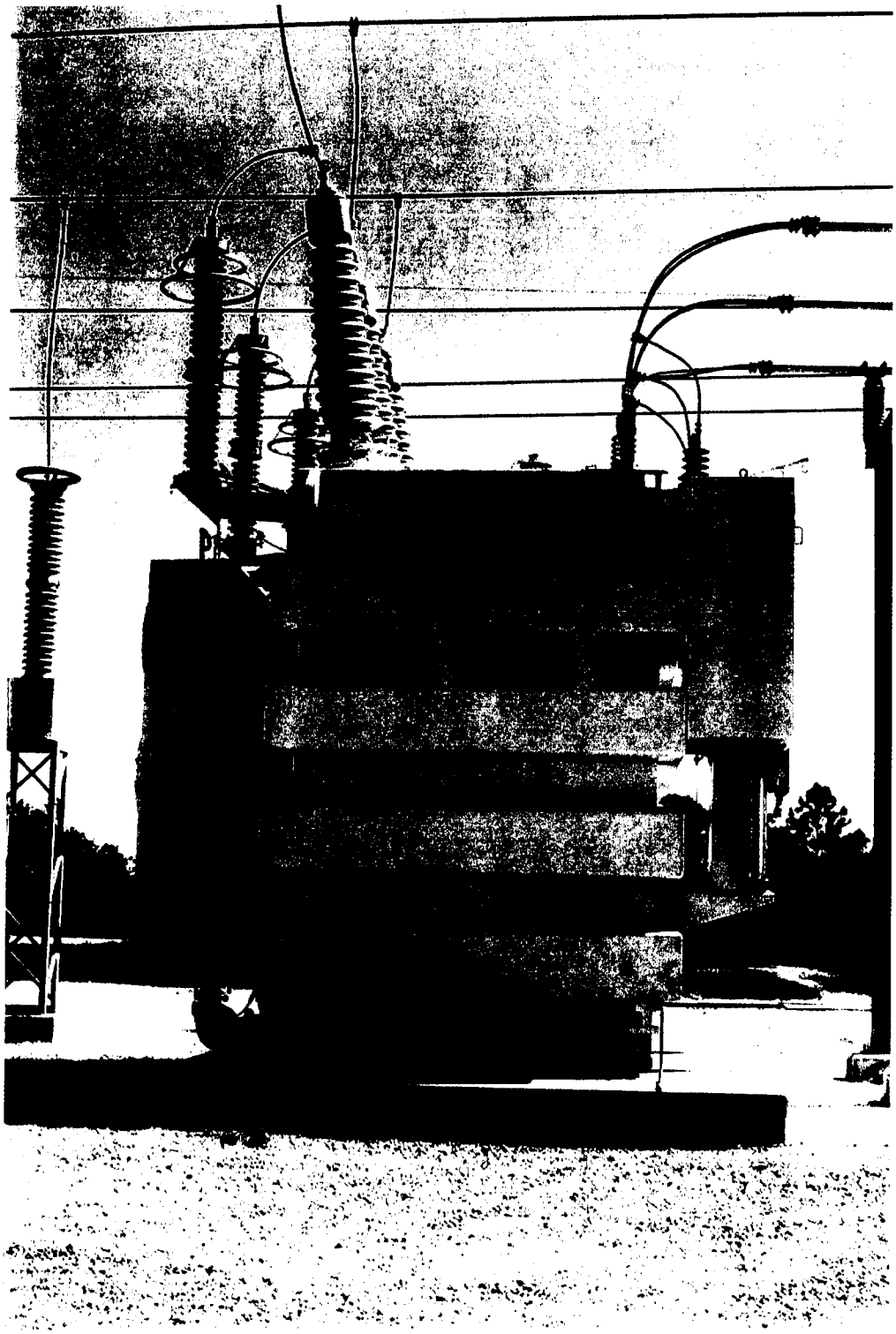
Picture 4: 150-MVA Transformer Nameplate



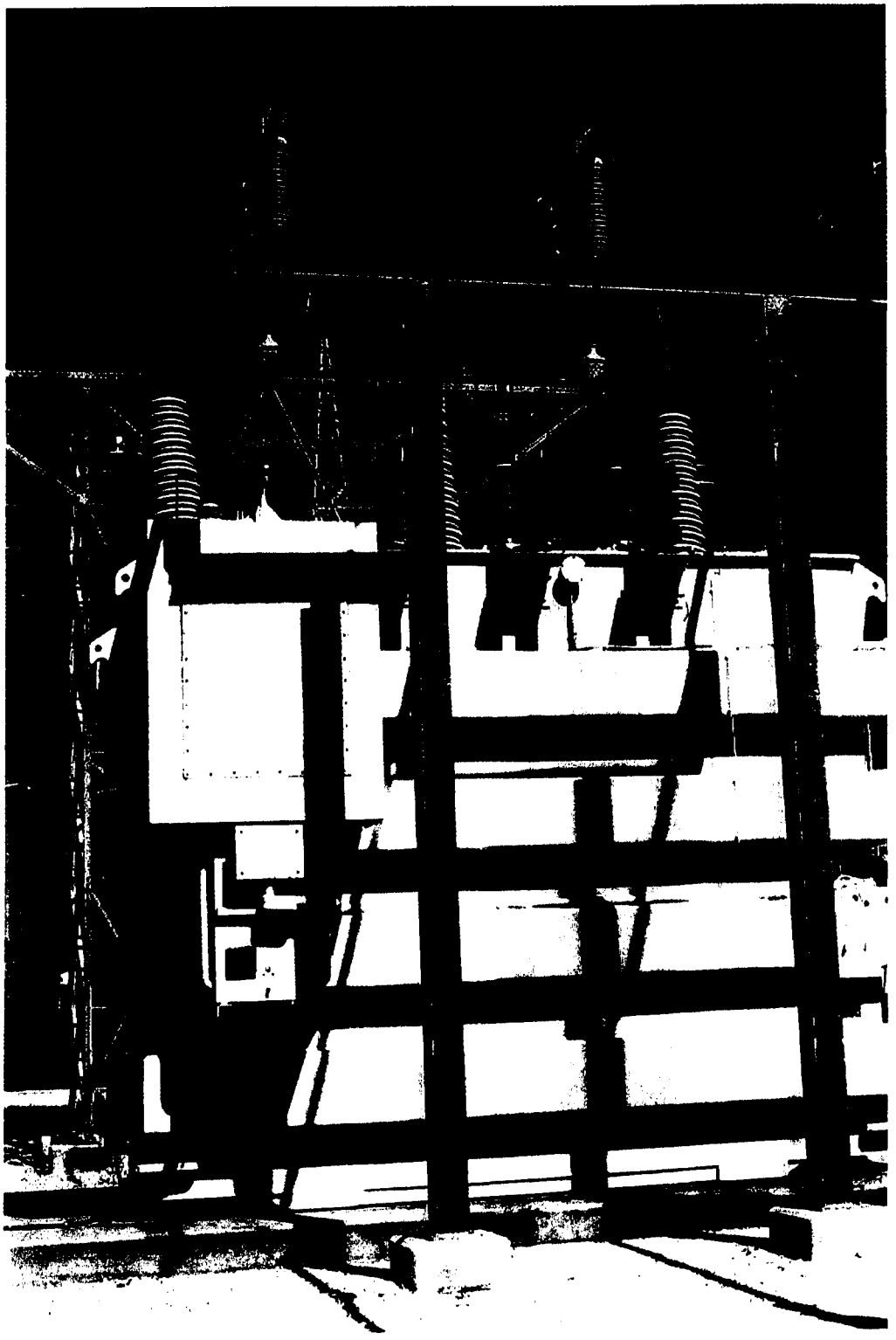
Picture 5: 480-V power distribution panel board on 150-MVA transformer



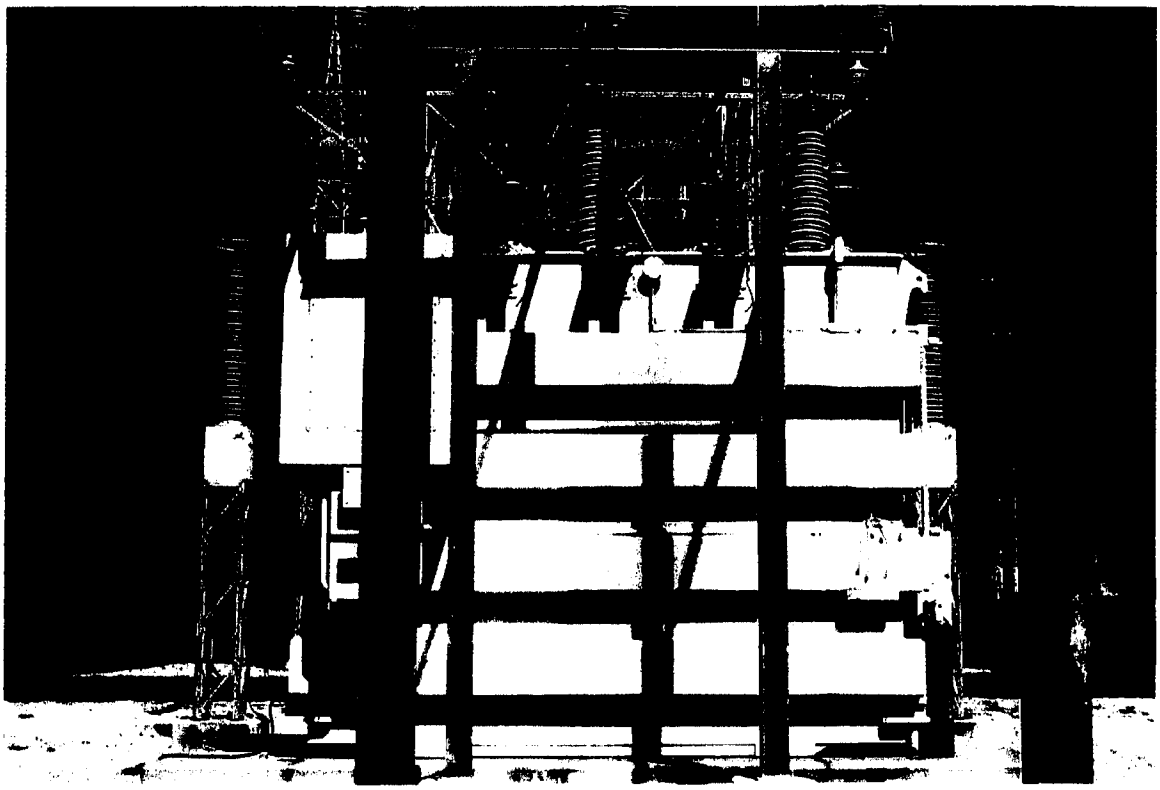
Picture 6: View of existing radiators and fans on 150-MVA transformer (Note proximity to potential device supports)



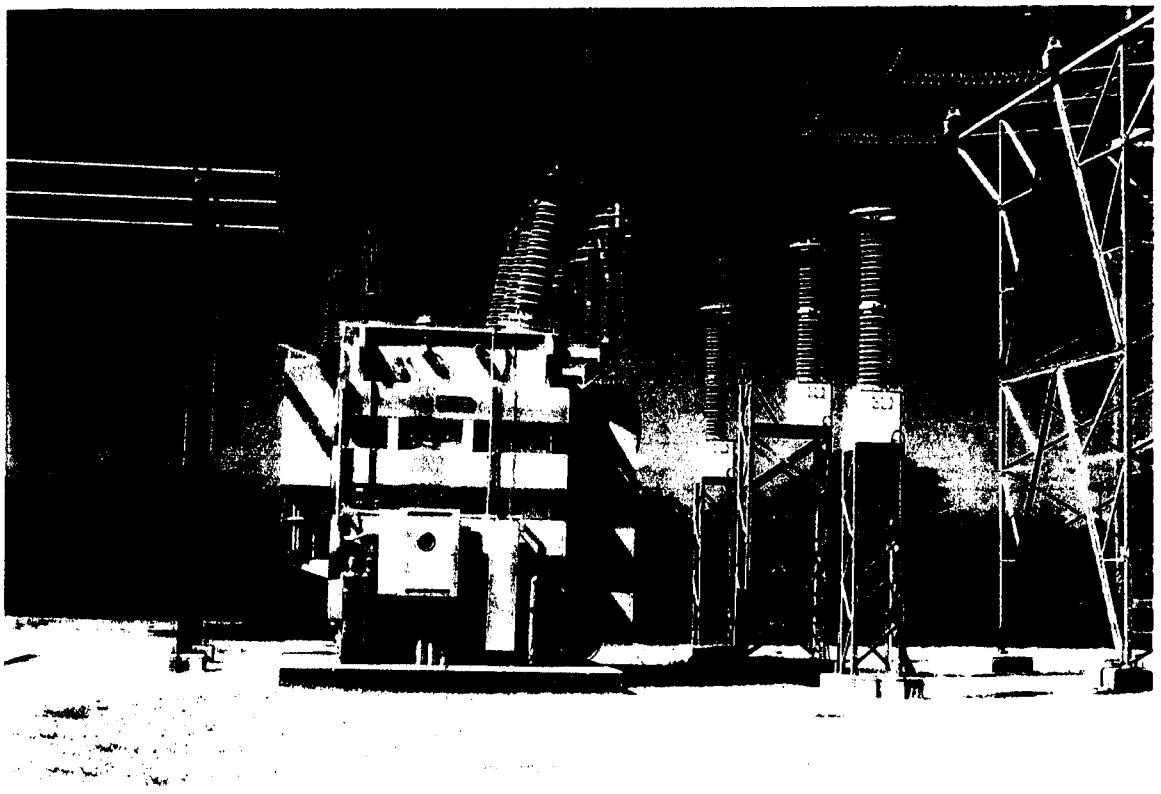
Picture 7: West side of 150-MVA transformer. Potential location for new auxiliary cooling devices.



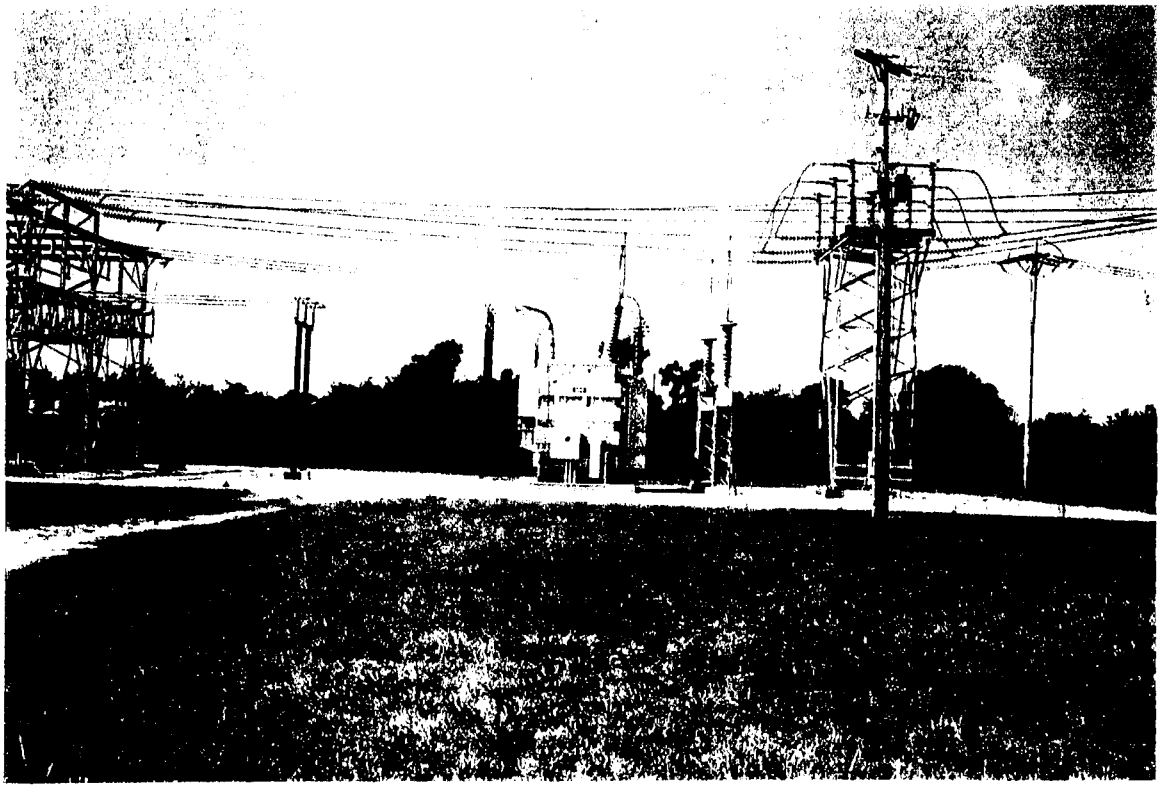
Picture 8: South side of 150-MVA transformer showing LTC.



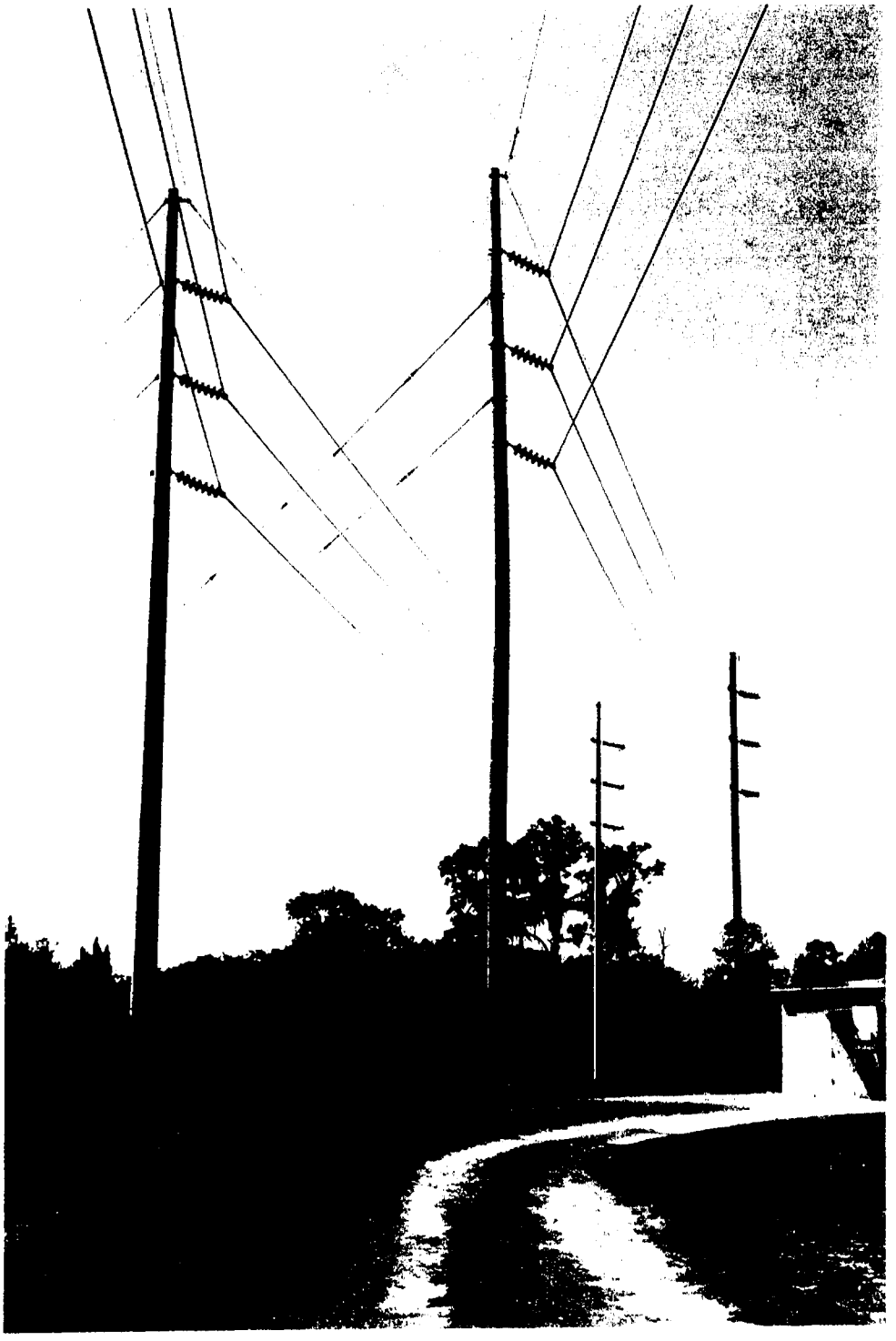
Picture 9: South side of 150-MVA transformer



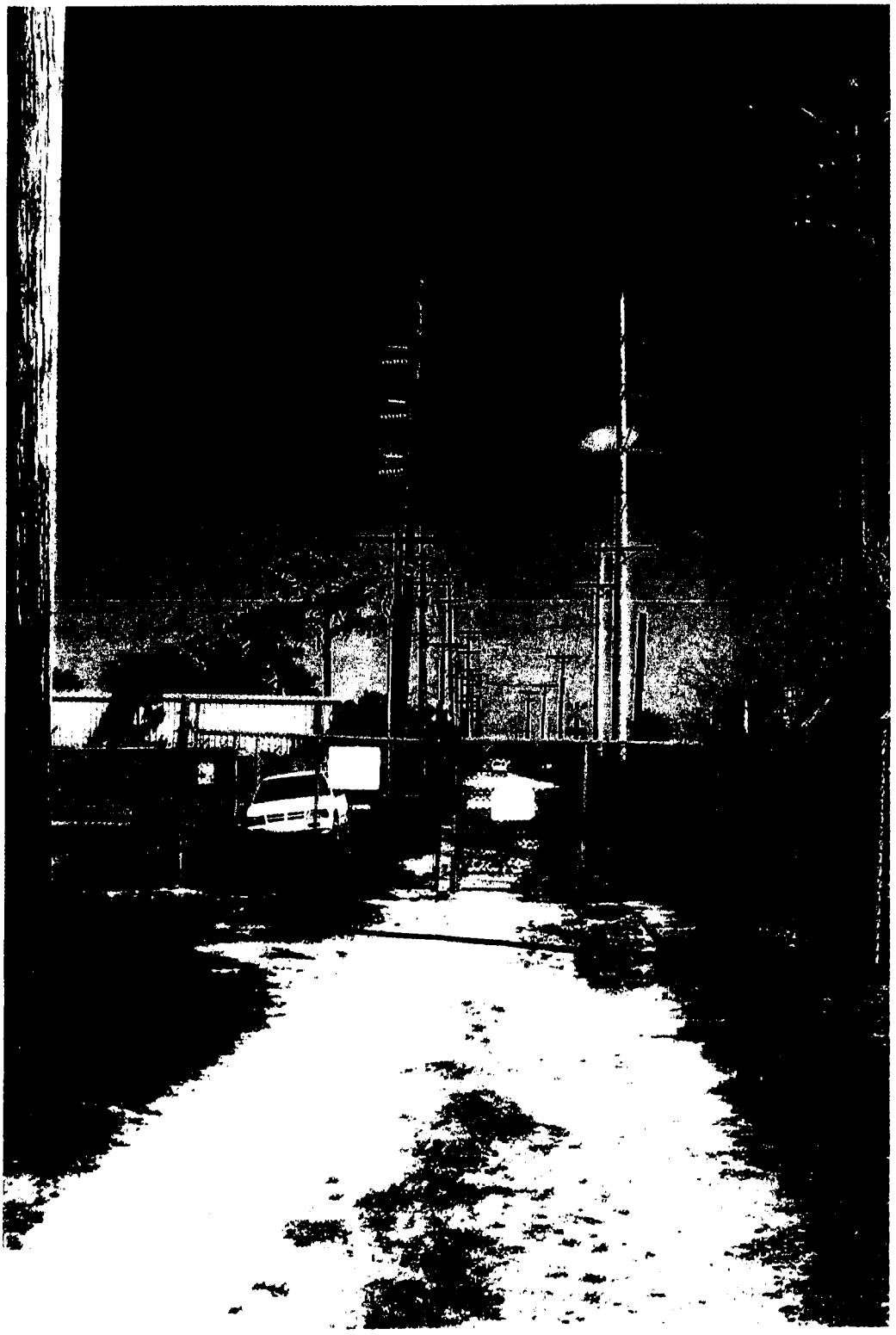
Picture 10: East side of 150-MVA transformer showing bus arrangement and surrounding facilities



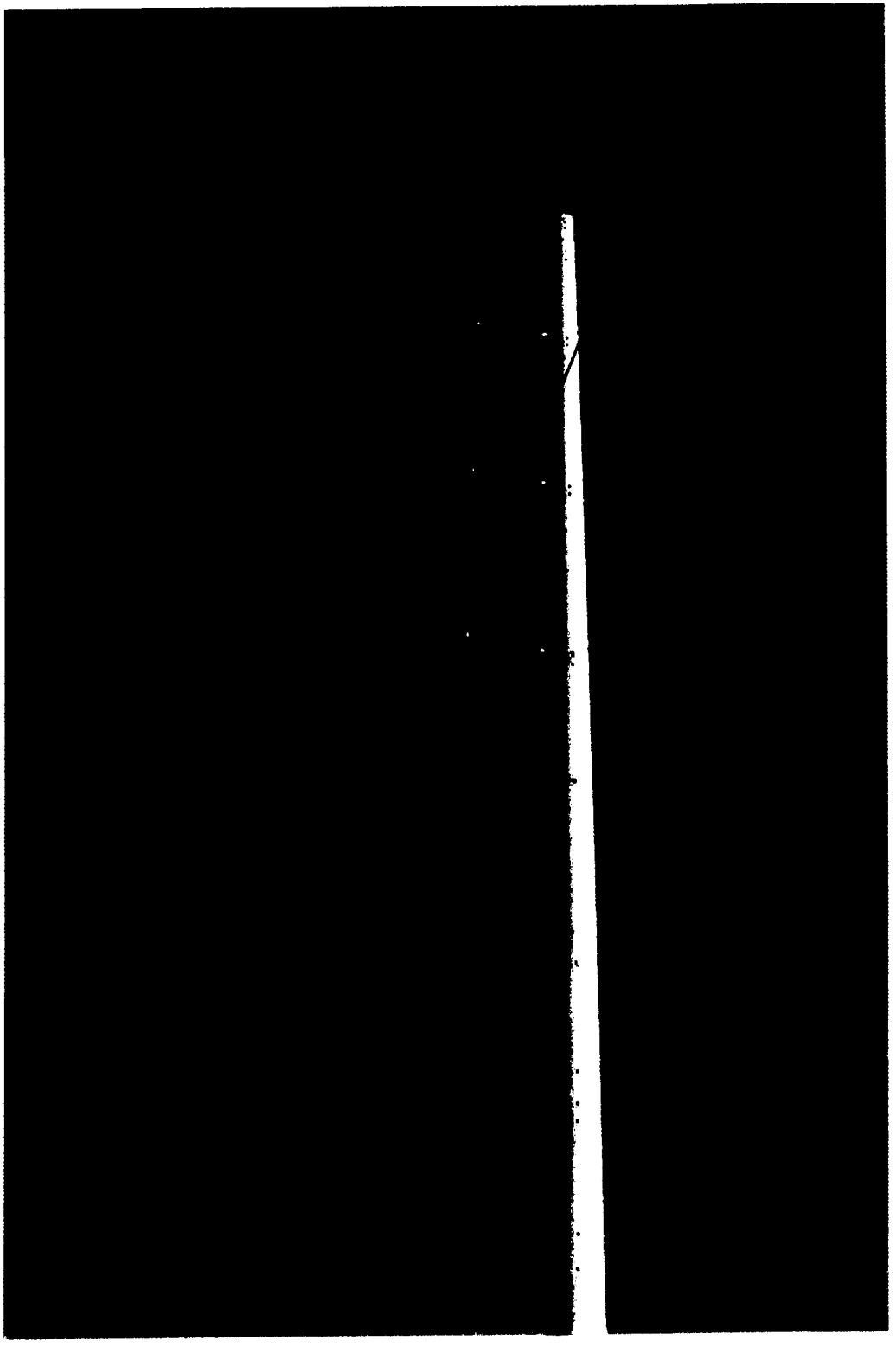
Picture 11: Panoramic view of Ariana Substation



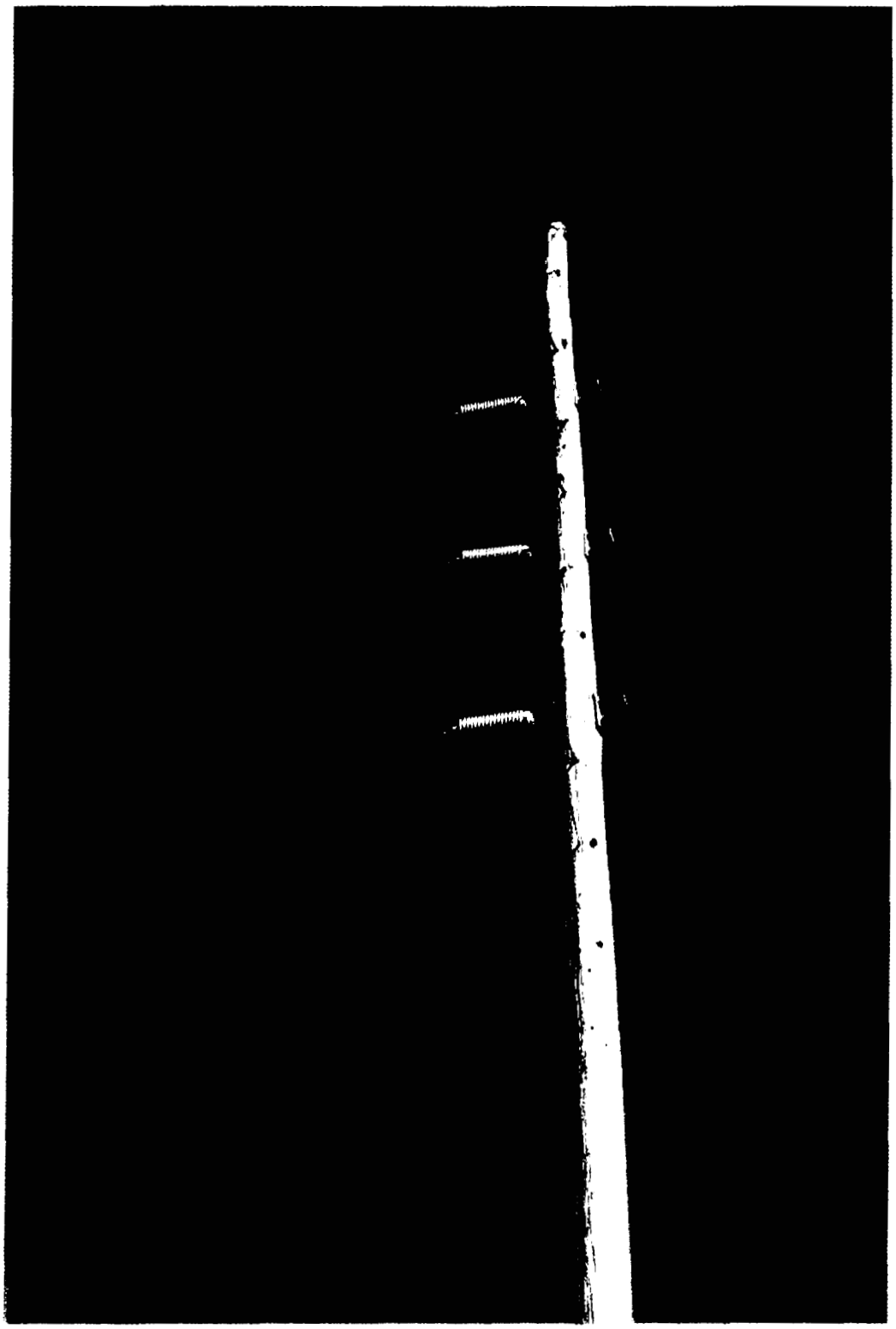
Picture 12: Typical single pole wood and concrete angle structures



Picture 13: Access road to Ariana Substation. Background shows typical single pole wood and concrete corner structures.



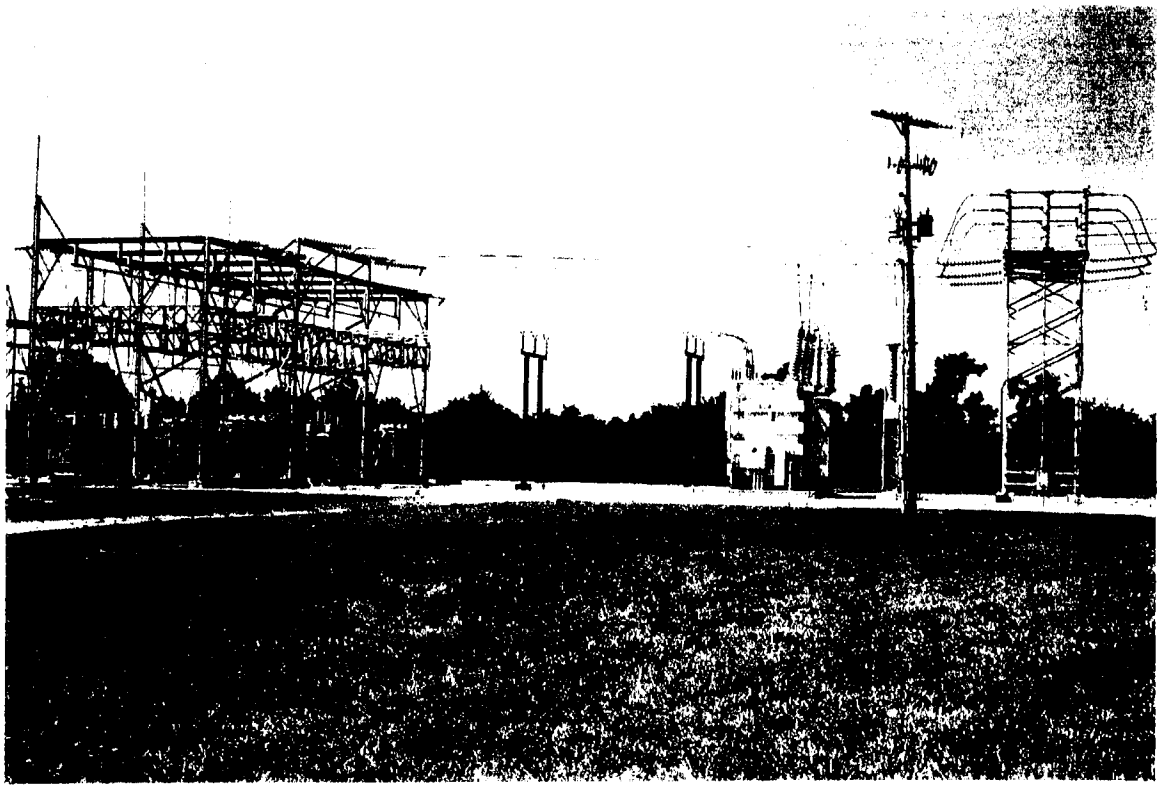
Picture 14: Typical single pole concrete tangent structure



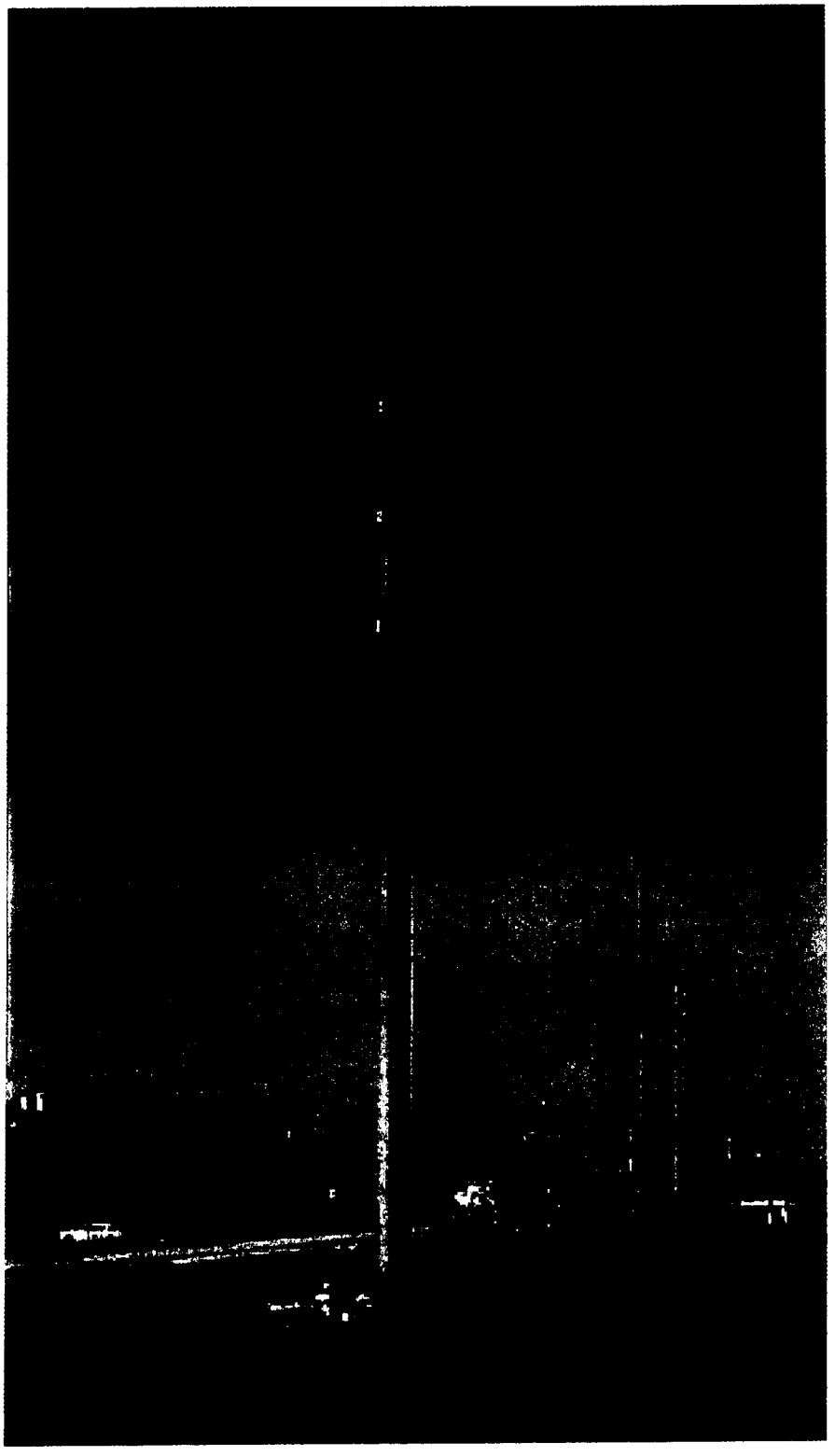
Picture 15: Typical single pole wood tangent structure



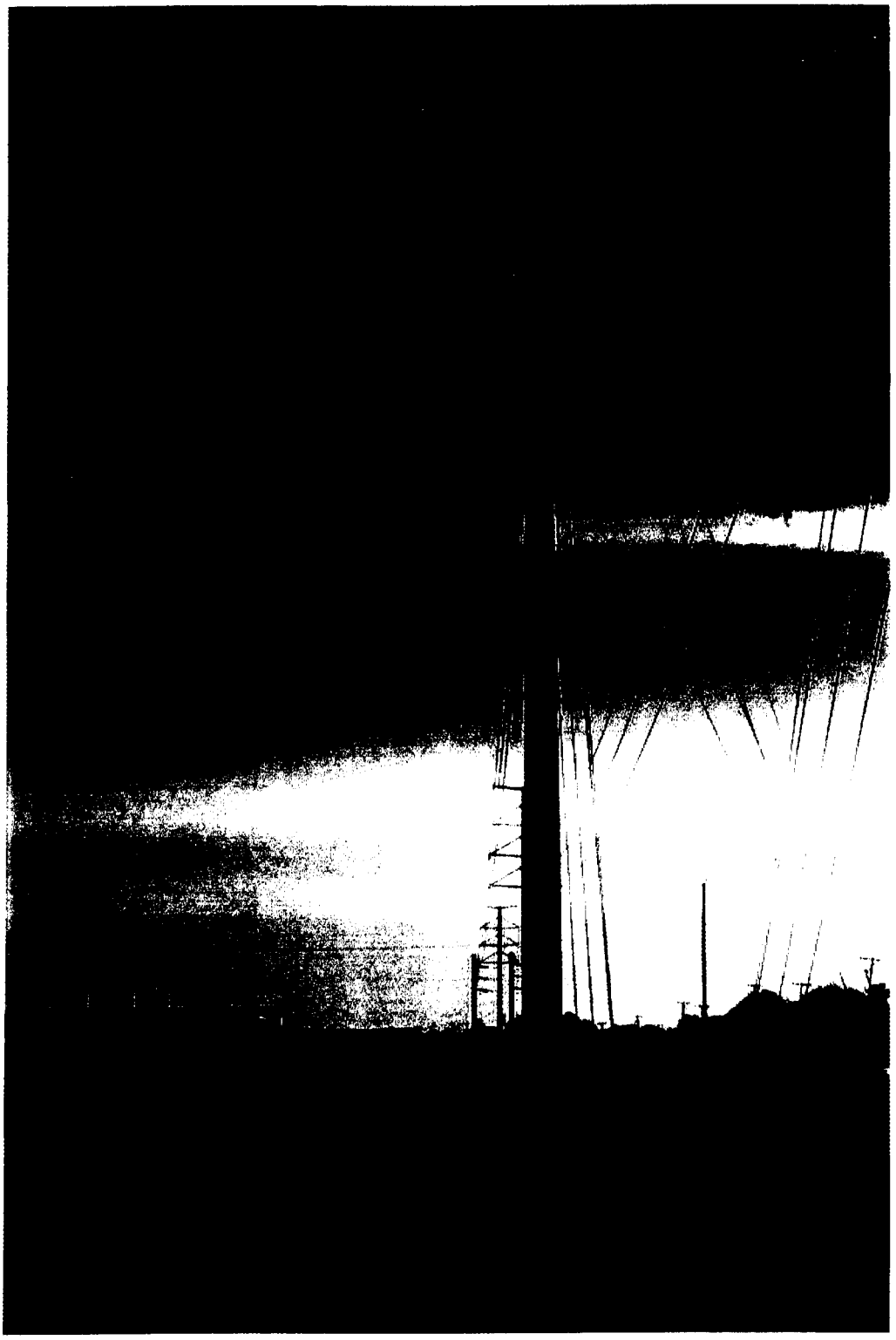
Picture 16: Panoramic view of Ariana Substation



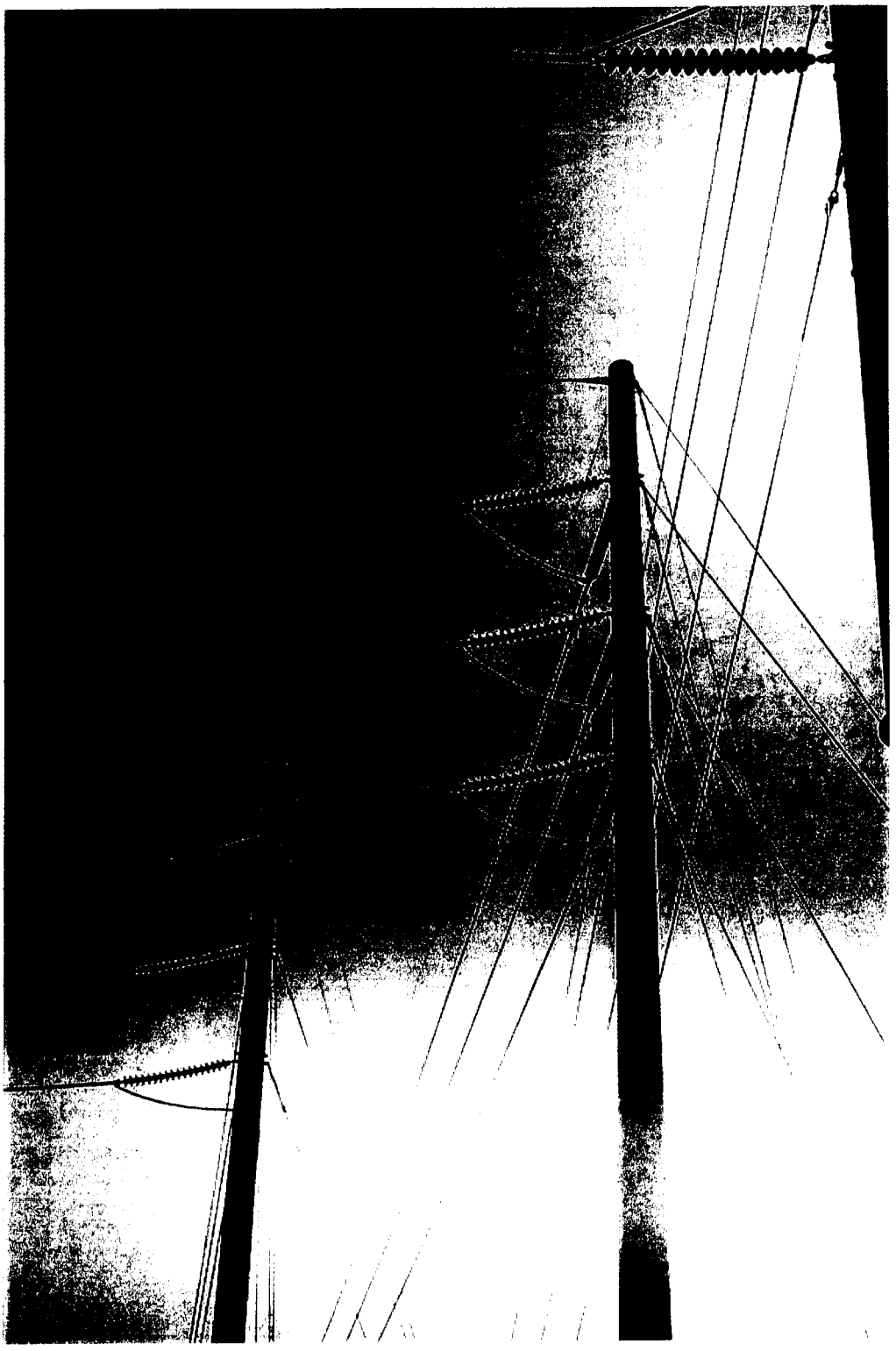
Picture 17: Panoramic view of Ariana Substation



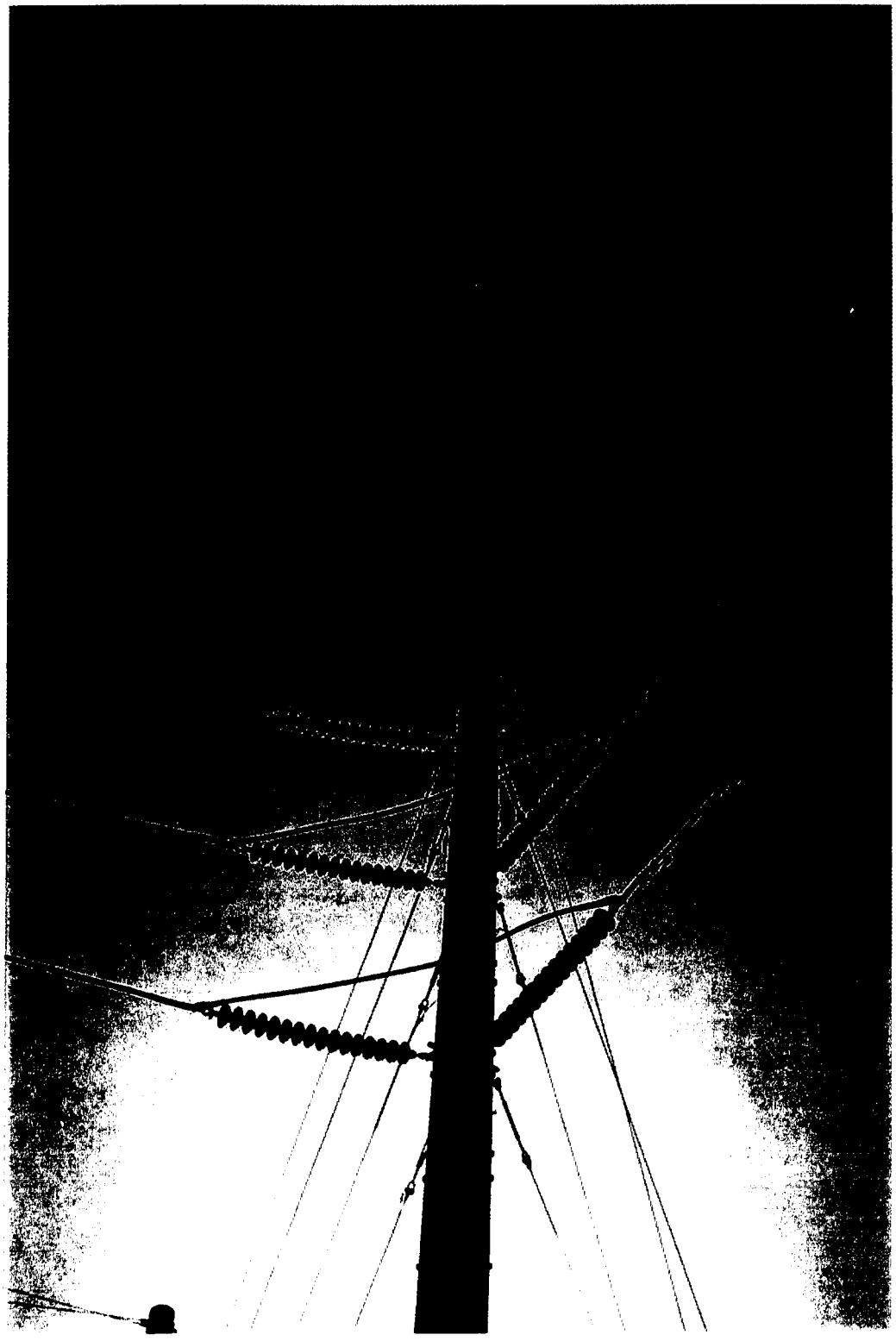
Picture 18: Typical single pole tubular steel tangent structure



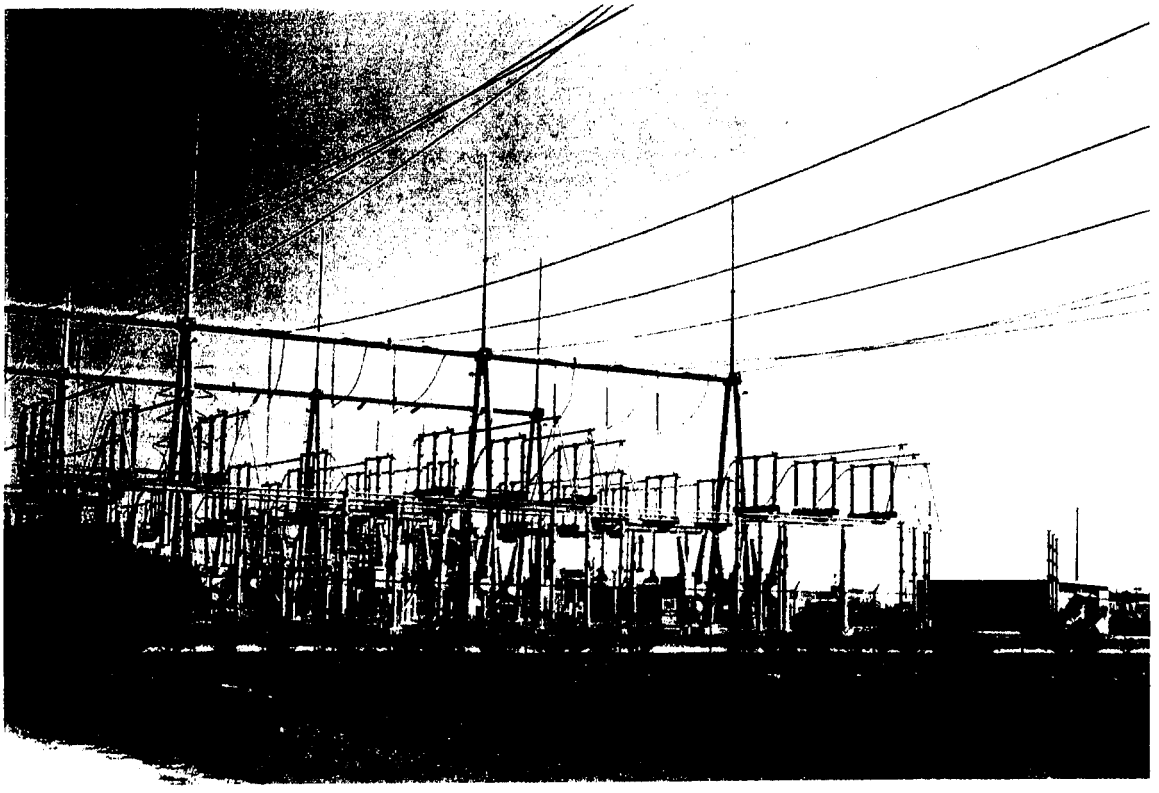
Picture 19: Typical single pole tubular steel corner structure



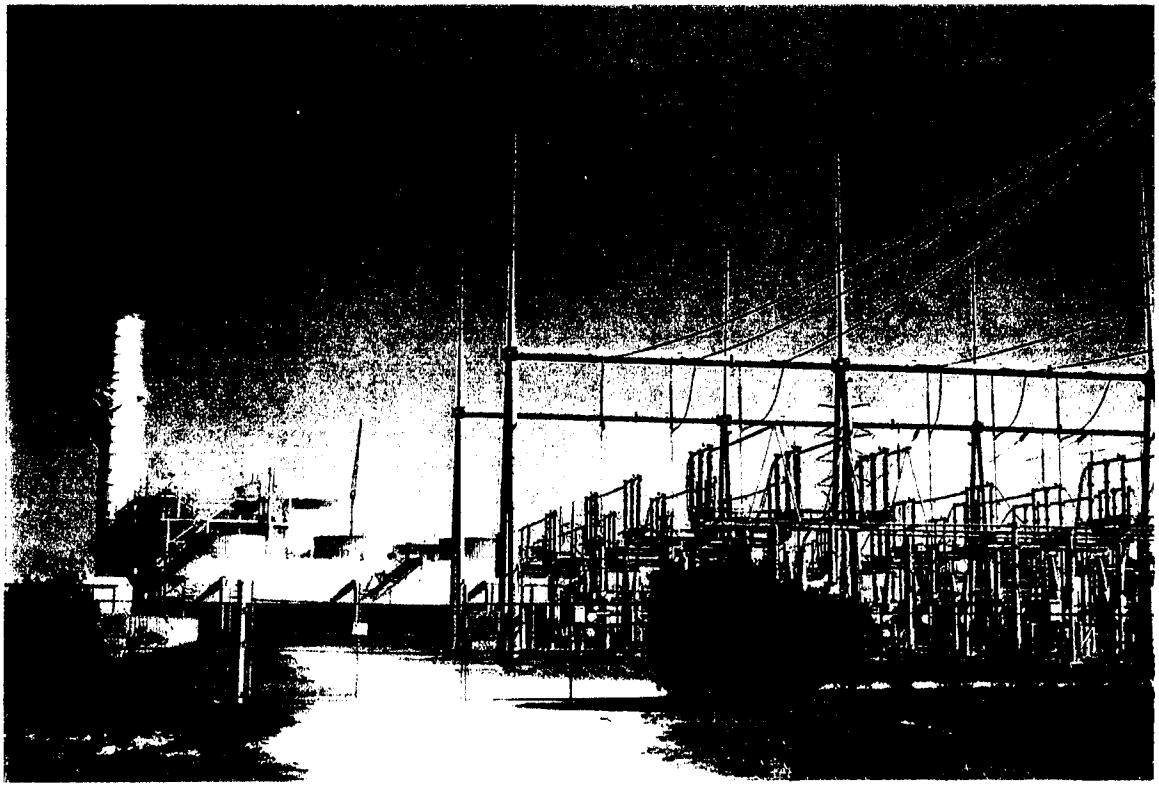
Picture 20: Pole top framing for single pole tubular steel corner structure



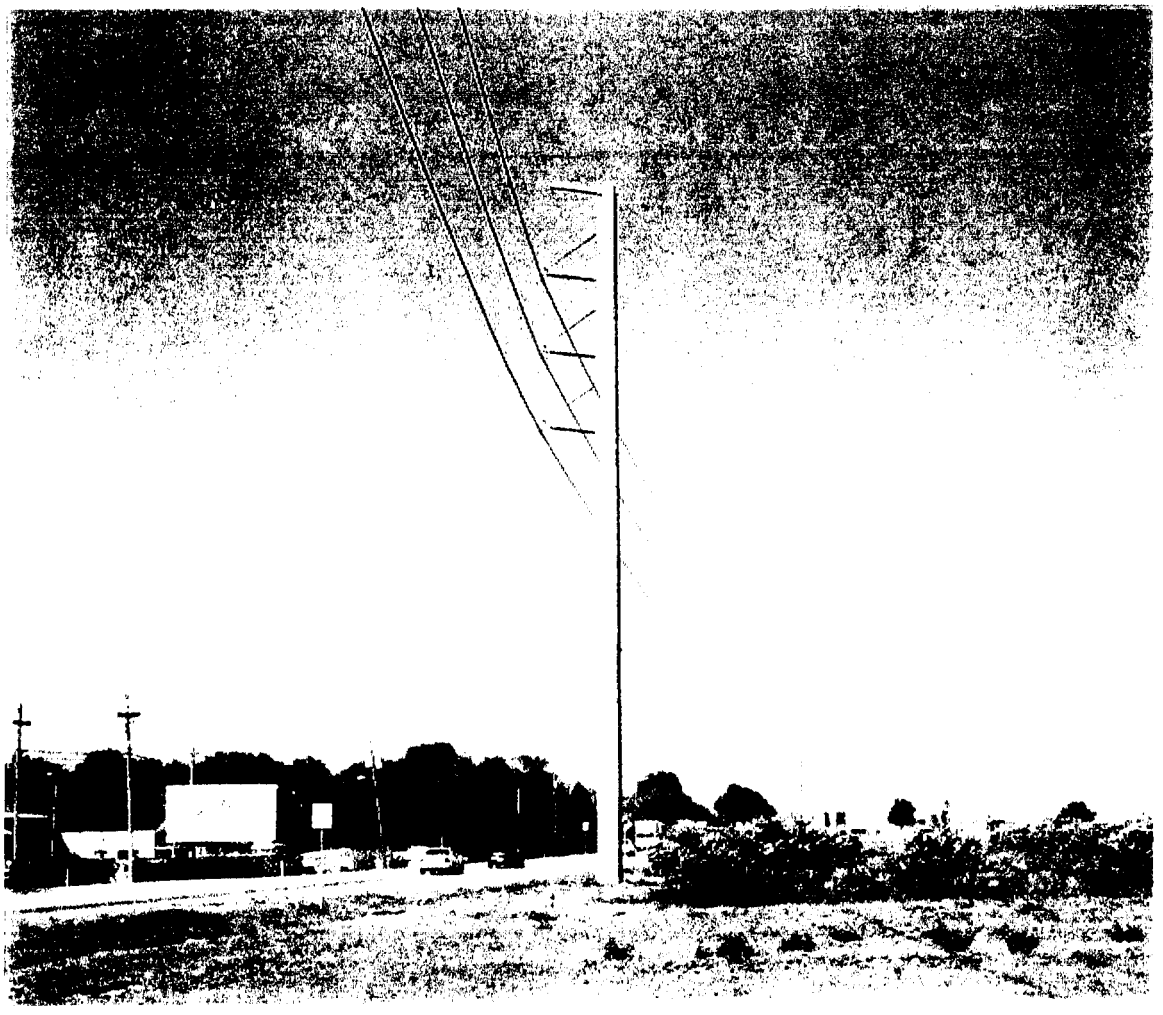
Picture 21: Pole top framing for single pole tubular steel corner structure



Picture 22: East half of Recker Substation

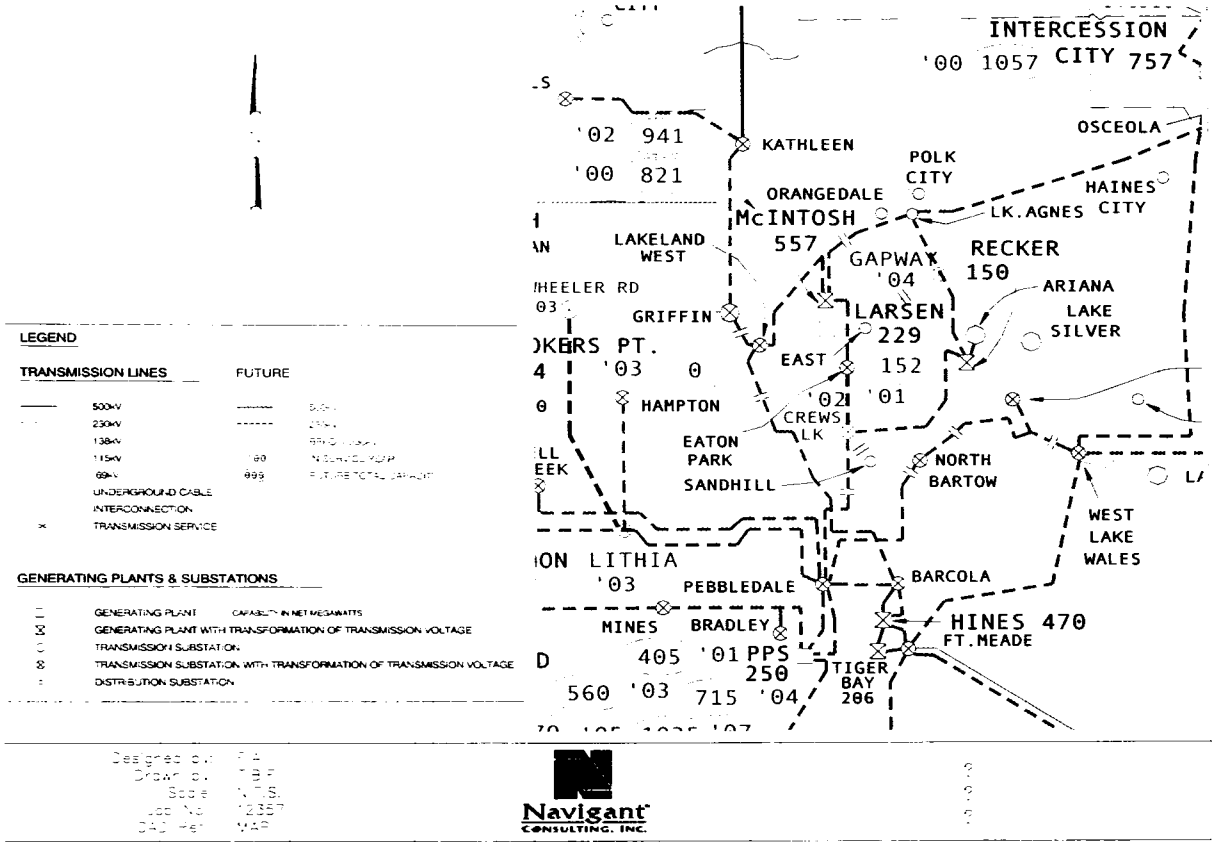


Picture 23: West half of Recker Substation



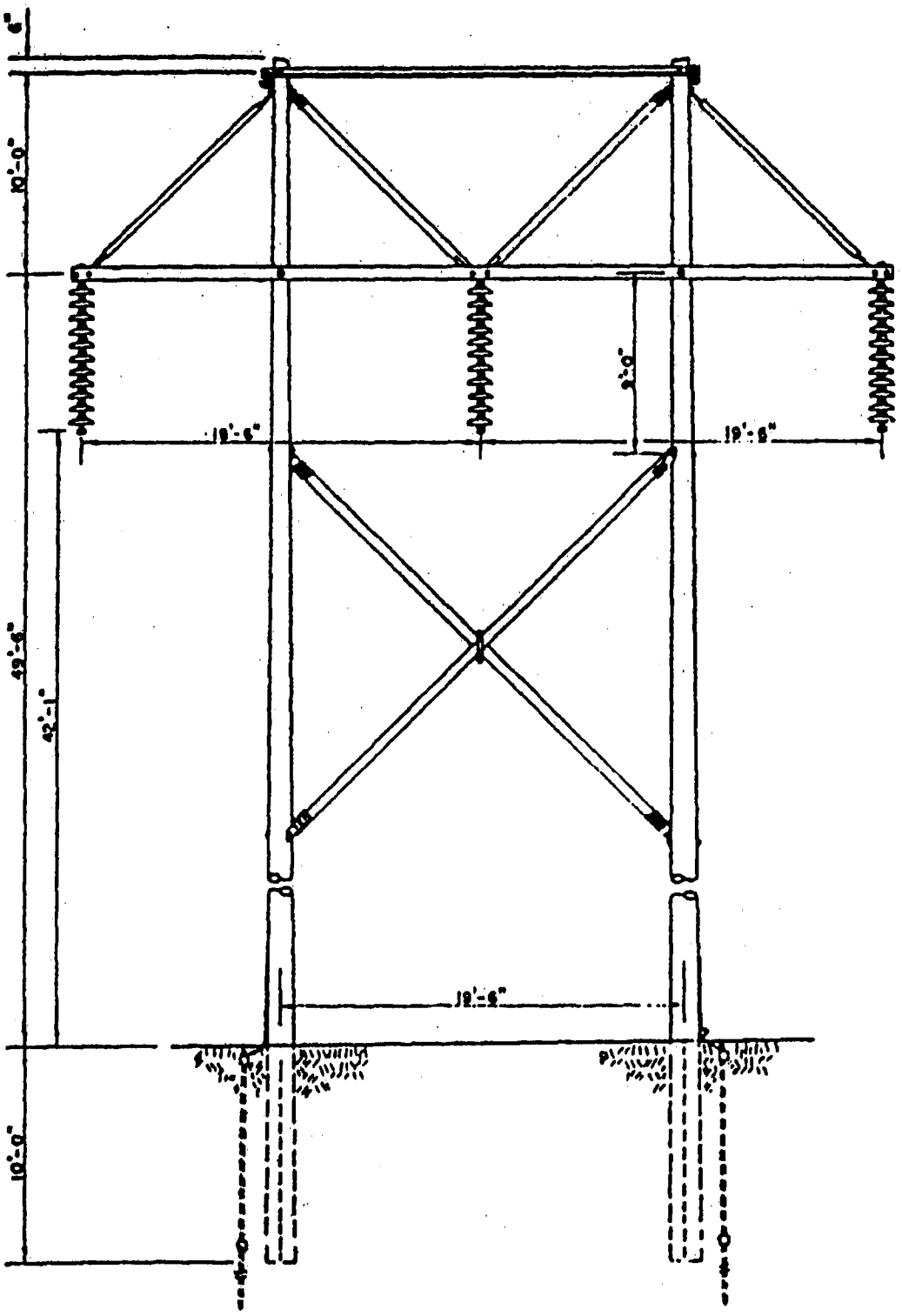
Picture 24: Typical single pole tubular steel tangent structure in Recker to Lake Agnes 230-kV line

APPENDIX C DRAWINGS



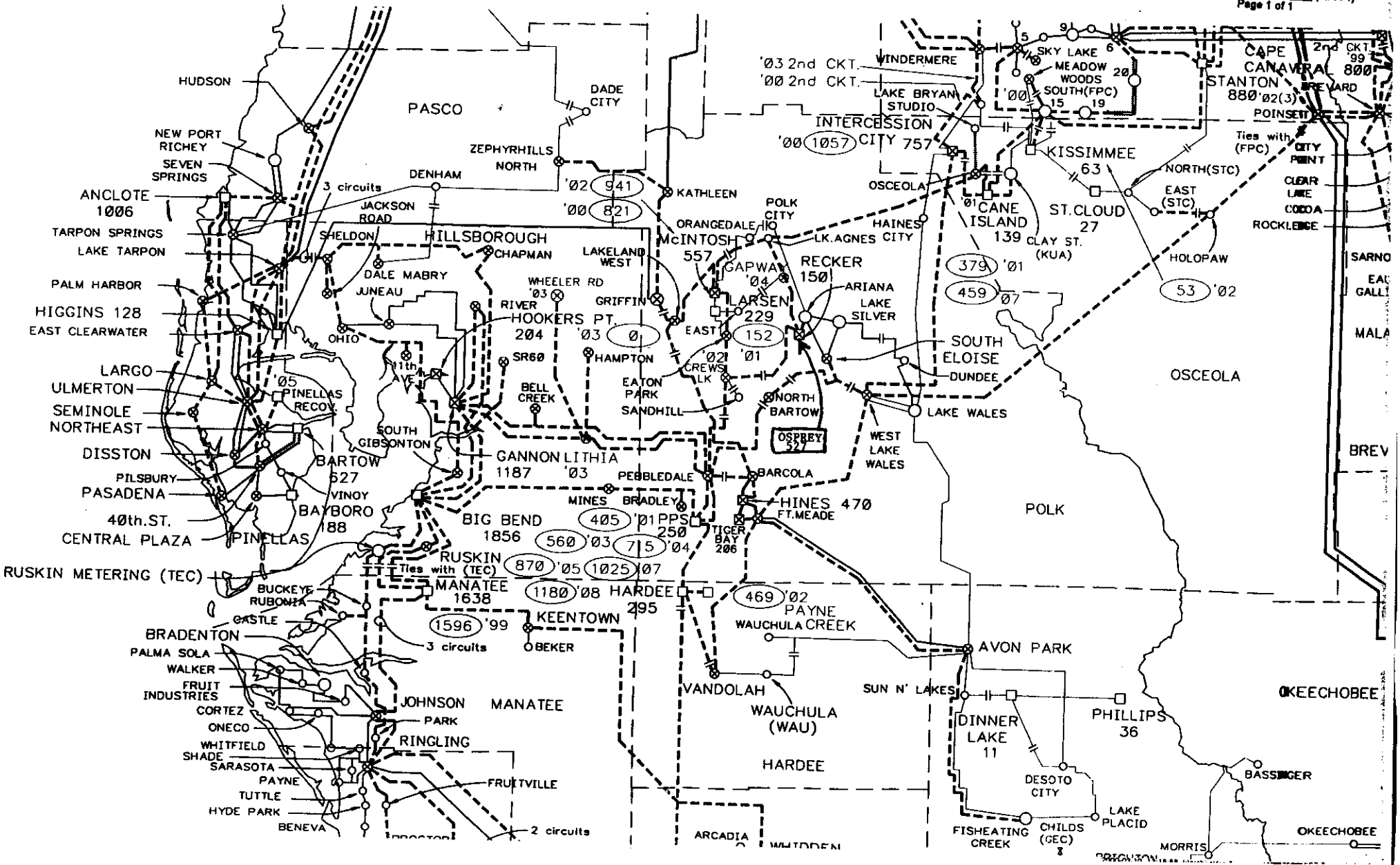
Designed by: FA
Drawn by: FBF
Scale: N.T.S.
Job No: 12357
DAD Ref: MAP

Navigant CONSULTING, INC.


6"
10'-0"
3'-0"
19'-6"
19'-6"
49'-6"
42'-1"
19'-6"
10'-0"

REGIONAL TRANSMISSION MAP OF WEST CENTRAL FLORIDA

Osprey Energy Center
Calpine
Witness: Michel P. Armand
Exhibit _____ (MPA-4)
Page 1 of 1





Calpine - Osprey Energy Center Transmission Service Request Facilities Study Report

Performed by:

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Tampa Electric Company
Energy Delivery
System Planning Department

August 31, 2000

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INTRODUCTION

Description of Project

Calpine Eastern Corporation (Calpine) has proposed to interconnect a 526 MW (summer rating) natural gas combined cycle generation plant named Osprey Energy Center with Tampa Electric Company's (TEC) transmission system near the City of Auburndale, Florida. The site is adjacent to, and the plant would interconnect to, the Recker 230kV Substation, owned and operated by Tampa Electric Company (TEC). Calpine has requested TEC to interconnect with this proposed generation plant and to provide 526 MW of firm point-to-point transmission service from this point of receipt to TEC's interconnections with Florida Power Corporation's transmission system, from June 2002 through December 2008.

Project Milestones

Completed Request for Transmission Service	December 7, 1999
System Impact Study Complete	March 8, 2000
Facilities Study Complete	August 31, 2000
Provide 230kV Station Service to Three GSU Transformers	December 1, 2001 (projected)
Provide 230kV Firm Transmission Service to Three Generators	June 1, 2002 (projected)

Executive Summary

The following facilities study determines the most cost-effective facilities required to interconnect Calpine's proposed Osprey Energy Center to the TEC transmission system at Recker 230kV Substation. This study also determines the most cost-effective facilities required to reliably deliver 526 MW of firm point-to-point transmission service from Recker Substation to the FPC transmission system, from June 2002 through December 2008. The addition of the proposed system improvements allows Tampa Electric Company to continue to satisfy its planning criteria as stated in its FERC 715 filing. Transmission facilities owned by both FPC and the City of Lakeland Electric Department were also monitored in all loadflow analyses, but no adverse impacts were identified.

The central purpose of transmission interconnection and service request studies is to assess the extent to which a contemplated project impacts the reliability of the transmission system. To this end, parallel analysis was performed on the TEC base case models and models containing the Calpine Osprey project. The base case models used are from TEC's published 10-year transmission plan at the time of Calpine's December 7, 1999 completed request for interconnection and

transmission service. The conclusions of this study are based on comparisons of these parallel results. Therefore, the study addresses those impacts related to the addition of the Calpine generation and its delivery to FPC, while filtering out any pre-existing system problems.

The analysis of this request for transmission interconnection and service revealed various impacts, including a minor overload with all facilities in-service, two major single-contingency overloads, and numerous major double-contingency (at 70% of peak) overloads in the first year of service (2002). While a low-cost automatic transfer-trip scheme could be implemented to prevent the identified system impacts, Calpine has indicated that this is not a viable option for firm transmission service. To solve these impacts, two projects were identified, Recker-South Eloise 230kV Loop and the Osceola 10 Ohm Reactor. These projects, which were found to most cost-effectively mitigate identified impacts in 2002 and 2003, were estimated in detail at TEC's Job-Order rate. The actual costs would be assessed to Calpine in order to provide the requested firm transmission service. Two single-contingency-impacted facilities in 2004 were mitigated by accelerating a planned TEC project from 2005 (Gapway 230/69kV Autotransformer). No voltage or fault duty problems were identified in any of the studies. The proposed Osprey generation significantly increases power oscillations among various generators and across various transmission lines in central Florida. In accordance with recommendations by the FRCC Stability Working Group (1999 Export Oscillation Study, September 1998, p. 3), and in keeping with TEC's policy for its own generation additions, power system stabilizers will be required on all three generators at the proposed Osprey Energy Center. The combination of these stabilizers and the Recker-South Eloise 230kV Loop is expected to mitigate identified stability impacts.

The cost to interconnect the Osprey Energy Center to TEC's Recker Substation is estimated at $2.4 million. In addition, the cost of the network upgrades required to provide 526 MW of firm point-to-point transmission service is estimated at $11.5 million. These estimates do not include O&M, tax, carrying charges and other expenses.

FACILITIES STUDY RESULTS

General Description of the Interconnection

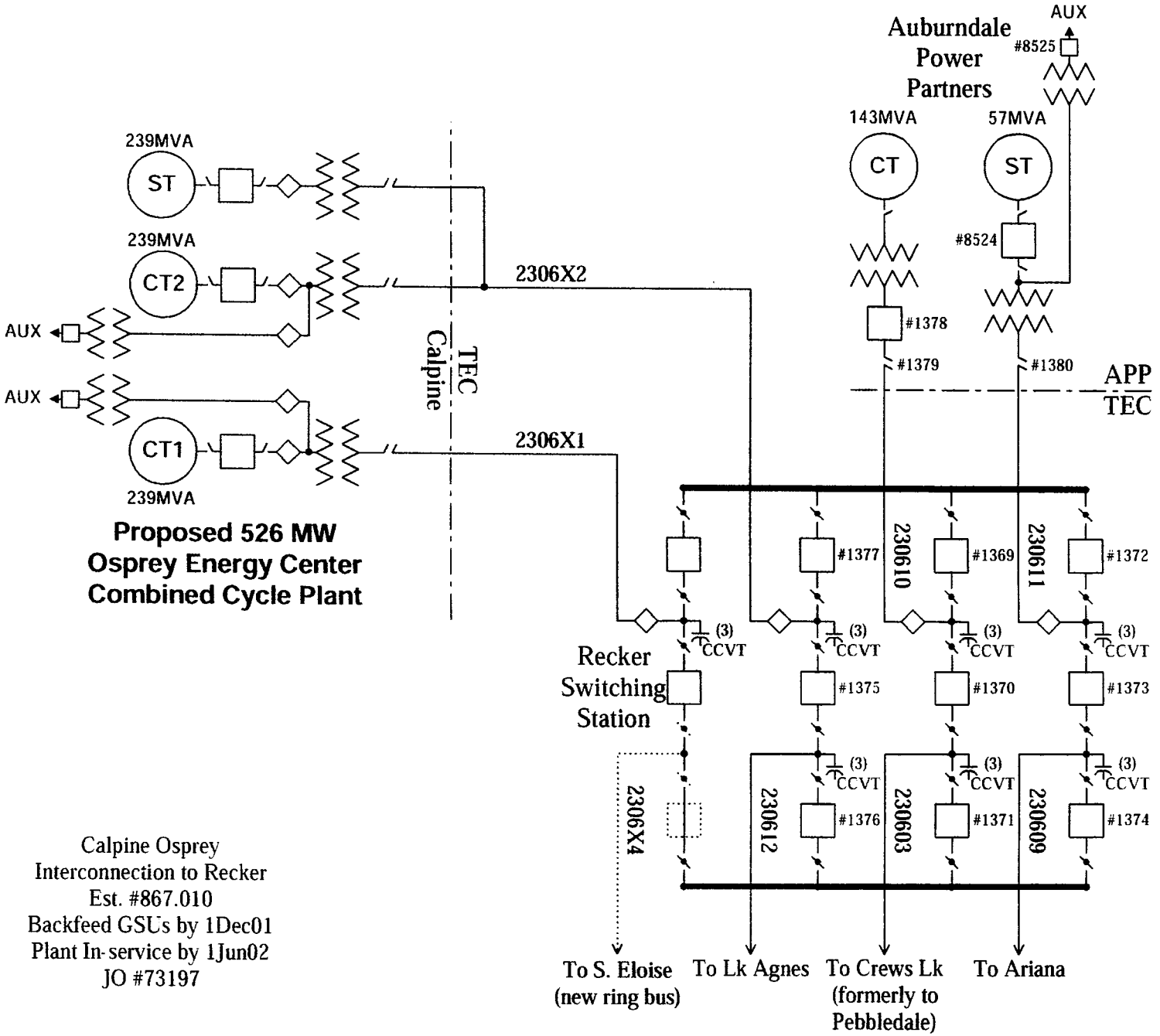
This section describes the layout and costs of interconnecting the Osprey Energy Center to TEC's Recker Substation.

The following list is a subset of the complete interconnection requirements. Please see Tampa Electric Company's *Facility Connection Requirements* documentation for further requirements.

- Two 230kV circuits from Recker Switching Station, terminating at three Calpine-owned deadend towers at the Osprey site.
- One of these circuits uses an existing bay, requiring one circuit breaker and one disconnect switch.
- One of these circuits requires extending the 230kV bus west to provide a new bay, with two breakers and four disconnects.
- All new breakers at Recker will be rated at least 2000 A and 40 kA and at most 2.5 cycle.
- Each of the two circuits requires (3) CCVTs, an LFCB for primary relaying, and a PG10 for backup relaying.
- Each of the two circuits requires (3) PTs and (3) CTs and metering at Recker.
- A fiber optic cable between Osprey and Recker and an RFL 9700 digital protection channel are required for telemetry and transfer trip.
- Calpine must provide a disconnect switch at each of the deadend towers at Osprey, with remote indication and capability of being locked and tagged out-of-service by TEC personnel.
- Calpine must provide and install revenue-grade 3-element metering CTs and PTs for each of the three generators and two station service transformers.
- Calpine must provide cabinet space, conduit and electrical connections at Osprey for a TEC RTU and five 9S meters.
- Calpine must provide system backup protection to trip the Osprey generators in case of primary and backup protection failure on the TEC system.
- A detailed cost-estimate performed by the engineering departments, reveals that the interconnection of Osprey to Recker is expected to cost $2.4 million.

See Figure 1 for an artist's conception of Calpine's proposed Osprey Energy Center and Figure 2 for an aerial photograph of Calpine's Auburndale Power Plant, TEC's Recker 230kV Substation and the site of Calpine's proposed Osprey Energy Center.

See Figure 3 for the one-line diagram detailing the proposed interconnection of Calpine's proposed Osprey Energy Center to TEC's Recker 230kV Substation. Existing facilities are shown in black. New facilities are shown in red. Locations reserved for future facilities are shown in red with dashed lines.



Calpine Osprey
Interconnection to Recker
Est. #867.010
Backfeed GSUs by 1Dec01
Plant In-service by 1Jun02
JO #73197

Figure 3 Calpine Osprey Interconnection to TEC's Recker Substation

Osprey Energy Center
Calpine
Witness: Michel P. Armand
Exhibit ____ (MPA-5)
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Load Flow Analysis

Tampa Electric's planning criteria was used to evaluate the impact of dispatching the Osprey plant at both peak and off-peak load conditions for the requested time frame (2002-2008). The following describes the overloaded facilities and the required upgrades to mitigate them.

2002 at 100% of peak, all facilities in service

TEC planning criteria states that with all facilities in service, there must be no equipment loaded above 100% of its normal rating (Rate-A). Table 1 clearly shows that, without system improvements, the Osprey plant would violate this criteria in the first year of the requested transmission service.

Table 1. 2002 at 100% of peak, all facilities in service

Facility	Base Case	Osprey Case
Ariana 230/69 (168 MVA Rate-A)	75.0% (125.9 MVA)	102.7% (172.5 MVA)

2002 at 100% of peak, single contingencies

TEC planning criteria states that, at 100% of peak system load, the transmission system must be able to withstand any single contingency, with no equipment loaded above 100% of it emergency rating (Rate-B). TEC planning criteria also specifies that, as long as the original overload does not exceed 115%, a reasonable amount of remotely controlled switching operations are allowed to reduce loading to 100% or less. There were two branches that developed single contingency overloads in excess of 115% due the addition of Osprey, as listed in Table 2 below.

Table 2. 2002 at 100% of peak, single contingencies

Worst Contingency	Overloaded Branch	Base Case	Osprey Case
Circuit 230617 Osceola-Cane Island	Circuit 66701 Osceola-Studio Cable (143 MVA Rate-B)	92.1% (131.7 MVA)	126.7% (185.4 MVA)
Circuit 230612 Recker-Lake Agnes	Transformer Ariana 230/69 (176 MVA Rate-B)	75.5% (132.9 MVA)	126.2% (222.0 MVA)

2002 at 70% of peak, double contingencies

TEC planning criteria states that, with each FRCC control area's load scaled down to 70% of peak and generation redispatched economically, the transmission system must be able to withstand any double contingency, with no equipment loaded above 100% of it emergency rating (Rate-B). TEC planning criteria also

specifies that, as long as the original overload does not exceed 115%, a reasonable amount of remotely controlled switching operations are allowed to reduce loading to 100% or less.

- In the base case (without Osprey), several contingencies result in overloads below 115%, all of which can be alleviated with remote switching.
- With Osprey, the double contingency of 230603 Recker-Crews Lake and 230612 Recker-Lake Agnes, forces the entire output of Auburndale Power Partners (131 MW) and Osprey Energy Center (526 MW) is forced through the Ariana 230/69kV autotransformer. This results in 16 overloaded branches, as listed below.

2002 summer at 70% of peak, with Osprey, double contingencies:

CONTINGENCY EVENTS	OVERLOADED LINES					MVA(MW)FLOW			
MULTI-SECTION LINE GROUPINGS	FROM NAME	TO NAME	CKT	PRE-CNT	POST-CNT	RATING	PERCENT CONTINGENCY 1
OPEN LINE FROM BUS 9100 [RECKER 230.00] TO BUS 6105 [CREWSLK 230.00] CKT 1							
OPEN LINE FROM BUS 9100 [RECKER 230.00] TO BUS 9150 [LKAGNES 230.00] CKT 1							
	9124 SELOSE-N69.0	9172*JAN PHYL69.0	1	35.8	254.7	57.4	465.5
	9102 ARIANA-N69.0	9110*ARIANA 230	1	142.7	685.2	176.0	389.3
	9102*ARIANA-N69.0	9174 JANPHYLN69.0	1	53.4	273.5	124.0	230.0
	9172*JAN PHYL69.0	9174 JANPHYLN69.0	1	48.0	266.6	124.0	225.6
	9158 BERKLY 69.0	9166*BERKLY T69.0	1	24.5	188.3	93.0	212.6
	9102*ARIANA-N69.0	9166 BERKLY T69.0	1	24.5	189.6	93.0	212.6
	9158*BERKLY 69.0	9162 GAPWAY 69.0	1	9.4	174.4	93.2	197.2
	9114*DAIRY RD69.0	9126 LKGUM 69.0	1	27.5	147.8	93.0	168.0
	9102 ARIANA-N69.0	9106*ARIANA T69.0	1	44.6	166.3	120.0	144.7
	9106 ARIANA T69.0	9112*MNTMD T 69.0	1	44.6	165.8	120.0	144.6
	9112*MNTMD T 69.0	9114 DAIRY RD69.0	1	43.8	165.2	120.7	143.3
	9100 RECKER 230	9110*ARIANA 230	1	142.4	685.2	478.0	138.1
	9162*GAPWAY 69.0	9164 PLKCTY 69.0	1	4.0	77.9	63.3	129.4
	9164*PLKCTY 69.0	6028 ORNGDALE69.0	1	9.3	73.8	63.0	123.1
	9162*GAPWAY 69.0	6044 EAST 69.0	1	16.0	107.8	105.0	107.9
	9122*SELOSE-S69.0	9176 GORDNVIL69.0	1	7.0	58.2	57.0	107.2

These overloads are not dependent on system load level, nor are they dependent on the point of delivery of transmission service. Rather, they are strictly dependent on the amount of generation connected to Recker Substation (657 MW). This situation could result in widespread blackouts and catastrophic damage to transmission lines and substation equipment, and the overloads cannot be remedied by simply upgrading equipment. This double contingency is specified by the NERC Planning Standards as Category C.3 "SLG or 3 Phase Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3 Phase Fault, with Normal Clearing." Following the first contingency, the only "manual system adjustment" that would prevent these overloads upon the second contingency, would be to completely trip the Osprey Energy Center. Thus, the plant could never remain on-line during a single contingency outage or maintenance outage of either 230603 Recker-Crews Lake (14.1 miles) or 230612 Recker-Lake Agnes (9.9 miles). The option to use relays to automatically transfer-trip the plant following a single-contingency was proposed in a meeting with Calpine. However, Calpine clearly indicated the desire for this base-load plant to remain on-line during contingencies, so this option was ruled out and not pursued any further by TEC. Therefore, firm transmission service from the Osprey Energy Center requires additional transmission expansion to tie Recker into the 230kV grid.

Several alternatives were considered to solve this problem:

1. Recker-Crews Lake 2nd 230kV Circuit. This requires 14.1 miles of new transmission in an existing corridor and at least two breakers. This new line

would drastically aggravate overloads on 66654 Crews Lake-Sandhill (3.0 miles) and 230608 Crews Lake-Pebbledale (9.6 miles). Because this project would require a joint study to establish a new interconnect with Lakeland, it is not considered a viable solution, given the scope and time frame of this Facilities Study.

2. Recker-Pebbledale 230kV Circuit. This requires 23.7 miles of new transmission in an existing corridor and at least two breakers. This new line would drastically aggravate overloads on 230005 Pebbledale-Hampton Tap-Gannon (33.8 miles), 230021 Pebbledale-Bell Creek (25.4 miles) and 230004 Bell Creek-Gannon (8.4 miles). Also, this line would consume an available circuit position at Pebbledale that must be reserved for the buildout of Polk Power Station. This is not considered a viable solution.

3. Recker-Lake Agnes 2nd 230kV Circuit. This requires 9.9 miles of transmission, at least 4.9 miles of which would require new poles in an existing corridor, and at least five new breakers. This would drastically aggravate overloads on TEC's 66701 Osceola-Studio, Orlando's 230616 Lake Agnes-Osceola and Lakeland's 230kV Tenoroc-Interstate line. Because this project would require a joint study to establish a new interconnect with Lakeland and Orlando, it is not considered a viable solution, given the scope and time frame of this Facilities Study.

4. Recker-West Lake Wales 230kV Circuit. This requires 17.0 miles of new transmission (7.1 miles on road right-of-way, 7.6 miles in an existing TEC corridor and 2.3 miles in an existing FPC corridor), at least five new breakers, and a new interconnect with FPC. This would consume an available circuit position at West Lake Wales that FPC has reserved for the buildout of Hines Energy Complex, and would drastically aggravate overloads on the West Lake Wales-Intercession City 230kV line. Because this project would require a joint study to establish a new interconnect with FPC, it is not considered a viable solution, given the scope and time frame of this Facilities Study.

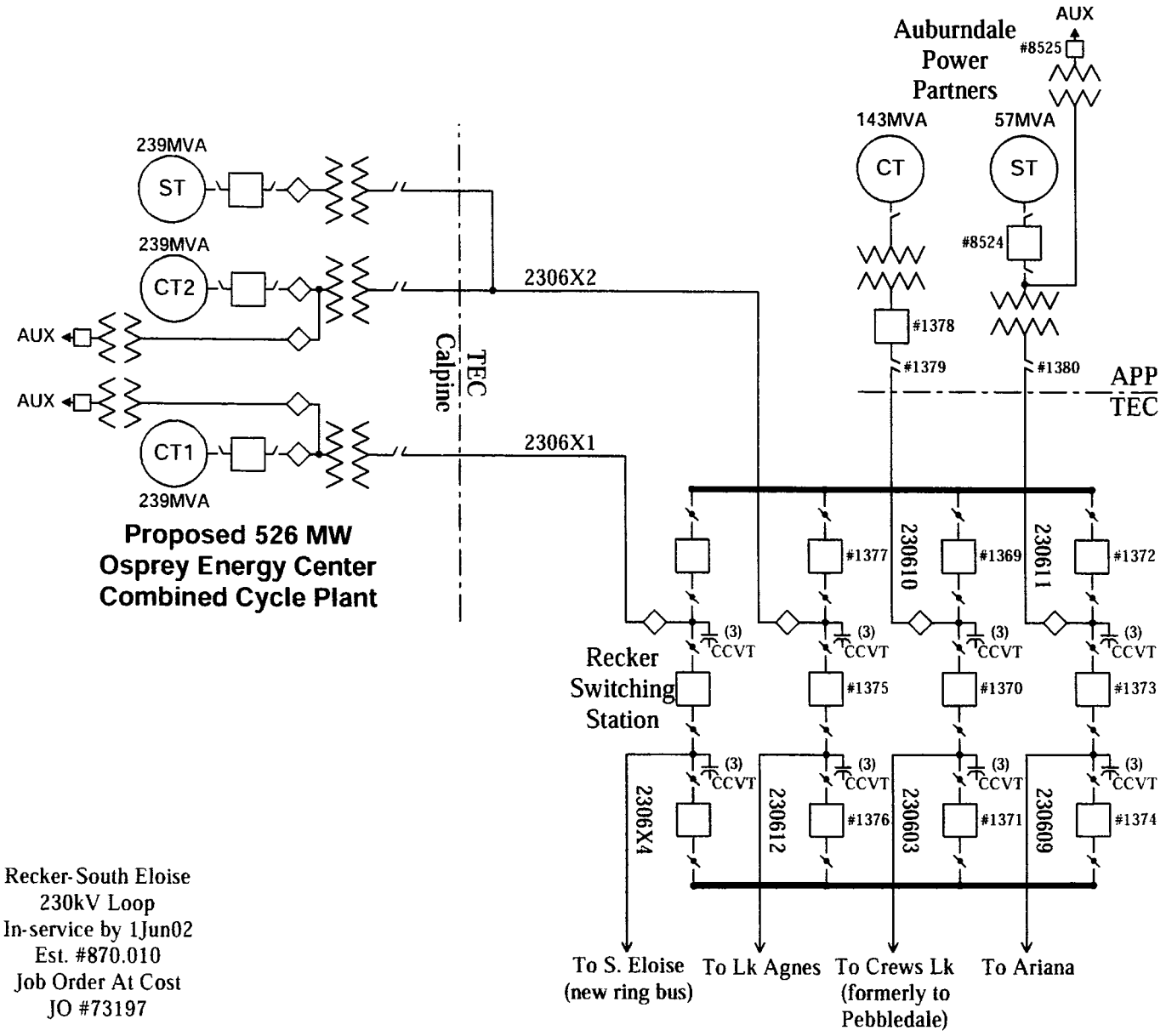
5. Recker-South Eloise 230kV Loop. This requires 11.1 miles of new transmission (3.2 miles on new road right-of-way, 4.4 overbuilding existing line, and 3.5 miles in an existing TEC corridor) and five new breakers. The South Eloise 230/69kV transformer is currently sourced by a 3.5 mile radial line, tapped from circuit 230604 North Bartow-West Lake Wales. Because South Eloise is the 3rd terminal (and weak source) of this circuit, one cannot simply build a 230kV circuit from Recker to South Eloise. Thus, 3.5 miles of line must be built to loop the North Bartow-West Lake Wales line through South Eloise, splitting it up into two 2-terminal circuits. This is considered a viable solution.

6. Ariana-South Eloise 230kV Loop. This project is similar to alternative 5, except that it would require a new three-breaker 230kV station at Ariana and the re-rating of 1.5 miles of existing line, in order to avoid 1.5 miles of new line construction and one breaker at Recker. This is considered a viable alternative. However, the additional substation costs at Ariana would more than offset the avoided transmission costs. Also, this alternative, by extending an existing line from Recker, would provide substantially less reliability than alternative 5, which builds an entirely new line from Recker.

7. Recker-South Eloise-New Station 230kV Circuits. This project is also similar to the alternative 5, except that it would require an entirely new three-breaker 230kV switching station to be built at the tap point of 230604, in order to avoid building 3.5 miles of new 230kV line in an existing corridor. This is considered a viable alternative. However, the additional substation, real estate and telecommunication costs to build a new switching station would more than offset the avoided transmission costs.

The Recker-South Eloise 230kV Loop (alternative 5) was selected as the most economical and reliable solution to the no-contingency, single-contingency and double-contingency problems at Recker and Ariana. Note that this 230kV loop causes circuit 230604 South Eloise-West Lake Wales to load up to 98.5% of its 402 MVA rating for the contingency loss of FPC's Ft. Meade-West Lake Wales 230kV line in the summer of 2002. Therefore, included, as part of the project will be any work necessary to rerate the 7.6-mile TEC portion of this tie line to 550 MVA. The 2.3-mile FPC owned section of this circuit is presently rated 603 MVA (Rate-B). This project was modeled and included in all further analysis of the Osprey cases. A detailed cost-estimate performed by TEC engineering departments, identifies an expected capital cost of $11.1 million.

See Figure 4 and Figure 5 for one-line diagrams detailing the proposed Recker-South Eloise 230kV Loop project. See also the first two pages of Appendix A for a geographic transmission map of the greater Winter Haven area and a close-up map of the Recker-South Eloise area.



Recker-South Eloise
230kV Loop
In-service by 1Jun02
Est. #870.010
Job Order At Cost
JO #73197

Figure 4. Recker-South Eloise 230kV Loop Project

Osprey Energy Center
Calpine
Witness: Michel P. Armand
Exhibit _____ (MPA-5)
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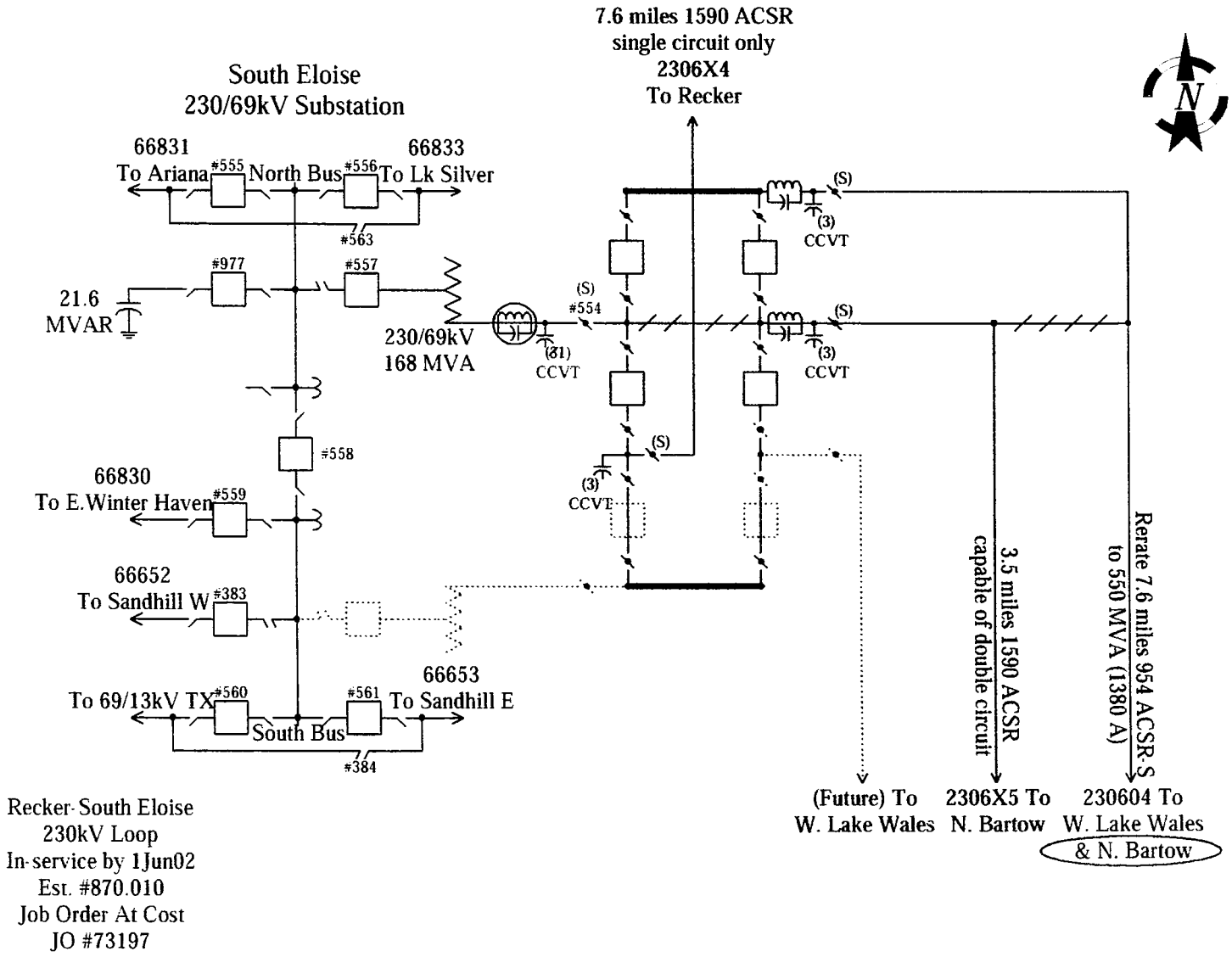


Figure 5. Recker-South Eloise 230kV Loop Project

Osprey Energy Center
Calpine
Witness: Michel P. Armand
Exhibit _____ (MPA-5)
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2002 at 100% of peak, single contingencies (continued)

The single contingency overload of 66701, the Osceola-Studio cable, although reduced slightly (from 126.7% to 122.0%) by the Recker-South Eloise 230kV Loop, must still be addressed in 2002. Please refer to the 3rd page of Appendix A for a geographic transmission map of the Osceola-Studio area. The contingency that causes the overload is 230617 Osceola-Cane Island. Since Osceola is a 3-element ring bus, when this line removed, the Osceola 230/69kV autotransformer and the Osceola-Studio 69kV cable form a direct low-impedance path from Lake Agnes 230kV Switching Station to Reedy Creek's Studio 69/13kV Substation. Since Tampa Electric has no other facilities in this area, there is no remedial switching action for alleviating overloads that are less than 115%. Therefore, the single contingency loading must not be allowed to exceed 100%. Circuit 66701 presently includes 4 Ohm series reactors, that adequately prevent single contingency overloads through 2006. Tampa Electric's base case plan calls for replacing these reactors with 8 Ohm reactors in 2007. The Osprey cases require that this project be accelerated from 2007 to 2002 and that reactors greater than 8 Ohm be used. An impedance of 10 Ohm is required to prevent single contingency overloads through 2008 (the duration of the Calpine service request). Therefore, the Osceola 10 Ohm Reactor Project was modeled and will be included in all further analysis of the Osprey cases. The table below lists the circuit loadings for each study year, with the base case, the Osprey case (including the Recker-South Eloise 230kV Loop) and the Osprey case with 10 Ohm reactors installed in 2002. A detailed cost-estimate of this project shows an expected capital cost of approximately $237 thousand.

Table 3. Loading on 66701 Osceola-Studio Cable (143 MVA Rate-B), Due to Single Contingency (230617 Osceola-Cane Island)

Year	Base Case	Osprey Case	Osprey Case w/10 Ohm
2002	92.1% (131.7 MVA)	114.0% (163.0 MVA)	79.8% (114.1 MVA)
2003	80.6% (115.2 MVA)	105.9% (151.5 MVA)	74.2% (106.0 MVA)
2004	84.2% (120.3 MVA)	109.3% (156.3 MVA)	76.5% (109.3 MVA)
2005	95.3% (136.2 MVA)	123.6% (181.7 MVA)	86.3% (123.5 MVA)
2006	97.8% (139.8 MVA)	127.1% (181.7 MVA)	88.6% (126.7 MVA)
2007	83.3% (119.2 MVA)*	107.6% (153.9 MVA)*	96.7% (138.3 MVA)
2008	82.3% (117.7 MVA)*	105.8% (151.3 MVA)*	95.1% (136.0 MVA)

*Base case plan calls for changing out 4 Ohm reactors to 8 Ohm in 2007.

2002 at 70% of peak, double contingencies (continued)

The study now focuses on any remaining overloads that exceed 115% of rating. The following compares the worst double contingency overloads (exceeding 115%) between the base case (case1) and the Osprey case (case2).

```
Branch SELOSE-N69.0( 9124) TO JAN PHYL69.0( 9172) CKT 1 RATING SET B   57.4 MVA
  113.2% in case1 when: OPEN LINE FROM BUS 9120 [SELOSE  230.00] TO BUS 9124 [SELOSE-N69.000] CKT 1
                        OPEN LINE FROM BUS 9126 [LKGUM   69.000] TO BUS 9132 [LKALFRED69.000] CKT 1
  130.7% in case2 when: same
   17.5% change from case 1 to case 2
```

The circuit shown here as exceeding 115% in the 2002 case due to Osprey would have overloaded without Osprey in 2003. Therefore, the following TEC base case project for 2003 would have to be accelerated to 2002 to accommodate Osprey.

Circuit 66831 Rebuild

- Rebuild 4.4 miles of 4/0 CU from South Eloise to Jan Phyl.
- Standard 954 AAC is sufficient for all new conductor.

2002 at 70% of peak, double contingencies (continued)

Now that all overloads exceeding 115% have been addressed, the study considers any remaining overloads that are significantly attributable to the Osprey project. The following compares the worst double contingency overloads between the base case (case1) and the Osprey case (case2).

```
case1: base02_70
case2: calpine02_70 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
 < 90.0% in case1
  109.9% in case2 when: OPEN LINE FROM BUS 6105 [CREWSLK 230.00] TO BUS 9100 [RECKER  230.00] CKT 1
                        OPEN LINE FROM BUS 9100 [RECKER  230.00] TO BUS 9120 [SELOSE  230.00] CKT 1
   19.9% change from case1 to case2 (at least)

Branch FOWLER  69.0( 8322) TO FOWLER-E69.0( 8324) CKT 1 RATING SET B  130.0 MVA
   90.3% in case1 when: OPEN LINE FROM BUS 8302 [RIVER-N 69.000] TO BUS 8438 [GTE-COLL69.000] CKT 1
                        OPEN LINE FROM BUS 8400 [CHAPMAN 230.00] TO BUS 8730 [SR 60   230.00] CKT 1
  104.7% in case2 when: same contingency
   14.4% change from case1 to case2

Branch CREWSLK  230( 6105) TO PEBB     230( 9050) CKT 1 RATING SET B  402.0 MVA
 < 90.0% in case1
  102.5% in case2 when: OPEN LINE FROM BUS 6104 [TENOROC 230.00] TO BUS 6106 [I-STATE 230.00] CKT 1
                        OPEN LINE FROM BUS 9100 [RECKER  230.00] TO BUS 9120 [SELOSE  230.00] CKT 1
   12.5% change from case1 to case2 (at least)

Branch RIVER-S 69.0( 8308) TO FOWLER-E69.0( 8324) CKT 1 RATING SET B  143.0 MVA
 < 90.0% in case1
  102.5% in case2 when: OPEN LINE FROM BUS 8302 [RIVER-N 69.000] TO BUS 8438 [GTE-COLL69.000] CKT 1
                        OPEN LINE FROM BUS 8400 [CHAPMAN 230.00] TO BUS 8730 [SR 60   230.00] CKT 1
   12.5% change from case1 to case2 (at least)

Branch RIVER-N 69.0( 8302) TO GTE-COLL69.0( 8438) CKT 1 RATING SET B  143.0 MVA
 < 90.0% in case1
  102.5% in case2 when: OPEN LINE FROM BUS 8308 [RIVER-S 69.000] TO BUS 8324 [FOWLER-E69.000] CKT 1
                        OPEN LINE FROM BUS 8400 [CHAPMAN 230.00] TO BUS 8730 [SR 60   230.00] CKT 1
   12.5% change from case1 to case2 (at least)

Branch FORT6 T 69.0( 8316) TO GTE-COLL69.0( 8438) CKT 1 RATING SET B  128.0 MVA
 < 90.0% in case1
  102.4% in case2 when: OPEN LINE FROM BUS 8308 [RIVER-S 69.000] TO BUS 8324 [FOWLER-E69.000] CKT 1
                        OPEN LINE FROM BUS 8400 [CHAPMAN 230.00] TO BUS 8730 [SR 60   230.00] CKT 1
   12.4% change from case1 to case2 (at least)
```

```
Branch CARGILL 69.0( 8704) TO BAYMET T69.0( 8786) CKT 1 RATING SET B   93.0 MVA
 < 90.0% in case1
  101.3% in case2 when: OPEN LINE FROM BUS 8500 [11TH AVE230.00] TO BUS 8900 [B BEND  230.00] CKT 1
                        OPEN LINE FROM BUS 8730 [SR 60   230.00] TO BUS 8900 [B BEND  230.00] CKT 1
   11.3% change from case1 to case2 (at least)

Branch FORTY6T269.0( 8318) TO FOWLER  69.0( 8322) CKT 1 RATING SET B  121.0 MVA
 < 90.0% in case1
  101.2% in case2 when: OPEN LINE FROM BUS 8302 [RIVER-N 69.000] TO BUS 8438 [GTE-COLL69.000] CKT 1
                        OPEN LINE FROM BUS 8400 [CHAPMAN 230.00] TO BUS 8730 [SR 60   230.00] CKT 1
   11.2% change from case1 to case2 (at least)

Branch FORTY6T269.0( 8318) TO MCKINLEY69.0( 8326) CKT 1 RATING SET B  121.0 MVA
 < 90.0% in case1
  101.2% in case2 when: OPEN LINE FROM BUS 8302 [RIVER-N 69.000] TO BUS 8438 [GTE-COLL69.000] CKT 1
                        OPEN LINE FROM BUS 8400 [CHAPMAN 230.00] TO BUS 8730 [SR 60   230.00] CKT 1
   11.2% change from case1 to case2 (at least)

Branch SELOSE-N69.0( 9124) TO JAN PHYL69.0( 9172) CKT 1 RATING SET B   57.4 MVA
  114.4% in case1 when: OPEN LINE FROM BUS 9120 [SELOSE  230.00] TO BUS 9124 [SELOSE-N69.000] CKT 1
                        OPEN LINE FROM BUS 9126 [LKGUM   69.000] TO BUS 9132 [LKALFRED69.000] CKT 1
 < 90.0% in case2
  -24.4% change from case1 to case2 (at least)
```

Most of these impacted circuits are remote from the Osprey site, and are impacted primarily due to the redispatch of FPC units to accommodate the requested transmission service from Calpine to FPC. The two local impacts (due simply to interconnecting 526 MW of additional generation at Recker) are the Crews Lake–Pebbledale 230kV line and the Ariana 230/69kV autotransformer. Although these overloads can be alleviated by post-contingency switching, the impacts must still be documented.

2003 at 100% of peak, single contingencies

Now that all impacts in the initial year (2002) have been addressed or documented, the study proceeds to the later year cases (2003 - 2008).

```
case1: base03
case2: calpine03 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

Branch SELOSE   230( 9120) TO SELOSE-N69.0( 9124) CKT 1 RATING SET B  177.0 MVA
   99.4% in case1 when: OPEN LINE FROM BUS 9102 [ARIANA-N69.000] TO BUS 9110 [ARIANA  230.00] CKT 1
  114.2% in case2 when: same contingency
   14.8% change from case1 to case2

Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
  102.1% in case1 when: OPEN LINE FROM BUS 9120 [SELOSE  230.00] TO BUS 9124 [SELOSE-N69.000] CKT 1
  113.7% in case2 when: same contingency
   11.6% change from case1 to case2
```

Both of these overloads can be alleviated with post-contingency switching.

2003 at 70% of peak, double contingencies

```
case1: base03_70
case2: calpine03_70 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)
```

```
Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
 < 90.0% in case1
  114.3% in case2 when: OPEN LINE FROM BUS 6105 [CREWSLK 230.00] TO BUS 9100 [RECKER  230.00] CKT 1
                        OPEN LINE FROM BUS 9100 [RECKER  230.00] TO BUS 9120 [SELOSE  230.00] CKT 1
   24.3% change from case1 to case2 (at least)

Branch CREWSLK  230( 6105) TO PEBB     230( 9050) CKT 1 RATING SET B  402.0 MVA
 < 90.0% in case1
  112.7% in case2 when: OPEN LINE FROM BUS 6104 [TENOROC 230.00] TO BUS 6106 [I-STATE 230.00] CKT 1
                        OPEN LINE FROM BUS 9100 [RECKER  230.00] TO BUS 9120 [SELOSE  230.00] CKT 1
   22.7% change from case1 to case2 (at least)

Branch HOPEWELL69.0( 8652) TO MULB-S  69.0( 8662) CKT 1 RATING SET B   61.0 MVA
   96.0% in case1 when: OPEN LINE FROM BUS 8600 [HAMPTN  230.00] TO BUS 8602 [HAMPTN  69.000] CKT 1
                        OPEN LINE FROM BUS 8648 [IMPRLK T69.000] TO BUS 8662 [MULB-S  69.000] CKT 1
  103.4% in case2 when: same contingency
    7.4% change from case1 to case2

Branch MULB-S  69.0( 8662) TO RDGWD T269.0( 9074) CKT 1 RATING SET B   97.0 MVA
   98.3% in case1 when: OPEN LINE FROM BUS 8600 [HAMPTN  230.00] TO BUS 8602 [HAMPTN  69.000] CKT 1
                        OPEN LINE FROM BUS 8662 [MULB-S  69.000] TO BUS 9081 [ROYSTR T69.000] CKT 1
  104.3% in case2 when: same contingency
    6.0% change from case1 to case2

Branch SANDHL-W69.0( 9032) TO ROYSTR T69.0( 9081) CKT 1 RATING SET B   97.0 MVA
   96.3% in case1 when: OPEN LINE FROM BUS 8600 [HAMPTN  230.00] TO BUS 8602 [HAMPTN  69.000] CKT 1
                        OPEN LINE FROM BUS 8662 [MULB-S  69.000] TO BUS 9074 [RDGWD T269.000] CKT 1
  102.1% in case2 when: same contingency
    5.8% change from case1 to case2

Branch MULB-S  69.0( 8662) TO ROYSTR T69.0( 9081) CKT 1 RATING SET B   97.0 MVA
   96.3% in case1 when: OPEN LINE FROM BUS 8600 [HAMPTN  230.00] TO BUS 8602 [HAMPTN  69.000] CKT 1
                        OPEN LINE FROM BUS 8662 [MULB-S  69.000] TO BUS 9074 [RDGWD T269.000] CKT 1
  102.1% in case2 when: same contingency
    5.8% change from case1 to case2
```

All of these overloads can be alleviated with post-contingency switching.

2004 at 100% of peak, single contingencies

```
case1: base04
case2: calpine04 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

Branch SELOSE   230( 9120) TO SELOSE-N69.0( 9124) CKT 1 RATING SET B  177.0 MVA
  107.0% in case1 when: OPEN LINE FROM BUS 9102 [ARIANA-N69.000] TO BUS 9110 [ARIANA  230.00] CKT 1
  122.6% in case2 when: same contingency
   15.6% change from case1 to case2

Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
  110.7% in case1 when: OPEN LINE FROM BUS 9120 [SELOSE  230.00] TO BUS 9124 [SELOSE-N69.000] CKT 1
  122.8% in case2 when: same contingency
   12.1% change from case1 to case2

Branch SELOSE-S69.0( 9122) TO SELOSE-N69.0( 9124) CKT 1 RATING SET B  143.4 MVA
   91.0% in case1 when: OPEN LINE FROM BUS 9124 [SELOSE-N69.000] TO BUS 9154 [LKWNTRST69.000] CKT 1
  100.0% in case2 when: same contingency
    9.0% change from case1 to case2
```

2004 at 70% of peak, double contingencies

```
case1: base04_70
case2: calpine04_70 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
 < 90.0% in case1
  116.4% in case2 when: OPEN LINE FROM BUS 6105 [CREWSLK 230.00] TO BUS 9100 [RECKER  230.00] CKT 1
                        OPEN LINE FROM BUS 9100 [RECKER  230.00] TO BUS 9120 [SELOSE  230.00] CKT 1
   26.4% change from case1 to case2 (at least)
```

```
Branch CREWSLK  230( 6105) TO PEBB     230( 9050) CKT 1 RATING SET B  402.0 MVA
 < 90.0% in case1
  110.3% in case2 when: OPEN LINE FROM BUS 6104 [TENOROC 230.00] TO BUS 6106 [I-STATE 230.00] CKT 1
                        OPEN LINE FROM BUS 9100 [RECKER  230.00] TO BUS 9120 [SELOSE  230.00] CKT 1
   20.3% change from case1 to case2 (at least)

Branch MULB-S  69.0( 8662) TO RDGWD T269.0( 9074) CKT 1 RATING SET B   97.0 MVA
   96.5% in case1 when: OPEN LINE FROM BUS 8600 [HAMPTN  230.00] TO BUS 8602 [HAMPTN  69.000] CKT 1
                        OPEN LINE FROM BUS 8662 [MULB-S  69.000] TO BUS 9081 [ROYSTR T69.000] CKT 1
  102.3% in case2 when: same contingency
    5.8% change from case1 to case2

Branch MULB-S  69.0( 8662) TO ROYSTR T69.0( 9081) CKT 1 RATING SET B   97.0 MVA
   94.5% in case1 when: OPEN LINE FROM BUS 8600 [HAMPTN  230.00] TO BUS 8602 [HAMPTN  69.000] CKT 1
                        OPEN LINE FROM BUS 8662 [MULB-S  69.000] TO BUS 9074 [RDGWD T269.000] CKT 1
  100.3% in case2 when: same contingency
    5.8% change from case1 to case2
```

In 2004, both the South Eloise and the Ariana 230/69kV autotransformers are impacted to such a degree that their single contingency loading exceeds the 115% criteria. Also, at a system load level of 70% of peak in 2004, the Ariana transformer is pushed over the 115% criteria upon the double-contingency loss of the Recker-South Eloise and Recker-Crews Lake 230kV circuits. Therefore, firm transmission service to Osprey Energy Center requires a solution to these autotransformer overloads to be implemented prior to the summer of 2004.

Tampa Electric's base case plan includes a new 230/69kV autotransformer at Gapway Substation in 2005. This transformer installation requires a single 69kV breaker, a 1,000-foot tap to the Recker-Lake Agnes 230kV circuit, and three 230kV switches. This project alleviates the Ariana and South Eloise overloads in the base cases and the Osprey cases from 2005 through 2008. Therefore, the Gapway project must be accelerated from 2005 to 2004 to mitigate the impacts due to Osprey. The following lists show the remaining impacts (single-contingency only) caused by the Osprey project, for the years 2005 through 2008.

2005 at 100% of peak, single contingencies

```
case1: base05
case2: calpine05 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

no changes exceeding 5%
```

2006 at 100% of peak, single contingencies

```
case1: base06
case2: calpine06 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
   90.0% in case1 when: OPEN LINE FROM BUS 9120 [SELOSE  230.00] TO BUS 9124 [SELOSE-N69.000] CKT 1
  100.7% in case2 when: same contingency
   10.7% change from case1 to case2

Branch SELOSE   230( 9120) TO SELOSE-N69.0( 9124) CKT 1 RATING SET B  177.0 MVA
   98.3% in case1 when: OPEN LINE FROM BUS 9102 [ARIANA-N69.000] TO BUS 9110 [ARIANA  230.00] CKT 1
  104.9% in case2 when: same contingency
    6.6% change from case1 to case2
```

```
Branch LK BRYAN69.0( 2120) TO LK BRYAN 230( 2166) CKT 2 RATING SET B  280.0 MVA
   93.8% in case1 when: OPEN LINE FROM BUS 2120 [LK BRYAN69.000] TO BUS 2166 [LK BRYAN230.00] CKT 1
  100.2% in case2 when: same contingency
    6.4% change from case1 to case2

Branch LK BRYAN69.0( 2120) TO LK BRYAN 230( 2166) CKT 1 RATING SET B  280.0 MVA
   93.8% in case1 when: OPEN LINE FROM BUS 2120 [LK BRYAN69.000] TO BUS 2166 [LK BRYAN230.00] CKT 2
  100.2% in case2 when: same contingency
    6.4% change from case1 to case2
```

2007 at 100% of peak, single contingencies

```
case1: base07
case2: calpine07 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

Branch OSCEOLA  230( 7890) TO LKAGNES  230( 9150) CKT 1 RATING SET B  553.0 MVA
 < 80.0% in case1
  113.5% in case2 when: OPEN LINE FROM BUS 2876 [LOUGHMAN230.00] TO BUS 2891 [WLK WALE230.00] CKT 1
   33.5% change from case1 to case2 (at least)

Branch LOUGHMAN 230( 2876) TO WLK WALE 230( 2891) CKT 1 RATING SET B  593.0 MVA
 < 80.0% in case1
  111.1% in case2 when: OPEN LINE FROM BUS 7890 [OSCEOLA 230.00] TO BUS 9150 [LKAGNES 230.00] CKT 1
   31.1% change from case1 to case2 (at least)

Branch LOUGHMAN 230( 2876) TO INTERCSN 230( 2883) CKT 1 RATING SET B  603.0 MVA
 < 80.0% in case1
  109.3% in case2 when: OPEN LINE FROM BUS 7890 [OSCEOLA 230.00] TO BUS 9150 [LKAGNES 230.00] CKT 1
   29.3% change from case1 to case2 (at least)

Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
   90.9% in case1 when: OPEN LINE FROM BUS 9120 [SELOSE  230.00] TO BUS 9124 [SELOSE-N69.000] CKT 1
  102.3% in case2 when: same contingency
   11.4% change from case1 to case2
```

2008 at 100% of peak, single contingencies

```
case1: base08
case2: calpine08 (with Osceola Reactor Upgrade and Recker-South Eloise 230kV Loop)

Branch LOUGHMAN 230( 2876) TO WLK WALE 230( 2891) CKT 1 RATING SET B  593.0 MVA
 < 80.0% in case1
  109.0% in case2 when: OPEN LINE FROM BUS 7890 [OSCEOLA 230.00] TO BUS 9150 [LKAGNES 230.00] CKT 1
   29.0% change from case1 to case2 (at least)

Branch OSCEOLA  230( 7890) TO LKAGNES  230( 9150) CKT 1 RATING SET B  553.0 MVA
 < 80.0% in case1
  108.6% in case2 when: OPEN LINE FROM BUS 2876 [LOUGHMAN230.00] TO BUS 2891 [WLK WALE230.00] CKT 1
   28.6% change from case1 to case2 (at least)

Branch LOUGHMAN 230( 2876) TO INTERCSN 230( 2883) CKT 1 RATING SET B  603.0 MVA
 < 80.0% in case1
  107.2% in case2 when: OPEN LINE FROM BUS 7890 [OSCEOLA 230.00] TO BUS 9150 [LKAGNES 230.00] CKT 1
   27.2% change from case1 to case2 (at least)

Branch ARIANA-N69.0( 9102) TO ARIANA   230( 9110) CKT 1 RATING SET B  176.0 MVA
   86.7% in case1 when: OPEN LINE FROM BUS 9120 [SELOSE  230.00] TO BUS 9124 [SELOSE-N69.000] CKT 1
  100.1% in case2 when: same contingency
   13.4% change from case1 to case2

Branch HIGGINS  115( 2245) TO GRIFFIN  115( 2249) CKT 1 RATING SET B  176.0 MVA
   93.7% in case1 when: OPEN LINE FROM BUS 2271 [GRIFFIN 230.00] TO BUS 2884 [KATHLEEN230.00] CKT 1
  101.0% in case2 when: same contingency
    7.3% change from case1 to case2
```

Note that many of the impacted facilities listed above are owned by Florida Power Corporation. FPC's System Planning department was provided, via telephone conversation and e-mail on July 6, 2000, all of the pertinent details regarding this study. FPC replied, via e-mail on August 8, 2000, indicating that "Any facilities that are impacted on the FPC system are minimally impacted (less than 3% in early years and less than 5% in later years) or FPC has plans to upgrade the facilities in the same time frame as the impact." However, FPC also stated "This evaluation only pertains to the PTP Transmission Service Request under study and in no way implies approval of this as a Network Resource on the FPC transmission system." Therefore, Florida Power Corporation's impacted facilities were not considered as requiring further action for this Tampa Electric Facilities Study.

The City of Lakeland Electric Department's facilities were also monitored in all of the loadflow analysis of this study, but no adverse impacts were identified.

SUMMARY OF REQUIRED FACILITIES

Facilities Required for Interconnection

- Recker Substation Modifications, in-service by December 2001 - Capital costs $2.4M, non-escalated.

Description	Labor/Sub-Contract($)	Vehicle($)	Material($)	Other($)	Total($)
2-230kV circuits from Recker, terminating at three Calpine-owned dead-end towers at the Osprey site. Extend the 230kV bus west, install 3-230kV circuit breakers and five disconnect switches.	$976.7K	$89.5K	$1,101.1K	$226.7K	$2,394.0K

Network Upgrades Required for Firm Transmission

- Recker-South Eloise 230kV Loop, in-service by June 2002 - 11.1 miles of new 230kV transmission and 5 new 230kV circuit breakers. Capital costs $11.1M, non-escalated.
- Circuit 66831 Rebuild, in-service by June 2002 - Rebuild 4.4 miles of 4/0 CU from South Eloise to Jan Phyl. Project is in TEC's base expansion plan for 2003 and will be accelerated 1 year. Due to logistics of sharing the same pole-line, these costs are included in the Recker-South Eloise 230kV Loop estimate.

Description	Labor/Sub-Contract($)	Vehicle($)	Material($)	Other($)	Total($)
11.1 miles of new 230kV transmission, 1-230kV circuit breaker at Recker, new 230kV ring bus with 4-230kV circuit	$3,218.1K	$762.5K	$6,393.9K	$702.6K	$11,077.1K

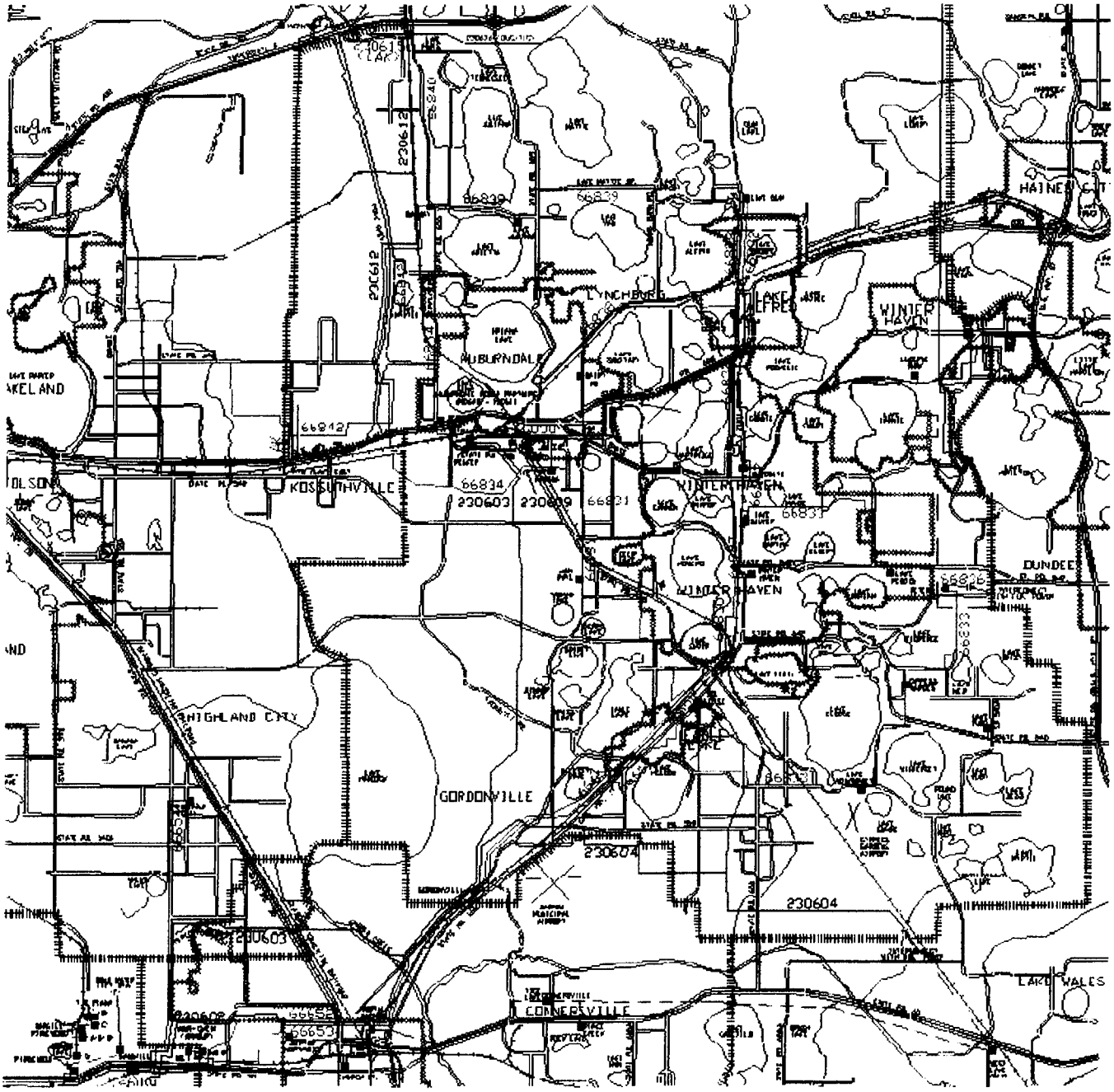
- Osceola 10 Ohm Reactor, in-service by summer 2002 - Upgrade 4 ohm reactors on circuit 66701 (Osceola-Studio 69kV cable) to 10 ohms. Project (8 ohm reactors) is in TEC's base expansion plan for 2007 and will be accelerated 5 years. Capital costs $236.9K, non-escalated. Calpine's capital cost responsibilty for accelerating project 5 years is $81K.

Description	Labor/Sub-Contract($)	Vehicle($)	Material($)	Other($)	Total($)
Remove (3) 4 Ohm series reactors, install (3) 10 Ohm series reactors at Osceola.	$25.6K	$2.5K	$204.6K	$4.2K	$236.9K

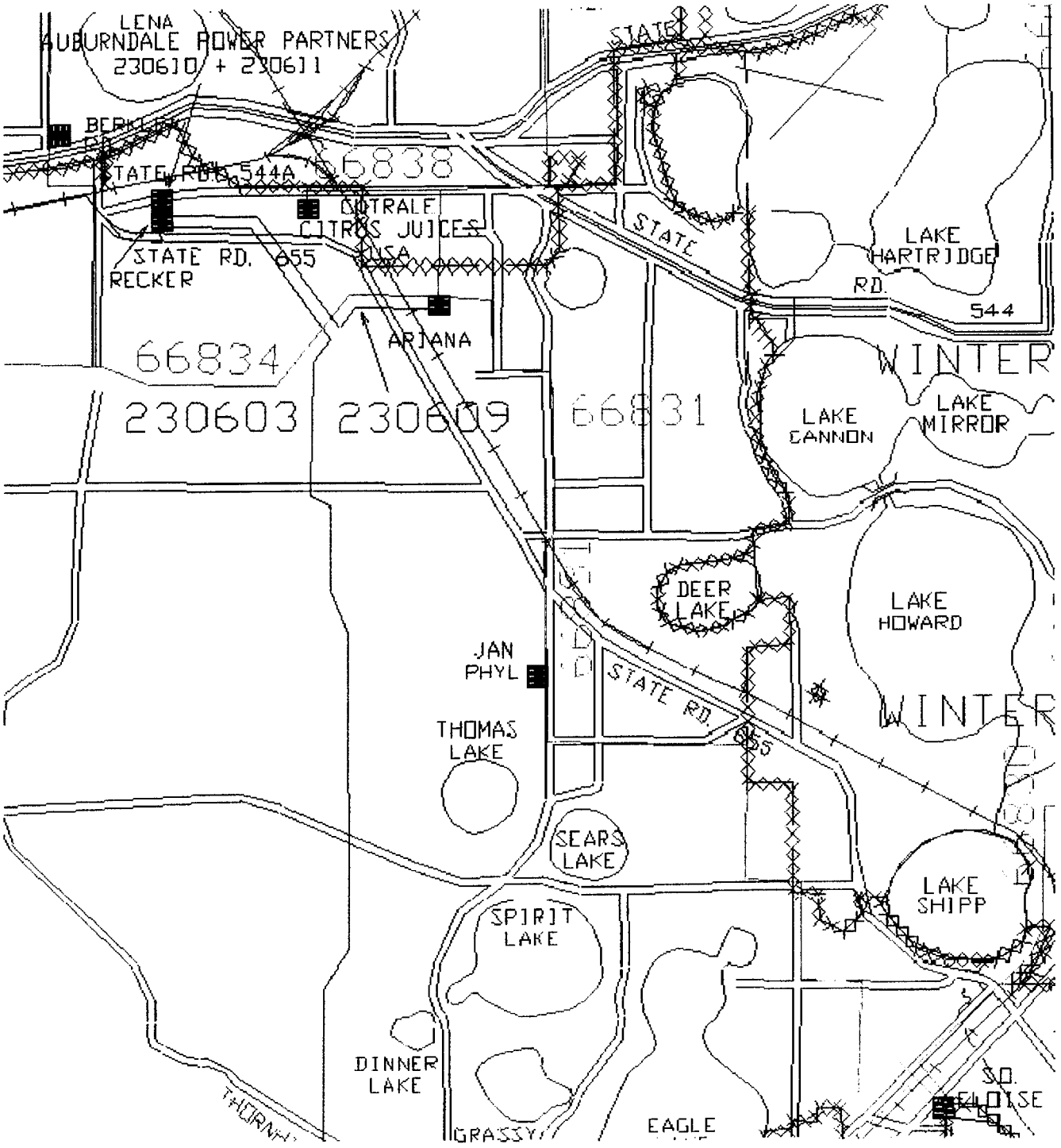
- Gapway 230/69kV transformer, in-service by summer 2004 - $3.7M, non-escalated. Project is in TEC's base expansion plan for 2005 and will be accelerated 1 year. Calpine's capital cost responsibilty for accelerating project 1 year is $328K.

Description	Labor/Sub-Contract($)	Vehicle($)	Material($)	Other($)	Total($)
New 230/69kV autotransformer, 1-69kV breaker, 3-230kV switches, 0.2 mile new 230kV	$928.3K	$126.6K	$2,664.0K	$8.9K	$3,727.8K

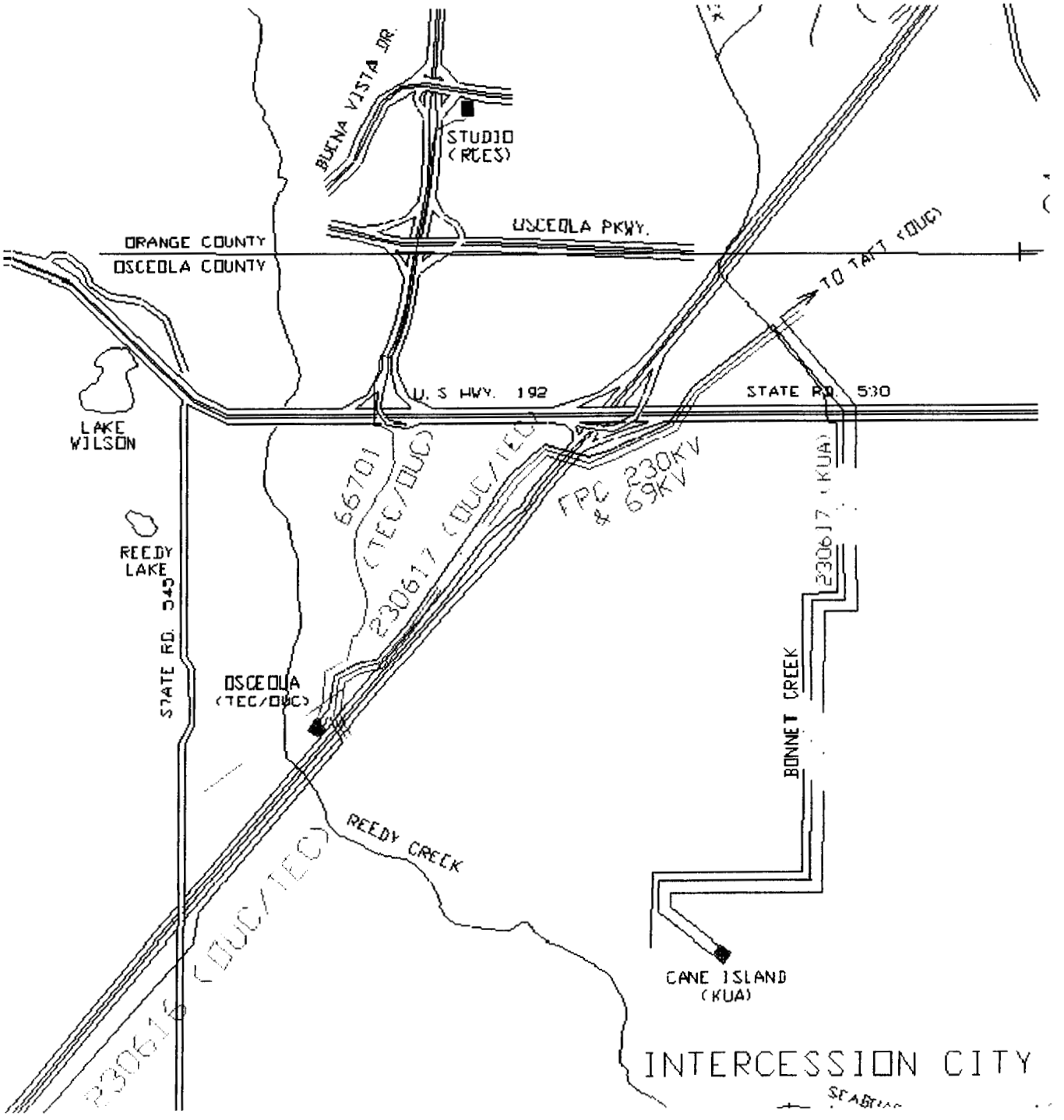
Appendix A



Geographic transmission map of greater Winter Haven area.



Geographic transmission map of Recker- South Eloise area.



Geographic transmission map of Osceola- Studio area.

Michael D. Petit

8 Springvalley Road
Medfield, MA 02052
508-359-8659 (home)
617-557-5306 (work)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001748-EC EXHIBIT NO. 10
COMPANY/
WITNESS: Calpine / Petit
DATE: 12-12-01

SUMMARY

Twenty-three years of experience in the energy industry in a variety of commercial functions.

EXPERIENCE

Calpine Eastern Corporation
1999-Present Director--Fuels Management

Develop fuel supply strategies for merchant power plants and cogeneration facilities in the eastern United States.
Negotiate term natural gas supply, transportation and interconnect agreements.
Coordinate fuel regulatory activity with FERC and State Regulatory Agencies.
Perform fuel due diligence on acquisition opportunities.
Evaluate strategic benefit of equity interest in reserves, storage and pipeline assets.
Optimize term fuel supply and transportation contracts for electric generation facilities.
Testify in State Siting Board proceedings.

Energy Consulting
1998-1999 Principal

Initiated consulting practice which provided fuel supply, transportation and regulatory services to power plant developers, pipelines and gas utilities.
Developed fuel supply plans for merchant generation and cogeneration facilities.
Negotiated term fuel supply and transportation arrangements.

U.S. Generating Company/J. Makowski Associates
(PG&E Generating Company)
1995-1998 Director, Project Management Services--NE Region
1995-1997 Vice President of Alberta Northeast Gas Limited and Boundary Gas Inc.
1992-1994 Manager, Fuel Acquisition and Operations

Responsible for the optimization of long term fuel supply and transportation contracts for electric generation facilities.
Negotiator of major natural gas supply, sales and transportation contracts.
Experienced in Project Development and Acquisitions/sales activity for gas and electric generation assets.
Coordinated pipeline rate cases on major pipelines and successfully led settlement proceedings.
Developed strategies for FERC and NEB initiatives.
Testified in NEB and State Sitting Board proceedings on fuel related issues.

Managed short-term marketing, hedging and fuel procurement activity.
Directed daily operations, contracting, reporting and fuel budgeting.
Managed the Canadian supply agreements for 500,000 MCF/Day of natural gas for a consortium of 20 Northeastern local gas and gas/electric distribution companies.

Intercontinental Energy Company
1991-1992 Manager Fuel Supply

Optimized long term fuel supply and transportation agreements for cogeneration facilities.
Negotiated short term fuel supply and transportation arrangements.
Developed and implemented fuel management systems.

Citizens Energy Corporation
1988-1991 Natural Gas Marketing Manager
1985-1988 Manager Oil Trading & Operations

Negotiated sales and purchases of natural gas including back to back transactions.
Managed multiple interstate pipeline supplies to optimize transportation
Coordinated sales endeavors of Field Representatives.
Analyzed and implemented trading opportunities in crude oil and refinery products.
Managed crude oil and refinery product contracts to maximize value.
Scheduled pipeline and vessel activity for crude oil and refinery products.
Initiated Bank Letters of Credit and implemented fuel reporting system.

Atlantic Richfield Company
1977-1985 Five Commercial and three analytical positions

Coordinated Finished (Refinery) Product, Mid-continent crude oil and Feedstock trading activity.
Negotiated spot and term crude oil and refinery product supply, sales and transportation arrangements.
Managed inventory within multifaceted crude oil pipeline systems.
Developed inventory and contract management tracking and scheduling system.
Approved Bank Letters of Credit.

EDUCATION

Bachelor of Science, Accounting--Villanova University 1977

MEMBERSHIPS

New England Gas Association

PRECEDENT AGREEMENT

This Precedent Agreement ("Agreement"), is made and entered into as of this 8th day of October, 1999, by and between Calpine East Fuels, L.L.C., a Delaware limited liability company ("Shipper"), and Gulfstream Natural Gas System, L.L.C., a limited liability company formed under the laws of the State of Delaware ("Gulfstream") (hereinafter Shipper and Gulfstream are sometimes referred to individually as a "Party" or collectively as the "Parties").

WITNESSETH:

WHEREAS, Gulfstream intends to design, construct, own and operate a natural gas pipeline that will extend from interconnections with the facilities of various natural gas treatment plants, processing plants and interstate natural gas transmission systems in the vicinity of Mobile, Alabama and southeastern Mississippi to various delivery points in peninsular Florida ("Gulfstream Project"); and

WHEREAS, Shipper intends to design, construct, own and operate a natural gas fired electric generating plant in Polk County, Florida ("Plant") which Shipper plans to have in-service on or before and desires to receive firm transportation service(s) from Gulfstream on the Gulfstream Project for the natural gas supply required for the Plant; and

WHEREAS, subject to the terms and conditions set forth in this

Agreement, Gulfstream is willing to proceed with its efforts to develop the Gulfstream Project for the provision of the firm transportation service(s) hereinafter described, and Shipper is willing to subscribe for such transportation services.

NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, and intending to be bound, Shipper and Gulfstream agree as follows:

1. Notice of Intent to Proceed. This Agreement is subject to (i) the outcome of an open season for the Gulfstream Project, and (ii) the determination by Gulfstream, in the exercise of its sole discretion, whether or not to proceed with the filing and prosecution of application(s) for the governmental and regulatory authorization(s) described in Paragraph 2 below. Within a reasonable time following execution and delivery of this Agreement by Shipper, Gulfstream will proceed with the filing and prosecution of such application(s) with respect to the Gulfstream Project. To facilitate Gulfstream's ability to develop the Gulfstream Project, Shipper will refrain from committing to obtain any transportation service(s) from other person(s) which service(s) would be in lieu of the transportation services provided for herein.

2. Regulatory Authorizations To Be Sought By Gulfstream. Subject to the other terms and conditions of this Agreement, Gulfstream will proceed with due diligence to apply for and attempt to obtain all governmental and regulatory authorizations, including without limitation authorizations from the Federal Energy

Regulatory Commission ("FERC"), which Gulfstream determines are necessary for Gulfstream to (i) construct, own and operate (or cause to be constructed and operated) the Gulfstream Project, (ii) render the transportation service(s) contemplated in this Agreement and all of the precedent agreements with other shippers for transportation service(s) to be provided utilizing the Gulfstream Project and (iii) perform its obligations as contemplated in this Agreement. Gulfstream will request that the FERC issue a preliminary determination on the non-environmental aspects of the Gulfstream Project. Gulfstream reserves the right to file and prosecute any and all applications for such authorizations (and any supplements and amendments thereto) and, if necessary, institute any court review with respect thereto, in such manner as it deems to be in its best interest. Shipper agrees to support and cooperate in the efforts of Gulfstream to obtain all authorizations which Gulfstream determines are necessary for Gulfstream to construct, own and operate the Gulfstream Project and render the transportation service(s) contemplated in this Agreement, including, at the sole discretion of Shipper, the filing of an intervention or other pleading in support of the Gulfstream Project. If the FERC determines that information related to Shipper's markets, gas supply or upstream or downstream transportation arrangements is required from Gulfstream, Shipper agrees to provide Gulfstream with such information in a timely manner to enable Gulfstream to respond within the time required by

FERC; provided that Gulfstream will use reasonable best efforts to obtain a protective order from the FERC for any commercially sensitive or confidential information identified by Shipper.

3. Shipper's Regulatory Authorizations.

Subject to the other terms and conditions of this Agreement, Shipper shall proceed with due diligence to apply for and attempt to obtain from all governmental and regulatory authorities having jurisdiction all authorizations necessary for Shipper to (i) construct, own and operate (or cause to be constructed and operated) the Plant and all other facilities necessary to enable Shipper to utilize the transportation service(s) contemplated in this Agreement and (ii) perform its obligations as contemplated in this Agreement. Shipper reserves the right to file and prosecute applications for such authorizations (and any supplements and amendments thereto) and, if necessary, institute any court review with respect thereto, in such manner as it deems to be in its best interest; provided, however, that Shipper shall prosecute such applications (and any supplements and amendments thereto or court appeals) in a timely manner and in no event shall Shipper take any action that would obstruct, interfere with or delay the receipt by Gulfstream of the authorizations described in Paragraph 2 above. Gulfstream agrees to support and cooperate in the efforts of Shipper to obtain all authorizations necessary for Shipper to utilize the transportation service(s) contemplated herein. Subject to its receipt of all such necessary authorizations and subject to

the satisfaction of each of the conditions precedent set forth in Paragraph 6 below (or written waiver of the same by the Party on whose behalf such condition is imposed), Shipper agrees to proceed with due diligence to construct, or cause to be constructed, the Plant and all other facilities necessary for Shipper to utilize the transportation service(s) contemplated herein.

4. Service Agreement.

(a) Service Agreement. Shipper and Gulfstream agree to execute, within ten (10) business days after the date each Party gives the other Party written notice that each of the conditions precedent imposed on behalf of such Party in Paragraph 6 hereof has been satisfied or waived by such Party, the Firm Transportation Service Agreement attached hereto as Attachment 1, as such Agreement may be amended from time to time to conform to changes approved by the FERC to Gulfstream's FERC Gas Tariff ("Service Agreement"). Service under the Service Agreement will commence as set forth in Paragraph 4(b) below.

(b) Commencement and Term of Service. Shipper will give Gulfstream written notice of the date Shipper plans to place the Plant in-service no less than months prior to such date (the "Plant In-Service Date"); provided that Shipper shall give Gulfstream timely written notice thereafter of any change(s) to the Plant In-Service Date which change(s) shall not delay the Plant In-Service Date by more than months and, if such written notice is provided, the date specified therein shall become

the new Plant In-Service Date; and further provided that the Plant In-Service Date shall be no later than . Transportation service(s) under the Service Agreement will commence on the date specified by Gulfstream in the written notice to be provided to Shipper pursuant to Paragraph 4(c) below. After transportation service(s) commences under the Service Agreement, such service(s) will continue for the primary term set forth therein and year to year thereafter subject to termination in accordance with the provisions of the Service Agreement. Nothing in this Subparagraph 4(b) shall modify or otherwise change Shipper's right, as set forth in Subparagraph 5(b), to terminate this Agreement or the Service Agreement, as the case may be, if Gulfstream does not commence service on or before

(c) Notice of Commencement of Transportation Service(s). No less than thirty (30) days prior to the date Gulfstream is ready to commence transportation service(s) under the Service Agreement, Gulfstream will notify Shipper in writing that such transportation service(s) will commence on a date certain, which date will be the later to occur of (1) June 1, 2002 or (2) the Plant In-Service Date (the "Commencement Date"). As of the Commencement Date, Gulfstream

will stand ready to provide firm transportation service(s) to Shipper pursuant to the provisions of the Service Agreement, and Shipper will pay to Gulfstream all applicable charges provided for in the Service Agreement.

(d) Test Gas

5. Construction of Facilities.

(a) Design and Construction. Upon execution and delivery of this Agreement by Shipper, Gulfstream will undertake the preliminary design of the facilities for the Gulfstream Project and any other preparatory actions required for Gulfstream to complete and file application(s) with the FERC and other governmental or regulatory agencies having jurisdiction for the authorizations which Gulfstream determines are necessary for Gulfstream to (i) construct, own and operate (or cause to be constructed and operated) the Gulfstream Project, (ii) render the transportation service(s) contemplated in this Agreement and all of the precedent agreements with other shippers for transportation service(s) to be provided utilizing the Gulfstream Project and (iii) perform its obligations as contemplated in this Agreement. Upon satisfaction of each of the conditions precedent set forth in Paragraph 6 below,

or written waiver of the same by the Party on whose behalf such condition is imposed, and subject to the continuing commitments of Shipper and all of the other shippers who have executed precedent agreements for transportation service(s) to be provided utilizing the Gulfstream Project, Gulfstream will proceed with due diligence to construct the pipeline and other facilities (as authorized by the FERC and other governmental or regulatory agencies having jurisdiction) which are necessary for the provision of the firm transportation service(s) contemplated in this Agreement. Notwithstanding Gulfstream's due diligence, if Gulfstream is unable to commence the transportation service(s) for Shipper as contemplated herein by the Plant In-Service Date, Gulfstream will continue to proceed with due diligence to complete construction of such necessary pipeline and other facilities, and commence transportation service(s) for Shipper at the earliest practicable date thereafter.

(b) Limitation of Liability. Gulfstream will neither be liable to Shipper nor will this Agreement or the Service Agreement be subject to cancellation (except as hereinafter provided) if Gulfstream is unable to complete the construction of such pipeline and other facilities and commence the firm transportation service(s) contemplated herein by the Plant In-Service Date; provided, however, Gulfstream will continue to proceed with due diligence to complete construction of such pipeline and other facilities, and commence such transportation service(s) for Shipper

at the earliest practicable date thereafter. If Gulfstream is unable to commence the transportation service(s) for Shipper as contemplated herein by the Plant In-Service Date which shall not be earlier than . Shipper, in its sole discretion, will have the option not to commence the transportation service(s) until and, in that event, applicable charges under the Service Agreement will not commence until .

If Gulfstream is unable to commence the transportation service(s) for Shipper by four (4) months prior to the Plant In Service Date, Shipper, in its sole discretion, will have the option to terminate this Agreement and will have no further liability to Gulfstream.

6. Conditions Precedent.

The commencement of transportation service(s) under the Service Agreement, and Gulfstream's and Shipper's respective rights and obligations hereunder and under the Service Agreement, are expressly made subject to the satisfaction of each of the following conditions precedent; provided, however, that each such condition may be waived in writing by the Party on whose behalf the condition is imposed:

(a) Conditions Precedent Imposed On Behalf Of Gulfstream:

(b) Conditions Precedent Imposed On Behalf Of Shipper:

7. Rates and Rate Design Methodology. Shippers electing a negotiated rate agree to pay such rate without regard to any action or determination of the FERC with respect to Gulfstream's FERC-approved, filed rates. Shippers electing recourse rates agree to pay such rates, subject to changes determined by the FERC from time to time. Recourse rates will be the rates filed with and approved by the FERC, pursuant to the Natural Gas Act or successor legislation.

8. Representations and Warranties.

(a) Gulfstream. Gulfstream represents and warrants that (i) it is duly organized and validly existing under the laws of the State of Delaware and has all requisite legal power and authority to execute this Agreement and carry out the terms, conditions and provisions hereof; (ii) this Agreement constitutes the valid, legal and binding obligation of Gulfstream, enforceable in accordance with the terms hereof, (iii) there are no actions, suits or proceedings pending or, to Gulfstream's knowledge, threatened against or affecting Gulfstream before any Court or administrative

body that might materially adversely affect the ability of Gulfstream to meet and carry out its obligations hereunder; and (iv) the execution and delivery by Gulfstream of this Agreement has been duly authorized by all requisite limited liability company action.

(b) Shipper. Shipper represents and warrants that (i) it is duly organized and validly existing under the laws of the State of Delaware and has all requisite legal power and authority to execute this Agreement and carry out the terms, conditions and provisions hereof; (ii) this Agreement constitutes the valid, legal and binding obligation of Shipper, enforceable in accordance with the terms hereof, (iii) there are no actions, suits or proceedings pending or, to Shipper's knowledge, threatened against or affecting Shipper before any Court or administrative body that might materially adversely affect the ability of Shipper to meet and carry out its obligations hereunder; (iv) the execution and delivery by Shipper of this Agreement has been duly authorized by all requisite corporate action, and (v) upon execution and delivery of the Service Agreement, Shipper will satisfy the Agreed Creditworthiness Requirements

9. Term. This Agreement shall become effective when executed by both Gulfstream and Shipper, and shall remain in effect unless and until terminated as hereinafter provided.

(a) Termination of Precedent Agreement. In the event each of the conditions precedent set forth in Paragraph 6 above has not

been satisfied or waived by the Party on whose behalf such condition is imposed by the date specified in such Paragraph, then such Party may terminate this Agreement by giving written notice of termination to the other Party within thirty (30) days of such date.

(b) Commencement of Transportation Service(s). If this Agreement is not terminated pursuant to Paragraph 5(b) or Paragraph 9(a) above, then this Agreement will terminate by its express terms on the Commencement Date, and thereafter Gulfstream's and Shipper's respective rights and obligations related to the transactions contemplated herein shall be determined pursuant to the terms and conditions of the Service Agreement and the terms and conditions of Gulfstream's FERC Gas Tariff, as in effect from time to time.

10. Assignment. This Agreement shall be binding upon Gulfstream, Shipper and their respective successors and assigns; provided, however, that neither Party shall assign this Agreement or any rights or obligations hereunder without first obtaining the prior written consent of the other Party (which consent shall not be unreasonably withheld), the consent of Gulfstream's lenders if required, and any necessary governmental and regulatory authorizations. Nothing contained herein shall prevent Gulfstream from pledging, mortgaging or assigning its rights as security for its indebtedness and Gulfstream may assign to the pledgee or mortgagee (or to a trustee for a holder of such indebtedness) any monies due or to become due under the Service Agreement. Subject

to the provision of adequate credit support in Gulfstream's and, if required, Gulfstream's Lenders, reasonable judgment, Shipper may assign this Agreement to any direct or indirect subsidiary or affiliate of Shipper. Shipper may also assign this Agreement as security for financing to any person or persons providing debt or equity financing to Shipper to provide funds for the development, design, construction and operation of the Plant.

11. Modification or Waiver.

No modification or waiver of the terms and conditions of this Agreement shall be made except by the execution by the Parties of a written amendment to this Agreement.

12. Notices.

All notices, requests, demands, instructions and other communications required or permitted to be given hereunder shall be in writing and shall be delivered personally or mailed by certified mail, postage prepaid and return receipt requested or by facsimile, as follows:

If to Gulfstream:

Gulfstream Natural Gas System, L.L.C.
500 Renaissance Center
Detroit, Michigan 48243
Attention: Stanley A. Babiuk
Senior Vice President
Telephone: (313) 496-5653
Facsimile: (313) 496-5052

If to Shipper:

Calpine East Fuels, L.L.C.
Michael D. Petit
Director of Fuels Management - Eastern Region

The Pilot House, 2nd Floor
Lewis Wharf
Boston, Massachusetts 02110
Telephone: 617-723-7200 ext. 106
Facsimile: 617-723-7635

or to such other place within the United States of America as either Party may designate as to itself by written notice to the other Party. All notices given by personal delivery or mail shall be effective on the date of actual receipt at the appropriate address. Notice given by facsimile shall be effective upon actual receipt if received during recipient's normal business hours or at the beginning of the next business day after receipt if received after the recipient's normal business hours.

13. Limitation of Liability. Each Party agrees that any and all claims, demands and causes of action that it may bring against the other Party shall be limited to the assets of the other Party. Execution of this Agreement does not bind any Member of Gulfstream or any of its affiliates (or Shipper or any of its affiliates) or require any Member of Gulfstream or any of its affiliates (or Shipper or any of its affiliates) to undertake any obligation in connection with this Agreement. Accordingly, each Party waives its rights to proceed against, in the case of Shipper, the Members of Gulfstream or any of their respective affiliates or in the case of Gulfstream, any of Shipper's affiliates. Shipper and Gulfstream further agree that neither Party shall be liable to the other Party for consequential, incidental, indirect or punitive damages, whether arising in contract, tort or otherwise. As used in this

Paragraph 13, the term "affiliates" means with respect to a Party, a person that, directly or indirectly through one or more intermediaries, controls or is controlled by or is under common control with such Party.

14. No Third Person Beneficiary. This Agreement shall not create any rights in third parties, and no provision hereof shall be construed as creating any obligations for the benefit of, or rights in favor of, any person or entity other than Gulfstream and Shipper.

15. Governing Law. THE CONSTRUCTION, INTERPRETATION, AND ENFORCEMENT OF THIS AGREEMENT SHALL BE GOVERNED BY THE LAWS OF THE STATE OF DELAWARE, EXCLUDING ANY CONFLICT OF LAW OR RULE WHICH WOULD REFER ANY MATTER TO THE LAWS OF A JURISDICTION OTHER THAN THE STATE OF DELAWARE.

16. Multiple Counterparts. This Agreement may be executed by the Parties in any number of counterparts, each of which shall be deemed an original instrument, but all of which shall constitute but one and the same agreement.

17. Effect of Invalid Provision. Except as otherwise expressly stated herein, in the event any provision contained in this Agreement shall for any reason be held invalid, illegal or unenforceable by a court or regulatory agency of competent jurisdiction by reason of a statutory change or enactment, such invalidity, illegality or unenforceability shall not affect the remaining provisions of this Agreement.

18. Confidentiality. Except as hereinafter provided, neither Gulfstream nor Shipper, nor their respective affiliates, directors, officers, and employees, advisors and representatives shall disclose to any third person the terms and conditions of this Agreement, or any confidential or proprietary information, whether written or verbal, disclosed by either Party at any time in connection with the transaction contemplated herein and clearly designated at the time of disclosure as confidential or proprietary, without the other Party's prior written consent to such disclosure. This Paragraph 18 shall not apply to disclosures that, in the opinion of Gulfstream's or Shipper's counsel, as the case may be, are required by state or federal laws, rules or regulations or are required by the FERC in respect of the Gulfstream Project or by the Florida Public Service Commission in respect of the Plant (in which case, the Party so required to make such disclosure shall advise the other Party prior to such disclosure and, if requested by the other Party, shall use every reasonable effort to maintain the confidentiality of this Agreement, including, without limitation, seeking a protective order). The provisions of this Paragraph 18 shall not apply to any bank, lender or financial institution providing funds to Gulfstream in connection with the financing of the Gulfstream Project or to Shipper in connection with the financing of Shipper's Plant (in which case, the Party making the disclosure shall advise the other

Party prior to such disclosure and, if requested by the other Party, shall use every reasonable effort to maintain the confidentiality of this Agreement). The disclosure of any information pertaining to this Agreement within Gulfstream's or Shipper's internal organization (including affiliates) and within the organization of any third person to which disclosure is authorized by Gulfstream or Shipper shall be limited to those personnel whose duties require their review or counsel with respect to this Agreement and the Party making such disclosure shall instruct such personnel to maintain the confidentiality of this Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed in multiple originals by their duly authorized officers as of the date first written above.

GULFSTREAM NATURAL GAS SYSTEM, L.L.C.

By: _____
Name: Stanley A. Babiuk
Title: Senior Vice President

CALPINE EAST FUELS, L.L.C.

By: _____
Name: Robert K. Alff
Title: Vice President
East Coast Region

Attachment 1

FORM OF AGREEMENT
Rate Schedule FTS

Date: _____,__ Contract No._____

SERVICE AGREEMENT

This AGREEMENT is entered into by Gulfstream Natural Gas System, L.L.C. ("Transporter") and Calpine East Fuels, L.L.C. ("Shipper").

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below, together with the terms and conditions of Transporter's applicable Rate Schedule and General Terms and Conditions of Transporter's FERC Gas Tariff constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. AUTHORITY FOR TRANSPORTATION SERVICE WILL BE UNDER SECTION 284G.

2. RATE SCHEDULE: FTS

3. CONTRACT DATA:

   Note: List Receipt Point(s), Delivery Point, MDQ, MHQ, Receipt Point MDQ and delivery pressure on Exhibit A.

   Such Contract Quantities shall be reduced for scheduling purposes, but not for billing purposes, by the Contract Quantities that Shipper has released through Transporter's capacity release program for the period of any release.

4. TERM:

   This Agreement shall be effective on the Plant In-Service Date.

Transporter will stand ready to provide firm transportation service(s) to Shipper pursuant to the provisions of this Agreement, and Shipper will pay to Transporter all applicable charges provided for in this Agreement. If Gulfstream is unable to commence the transportation service(s) for Shipper as contemplated herein by the Plant In-Service Date which shall not be earlier than November 1, 2002, Shipper, in its sole discretion, will have the option not to commence the transportation service(s) until November 1, 2003, and, in that event, applicable charges under the Service Agreement will not commence until November 1, 2003.

c e(s)
ie dis

1. This Agreement shall remain in force and effect for a primary term of 20 years

5. RATES:

6. INCORPORATION BY REFERENCE:

The provisions of Transporter's applicable Rate Schedule and the General Terms and Conditions of Transporter's FERC Gas Tariff are specifically incorporated herein by reference and made a part hereof.

7. NOTICES:

All notices can be given by telephone or other electronic means, however, such notice shall be confirmed in writing at the addresses below or through Transporter's EBB. Shipper or Transporter may change the addresses below by written notice to the other without the necessity of amending this Agreement:

TRANSPORTER:

Gulfstream Natural Gas System, L.L.C.
500 Renaissance Center
Detroit, MI 48243
Attention: Gas Control (Nominations)
Volume Management (Statements)
Cash Control (Payments)
System Marketing (All Other Matters)

SHIPPER:

Calpine East Fuels, L.L.C.
Michael D. Petit
Director of Fuels Management - Eastern Region
The Pilot House, 2nd Floor
Lewis Wharf
Boston, Massachusetts 02110
Telephone: 617-723-7200 ext 106
Facsimile: 616-723-7635

INVOICES AND STATEMENTS:

Same as above

NOMINATIONS:

Same as above

8. FURTHER AGREEMENT:

This Agreement shall be binding upon Transporter, Shipper and their respective successors and assigns; provided, however, that neither Party shall assign this Agreement or any rights or obligations hereunder without first obtaining the prior written consent of the other Party (which consent shall not be unreasonably withheld), the consent of Transporter's lenders if required, and any necessary governmental and regulatory authorizations. Nothing contained herein shall prevent Transporter from pledging, mortgaging or assigning its rights as security for its indebtedness and Transporter may assign to the pledgee or mortgagee (or to a trustee for a holder of such indebtedness) any monies due or to become due under this Agreement. Subject to the provision of adequate credit support in Transporter's and, if required, Transporter's Lenders, reasonable judgment, Shipper may assign this Agreement to any direct or indirect subsidiary or affiliate of Shipper. Shipper may also assign this Agreement as security for financing to any person or persons providing debt or equity financing to Shipper to provide funds for the development, design, construction and operation of the Plant (as such term is defined in the Precedent Agreement).

9. OPERATIONAL FLOW ORDERS:

Transporter has the right to issue an effective Operational Flow Order pursuant to Section 13 of the General Terms and Conditions.

10. SPECIFICATION OF NEGOTIATED RATE (See Exhibit B):

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed by their respective Officers or Representatives thereunto duly authorized to be effective as of the date stated above.

Calpine East Fuels, L.L.C.SHIPPER:_____

TRANSPORTER: Gulfstream Natural Gas System, L.L.C.

By: _____
Title: _____
Date: _____

By: _____
Title: _____
Date: _____

EXHIBIT A

FORM OF AGREEMENT
Transporter's Rate Schedule FTS
(Continued)

BETWEEN GULFSTREAM NATURAL GAS SYSTEM AND CALPINE EAST FUELS, L.L.C.

CONTRACT NUMBERS: _____

CONTRACTED CAPACITY: Dth/d

ORIGINAL CONTRACT DATE: _____

AMENDMENT DATE: _____

Primary Delivery Points: Shipper's when constructed and placed in-service or other plants that Calpine or its affiliates own or operate along the primary path.

Total Delivery Point MDQ: Dth/d

MHQ at Primary Delivery Point: of MDQ . Shipper may vary the flow rate at any of the Primary Delivery Points from per hour to Dth per hour, as long as the cumulative hourly flow rate at Primary Delivery Points does not exceed (1) Dth per hour and (2) the quantities nominated and scheduled for the day under this Agreement. In addition, the cumulative hourly flow rate under the firm Service Agreements between Shipper and Transporter may not exceed per hour at

Minimum Delivery Pressure: 650 psig

Contract Number/ Primary Route	Primary Receipt Point (1)	Primary Receipt Point MDQ

(1) All receipt points added in the Mobile Bay, Alabama area will be available to Shipper. Gulfstream will use reasonable best efforts to obtain interconnections with DIGS Process Plant, Mobil's Maryann Plant, Williams Process Plant, Mobile Bay Pipeline, Destin Pipeline and WGP-Transco.

EXHIBIT B

STATEMENT OF NEGOTIATED RATES

Shipper	Contract Number	Contract Term 20yrs	Rate Schedule	Reservation Charge	Commodity Charge	Receipt Points See Ex .A	Delivery Points See Ex.A	Quantity Dth/d

Clean Energy For Florida's Future

Gulfstream
Natural Gas System

July 21, 2000

Mr. Michael D. Petit
Director of Fuels Management
Calpine Eastern
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

Dear Mr. Petit:

You requested that I update you regarding the status of the Gulfstream Natural Gas System L. L. C. project ("Gulfstream"). Gulfstream filed its application with the Federal Energy Regulatory Commission ("FERC") 0n October 15, 1999 for a certificate of public convenience and necessity to construct, own and operate an interstate natural gas pipeline.

As required by the FERC, the filing includes a comprehensive environmental report that reflects extensive research and field activities relating to Gulfstream's route. This includes surveys for endangered species, cultural resources, wetlands, and other land features. Gulfstream is determined to develop a project that respects, protects, and where possible, enhances the environment. Furthermore, in preparing the filing, Gulfstream developed a route that took into account the needs and desires of affected landowners. To accomplish this, early in the pipeline's planning stages, Gulfstream invited the views of the landowners, government agencies, environmental groups and others with respect to the best possible route for the pipeline. Gulfstream narrowed the route from an original study corridor of ten miles, to a three mile study corridor, and later, to a 1000 foot study corridor. The corridor was finally narrowed to 300 feet for the filing and has been further refined. Since the filing Gulfstream has worked with affected landowners and communities on refining the route. The original route has been slightly modified to accommodate the wishes of those affected. Indeed, Gulfstream believes that the collaborative process engaged in with landowners, government agencies, environmental groups and others has resulted in unprecedented support for the project.

Gulfstream obtained a preliminary determination, on its application to build the Gulfstream project, from the FERC on April 28, 2000. The preliminary determination covers all non-environmental aspects of Gulfstream's application, such as rates and other business issues. A draft environmental impact statement is expected to be issued by FERC staff this summer.

Based upon the timelines in other cases, and given the completeness of the application that was filed, Gulfstream projects that it will have a certificate by the first quarter of 2001, and will be in service by June 2002.

If you need any additional information, please call me at (813) 288-1811.

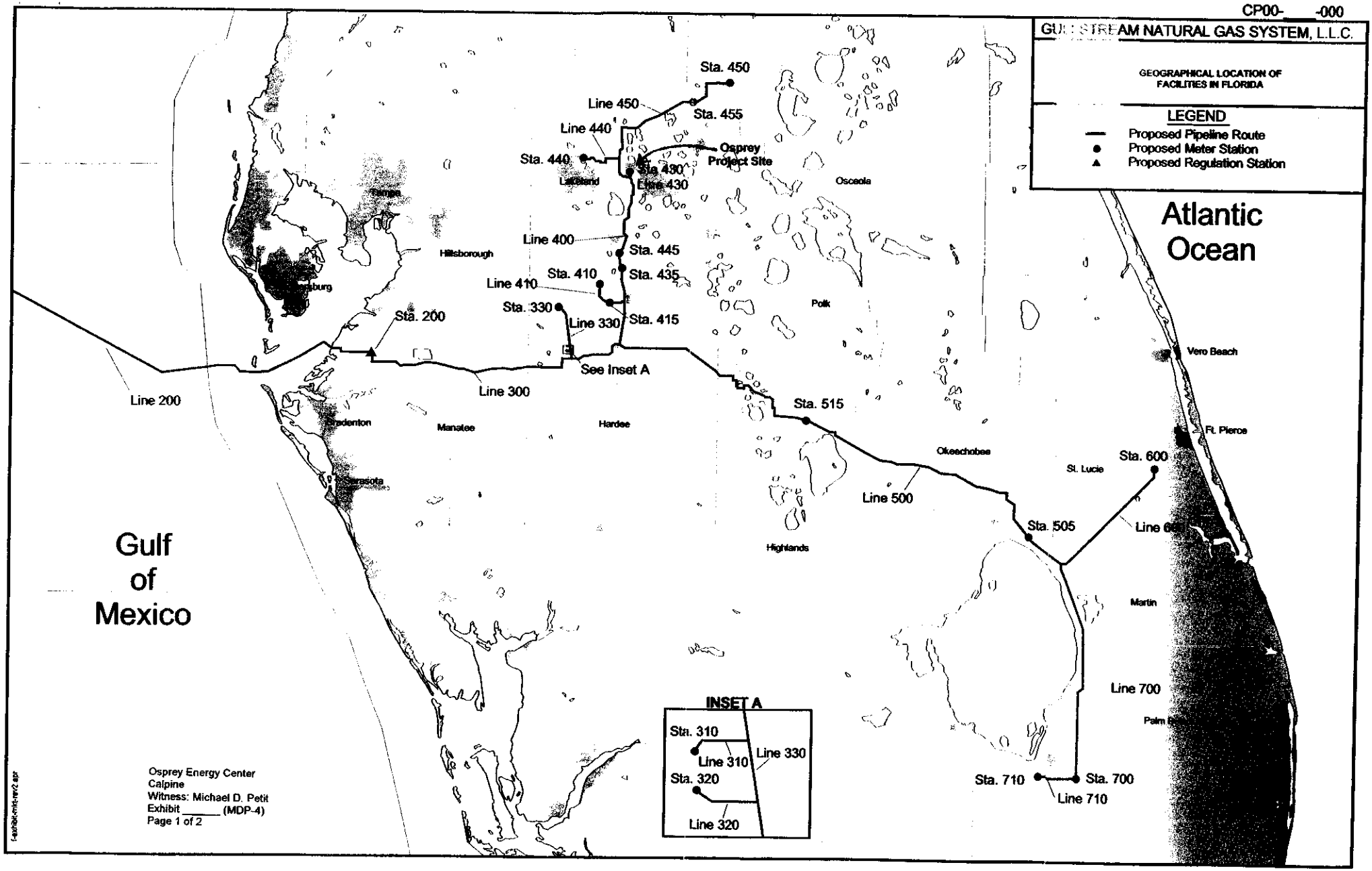
Sincerely,

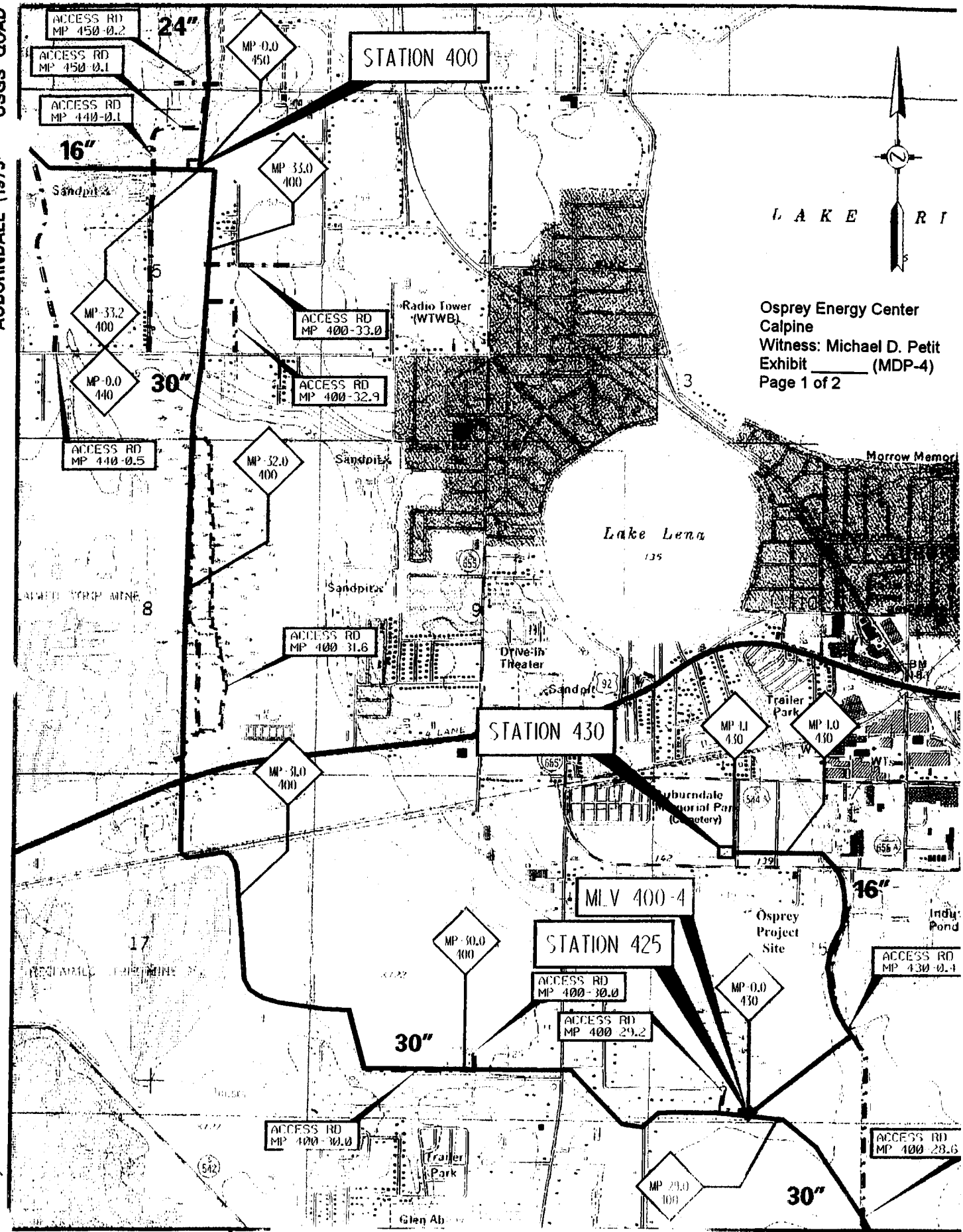
George E. Matzke
Executive Director Business Development

Gulfstream Natural Gas System, L. L. C.
2502 Rocky Point Drive • Suite 1040 • Tampa, FL 33607 • (813) 288-1811 • Fax (813) 289-4438 • www.gulfstreamgas.com

Osprey Energy Center
Calpine
Witness: Michael D. Petit
Exhibit _____ (MDP-3)
Page 1 of 1

CP00- -000


GULFSTREAM NATURAL GAS SYSTEM, L.L.C.
GEOGRAPHICAL LOCATION OF FACILITIES IN FLORIDA
LEGEND
Proposed Pipeline Route
Proposed Meter Station
Proposed Regulation Station
Atlantic Ocean
Gulf of Mexico
Sta. 450
Line 450
Sta. 455
Line 440
Sta. 440
Osprey Project Site
Sta. 430
Line 430
Lake
Osceola
Pasco
Hillsborough
Line 400
Sta. 445
Sta. 410
Sta. 435
Line 410
Sta. 330
Line 330
Sta. 415
Polk
Sta. 200
See Inset A
Line 200
Line 300
Vero Beach
Sta. 515
Manatee
Hardee
Okeechobee
Ft. Pierce
Sta. 600
St. Lucie
Line 500
Sta. 505
Highlands
Martin
Line 700
Sta. 710
Sta. 700
Line 710
INSET A
Sta. 310
Line 310
Line 330
Sta. 320
Line 320
Osprey Energy Center
Calpine
Witness: Michael D. Petit
Exhibit _____ (MDP-4)
Page 1 of 2


AUBURNDALE (1975) USGS QUAD
ACCESS RD MP 450-0.2
ACCESS RD MP 450-0.1
ACCESS RD MP 440-0.1
24"
16"
30"
MP 0.0 450
STATION 400
MP 33.0 400
MP 33.2 400
MP 0.0 440
ACCESS RD MP 400-33.0
Radio Tower (WTWB)
ACCESS RD MP 400-32.9
ACCESS RD MP 440-0.5
MP 32.0 400
Sandpit
Lake Lena
ACCESS RD MP 400 31.6
Drive-In Theater
Trailer Park
STATION 430
MP 1.1 430
MP 1.0 430
MP 31.0 400
MLV 400-4
STATION 425
MP 30.0 400
Osprey Project Site
ACCESS RD MP 400-30.0
ACCESS RD MP 400 29.2
MP 0.0 430
ACCESS RD MP 430-0.4
ACCESS RD MP 400-30.0
ACCESS RD MP 400 28.6
MP 29.0 400
Glen Ab
LAKE
Osprey Energy Center
Calpine
Witness: Michael D. Petit
Exhibit _____ (MDP-4)
Page 1 of 2
LOCATION MAP
GULFSTREAM NATURAL GAS SYSTEM, L.L.C.
GEOGRAPHICAL LOCATION OF FACILITIES
(Auburndale/Osprey Area)
LOC. POLK COUNTY, FLORIDA
REV. 0
CKD. BY
ENG.
DATE 10-15-99
W.O.
DRN. BY
SCALE 1" = 2000'
DWG. NO. 9 of 9
Gulfstream Natural Gas System

FIRST AMENDMENT TO PRECEDENT AGREEMENT

This First Amendment to Precedent Agreement ("First Amendment") related to the Osprey Plant (formerly Auburndale Plant), is made and entered into as of this 26th day of October, 2000, by and between Calpine East Fuels, L.L.C., a Delaware limited liability company ("Shipper") and Gulfstream Natural Gas System, L.L.C., a limited liability company formed under the laws of the State of Delaware ("Gulfstream") (hereinafter Shipper and Gulfstream are sometimes referred to individually as a "Party" or collectively as the "Parties").

WHEREAS, Shipper and Gulfstream entered into a Precedent Agreement dated as of October 8, 1999 (the "Precedent Agreement"), with respect to natural gas transportation service(s) utilizing the Gulfstream Project (as such term is defined in the Precedent Agreement) to a natural gas fired electric generating plant then referred to as the Auburndale Plant which Shipper intends to design, construct, own and operate in Polk County, Florida for a planned in-service date on or before May 1, 2003; and

WHEREAS, Shipper and Gulfstream desire to amend the Precedent Agreement as hereinafter set forth.

NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, and intending to be bound, Shipper and Gulfstream agree as follows:

1. The Precedent Agreement and Attachment 1 to the Precedent Agreement are amended by changing all references to the "Auburndale Plant" or "Plant" contained therein to the "Osprey Plant".
2. The Precedent Agreement is amended by adding a new Section 5(c) which reads as follows:

Gulfstream will include in the design of the Gulfstream Project the facilities necessary to interconnect the facilities of the Gulfstream Project and the Osprey Plant and the adjacent Auburndale Plant, including but not limited to all necessary measurement, pressure regulation and control, heating equipment and lateral pipeline ("Gulfstream Interconnection Facilities."). Gulfstream shall be responsible for all costs associated with designing, engineering, constructing, testing and placing in service the Gulfstream Interconnection Facilities for the Osprey Plant and the adjacent Auburndale Plant.

3. Exhibit A (and, where indicated, Exhibit B) to Attachment 1 to the Precedent Agreement ("Exhibit A" and/or "Exhibit B") is amended by (1) changing all references therein to "Auburndale",

to, "Osprey Plant",

4. The rate under the heading "Reservation Charge" in Exhibit B is confirmed to be

5. The Precedent Agreement is amended only as herein before provided. In all other respects, the Precedent Agreement is confirmed and shall continue in full force and effect.

6. This First Amendment may be executed in any number of counterparts, all of which shall be considered together as one instrument.

IN WITNESS WHEREOF, the Parties have caused this First Amendment to be duly executed in multiple originals by their duly authorized officers as of the date first above written above.

GULFSTREAM NATURAL GAS SYSTEM, L.L.C.

By: Stanley A. Babiuk
Name: Stanley A. Babiuk
Title: Senior Vice President

CALPINE EAST FUELS, L.L.C.

By: Robert K. Acff
Name: Robert K. Acff
Title: SVP

Clean Energy For Florida's Future

Gulfstream
Natural Gas System

January 22, 2001

Mr. Michael D. Petit
Calpine Eastern
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

RE: Permitting Status of Gulfstream

Dear Mike:

I have reviewed the schedule previously sent to Calpine Eastern and can confirm that everything is on schedule.

Gulfstream filed its certificate application with the Federal Energy Regulatory Commission (FERC) on October 15, 1999. The Notice of Intent to prepare an Environmental Impact Statement (EIS) was issued by FERC on December 6, 1999. The FERC issued a preliminary determination addressing all non-environmental aspects of the project on April 28, 2000, The Draft Environmental Impact Statement (DEIS) was issued by FERC August 31, 2000.

We anticipate receiving final certificate authorization from FERC in February, 2001. The date satisfies our timeline requirements to meet a June 1, 2002 in-service date.

Attached is a detailed summary/status of major permits, licenses and certifications required for the project.

If you need any other information, do not hesitate to call me.

Sincerely,

George Matzke
Executive Director
Business Development

Cc: Robert Scheffel Wright

TABLE 1
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
Federal			
Review of project features that affect cultural resources that are either listed on or eligible for listing on the NRHP	**Advisory Council on Historic Preservation**	State SHPO Field survey reports filed October 15, 1999. Supplemental Filing Submitted 2/29/00.	AL/MS Clearances are complete.
Certificate of Public Convenience and Necessity	**Federal Energy Regulatory Commission**	Filing submitted October 15, 1999. Supplemental Filing submitted 2/29/00. Northern Highlands Alternative filing submitted May 15, 2000. DEIS Comments and updates filed 10/24/00. FEIS expected January 2001.	Certificate Expected February 2001
	U.S. Department of the Army		
Section 10 Permit, Fairway crossings Approval Section 404 Permit	Army Corps of Engineers (Mobile and Jacksonville)	Consolidated Permit in Florida filed February 29, 2000. Jacksonville District Permit filed 2/29/00. Mobile District section 10 and 404 permit to be filed December, 2000.	Jacksonville District permit expected February 2001 Mobile District permit expected April, 2001.
	U.S. Department of the Interior		
Section 7, Endangered and Threatened Species Consultation	Fish and Wildlife Service (Daphne, Vero Beach, Jacksonville)	Biological Assessment (BA) Filed with FWS October 15, 1999. Supplemental Survey Report filed 2/29/00. Updated BA Report filed 8/10/00 and 10/24/00. Expecting BO process complete January 2001.	Alabama/Mississippi Clearance letter dated January 31, 2000 Received. Florida pending review
Right-of-Way Permit	Minerals Management Service	Permit application filed October 15, 1999. Supplemental video survey report filed March 8, 2000. Submitted Live Bottom survey report July 28 and October 24, 2000.	Expected May 2001 (after COE Permit issuance)
Hydrostatic Test Water Discharge Permit Offshore Gulf of Mexico	U.S. Environmental Protection Agency	Permit to be filed in November, 2000.	Expected February 2001
NPDES General Stormwater discharge permit in Florida	U.S. Environmental Protection Agency/FDEP	Permit to be filed in November, 2000.	Expected February 2001

TABLE 1
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
	U.S. Department of Commerce		
Section 7, Endangered and Threatened Species Consultation	National Marine Fisheries Service	Clearance requested October 15, 1999. Live Bottom survey report submitted July 28, 2000.	Clearance expected January 2001
Mississippi Section 401 Water Quality Certification Storm Water Discharge Permit (Section 4.2, NPDES) Notice of Construction General Discharge Permit (hydrostatic testing)	Mississippi Department of Environmental Quality	General permit to be filed in December 2000. 401 certificate tied to coastal wetlands permit (Joint USACOE Permit Mobile District).	Expected April 2001 —
Easement to cross offshore bottom lands	Mississippi Secretary of State	To be filed December, 2000 (jointly with USACOE permit).	Expected April 2001
Coastal Wetlands Permit Coastal Zone Management Act Consistency Determination	Mississippi Department of Marine Resources	Gulfstream's determination filed 10/15/99. To be filed December, 2000 (jointly with USACOE permit).	Expected April 2001
Mississippi (cont.) Section 106 NHPA consultation	Mississippi Department of Archives and History	Survey methods approved June 15, 1999. Field survey report filed October 15, 1999. Clearance granted October 25, 1999. Supplemental Report for Line changes filed February 29, 2000.	Clearance granted October 25, 1999.
Alabama Storm Water Discharge Permit, Air Permitting, NPDES General Discharge Permit (hydrostatic testing), Coastal Zone Management Act consistency determination	Alabama Department of Environmental Management	Air permit filed October 15, 1999. Air Permit update report filed June 2000. NPDES General hydrostatic testing permits to be filed in December 2000. Gulfstream's request for coastal zone consistency determination filed 10/15/99 (offshore). Coastal Zone determination for onshore and state waters to be filed concurrent with USACOE Section 10/404 permit application.	Air Permit Expected January 2001 NPDES Permit Expected March 2001 Offshore CZM Consistency expected concurrent with MMS ROW Permit (Expected April 2001).

TABLE 1 (cont.)
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
Easement to cross offshore bottom lands, listed species, fisheries, wetlands review and consultation	Alabama Department of Conservation and Natural Resources	To be filed December, 2000 (jointly with USACOE permit).	Expected April 2001
Section 106 NHPA consultation	Alabama Historical Commission	Survey methods approved July 1, 1999. Field survey report filed October 15, 1999.	Onshore Clearance Letter received November 18, 1999. Offshore Clearance Letter Received July 3, 2000.
Florida			—
Environmental Resource Permit (ERP), Easement to cross state-owned uplands and sovereign submerged lands	Department of Environmental Protection (FDEP)	Consolidated Permit filed February 29, 2000. Easements filed February 29, 2000.	Permit and Easements expected January 2001
Coastal Zone consistency determination	FDEP	Request for Determination filed 10/15/00 (FERC Filing) and 2/29/00 (Florida Consolidated Permit Application).	Expected January 2001
Letter of acknowledgment for completion of cultural resource investigations recommended for the project area	Department of State, Division of Historical Resources	Survey methods approved July 20, 1999 and Unanticipated Finds Plan approval on September 14, 1999. Field survey report filed October 15, 1999. SHPO comments received December 20, 1999 (onshore Florida) and December 10, 1999 (offshore Florida). Supplemental Report for onshore Line changes filed February 29, 2000, additional Phase II report filed May, 2000. Florida offshore phase II survey report filed October, 2000.	Offshore Clearance received October 16, 2000. Florida onshore letter of acknowledgement received from SHPO on December 20, 2000, May 1 and 3, 2000, April 5, 2000, and June 9, 2000.
Natural heritage inventory review	Florida Natural Areas Inventory	Received T/E database information from Florida Natural Areas Inventory and Alabama/Mississippi Natural Heritage Program.	No clearance required

TABLE 1 (cont.)
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
Review of impacts to endangered and threatened species, Species Relocation permits (if necessary)	Florida Fish and Wildlife Conservation Commission	Field survey reports filed October 15, 1999. Supplemental follow-up report filed February 29, 2000. Northern Highlands Alternative Report filed 5/15/00. BA filed 8/10/00, 10/24/00	Clearance to be Granted January 2001
Consumptive Use permit for hydrostatic test water withdrawal.	Southwest Florida Water Management District, South Florida Water Management District, St. Johns River WMD	General permits filed in November 2000.	Expected March 2001
Industrial Wastewater Permit for Hydrostatic Testwater Discharge	Florida Department of Environmental Protection (FDEP)	Permits to be filed in November 2000.	Expected March 2001
General Permit for Geotechnical Borings	Florida Department of Environmental Protection (FDEP)	Issued June, 1999 and January 2000.	SW District Permits issued: 1) July 1, 1999 2) December 23, 1999 3) January 12, 2000 4) May 12, 2000 5) June 14, 2000 South District 1) February 2, 2000 2) April 12, 2000 Southeast District 1) February 3, 2000
Local Submerged Lands Easement	Tampa Port Authority	Filed jointly with Consolidated Permit February 29, 2000.	Expected January 2001

FT
FINANCIAL TIMES Energy

Tuesday, January 30, 2001

Gas Daily®

Daily Price Survey

Listed in the left column are the midpoints of the daily ranges for the most common prices, paid in $/mmBtu of a typical volume of 5 thousand mmBtu. The middle column shows absolute low/high prices for transactions reported on the date at the top of the column; the third column shows that day's ranges for the most common prices. The prices are generally for gas flowing today; weekends are usually priced using data collected Friday. Ranges are for deals done before nomination deadlines. Boldface indicates the price range is based on data reported the previous day. Plain type indicates insufficient data to reconfirm or change the previous range. The common range is built around the volume weighted average and the midpoint is calculated for the common range. Data in this table is Copyright 2001 by FT Energy.

NATIONAL AVERAGE PRICE: $7.295****

Trans. date	1/29	1/29	1/29
Flow date(s)	1/30	1/30	1/30
	Midpoint	Absolute	Common
Permian Basin Area			
El Paso	6.650	6.55-85	6.57-73
Northern (Mids 1-6)	6.460	6.42-70	6.42-54
Tex Inters, Waha area	6.545	6.45-75	6.47-62
Transwestern	6.685	6.60-70	6.54-69
East Texas-North Louisiana Area			
Carthage Hub tailgate	6.510	6.40-60	6.46-56
Koch (Zones 1&2)	6.185	5.09-27	5.12-21
Lone Star	6.255	6.20-30	6.23-28
MRT mainline	6.595	6.45-68	6.53-65
MRT west leg	6.525	6.51-56	6.51-54
NGPL TexOk (West)	6.420	6.35-58	6.37-47
NGPL TexOk (East)	6.435	6.33-60	6.37-50
Tennessee, 100 Leg	6.335	6.21-50	6.26-41
Texas Eastern (ETX)	6.300	6.20-40	6.25-35
Texas Gas (entire Z 1)	6.560	6.43-70	6.49-63
East-Houston-Katy			
Houston Ship Channel	6.615	6.46-75	6.54-69
Katy plant tailgate	6.553	6.35-70	6.47-64
Trunkline North	6.590	6.58-80	6.58-80
North-Texas Panhandle			
NGPL (Permian)	6.340	5.00-6.40	6.26-40
Northern (Mid 10)	6.190	6.15-23	6.17-21
Transwestern	6.665	6.60-70	6.64-69
South-Corpus Christi			
Agua Dulce hub	6.385	6.17-60	6.26-47
Florida Gas	6.500	6.35-63	6.43-57
HPL	6.440	6.20-50	6.39-49
Koch (Zone 1)	6.280	6.27-29	6.27-29
NGPL (STX)	6.415	6.27-53	6.35-48
Tennessee	6.400	6.25-65	6.30-50
Texas Eastern (STX)	6.190	6.00-43	6.05-30
Transco, St 30	6.485	6.15-52	6.35-53
Trunkline South	6.420	6.41-43	6.41-43
PG&E-GTT	6.130	6.05-20	6.09-17
Louisiana-Onshore South			
ANR	6.525	6.40-70	6.45-60
Columbia	6.590	6.39-81	6.46-72
Columbia, Mainline	6.660	6.46-79	6.58-74
FGT Z1	6.500	6.36-63	6.43-57
FGT Z2	6.555	6.40-74	6.47-64
FGT Z3	6.525	6.34-65	6.45-60
Henry Hub	6.600	6.29-7.00	6.42-78
Koch (Zones 2&4)	6.365	6.25-55	6.29-44
NGPL (La.)	6.475	6.36-69	6.39-56
Sonat	6.635	6.45-78	6.55-72
Tennessee, 500 Leg	6.475	6.28-72	6.36-59
Tennessee, 800 Leg	6.485	6.30-72	6.38-59
Texas E. (WLA)	6.250	6.02-50	6.13-37
Texas E. (ELA)	6.415	6.21-52	6.31-52
Texas Gas SL	6.500	6.42-62	6.49-58
Transco, St. 15	6.515	6.30-71	6.41-62
Transco, St 65	6.790	6.50-94	6.68-80
Trunkline WLA	6.465	6.35-68	6.38-55
Trunkline ELA	6.285	6.07-45	6.19-38
Oklahoma			
ANR	6.510	6.36-74	6.41-61
NGPL (Midcont)	6.465	6.40-62	6.41-52
Reliant (North/South)	6.570	6.45-65	6.52-62
Reliant (West)	6.465	6.35-65	6.38-54
Northern (Mid 11)	6.210	6.17-25	6.19-23
OGT	6.510	6.35-88	6.43-59

continued on next page

FTC clears El Paso Energy/Coastal merger

The Federal Trade Commission (FTC) yesterday said it would allow the $24 billion merger of El Paso Energy and Coastal Corp. to proceed, provided that the two companies divest their interests in 11 natural gas pipeline systems totaling more than 2,100 miles of pipe.

The commission voted 5-0 to accept the proposed consent agreement to allow the merger, which would create the nation's largest interstate pipeline company. The approval comes more than a year after El Paso said it would merge with Coastal in a stock deal then valued at approximately $16 billion, including $6 billion of assumed debt and preferred equity *(GD 1/19/00)*.

El Paso and Coastal had hoped to have the deal wrapped up by the fourth quarter of last year and, for a while, it seemed that the regulatory agencies would go along with that timetable. FERC

(continued on page 7)

Gulfstream snares environmental OK from FERC

After months of study, FERC last week issued a favorable environmental impact statement for the proposed Gulfstream Natural Gas System, which would bring gas to the Florida peninsula through a 700-mile undersea pipe. Although the project still awaits final certificate approval from FERC, it now appears poised to break Florida Gas Transmission's (FGT) interstate pipeline monopoly in the state.

Building an undersea pipeline poses major environmental challenges, and FERC conceded that the project would "result in temporary and permanent alteration of wildlife habitat, as well as direct impact on wildlife such as disturbance, displacement or mortality." But staff also found that the bulk of the impact would occur during construction, and therefore ruled that the project would have limited adverse effects.

The assessment should cheer the backers of Gulfstream, Williams and Duke Energy, who

(continued on page 7)

Cash off as NYMEX stumbles into March

Cash prices and the NYMEX might have been expected to pick up the pace Monday after the weekend, but continued mild weather forecasts had the market down

The slowdown started in overnight NYMEX Access trading, when six-to-10 day weather forecasts showed warmer-than-normal weather in store for the eastern half of the nation.

The Market

The NYMEX February futures contract was the first to be affected. It opened down substantially from Friday's settlement, and plummeted throughout the trading day before the monthly expiration.

As the NYMEX contract weakened, already soft cash prices fell off by 30¢-50¢ or more.

It was a "bloodbath" yesterday in Louisiana, one source said, as trading at the Henry Hub fell into the low $6.30s. "Louisiana has been strong until today [Monday]. The market should

(continued on page 6)

Bush forms energy task force on higher prices

After a weekend of pledging only tough love for California and its worsening energy crisis, the Bush administration yesterday named Vice President Dick Cheney to head a new federal task force that will focus on ways to deal with skyrocketing energy prices and the country's dependence on foreign oil.

California's problems are its own, and the state should expect no major lifeline from the federal government, key Bush team members told various weekend media outlets. Still, the administration spent time meeting yesterday to discuss the crisis in California, which threatens to spread to other western states.

On Thursday and Friday, Energy Secretary Spencer Abraham and FERC Chairman Curt Hébert are expected to attend a conference called by the Western Governors Assn. to discuss

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Osprey Energy Center
Calpine
Witness: Michael D. Petit
Supplemental Exhibit _____ (MDP-
Page 10 of 10

EIA notes convergence

In response to U.S. electricity restructuring and natural gas deregulation in recent years, the energy industry in the United States has gradually experienced the convergence of electric utilities and natural gas companies — creating a new form of energy company, the "energy services company."

A recent report of the U.S. Energy Information Administration (EIA) tracks the change of the energy companies in the United States that have followed from a flurry of recent mergers and acquisitions. While the number of vertically integrated petroleum companies has declined, the ranks of energy services companies have swelled, "signaling a fundamental change in the characteristics of a major U.S. energy company," EIA said.

Energy services companies, according to EIA, "have greater flexibility to market both electricity and natural gas interchangeably, thereby having the opportunity to maintain and/or increase their customer base." Through mergers, EIA added, companies also benefit from improved efficiency, lower operating costs, and "the opportunity to participate in the growing market for natural gas-fired power plants."

The four leading energy companies in the U.S. — Enron, Williams, El Paso Energy and Coastal — are all energy services companies, EIA noted.

The U.S. energy industry had six convergence mergers in 1997, two in 1998, three in 1999 and six in 2000, with six additional transactions now pending, EIA said. VT

Pipeline operational update

Effective immediately and until further notice, El Paso Natural Gas is declaring an unauthorized overpull penalty. Shippers are urged to immediately review their supply/demand balance and the performance of their suppliers, to ensure sufficient gas is being delivered to El Paso to cover the gas being taken off the system. To ensure system integrity, El Paso will place limits on scheduled volumes at interconnections that are underperforming.

Southern Natural Gas second North Main line repair has been completed. Therefore, the capacity allocations for Group 1 - Birmingham Group, Group 2 - Gadsden Group, Group 4 - Chattanooga Group and Group 13 - East Tennessee Group that were implemented for Jan. 27 have been canceled.

To prepare for implementation of Fort Nelson Gathering System's Patry Lake byproduct allocation enhancements, Westcoast Energy's WestFLO will be unavailable today from 7 p.m. until 7 a.m. tomorrow. VT

Gulfstream gets postive review ... (from page 1)

recently sealed an agreement to purchase the project from Coastal (*GD 11/20*). Williams and Duke scrapped their own plans to build a competing undersea route, Buccaneer Gas Pipeline, choosing instead to proceed with the $1.65 billion Gulfstream project once the deal with Coastal is completed.

Stan Mays, a Coastal spokesman, said the project's backers were "pleased with FERC's timely review" of the project. Gulfstream now expects final approval to come within the next few months.

But the Gulfstream project still faces competition from FGT, which has forwarded its own plans for an aggressive expansion of its current system. In evaluating the merits of the Gulfstream route, FERC also considered three system alternatives, including an expansion of the FGT system, a Buccaneer/Gulfstream link-up in central Florida and a stand-alone underwater segment built by Buccaneer.

As envisioned, Gulfstream would run across the Gulf of Mexico from a point near Mobile, Ala., before coming onshore in the Tampa Bay area and proceeding east to West Palm Beach. Buccaneer would also have originated in the Mobile Bay area, but would have had landfall at a point further north.

Gulfstream and Buccaneer were designed to tap into a booming market for gas-fired generation in Florida. At present, FGT does not have the capacity to meet demand.

Moving into the Florida market will be a major undertaking for Gulfstream. All told, the project would require 743 miles of pipe, 128,000 HP of compression, 22 meter stations, 4 manifold stations, 34 mainline valves and 28 pig launchers. During the scoping process, the project encountered resistance over routing through Highland County; FERC, in turn, directed Gulfstream to consider a route alternative.

In addition, the project raised questions about possible impacts on threatened or endangered species. FERC originally identified a number of marine animals — including the Florida manatee and several species of sea turtle — that might possibly be harmed by construction. Gulfstream has promised to use construction techniques such as directional drilling to minimize displacement of or injury to marine populations; but, as FERC noted, "if directional drilling is shown to be infeasible or fails during construction [of] this waterbody, the conventional open-cut trench technique would be used."

Regarding the impact on land species, FERC concluded that most would not be directly in the construction area, and therefore would not be in danger.

FERC was also encouraged by plans to keep most of the onshore pipeline segment within existing rights-of-way. According to the recent finding, "with the use of Gulfstream's proposed mitigation and adoption of our recommended mitigation measures, construction and operation of the proposed facilities would result in limited environmental impacts." (CP00-6) NH

FTC OKs El Paso merger ... (from page 1)

approved the merger last summer (*GD 7/27/00*). However, FTC officials saw more potential for the merger creating non-competitive situations in several regions of the country.

The proposed agreement, which the companies have endorsed, provides for the divestiture of the proposed Gulfstream pipeline in Florida to a new purchaser to ensure future competition for gas transportation into the state. The agreement also provides for divestiture of El Paso and Coastal interests in existing gas pipelines serving customers in New York State and the Midwest.

In addition, it would require the divestiture of seven pipelines in the Gulf of Mexico and establish a development fund for the purchaser of El Paso's Green Canyon and Tarpon pipelines to cover the costs of extending these pipelines to specified areas in the Gulf where El Paso and Coastal pipelines are significant competitors.

"The series of divestitures required by this order address the very real competitive concerns that have resulted from the recent and rapid consolidation in the U.S. market for natural gas transportation," said Molly Boast, acting director of the FTC's Bureau of Competition. "Appropriately, the order goes even further, by requiring competitive protections for future pipeline construction and extensions in key parts of the country."

Officials with both companies praised the FTC decision. "This merger is a transforming event for both El Paso Energy and Coastal," said El Paso Chairman, President and CEO William Wise. "The scale we now possess opens an even wider range of extraordinary opportunities. Our combination of assets, intellectual capital and financial resources creates the largest

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RICHARD A. ZWOLAK, AICP

Golder Associates

EDUCATION

M.A.	1979	Geography	University of South Florida
B.A.	1976	Geography	University of South Florida

ACCREDITATION

American Institute of Certified Planners, 1986

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001748-EI EXHIBIT NO. 11
COMPANY/ WITNESS: Calpine/ Zwolak
DATE: 2-21-01

ASSOCIATIONS

American Planning Association, National, Florida and Suncoast Chapters
American Planning Association, Environment, Natural Resources, and Energy Division

PROFESSIONAL HISTORY

Director of Environmental Planning, Power Market Sector Leader, Golder Associates, Inc., 1996 to present.

Principal Environmental Planner, KBN Engineering and Applied Sciences, Inc., 1989 to 1996.

Planning Director, Reynolds, Smith and Hills, Architects-Engineers-Planners, Inc., 1988 to 1989.

Environmental Planning Department Head, Reynolds, Smith and Hills, Architects-Engineers-Planners, Inc., 1985 to 1988.

Senior Associate Scientist, Environmental Science and Engineering, Inc. (subsidiary of Reynolds, Smith and Hills), 1979 to 1985.

Planning Research Assistant, Hillsborough County City-County Planning Commission, 1978 to 1979.

EXPERIENCE SUMMARY

Richard A. Zwolak, M.A., AICP, has conducted more than 200 environmental studies for both public and private sector electric utility clients and he has been responsible for siting electric power plants and obtaining many air, land and water resource permits and approvals for project development. He has more than 19 years of environmental planning experience in Florida and has participated in projects in 22 other states in the United States and Albania, the Commonwealth of the Bahamas, the Dominican Republic, Estonia, Guatemala, Turkey, Yemen and. Mr. Zwolak received both a bachelor of arts and master of arts degree in geography from the University of South Florida and is certified by the American Institute of Certified Planners.

Mr. Zwolak's technical experience includes land use compatibility analyses and overall project management for residential, commercial, industrial, utility, and mixed-use development sites/projects. He has served as project manager or principal author for National Environmental Policy Act (NEPA) environmental assessments (EAs) and environmental impact statements (EISs) under various federal programs, including the Environmental Protection Agency (EPA), U.S. Postal Service (USPS),

Federal Highway Administration (FHWA), Federal Aviation Administration (FAA), Federal Housing Administration (FHA), Rural Utility Services (formerly Rural Electrification Administration), Department of Energy (DOE), and Department of Defense (U.S. Navy, Air Force, and Army). He has also served as project manager or principal author for Development of Regional Impact (DRI) projects and utility licensing under the Florida Transmission Line Siting Act and the Florida Electrical Power Plant Siting Act.

With respect to international environmental law, Mr. Zwolak has been retained repeatedly by The World Bank to oversee the environmental aspects of thermal power and hydroelectric plants, transmission lines and substations. He has conducted workshops and training classes in the integration of environmental criteria with economic and engineering considerations for power plant siting and permitting. On many of the international projects for The World Bank, he has evaluated the environmental capability of existing utility staff and made for staffing, organization, and facility support recommendations to enhance environmental capability of the electric utility.

His participation has included presentations at public hearings, meetings, and workshops and general public and agency scoping meetings. He has also presented projects to local government political bodies including county commissions and city councils, regional planning councils, and various boards (variance reviews, resource management, development reviews) and technical advisory committees. Mr. Zwolak has presented expert testimony on land use compatibility issues at administrative hearings and developed several land use plans/regulatory programs for local, regional, and state government bodies.

PROJECT EXPERIENCE-POWER PLANT SITING AND PERMITTING

Environmental Permitting for a Simple-Cycle Power Plant for Constellation Development, Inc. Project Manager for obtaining all land use approvals and environmental permits associated with a 850 MW simple cycle power plant in unincorporated Brevard County, Florida near Cocoa. The proposed plant would use natural gas as a primary fuel and low sulfur fuel oil as a back up source. Responsibilities include identification of all permits required to construct and operate the facility, preparation of permit applications, respond to agency questions, and negotiate permit conditions. Responsibilities also included conduct of site planning activities, civil design, water/wastewater alternatives analysis, and implementation of public involvement activities.

Siting Study for a Combined-Cycle Power Plant for Seminole Electric Cooperative Incorporated ▶ Land Use Discipline Manager for project siting a 660-MW combined-cycle power plant in a 47-county study area. Responsibilities included the identification, evaluation, and rating of socioeconomic and land use compatibility factors, including land utilization, ownership and productivity, regional and local economics, community impact, prime and unique farmlands, and archaeological and historical resources.

Power Plant SCA for Seminole Electric Cooperative Incorporated ▶ Land Use/Socioeconomic Discipline Manager responsible for management and preparation of socioeconomic baseline and impact sections of SCA document for a 600-MW coal-fired power plant in a rural, coastal portion of Taylor County, Florida. Major work efforts included population and housing, land use, community facilities, transportation, economic, aesthetic, and cultural resource analyses. Analysis of a rail spur to the plant site was also conducted.

Coal-Fired Power Plant SCA for Florida Crushed Stone Company ▶ Land Use Discipline Manager for project consisting of the relocation of a 125-MW coal-fired power plant to a limestone mine in central Hernando County, Florida. Services involved providing expert

testimony on land use compatibility and comprehensive plan and zoning conformance during the certification hearing required under the Florida Electrical Power Plant Siting Act.

Grand Bahamas Island Power Plant Licensing Fatal Flaw Analysis for Mid-South Utilities (MSU) System Services, Inc. ▶ Land Use Discipline Manager for proposed construction of two 800-MW coal-fired power plants on one of three sites in the vicinity of Freeport Harbor, Grand Bahamas Island. A fatal flaw analysis was conducted to determine whether the proposed project would be licensable under Commonwealth Regulations and United States NEPA standards. Major socioeconomic/land use topics included land use compatibility with adjacent development, the potential conflicts with the air space of Freeport International Airport, and the ability of the island's utilities and public services to accommodate construction and operation work forces.

Combined-Cycle Power Plant Site Selection Study for Tampa Electric Company ▶ Land Use Discipline Manager for a site selection study performed over a six-county study area to locate 440 MW (two 220-MW units) of combined-cycle capacity. The process consisted of three phases to select recommended sites. Land use factors evaluated included population densities, land use patterns, visibility, special resource (or regulated) areas, and archaeological/historical resources.

Lauderdale Repowering Project for Florida Power & Light Company ▶ Land Use Discipline Manager for project consisting of replacing existing steam generators with combustion turbines (CTs) and heat recovery steam generators (HRSGs). Responsibilities included preparing baseline, construction, and operation impact sections concerning governmental jurisdiction, land use and zoning, transportation, population, landmarks, and archaeological and historic sites. Responsibilities also included determining the direct and indirect economic affects of construction and operation on Broward County and the region.

Alternative Site Evaluation for Potomac Electric Power Company ▶ Land Use Discipline Manager for project evaluating four sites for construction of a midsize coal-fired power plant. Responsibilities included preparation of land use, air transportation, aesthetics, archaeological/historical baseline and impact analyses sections, and comparative analyses to assist in site selection.

Site EA for Atlantic City Electric Company ▶ Land Use Discipline Manager responsible for baseline development and impact analysis of land use and zoning, regional and local community facilities and services, visual quality, recreation, and archaeological/historical resources for construction and operation of a 290-MW coal-fired generating station. Special emphasis was placed on aesthetic impacts by using visual resource management methodologies and key view simulation techniques. A door-to-door survey was used to identify significance of visual impact of a 290-MW plant in southern New Jersey. Responsibilities also included obtaining and supervising a cultural resource subcontractor. The resultant site survey provided background data for the power plant site EA.

Site Certification Applications for Florida Power Corporation ▶ Land Use Planner responsible for preparing socioeconomic inventory and impact analysis for power plant SCAs in Gulf and Osceola Counties, Florida. Assessment included impacts on land use and zoning, transportation, housing, labor/employment, recreation, and public services and finances. For the Gulf County site, special emphasis was placed on the ranking of more than 280 miles of 230-kV transmission corridor alternatives in 10 panhandle counties. For the Osceola County site,

special emphasis was placed on the recreational demand on Lake Kissimmee. To identify existing and projected recreational use of the lake, a systematic survey was undertaken of public and private marinas, camps, and Kissimmee State Park. User origin, seasonal frequency, and facilities used were identified. Statistical analysis was performed to determine lake-wide use as a recreational resource in comparison to other lakes.

Compressed Air Energy Storage System Environmental Analysis for Soyland Power Cooperative, Inc. ► Land Use Discipline Manager of an environmental analysis conducted for a compressed air energy storage peak generating system in western Illinois. Analysis included baseline descriptions and impact assessments on socioeconomic variables, including land use and zoning, demographics and housing, community services and facilities, transportation, local and regional economies, and archaeological and historical resources. Special emphasis was placed on two issues: agriculture as it relates to prime and unique farmland; and water transport activity on the Illinois and Mississippi Rivers.

Coal-Fired Power Plant (3,200 MW) Site Selection Study in West-Central Florida for Tampa Electric Company ► Land Use Planner responsible for identification, evaluation, and rating of socioeconomic and land use compatibility factors, including land utilization, zoning compatibility, ownership, agricultural productivity, regional and local economics, community facility impact, prime and unique farmlands, and archaeological/historical resources.

Combined -Cycle Power Plant Permit Feasibility Strategy for Southern Energy Task Manager responsible for identifying environmental permits and land use approvals for a 100+ MW natural gas-fired cogeneration plant to be constructed at an existing pulp and paper mill.

Environmental Permitting Strategy for a 225 MW Combined Cycle Facility for AES, Inc. Project Manager responsible for determining permitting requirements, schedule, and cost for "behind the fence" combined cycle power plant to be colocated with a large regional phosphate mine, beneficiation, and chemical plant in west-central Florida.

Environmental Certification for Simple Cycle Power Plant in Santo Domingo, Dominican Republic for AES, Inc. Project Manager responsible for obtaining third party certification of environmental aspects of operating power plant. Certification was used to finance acquisition of facility.

Site Selection and Permitting Feasibility Investigations for the Southeast US for Progress Energy, Inc. Project Manager responsible for identifying sites for potential simple and/or combined cycle power plant throughout the southeast US. Specific multiple site evaluations were conducted in Texas, Mississippi, Tennessee, Alabama, Georgia, Florida, and North Carolina.

Comparative Evaluation of Two Power Plant Sites for Obtaining Air Resource Permits in Georgia for Progress Energy, Inc. Project Manager responsible for directing an evaluation of the ability to obtain Prevention of Significant Deterioration Permits for a Simple Cycle natural gas-fired power plant in central Georgia. Sites were located outside of and either east or west of the Atlanta regional nonattainment zone.

Environmental Permit Inventory and Alternative Site Evaluations in Alabama for Kenetech Project Manager responsible for developing a list of environmental permits and land use approvals to construct and operate a combined cycle power plant in east-central Alabama. Alternative sites were reviewed in order to determine suitability of the sites for permitting.

Environmental Permitting Feasibility for Cogeneration Plant Development for Air Products, Inc. Project Manager responsible for evaluating permit feasibility associated with three levels of thermal power plant development, 250, 400 and 500 MW of generating capacity. Primary issues included make-up water supply alternatives and industrial wastewater disposal.

PROJECT EXPERIENCE-TRANSMISSION LINES

Hardee Power Station Site Certification, TECO Power Services and Seminole Electric Cooperative ▶ Task manager responsible for conducting third party review of all socioeconomic and land use sections of the Hardee Power Station (HPS) application, including the proposed power plant site and three 230-kV transmission line corridors traversing approximately 102 miles.

Project responsibilities also included research on portions of the transmission line corridor routes that received scrutiny from public and parties intervening in the certification hearing. Research was conducted on the following segments:

HPS to Pebbledale Substation- Polk County,
HPS to Vandola Substation- Hardee County, and
HPS to Lee Substation- Lee County.

Research was used for expert testimony presentation and post-certification project activity.

Transmission Line Environmental Review, Florida Power Corporation ▶ Florida Project Manager/Expert Witness for an environmental review of a proposed 230-kV transmission line to be collocated with existing transmission in the City of Oldsmar, Pinellas County, Florida. The evaluation focused on land use compatibility issues and collocation aspects of transmission line siting. Results of the study included the reasonableness of the proposed project's location given social, water resource, and ecological siting opportunities and constraints. Findings were presented during expert witness testimony in circuit court.

Transmission Line Post-Certification Compliance for Florida Power and Light (FPL) ▶ Project Manager responsible for the coordination and conduct of a systematic archaeological survey of portions of the proposed right-of-way from Duval Substation in Duval County to Poinsett Substation in Orange County. During the site selection study, the Florida Department of State, Division of Historical Resources identified archaeologically sensitive areas requiring a pedestrian survey with subsurface testing. The surveys were conducted after a specific right-of-way was selected by FPL. A number of sites were discovered, documented, and reported to the state, which concurred with the findings of the study.

Transmission Line Siting and EA for Turkish Electric Authority (TEK) ▶ Project Manager of proposed 380-kV transmission line from Ataturk Dam in eastern Turkey to Istanbul, a distance of 1,300 kilometers (km) (approximately 800 miles). Responsibilities included reviewing the alignment of the eastern two-thirds of the project to determine sensitive environmental areas and to provide guidance in determining the scope for an EA per World Bank guidelines entitled Operation Directive 4.00, Annex A: Environmental Assessment. The western one-third of the route was reviewed to determine sensitive areas and to guide TEK in developing an environmentally sensitive site selection methodology. Seminars and training sessions were conducted to develop TEK capabilities for siting major transmission lines and preparing EAs. A follow-up field trip was conducted to review the draft EA and assist in the development of mitigation and monitoring programs for the proposed project.

Transmission System Expansion Environmental Review, Cukurova Electric, Adana, Turkey ▶ Project Manager for an evaluation of transmission system improvements proposed by Cukurova to meet year 2000 system needs in their service area. The transmission system expansion consists of constructing over 700 km of 154-kV transmission lines, five new substations, and expansion of eight existing substations. A dispatch center was proposed to replace an existing facility which is at capacity and antiquated. Project efforts consisted of reviewing the proposed system expansion plan and preparing a scope of work to conduct a comprehensive environmental assessment consistent with World Bank Environmental Assessment Guidelines.

Liquid Fuel Pipeline Corridor for Tampa Electric Company (TECO) Power Services ▶ Project Manager of study involving the siting and licensing of a liquid-fuel pipeline corridor from Port Manatee (Manatee County) to the TECO Power Services Hardee Power Station, a distance of approximately 43 miles. A three-stage methodology was developed and implemented to define a preferred and alternative corridor for the 8-inch liquid-fuel pipeline. Natural resource and socioeconomic/land use criteria were developed to enable the multidisciplinary siting team to avoid sensitive resources. Once the two corridors were identified, the lineal facilities section of the Florida Electrical Power Plant Siting Act Site Certification Application (SCA) was prepared. Land use factors evaluated include the proposed project's compatibility with existing land use, its consistency with local zoning ordinances, and its compliance with applicable land use plans. In addition to the liquid-fuel- pipeline corridor project, a review of the land use and economic section of the SCA was conducted for the 295-megawatt (MW) combined-cycle power plant, a 49-mile natural gas pipeline, and three 230-kilovolt (kV) transmission lines (16, 8, and 78 miles).

230-kV Transmission Line Siting and Certification for Florida Power Corporation ▶ Land use task manager/Assistant project manager for the siting and environmental certification of a 230-kV transmission line to be constructed from the FPC's DeBary power plant to the Winter Springs substation. The project was colocated with existing linear facilities to the maximum extent practical and traversed urban and suburban portions of Volusia and Seminole County, five incorporated municipalities and the St. Johns River. A public participation plan was instituted to obtain local input and disseminate information. Expert witness testimony was provided in the areas of land use compatibility, consistency and compliance with comprehensive plans and land development regulations, and impacts to recreation and cultural resources.

Transmission System Expansion Environmental Review, Mid-80's Project, Florida Power Corporation (FPC) ▶ Task manager responsible for conducting land use inventory and compatibility analysis for transmission system improvements to an existing transmission line network in northwest Florida. Existing 69-kV to 230-kV transmission lines which extended approximately 142 miles and located through several counties were evaluated to determine feasibility of upgrading/double-circuiting to 230-kV. Numerous federal and state lands were factored into the evaluation.

Florida-Georgia 500-kV Transmission Line Siting Study, Florida Power Corporation (FPC) ▶ Provided land use/public workshop technical support for the siting of a 500-kV transmission line from the Florida-Georgia state border south to central Florida. The study area consisted of 9,000 square miles over 19 counties. A multiple phase siting study was undertaken to identify preferred and alternate corridors. Public involvement was obtained by conducting twenty "open houses" during the site selection process.

San Pedro de Macoris- Hainamosa Transmission Line Environmental Impact Assessment, The World Bank Project Manager responsible for preparing a World Bank Environmental Impact Assessment for a 78 km 138 kV transmission line and substation site. The proposed project and alternatives were evaluated for impacts to the physical, biological and social environmental

components. Major issues included the transmission line's proximity to sensitive coastal/marine wetlands and the need to conduct micro-routing of the transmission line alignment to avoid residential resettlement.

Griffin Road Transmission line and Substation Wetlands and Threatened and Endangered Species Surveys, Florida Power Corporation Project Manager responsible for determining federal and state wetland jurisdiction for a substation site and an approximate four mile long segment of an existing transmission line that was proposed for upgrading. A threatened and endangered species survey was also conducted for flora and fauna within and adjacent to the project site.

Carrabelle Transmission Line and Indian Pass Substation Wetlands and Threatened and Endangered Species Surveys, Florida Power Corporation Project Manager responsible for determining federal and state wetland jurisdiction for a substation site at Indian Pass and an approximate 13 mile long segment of new transmission line right-of-way. A threatened and endangered species survey was also conducted for flora and fauna within and adjacent to the project site.

Private Electrical Power Transmission Line Permit Plan, Confidential Client Project Manager responsible for determining environmental and land use permits and approvals for a private power transmission line originating at a proposed substation and ending at an existing industrial complex in west-central Florida.

PROJECT EXPERIENCE- HIGHWAYS

Environmental Assessments for Highway Improvements, Florida Department of Transportation ► Land Use Discipline Manager for determining land use and socioeconomic impacts of several highway widening or relocation projects in Florida. These projects included:

- State Road (SR) 50 in Hernando County,
- SR 54 in Pasco County,
- Interstate 275 in Pinellas County,
- Cortez Road in Manatee County,
- Roosevelt Bridge in Martin County, and
- U.S. Highway 1 in Broward and Dade Counties.

Areas of technical evaluation and analysis included community services, community cohesion, consistency with applicable sections of the Civil Rights Act, land use, utilities and railroads, relocation, cultural and historical resources, Section 4(f) lands, pedestrian and vehicle facilities, visual impacts, contamination impacts, wild and scenic rivers, farmlands, and energy.

I-95 Interchange EIS for the Florida Department of Transportation (FDOT) ► Land Use Discipline Manager of EIS prepared for three Interstate I-95 interchanges in Broward County as part of the overall I-95 widening project. Project responsibilities included preparing land use and socioeconomic sections of the EIS for the Hollywood Boulevard, Pembroke Road, and Hallandale Beach Boulevard interchanges. Land acquisition and relocation of residential land use and commercial businesses were addressed for each interchange.

U.S. Highway 1 EA for FDOT ► Land Use Discipline Manager for an EA prepared for US 1 (Federal Highway from Hallandale Beach Boulevard in Broward County to Miami Gardens Drive in Dade County). Land use socioeconomic sections of the EA were prepared to address impacts to utilities and relocation of businesses and dwellings as a result of the highway widening project.

PROJECT EXPERIENCE- AIRPORTS

Airport Land Use Plans for FAA ► Land Use Discipline Manager for general aviation airports in Florida (Winter Haven, Vero Beach, Venice, and Lake City) and the Tooele Valley Airport in Utah. Plan development goals consisted of maximizing the potential revenues from on-airport land development, buffering on-airport activities from off-airport land uses, and evaluating both on-airport and off-airport land uses with federal airport noise control/land use compatibility (ANCLUC) guidelines.

Airport Noise/Land Use Compatibility Planning for FAA ► Assistant Manager of FAA Part 150 studies conducted for four New England airports (Portland Jetport, Burlington International, Westfield-Barnes, and Martha's Vineyard), as well as Salt Lake City International Airport in Utah and Bishop International Airport in Flint, Michigan. For each project, noise monitoring and modeling tasks resulted in the establishment of noise contours. A detailed land use inventory was undertaken to quantify land use impacts by noise contour and political jurisdiction. Land use trends were determined and compatibility analyses conducted according to the FAA's land use compatibility guidelines. After noise abatement alternatives were determined, land use impacts were recalculated and land use strategies developed. Recommendations were presented to technical advisory committees, airport authorities, and affected city councils for review and approval.

Environmental Assessment for Airport Improvements, Chattanooga Airport Authority ► Land Use Discipline Manager for determining environmental impacts associated with airport improvements at Chattanooga Airport. Proposed improvements included runway expansion, passenger terminal relocation, and other airport support facilities. Residential and commercial relocations would be required to accommodate the improvements, and approach and departure noise impacts were evaluated to determine land use impacts to surrounding neighborhoods.

Fort Lauderdale-Hollywood International Airport ADA/DRI for the Broward County Aviation Authority ► Land Use Planner responsible for preparation of major sections of the application, including energy analysis, all public facility impacts (water, wastewater, solid waste, police, fire, recreation, and health care), and ANCLUC guidelines.

Spacecraft Integration and Test Facility ADA/DRI for Hughes Aircraft ► Land Use Discipline Manager responsible for assisting an architecture and engineering firm with limited site planning for a tract of land in Brevard County and the preparation of ADA responses to land use, public facilities (water, wastewater, solid waste, police, fire, health, and recreation), archaeological/historical sites, and economy sections.

PROJECT EXPERIENCE-GOVERNMENT

Benefit Cost Analysis for Green Swamp for SWFWMD ▶ Land Use Discipline Manager responsible for mapping existing land use in Green Swamp and the downstream reaches of the Hillsborough and Withlacoochee Rivers (portions of Hillsborough, Pasco, Hernando, Sumter, Lake, and Polk Counties) as part of a cost-benefit study for flood prevention alternatives. Historical development and ownership patterns were determined to project future development scenarios in the project area for a 50-year period. Flood damages were subsequently identified for six flood events and five flood-prevention alternatives.

Myakka Wild and Scenic River Management Plan for FDNR ▶ Project Manager of a resource management plan for a 43-mile segment of the Myakka River designated as a Florida Wild and Scenic River. The plan was developed with the assistance of the Myakka River Management Coordinating Council, a 29-member advisory board comprised of state, regional, and local governmental officials and staff, landowners, and environmental group representatives. The plan presented principles, objectives, and actions to guide in the management of the river and watershed's aquatic, terrestrial, geologic, economic, scenic, recreational, and cultural resources.

Hazardous Waste Management Plans for the Tampa Bay Regional Planning Council (TBRPC) ▶ Task Manager for project preparing hazardous waste management plans for the Tampa bay region and Hillsborough, Manatee, Pasco, and Pinellas Counties. Individual tasks included preparing and conducting a survey of potential small-quantity hazardous waste generators in the region (14,000 surveys were distributed); analyzing the results to determine generation characteristics, on-site storage conditions, and disposal practices; inventorying unlicensed, abandoned, closed, and active landfills; and selecting multiple sites in each county for a short-term hazardous waste storage/transfer facility. Criteria used to evaluate the sites included existing and future land use compatibility and conformance to local government comprehensive plans. The highest-ranked sites were presented to each county's board of county commissioners for review and approval.

Hazardous Waste Transfer Facility Site Selection Studies for the West Florida Regional Planning Council ▶ Task Manager of site selection studies for locating hazardous waste transfer facilities in seven northwest Florida counties (Escambia, Santa Rosa, Okaloosa, Walton, Bay, Holmes, and Washington). The siting study consisted of a three-stage, multidisciplinary examination and evaluation of up to 45 areas within each county. Project activities also consisted of obtaining approval from each county's board of county commissioners and reviewing transfer facility sites selected by each county commission to designate one or more sites for a regional (multicounty) facility.

Dredged Material Disposal Siting Study for the Jacksonville Port Authority ▶ Land Use Discipline Manager for the socioeconomic/land use section of a dredged materials upland disposal site study for a study area of 1-mile radius from the St. Johns River ship channel midline. Displacement of land uses and public utilities, land use compatibility, development trends, and conformance with city/county comprehensive plans were analyzed to exclude areas not compatible with disposal of dredged materials.

Halifax Harbor Marina ADA/DRI for the City of Daytona Beach, Florida ▶ Subproject Manager responsible for preparation of major sections of the application, including land use

compatibility, energy, public facilities, housing, floodplain issues, archaeological/historical resources, and marina-oriented ADA input.

Oakland Park Post Office Site Planning Report EA for the U.S. Postal Service Field Real Estate and Buildings Office ▶ Project Manager responsible for preparing an EA of a proposed postal facility in the City of Oakland Park, Broward County, Florida. The project's impacts on natural and socioeconomic resources were determined to assist in site planning and design activities. Major issues that were addressed include noise impacts from truck traffic on nearby residential areas, land use compatibility, traffic ingress and egress to the site, and vehicular and pedestrian safety associated with a nearby railroad crossing.

PROJECT EXPERIENCE- LAND DEVELOPMENT PERMITTING

Land Development and Environmental Planning Feasibility and Permitting for Paragon Group ▶ Project Manager of preliminary analysis of 14 sites throughout Tampa Bay, Fort Myers, Fort Lauderdale, and Orlando. Technical assistance provided included wetland delineation and agency jurisdiction determination; land use and zoning requirements; conceptual site planning; permit feasibility determination; dredge and fill permitting; wetlands mitigation; and submerged lands leasing. Approvals for most of the multifamily residential, office, or retail commercial projects required presentations to county commissions, city councils, or other boards/committees.

World Mart Center-Gateway Tampa, Application for Development Approval/DRI (ADA/DRI) for Gateway Tampa Development Corporation ▶ Project Manager responsible for the preparation of all environmental documentation for a proposed 3,000,000-square-foot (ft^2), high-rise, mixed-use development on 11.0 acres adjacent to the Hillsborough River in downtown Tampa. Major issues consisted of development intensity, setbacks from the river, view preservation, street traffic congestion, mass transit provisions, water and air quality, historical and archaeological resources, and endangered marine faunal species. The DRI application was submitted to regulatory agencies within 90 days of project initiation. The project was approved by the City of Tampa under a new zoning district (Tampa Quality Development) specifically created to accommodate the project's development program.

Southland Executive Park ADA/DRI for Southland Associates ▶ Land Use Discipline Manager responsible for land use, floodplain, archaeological/historical resources, economy, public facilities, and office parks sections of ADA for a mixed-use development proposed for 92 acres in Orange County, Florida. The analysis of fiscal impacts was determined by utilizing the University of Florida's Fiscal Impact Model.

Land Use Plan Amendment ▶ Tampa Technology Park for Trout Creek Associates ▶ Land Use Discipline Manager of a land use plan amendment application prepared for Tampa Technology Park, a proposed mixed-use development consisting of 13.8 million ft^2 of offices, warehouse, and retail commercial space; and 3,900 dwelling units on 3,830 acres in Hillsborough County. Primary areas of investigation include the determination of land use compatibility with adjacent existing and proposed uses and justifying market demand for the development components.

SELECTED PUBLICATIONS

Public Involvement: A Critical Component for Gaining Power Project Approvals (with Kenda Polio-Hein), Power Gen 96 International Conference and Exhibition, December, 1996

Local Government Role in Power Plant Permitting, Power Gen International Conference and Exhibition, December, 1995

Utilization of Environmental Data in Phosphate Mine Planning and Environmental Impact Assessment, International Fertilizer Development Center International Training Workshop, October, 1993

CALPINE
OSPREY
ENERGY CENTER

Amended Petition for Determination of Need for the Osprey Energy Center

Amended Exhibits Volume II

Submitted by

CALPINE
CONSTRUCTION FINANCE
COMPANY, L.P.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001748-EC EXHIBIT NO. 12
COMPANY/
WITNESS: Calpine
DATE: 2-12-01

AMENDED JOINT PETITION FOR DETERMINATION OF NEED
FOR THE OSPREY ENERGY CENTER

EXHIBITS - VOLUME II

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EXECUTIVE SUMMARY

General Description of the Osprey Energy Center

The Osprey Energy Center (the "Osprey Project" or the "Project") is a natural gas-fired combined cycle generating plant that will be located in the City of Auburndale, Polk County, Florida. The Osprey Project will have 529 megawatts ("MW") of net generating capacity at average ambient site conditions, excluding duct-firing and power augmentation. The Project is being developed by Calpine Construction Finance Company, L.P. ("Calpine") and is expected to commence commercial operation in the second quarter of 2003. Pursuant to a Power Purchase Agreement (the "PPA") between Seminole Electric Cooperative, Inc. ("Seminole") and Calpine Energy Services, L.P., an affiliate of Calpine, Calpine has committed to make up to the full output of the Osprey Project available to Seminole for an initial term of five years, from June 1, 2004 through May 31, 2009.

This Volume II of the Amended Exhibits contains information describing Calpine, the Project site, the Project and its operating characteristics, Calpine's use of the Project, the consistency of the Project with Peninsular Florida's need for additional power supply resources, the basic contractual arrangements pursuant to which Calpine has committed the Project's output to Seminole, the economics of the Project, the permitting and construction schedules for the Project, the Project's electrical interconnection to the

Peninsular Florida grid, and the Project's fuel supply and fuel transportation agreements. Volume I of the Amended Exhibits contains information describing Seminole and Seminole's need for the Project.

The Project will include two advanced technology combustion turbine generators, two matched heat recovery steam generators that include duct-firing capability for increased output, and one steam turbine generator. The Project is expected to have a heat rate of approximately 6,800 British thermal units ("Btu") per kilowatt-hour ("kWh"), based on the Higher Heating Value ("HHV") of natural gas at average ambient site conditions. The Project will meet or exceed all applicable environmental requirements. The Project's primary sources of makeup water to the cooling towers will be supplied by reclaimed water from the City of Auburndale and by on-site groundwater wells.

Projections prepared for Calpine indicate that the Project will operate approximately 7,500 to 8,500 hours per year, with projected generation of approximately 4.0 million to 4.4 million megawatt-hours ("MWH") per year, when operated on an economic dispatch basis and subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities.

The Project will be interconnected to the Peninsular Florida transmission grid at the Tampa Electric Company ("TECO") Recker Substation located adjacent to the east boundary of the Project

site. The Project will be fueled by natural gas, which will be delivered through a new trans-Florida pipeline to be constructed by Gulfstream Natural Gas System, L.L.C. ("Gulfstream") pursuant to a 20-year firm gas transportation agreement. Gulfstream will obtain all necessary permits for and construct the natural gas lateral pipeline to connect the main Gulfstream pipeline to the Project.

Ownership and Management

The Osprey Energy Center will be developed by Calpine Construction Finance Company, L.P., which will own the Project. Calpine Construction Finance Company, L.P., is a wholly-owned subsidiary of Calpine Corporation. Environmental engineering for the Project is being performed by Calpine and Golder Associates, Inc. Construction of the Project will be overseen by Calpine. The Osprey Energy Center will be managed by Calpine. Calpine plans to sell the power produced by the Project at wholesale to Seminole and, in the event that Seminole does not purchase all of the Project's output, Calpine expects to sell that output to other load-serving entities and retail-serving utilities for use in Peninsular Florida.

Site Description and Location

The Osprey Energy Center will be located in the City of Auburndale, Polk County, Florida, on approximately 19.5 acres situated approximately 1.5 miles south of downtown Auburndale and approximately 37 miles east of Tampa Bay. The site was formerly a

citrus grove and is currently unused. Land uses adjacent to the site include the TECO Recker Substation and existing TECO 230 kV transmission lines, the existing Auburndale Power Plant, which is a 150 MW natural gas-fired cogeneration plant (with oil back-up fuel) owned by Auburndale Power Partners, the Auburndale Memorial Park cemetery, commercial and industrial businesses, and two small residential enclaves. Access to the site will be from West Derby Avenue, a two-lane county collector road. The Project has been planned and designed to be consistent with the City of Auburndale's zoning category and comprehensive plan future land use designation applicable to utility uses.

Description of the Power Plant and Related Facilities

The power plant will consist of two advanced technology Siemens-Westinghouse Model 501F combustion turbine generators ("CTGs") in combined cycle configuration. Each CTG will be connected to a heat recovery steam generator ("HRSG") producing steam for a single steam turbine generator ("STG"). The net electrical output of the plant will be 529 MW at average ambient site conditions, excluding duct-firing and power augmentation. The Project will include the capability to duct-fire the HRSGs to increase steam production and power output. Duct-firing is a process whereby gas burners are placed within the HRSGs to increase gas temperature and generate more steam, thus increasing power generation from the STG. The Project will also include the

capability for power augmentation. Power augmentation is accomplished by injecting steam from the HRSGs into the gas turbines for the purpose of increasing mass flow through the CTGs, thereby increasing the electrical power output from the CTGs. The Project will utilize state-of-the-art dry low-NO_x[1] combustion technology and selective catalytic reduction ("SCR") to minimize NO_x emissions.

The Osprey Energy Center will be connected to the Peninsular Florida transmission grid at the existing TECO Recker 230 kV substation. Gas will be delivered through a 16-inch lateral pipeline from the new Gulfstream pipeline. Process and makeup water will be supplied from the City of Auburndale's wastewater treatment facilities and from on-site groundwater wells, and wastewater will be returned to the Allred treatment facilities. The City of Auburndale will obtain the necessary permits for the new pipelines for delivery of the reclaimed water to and return of wastewater from the Project; these pipelines will be paid for by Calpine.

Fuel Supply

The Project will be fueled by natural gas, which will be delivered via firm transportation service on the Gulfstream pipeline. The natural gas will be supplied to Gulfstream pipeline receipt points by various natural gas commodity producers and

[1] "NO_x" is used to refer generically to the oxides of nitrogen produced in the combustion process.

suppliers.

Project Costs and Financing

The Osprey Energy Center's direct construction cost is expected to be approximately $194.8 million, reflecting a cost of approximately $357 per kW of installed capacity (based on 545 MW at ISO). The Project will be constructed and brought into commercial service with a combination of equity and debt. Calpine Corporation will provide the equity, and the debt will be supplied from Calpine's "construction revolver," a form of revolving credit account with several investment banks used to fund the debt portion of the construction and development costs of multiple projects being developed by Calpine.

I. INTRODUCTION

The purpose of the Amended Joint Petition for Determination of Need (the "Amended Joint Petition") submitted by Seminole Electric Cooperative, Inc. and Calpine Construction Finance Company, L.P., is to obtain the Florida Public Service Commission's ("FPSC" or "Commission") affirmative determination of need for the Osprey Energy Center, a 529 MW natural gas-fired combined cycle generating plant that will be located in the City of Auburndale, Polk County, Florida.

The Commission's determination of need pursuant to Section 403.519, Florida Statutes, is part of the comprehensive permitting process for the Project under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, Florida Statutes (the "Siting Act"). Under Section 403.519, the Commission is to consider the following factors when making its decision whether to grant a determination of need for a power plant subject to the Siting Act:

1. the need for electric system reliability and integrity;
2. the need for adequate electricity at a reasonable cost;
3. whether the proposed plant is the most cost-effective alternative available for serving an identified need for power;
4. conservation measures taken by, or reasonably available to, the affected utility or utilities which might mitigate the need for the proposed plant; and
5. other matters within the Commission's jurisdiction that the Commission deems relevant to its determination.

The Amended Joint Petition and Volumes I and II of the Amended

Exhibits demonstrate that the Osprey Energy Center satisfies all relevant criteria under Section 403.519 and all relevant criteria under Rule 25-22.081, Florida Administrative Code. The Project will provide a power supply resource with proven, reliable, highly efficient, highly available, and environmentally favorable technology. The Project will provide a cost-effective power supply resource for meeting Seminole's need for additional electric generating capacity and electrical energy to meet the needs of Seminole's Member systems and of these systems' members-consumers for system reliability and integrity.

Subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the Project will also contribute meaningfully to the reliability of the power supply system in Peninsular Florida, lower the cost of electricity generation in Peninsular Florida, enhance the overall efficiency of electricity production in Peninsular Florida, and improve the environmental profile of electricity generation in Florida.

Section II of this Volume II of the Amended Exhibits describes Calpine. (Volume I of the Amended Exhibits describes Seminole, the other joint applicant.) Section III describes technical aspects of the Project, including the site, generating technology, operational reliability and related information, major systems, associated facilities, fuel supply, and the schedules for permitting and constructing the Project. Section IV describes Peninsular

Florida's need for the Project, including the energy efficiency and environmental benefits that the Project will provide, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities. Section IV also describes how Calpine will use the Project. Section V describes the cost-effectiveness of the Project to Peninsular Florida and Calpine, and Section VI addresses the adverse consequences on power supply reliability, on power supply costs, and on Florida's environment of delaying the construction and operation of the Osprey Energy Center.

II. CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

Calpine Construction Finance Company, L.P., is one of the Joint Applicants for the Commission's determination of need. This section of the Amended Exhibits describes the organization and ownership structure of the Osprey Energy Center and Calpine. Seminole Electric Cooperative, Inc., the other joint applicant, is a primarily affected utility within the meaning of the Commission's rules and orders. Volume I of the Amended Exhibits contains appropriate descriptive information concerning Seminole.

A. Overview and Project Structure.

Calpine Construction Finance Company, L.P., will be the owner of the Osprey Energy Center. Calpine will sell the Project's capacity and energy at wholesale to Seminole and, in the event that Seminole does not purchase all of the Project's output, to other load-serving utilities in Florida. Calpine is authorized by its FERC-approved tariff to engage in the business of generating and selling electricity at wholesale in Florida.

Calpine Construction Finance Company, L.P., is the developer of the Project, and in that role negotiated the PPA with Seminole and will negotiate various other contracts and perform other activities necessary for the Project's development and construction. The Project will be constructed and brought into commercial service solely with funding arranged by Calpine. Calpine anticipates that the Project will be financed with a

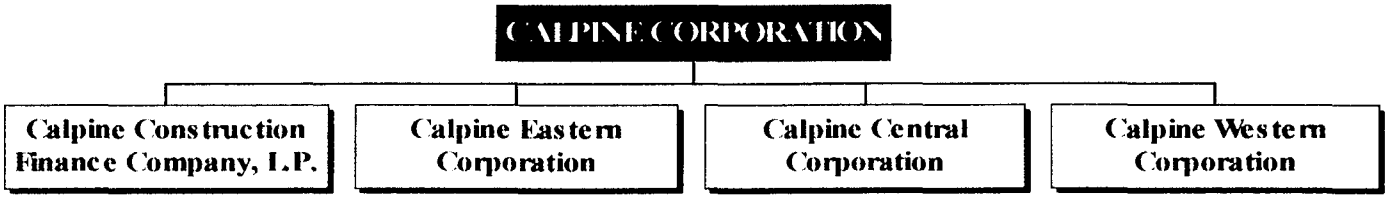
combination of equity and debt that will be used to pay the Project's development and construction costs. Calpine has retained Golder Associates, Inc. to provide engineering support and environmental licensing and permitting services for the Project. The natural gas fuel supply for the Project will be provided by natural gas marketing companies or producers to receipt points on the new trans-Florida natural gas pipeline to be constructed by Gulfstream Natural Gas System, L.L.C.

B. Calpine Construction Finance Company, L.P.

Calpine Construction Finance Company, L.P., a Delaware Limited Partnership, is a wholly-owned subsidiary of Calpine Corporation, a Delaware corporation. See Figure II-1. By order issued on February 23, 2000, FERC approved Calpine's tariff to sell wholesale power at market-based rates. In Re: Calpine Construction Finance Company, L.P., 90 FERC ¶61,164 (February 23, 2000). A copy of the order is included in Appendix A to Volume II of these Amended Exhibits. On November 3, 2000, Calpine submitted its application to the FERC for certification as an Exempt Wholesale Generator.

Calpine is the developer of the Osprey Energy Center. In that role, Calpine is arranging for the permitting of the Project, for the engineering, procurement, and construction of the Project, for the Project's fuel supply, and for other services necessary to bring the Project to commercial operation.

FIGURE II-1
CALPINE CONSTRUCTION FINANCE COMPANY, L.P.
OWNERSHIP STRUCTURE



Calpine's business strategy is to focus on building clean, environmentally responsible, efficient, natural gas-fired combined cycle power plants. Calpine expects to be represented on the Florida Reliability Coordinating Council.

C. **Calpine Corporation**.

Calpine Corporation, a Delaware corporation, is the parent corporation of Calpine Construction Finance Company, L.P. Calpine Corporation is headquartered in San Jose, California with regional offices in Boston, Massachusetts, Tampa, Florida, Houston, Texas, and Pleasanton, California. Founded over 15 years ago, Calpine Corporation is a leading independent power company engaged in the development, acquisition, ownership and operation of power generation facilities, and in the sale of electricity from Calpine's plants, predominantly in the United States. Calpine Corporation currently owns, has ownership interest in, or is developing or constructing a total of 78 generating assets (28 existing gas-fired and 19 existing geothermal projects, 18 projects under construction, and 13 projects under development) having a combined nominal capacity of 24,763.7 MW with Calpine Corporation's net ownership interest in these assets totaling 21,807.9 MW. Calpine Corporation's 28 operating gas-fired generating plants are located in California (7 plants), New Jersey (3 plants), New York (4 plants), Pennsylvania (2 plants), Texas (5 plants), and 1 plant each in Florida, Illinois, Massachusetts, Oklahoma, Rhode Island,

Virginia and Washington. Calpine Corporation now owns the entire ownership interest in Auburndale Power Partners' Auburndale Power Plant, which is immediately adjacent to the Osprey Project site. Calpine Corporation's geothermal power generating units have approximately 850 MW of capacity. Table II-1 presents a summary of Calpine Corporation's generating portfolio.

Calpine Corporation is a vertically integrated company with a full competency set that enables it to develop, finance, construct, own, and operate, on a long-term basis, power plants across the United States. As part of the above competencies, Calpine Corporation possesses the asset management, power marketing, risk management, and fuel management capabilities required for the long-term sustainable and reliable operation of a diverse set of generating assets. Additionally, Calpine Corporation has recently completed the acquisition of gas reserves in the Sacramento basin. The acquisition of additional gas reserves is part of Calpine Corporation's long-term business strategy.

TABLE II-1
Calpine Corporation Portfolio
of Generating Assets

Calpine

Operating Gas Fired Power Plants	Baseload Capacity (megawatts)	Calpine Interest Percentage	Calpine Net Interest (megawatts)
Agnews San Jose, CA	26.5	100%	26.5
Auburndale Auburndale, FL	143.0	100%	143.0
Bayonne Bayonne, NJ	158.0	7.5%	11.9
Bethpage Hicksville, NY	52.0	100%	52.0
Clear Lake Pasadena, TX	335.0	100%	335.0
Dighton Dighton, MA	162.0	50%	81.0
Gilroy Gilroy, CA	112.0	100%	112.0
Gordonsville Gordonsville, VA	233.0	50%	116.5
Grays Ferry Philadelphia, PA	143.0	40%	57.2
Greenleaf 1 Yuba City, CA	50.0	100%	50.0
Greenleaf 2 Yuba City, CA	50.0	100%	50.0
Hidalgo Edinburg, TX	502.0	78.5%	394.1
Kennedy Jamaica, NY	95.0	100%	95.0
King City King City, CA	103.0	100%	103.0
Lockport Lockport, NY	177.0	11.36%	20.1
Morris Morris, IL	155.0	86.45%	134.0
Newark Newark, NJ	47.0	80%	37.6
Parlin Parlin, NJ	89.0	80%	71.2

Pasadena Pasadena, TX	231.0	100%	231.0
Pasadena Expansion Pasadena, TX	520.0	100%	520.0
Philadelphia Philadelphia, PA	22.0	66.4%	14.6
Pittsburg Pittsburg, CA	64.0	100%	64.0
Pryor Pryor, OK	109.0	80%	87.2
Stony Brook Stony Brook, NY	36.0	100%	36.0
Sumas Sumas, WA	120.0	70%	84.0
Texas City Texas City, TX	465.0	100%	465.0
Tiverton Tiverton, RI	240.0	62.8%	150.7
Watsonville Watsonville, CA	29.0	100%	29.0

Operating Geothermal Power Plants	Baseload Capacity (megawatts)	Calpine Interest Percentage	Calpine Net Interest (megawatts)
Aidlin Middletown, CA	20.0	100%	20.0
Bear Canyon Middletown, CA	20.0	100%	20.0
Calistoga Middletown, CA	73.0	100%	73.0
Lake County (2 power plants) Middletown, CA	145.0	100%	145.0
Sonoma Middletown, CA	53.0	100%	53.0
Sonoma County (12 power plants) Middletown, CA	512.0	100%	512.0
West Ford Flat Middletown, CA	27.0	100%	27.0

Under Construction	Baseload Capacity (megawatts)	Calpine Interest Percentage	Calpine Net Interest (megawatts)

[redacted]

Acadia Eunice, LA	1,080.0	50%	540.0
Aries Pleasant Hill, MO	516.0	50%	258.0
Baytown Baytown, TX	704.0	100%	704.0
Channel Houston, TX	519.0	100%	519.0
Decatur Decatur, AL	659.0	100%	659.0
Delta Pittsburg, CA	798.0	50%	399.0
Freestone Freestone County, TX	1,002.8	100%	1,002.8
Hermiston Hermiston, OR	530.0	100%	530.0
Los Medanos Pittsburg, CA	493.0	100%	493.0
Lost Pines I Austin, TX	522.0	50%	261.0
Magic Valley Edinburg, TX	687.0	100%	687.0
Morgan Decatur, AL	660.0	100%	660.0
Oneta Coweta, OK	960.3	100%	960.3
Ontelaunee Ontelaunee, PA	511.0	100%	511.0
Rumford Rumford, ME	237.0	66.7%	158.1
South Point Bullhead City, AZ	526.0	100%	526.0
Sutter Yuba City, CA	516.0	100%	516.0
Westbrook Westbrook, ME	487.0	100%	487.0

Under Development	Baseload Capacity (megawatts)	Calpine Interest Percentage	Calpine Net Interest (megawatts)
Blue Heron Indian River County, FL	1,080.0	100%	1,080.0
Calgary Energy Centre Calgary, Alberta	198.0	100%	198.0

[redacted]

Fremont Fremont, Ohio	500.0	100%	500.0
Haywood Haywood County, TN	763.0	100%	763.0
Hillabee Tallapoosa County, AL	700.0	100%	700.0
Lawrence Hamilton Township, OH	850.0	100%	850.0
Lone Oak Lowndes County, MS	763.0	100%	763.0
Metcalf San Jose, CA	533.0	50%	266.5
Osprey Auburndale, FL	540.0	100%	540.0
Tearavva Thermal, CA	530.0	100%	530.0
Towantic Oxford, CT	508.0	100%	508.0
Wawayanda Middletown, NY	530.0	100%	530.0
West Phoenix Phoenix, AZ	511.0	50%	255.5

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USE OF THIS SITE CONSTITUTES AGREEMENT
TO THE FOLLOWING TERMS AND CONDITIONS

III. DESCRIPTION OF THE OSPREY ENERGY CENTER

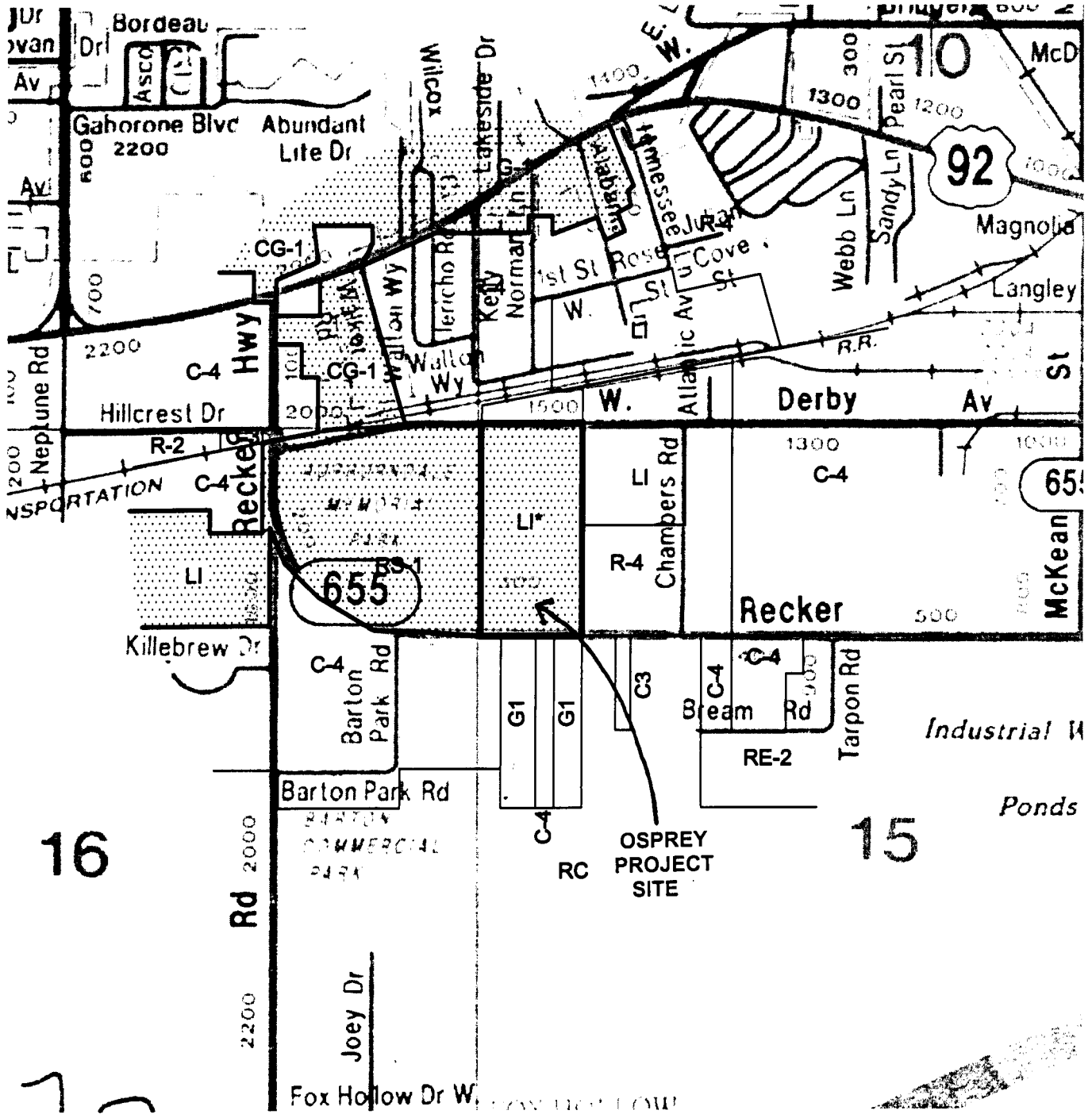
This section of the Amended Exhibits describes the Osprey Energy Center, including the Project's location, site arrangement, major systems and facilities, associated facilities, capital costs and financing, fuel supply, operational reliability, permitting and construction schedules, and operation and maintenance plan.

A. Site Location and Land Use Designation.

The Osprey Energy Center site is located in the City of Auburndale, in Polk County, Florida, on approximately 19.5 acres situated approximately 1.5 miles southwest of downtown Auburndale and approximately 37 miles east of Tampa Bay. The site is a non-producing citrus grove zoned "Light Industry" and is currently unused. Land uses adjacent to the site include the TECO Recker Substation and 230 kV transmission lines; the existing Auburndale Power Plant, which is a 150 MW natural gas-fired (with oil backup fuel) cogeneration plant owned by Auburndale Power Partners (and ultimately owned by Calpine Corporation); two small residential enclaves; a cemetery; and commercial and industrial businesses. Access to the site will be from West Derby Avenue, a two-lane county collector road. Figure II-2 is a map of the site location.

B. Site Arrangement.

A drawing of the expected layout of the generators, cooling towers and water processing and storage facilities is shown in Figure II-3, the site plan for the Project. The general arrangement of the power plant on the Project site is shown in Figure II-4, the



Auburndale Zoning Districts
- LI Light Industry
- RS-1 Single Family Residentual
- GI General Industrial

Polk County Zoning Disticts
- C-3 Regional Commercial
- C-4 Heavy Commercial
- GI General Industrial
- R-4 Residentual
- RC Rural Conservation
- RE-2 Rural Estates

REFERENCE

City of Auburndale Zoning Map
Polk County Zoning Map, Feb., 2000

* Site has been annexed. Zoning designation is based on Auburndale District

N

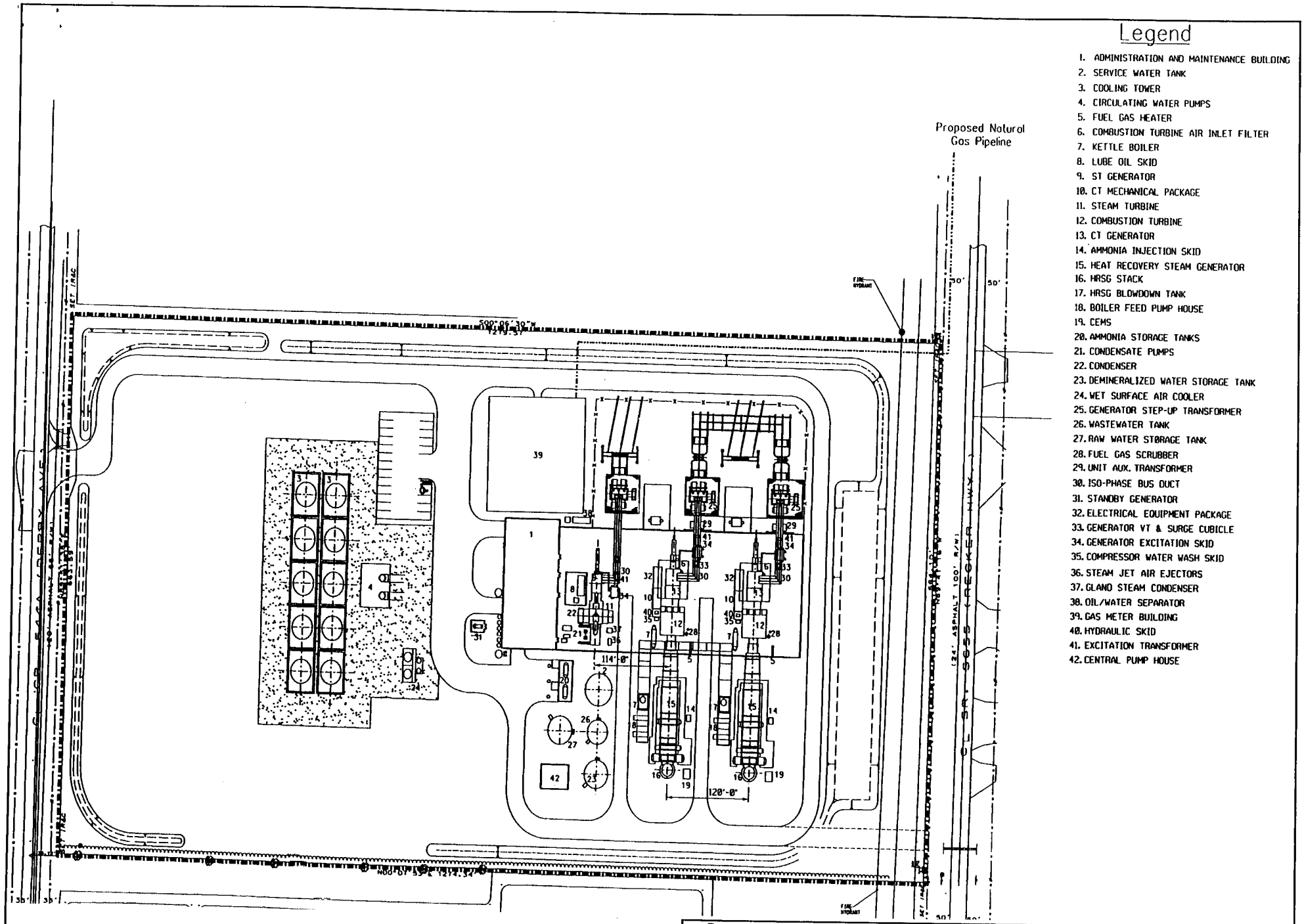
0 500' 1000'
SCALE

Golder Associates
Tampa, Florida

FIGURE II-2
SITE LOCATION RELATIVE TO LOCAL LANDMARKS AND ZONING DESIGNATIONS

Client / Project
Calpine Construction Finance Company, L.P.
Osprey Energy Center

CAD BY:	CDT	SCALE:	1"=1000'	Job No.	993-9570
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Legend

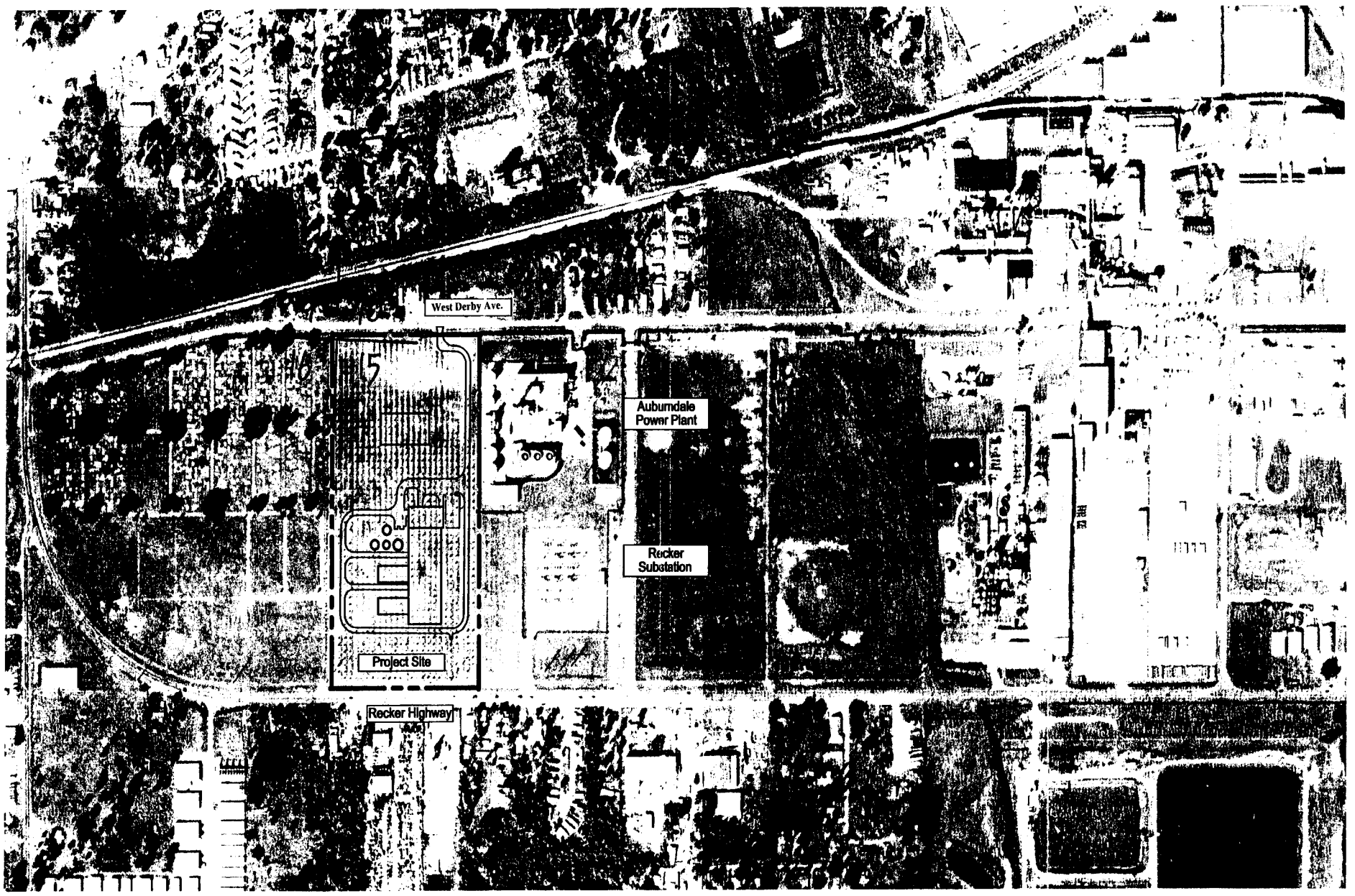
1. ADMINISTRATION AND MAINTENANCE BUILDING
2. SERVICE WATER TANK
3. COOLING TOWER
4. CIRCULATING WATER PUMPS
5. FUEL GAS HEATER
6. COMBUSTION TURBINE AIR INLET FILTER
7. KETTLE BOILER
8. LUBE OIL SKID
9. ST GENERATOR
10. CT MECHANICAL PACKAGE
11. STEAM TURBINE
12. COMBUSTION TURBINE
13. CT GENERATOR
14. AMMONIA INJECTION SKID
15. HEAT RECOVERY STEAM GENERATOR
16. HRSG STACK
17. HRSG BLOWDOWN TANK
18. BOILER FEED PUMP HOUSE
19. CEMS
20. AMMONIA STORAGE TANKS
21. CONDENSATE PUMPS
22. CONDENSER
23. DEMINERALIZED WATER STORAGE TANK
24. WET SURFACE AIR COOLER
25. GENERATOR STEP-UP TRANSFORMER
26. WASTEWATER TANK
27. RAW WATER STORAGE TANK
28. FUEL GAS SCRUBBER
29. UNIT AUX. TRANSFORMER
30. ISO-PHASE BUS DUCT
31. STANDBY GENERATOR
32. ELECTRICAL EQUIPMENT PACKAGE
33. GENERATOR VT & SURGE CUBICLE
34. GENERATOR EXCITATION SKID
35. COMPRESSOR WATER WASH SKID
36. STEAM JET AIR EJECTORS
37. GLAND STEAM CONDENSER
38. OIL/WATER SEPARATOR
39. GAS METER BUILDING
40. HYDRAULIC SKID
41. EXCITATION TRANSFORMER
42. CENTRAL PUMP HOUSE

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Client / Project
Calpine Construction Finance Company, L.P.
Osprey Energy Center

FIGURE II-3
Site Plan

CAD BY: CDT	SCALE: 1"=120'	Job No. 993-9570	
CHK BY: HGB	DATE: 08/11/00	FIGURE 3.2.0-2	Revision 1
REV BY: –	FILE No.: fig3_2_0-2.dwg		



400' 0 400'

scale feet

Golder Associates Tampa, Florida

Client / Project
Calpine Construction Finance Copany, L.P.
Osprey Energy Center

FIGURE II-4
PLOT PLAN

CAD BY: CDT	SCALE: 1"=400'	Job No. 993-9570
CHK BY: RAZ	DATE: 03/02/00	FIGURE
REV BY: –	FILE No.: plot-plan.dwg	

plot plan for the Project. An artist's computer-generated rendering of the Osprey Project is presented in Figure II-5.

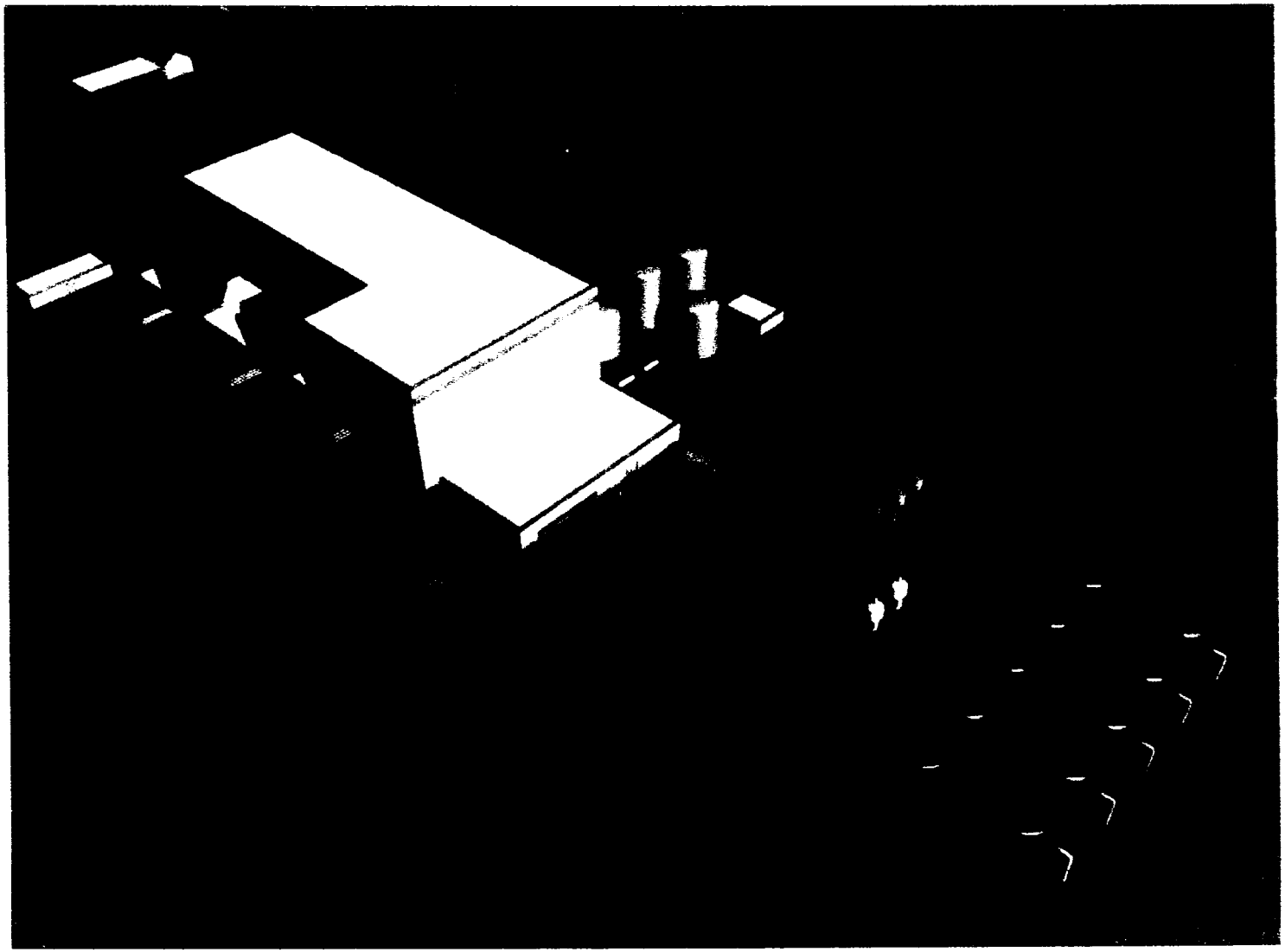
C. **Description of Major Systems and Facilities.**

The Project will produce 529 MW at average ambient temperature and humidity conditions, excluding duct-firing and power augmentation, and is rated at 496 MW at summer peak conditions and 578 MW at winter peak conditions (also without power augmentation or duct-firing). The power block will consist of two advanced-technology, dry low-NO_x combustion turbine generators with the capability to use power augmentation to increase the CTGs' power output, two matched heat recovery steam generators that include duct-firing capability to increase the steam generation capability of the HRSGs, and one steam turbine generator rated for the full steam production capacity (including duct-firing) of the HRSGs. Figure II-6 depicts the cycle of a gas-fired combined cycle power plant with a single combustion turbine and a single heat recovery steam generator.[2] Figure II-7 presents a one-line electrical diagram for the Project. The Project will be interconnected to the Peninsular Florida bulk transmission grid at the TECO Recker Substation and associated 230 kV transmission lines located adjacent to the east boundary of the site.

The Osprey Project will utilize a combination of reclaimed water and well water for its process and makeup water supply.

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[2] The Project will have two combustion turbines and two heat recovery steam generators.



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Tampa, Florida

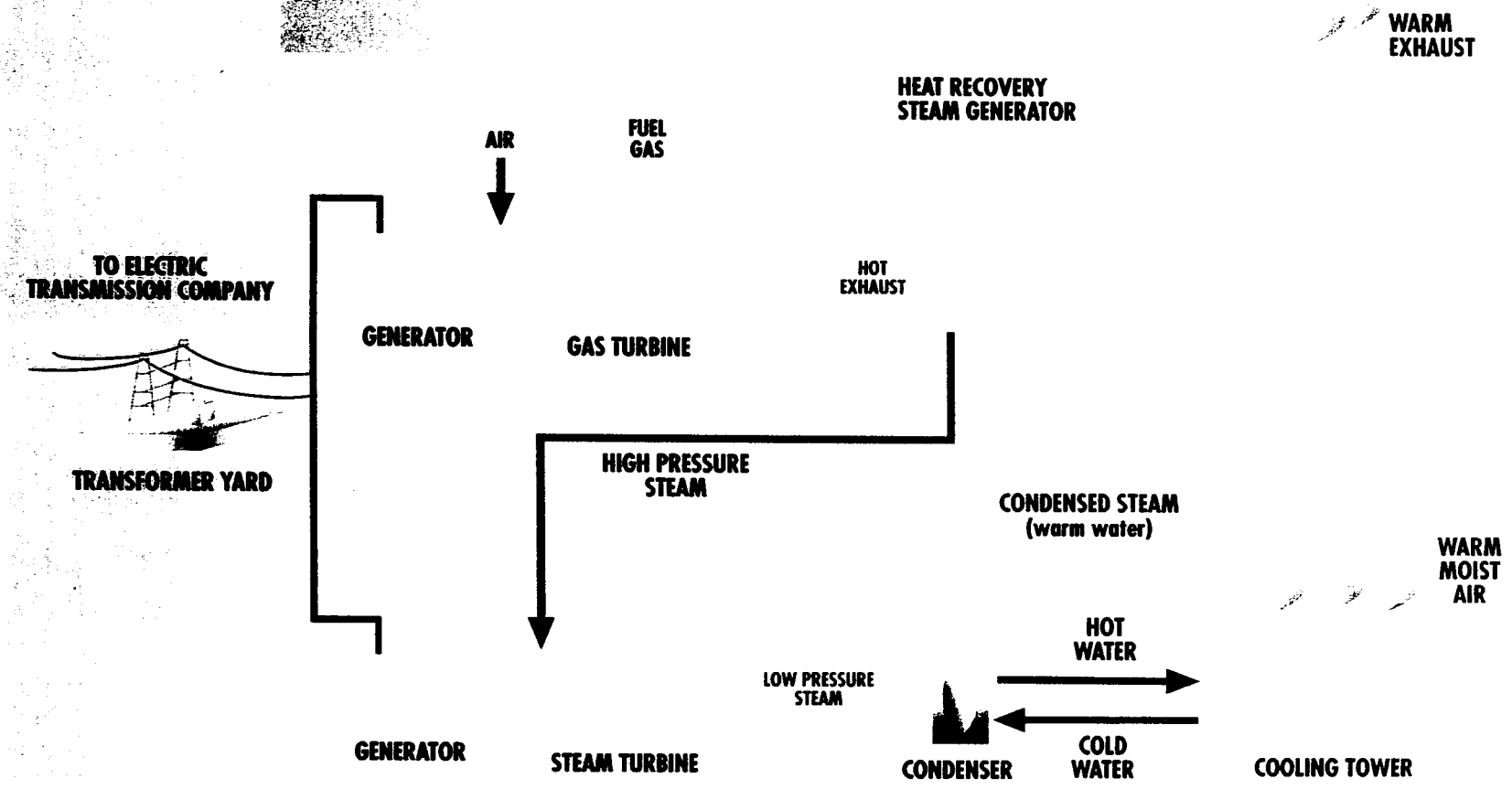
FIGURE II-5
PERSPECTIVE RENDITION

Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

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FIGURE 6
COMBINED-CYCLE GENERATION
SCHEMATIC DIAGRAM

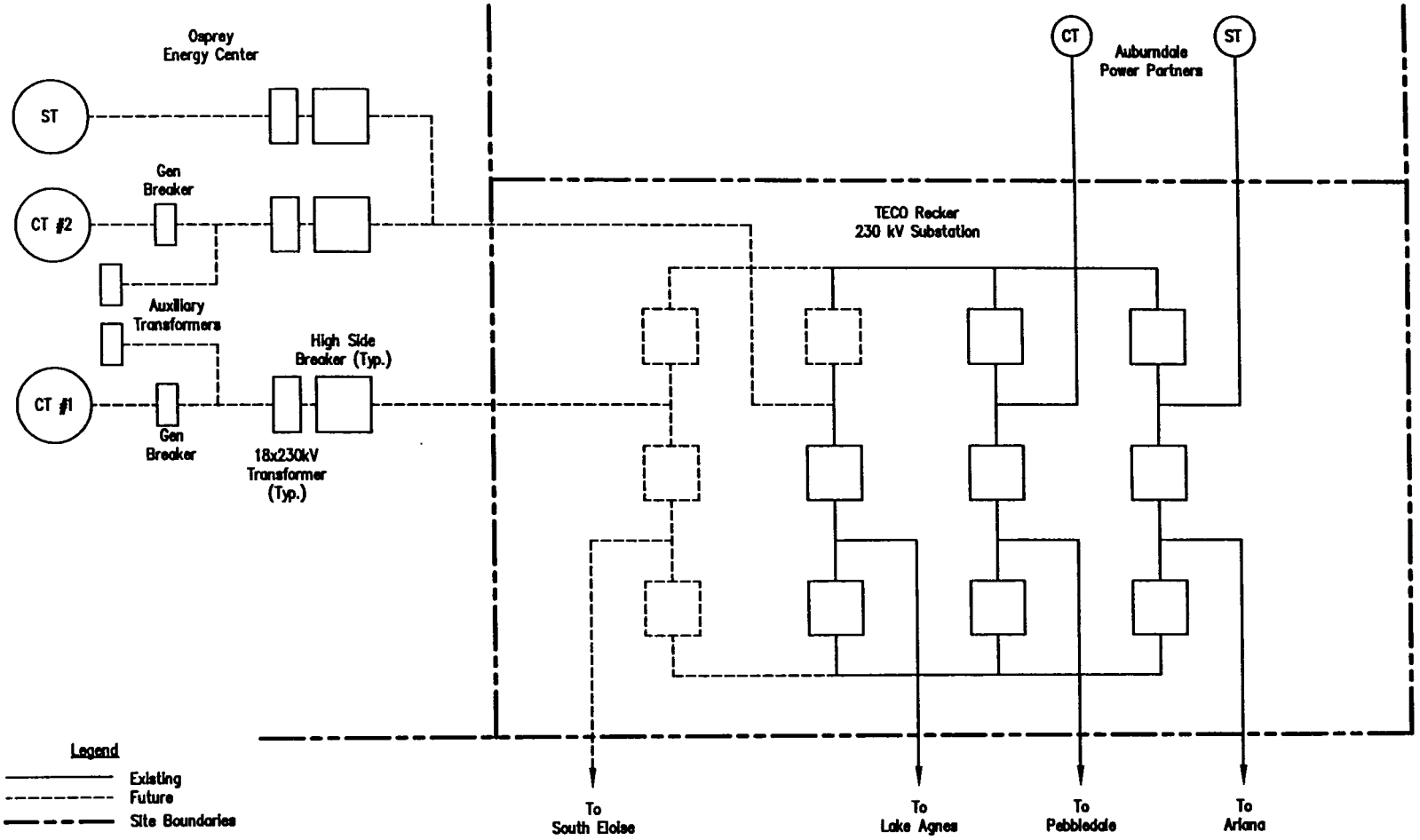








CALPINE EASTERN



Notes:
1. Switchyard breaker ratings are 2000 amp/40 Ka typical

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Tampa, Florida

Station One-Line
Electrical Diagram

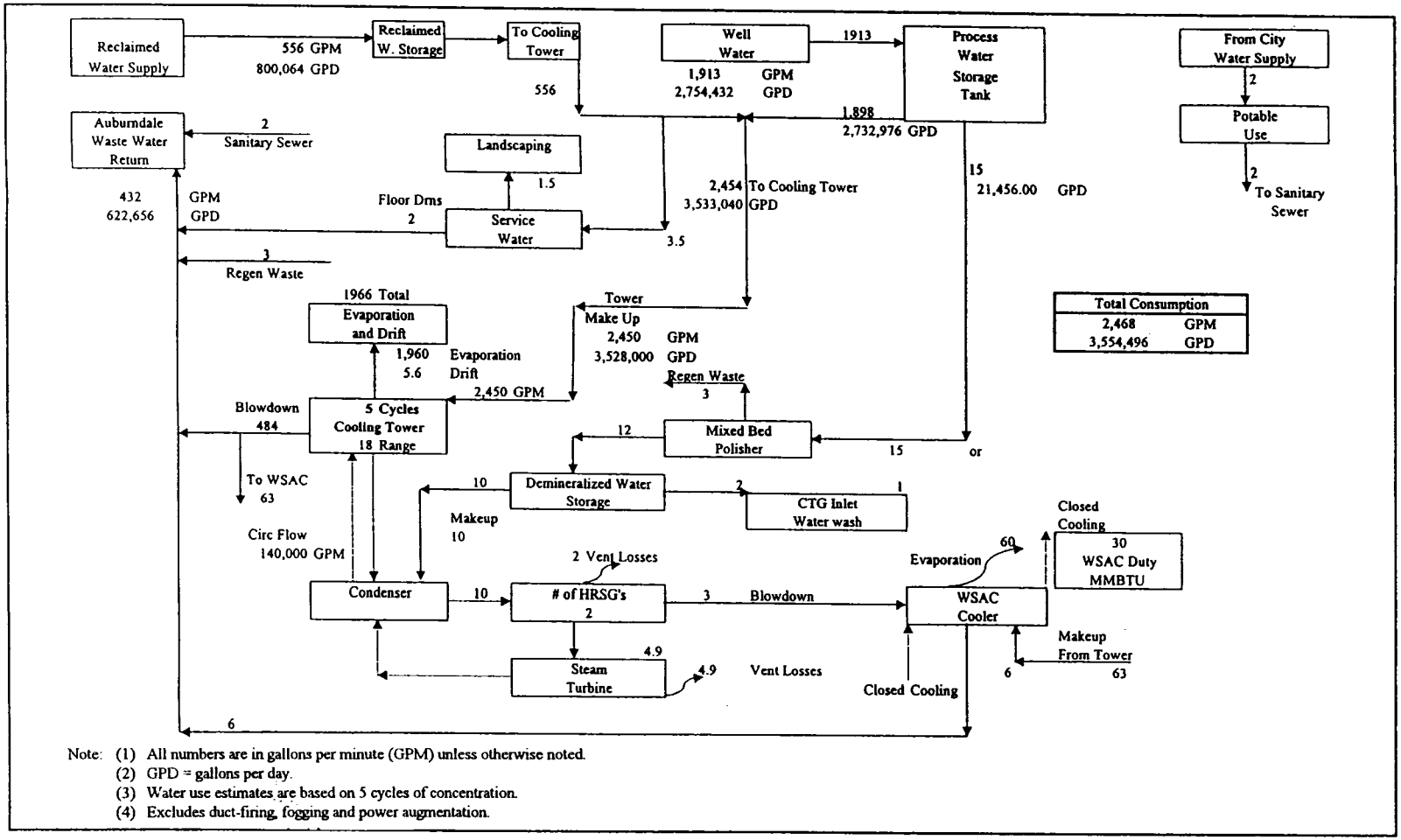
Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

CAD BY:	CDT	SCALE:	NTS	Job No.	993-9570
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Reclaimed water will be supplied from the City of Auburndale's Allred Wastewater Treatment Plant and may also be supplied from the City of Auburndale's Westside Regional Wastewater Treatment Plant. The Project will require the construction of reclaimed water pipelines to intertie with the City of Auburndale's wastewater treatment facilities. The pipelines to the Allred wastewater treatment facilities will be approximately one mile in length and will be constructed in existing public rights-of-way. Additionally, other minor pipeline modifications will be made to enhance discharge capability. The reclaimed water supply and return pipelines will run along the north Recker Highway right-of-way to the Osprey Project site boundary. The City of Auburndale will obtain the necessary permits for the water and wastewater pipelines. The remainder of the Osprey Project's water supply will be provided by new on-site wells withdrawing water from the Upper Floridan aquifer. The Project's preliminary average annual daily water balance for average conditions is shown in Figure II-8, and the preliminary peak month daily water balance is shown in Figure II-9.

The Osprey Energy Center is expected to have an estimated Equivalent Availability Factor of approximately 94.5 percent, and, based on production simulation analyses prepared for Calpine of the Project's operations within the Peninsular Florida bulk power supply system, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving



Note: (1) All numbers are in gallons per minute (GPM) unless otherwise noted.
(2) GPD = gallons per day.
(3) Water use estimates are based on 5 cycles of concentration.
(4) Excludes duct-firing, fogging and power augmentation.

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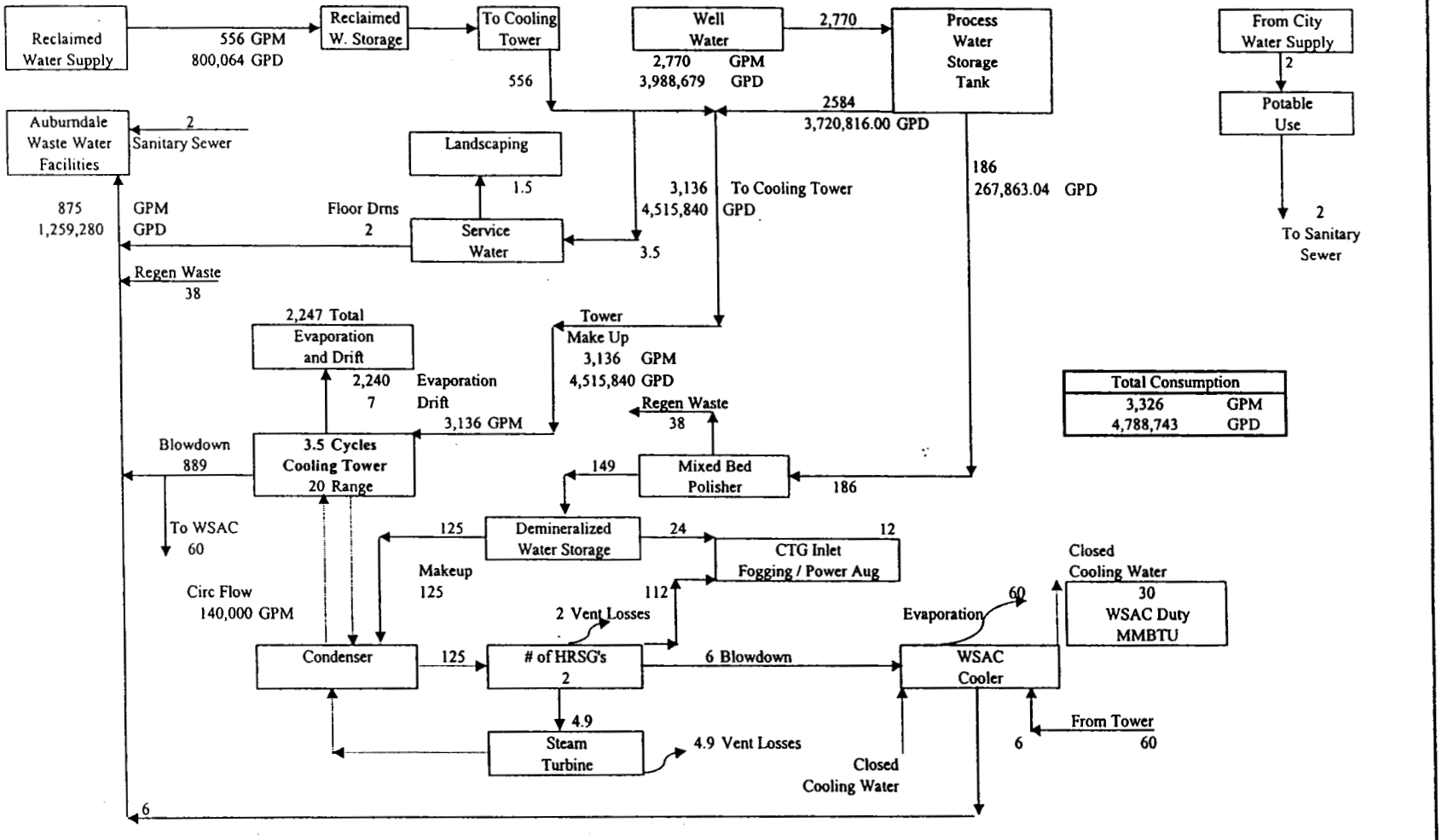
Tampa, Florida

Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

Average Annual Daily Water Balance Diagram

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Note: All numbers shown are in gallons per minute (GPM) unless otherwise noted.
GPD = gallons per day.
Water use estimates are based on 3.5 cycles of concentration.
Maximum water usage scenario reflects the use of duct firing, power augmentation and inlet fogging.

Golder Associates

Tampa, Florida

Peak Month Daily Water Balance Diagram

Client / Project

Calpine Construction Finance Company, L.P.
Osprey Energy Center

CAD BY:	CDT	SCALE:	NTS	Job No.	993-9570
CHK BY:	RAZ	DATE:	11/29/00		FIGURE II-9
REV BY:	--	FILE No.:	fig3_5_0-2.dwg		

utilities, an average capacity factor of approximately 91 percent. The Project's direct construction cost is projected to be approximately $194.8 million, or approximately $357 per kW of installed capacity (based on 545 MW output at ISO temperature and humidity conditions).

The Project has been designed with careful consideration of environmental issues and has a responsible environmental profile. The Project will be designed to control NO_x emissions using Best Available Control Technology ("BACT") measures, including state-of-the-art dry low-NO_x combustion technology and selective catalytic reduction. The Project will meet NO_x emission levels of 3.5 ppmvd, corrected to 15 percent oxygen. Both the use of clean-burning natural gas and good combustion practices will minimize sulfur dioxide, carbon monoxide, and volatile organic compound emissions and ensure that such emissions stay within permitted limits. See Table II-2 of this volume of the Amended Exhibits.

More detailed plant performance and emissions data for the Project are shown in Table II-3 of this volume of the Amended Exhibits. An overall schematic diagram of the power generation cycle is presented in Figure II-10.

D. **Transmission Facilities**.

The Osprey Energy Center will be electrically interconnected to the Peninsular Florida bulk transmission grid at TECO's Recker Substation, which is located adjacent to the east boundary of the Project site. The Recker Substation is tied to the transmission

TABLE II-2

OSPREY ENERGY CENTER
PROJECT PROFILE

Expected Plant Capacity:

a.	Average ambient rating (74°F, 80% R.H.):	529 MW
b.	Summer (95°F, 80% R.H.):	496 MW
	With Duct-firing & Power Augmentation:	575 MW
c.	Winter (32°F, 60% R.H.):	578 MW
	With Duct-firing & Power Augmentation:	666 MW
d.	ISO (59°F, 60% R.H.):	545 MW

Project Energy Production: Approximately 4,300,000 MWH/year (not including duct-firing or power augmentation)*

Technology Type: Two Siemens-Westinghouse 501F advanced firing temperature technology combustion turbines, two heat recovery steam generators, and one steam turbine generator in combined cycle configuration

Anticipated Construction Schedule:

a.	Engineering release date:	February 2001
b.	Construction mobilization date:	June 2001
c.	Commercial in-service date:	2nd quarter 2003

Fuel Use: Approximately 86 million Standard Cubic Feet of natural gas/day, annual average conditions (74°F, 80% R.H.), full load

Air Pollution Control Strategy: Dry low-NOx burners and SCR

Cooling Method: Wet Cooling Tower

Total Site Area: 19.5 acres (approximate)

Construction Status: Planned

Certification Status: Need Determination Petition and Site Certification Application filed.

Status with Federal Agencies: FERC has issued its order granting Calpine market-based rate authority.

TABLE 2

OSPREY ENERGY CENTER
PROJECT PROFILE
(CONTINUED)

Projected Unit Performance Data:

Planned Outage Factor (POF):	3.5%
Forced Outage Factor (FOF):	2.0%
Equivalent Availability Factor (EAF):	94.5%
Estimated Annual Average Capacity Factor (%):*	91.0%

Average Net Operating Heat Rate (ANOHR): 6800 Btu/kWh (HHV) (74°F, 80°R.H.) expected

Project Unit Financial Data (per Calpine Corporation):

Book Life (years):	35 years
Direct Construction Cost:	Approx. $194.8 million
AFUDC Amount:	Not applicable
Escalation ($/kW):	Not applicable
Fixed O&M ($/kW per year):	Proprietary
Variable O&M (4/MWH):	Proprietary
K-Factor:	Not applicable
Project Life:	35 years

Expected Plant Air Emissions:
NO_x: 3.5 ppmvd @15% O_2
SO_2: 20.8 lbs/hour
CO: 10 ppm

New Transmission Lines Required: None

Gas Pipeline Required: None

Water Requirements:
(Including Reclaimed Water)
Approx. 4.79 MGD, summer peak Conditions (95°F, 80 R.H.), (with power augmentation and duct-firing)
Approx. 3.55 MGD average (74°F, 80 R.H.), (without power augmentation or duct-firing)

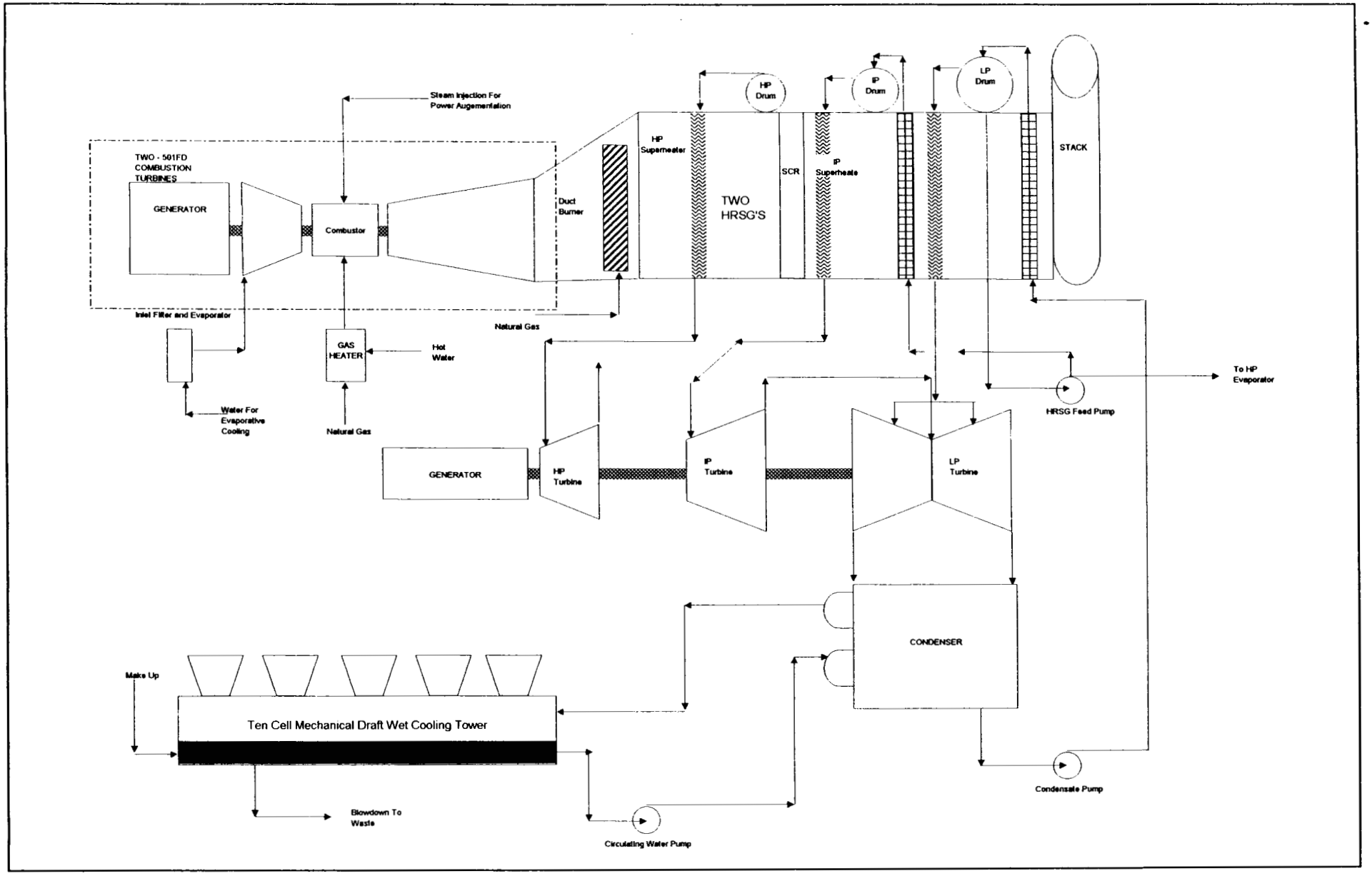
Wastewater Discharge:
Approx. 1.26 MGD. summer peak conditions (with power augmentation and duct-firing)
Approx. 0.62 MGD, average conditions (3.9 cycles of concentration without power augmentation and duct-firing)

*The estimated output and capacity factor values are subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities.

TABLE II-3
OSPREY ENERGY CENTER
Estimated Plant Performance and Emissions Data

Percent Load		100%	100%	100%	100%	70%	70%	70%	70%	60%	60%	60%	60%	100%
Ambient Temperature	F	95	74	59	32	95	74	59	32	95	74	59	32	95
Ambient Relative Humidity	%	80%	80%	60%	60%	80%	80%	60%	60%	80%	80%	60%	60%	80%
Gas Turbine Power	MW	324	347	362	390	222	240	253	272	190	205	216	233	357
Steam Turbine Power	MW	185	195	197	203	145	153	152	154	135	143	149	148	233
Net Cycle Power	MW	496	529	545	578	358	383	395	416	317	339	356	371	575
Net Cycle LHV Heat Rate	BTU/kW-hr	6,187	6,122	6,125	6,137	6,497	6,430	6,359	6,373	6,599	6,529	6,478	6,457	6,576
Net Cycle LHV Efficiency	%	55.2%	55.7%	55.7%	55.6%	52.5%	53.1%	53.7%	53.5%	51.7%	52.3%	52.7%	52.9%	51.9%
Net Cycle HHV Heat Rate	BTU/kW-hr	6,871	6,798	6,802	6,815	7,215	7,140	7,062	7,077	7,329	7,251	7,193	7,170	7,303
CTG fuel flow (lb/h)- total for two CTGs	lb/hr	146,325	154,237	159,099	168,918	110,864	117,346	119,634	126,212	99,806	105,621	109,911	114,296	155,858
CTG heat input, HHV basis (mmBtu/h)- total for two CTGs	MMBtu/hr	3,409	3,594	3,707	3,936	2,583	2,734	2,787	2,941	2,325	2,461	2,561	2,663	3,631
Duct burner fuel flow (lb/h)- total for two burners	lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	24,308
Duct burner heat input, HHV basis (mmBtu/h)- two burners	MMBtu/hr	0	0	0	0	0	0	0	0	0	0	0	0	566
CTG exhaust gas flow (lb/h)- total for two CTGs (two duct burners when on)	lb/hr	6,630,800	6,973,469	7,218,232	7,578,580	5,692,996	5,888,867	6,028,774	6,258,506	5,081,836	5,240,757	5,354,272	5,539,920	6,655,108
CTG exhaust gas composition (% by volume)														
Nitrogen	%	72.64	73.47	74.37	74.82	72.93	73.82	74.63	75.07	72.93	73.77	74.56	75.04	68.31
Argon	%	0.91	0.92	0.93	0.94	0.92	0.09	0.94	0.94	0.92	0.93	0.94	0.94	0.86
Oxygen	%	12.13	12.28	12.51	12.53	13.00	13.11	13.26	13.26	12.99	12.97	13.07	13.15	9.85
Carbon dioxide	%	3.70	3.74	3.74	3.79	3.31	3.37	3.40	3.47	3.31	3.43	3.49	3.52	4.26
Water	%	10.62	9.59	8.44	7.92	9.85	8.77	7.77	7.26	9.86	8.90	7.94	7.36	16.73
NOx as NO2 (lb/h)- total for two stacks	lb/hr	44.1	46.3	48.6	51.5	34.2	35.4	36.7	38.9	30.4	32.0	33.5	34.8	55.0
based on ppmvd @ 15% O2	ppm	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
CO (lb/h)- total for two stacks	lb/hr	78	82	86	90	60	62	64	68	266	279	292	304	279
based on ppmvd @ 15% O2	ppm	10	10	10	10	10	10	10	10	50	50	50	50	29
VOC as CH4 (lb/h)- total for two stacks	lb/hr	9.9	10.4	10.9	11.5	14.1	14.7	15.3	16.0	12.7	13.3	14.0	14.5	24.8
based on ppmvd @ 15% O2	ppm	2.3	2.3	2.3	2.3	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.6
SO2 (lb/h)- total for two stacks	lb/hr	18.8	19.8	20.7	22.0	14.4	15.0	15.6	16.4	13.0	13.7	14.3	14.9	23.9
Particulates as PM10 (lb/h)- total for two stacks	lb/hr	38.0	40.1	42.2	44.5	32.1	33.4	34.6	36.1	28.7	29.8	30.9	32.1	45.6

FIGURE II-10
OSPREY ENERGY CENTER
CYCLE SCHEMATIC DIAGRAM



grid by three 230 kV transmission lines: one line that interconnects to the Lake Agnes 230 kV Substation, one line that interconnects with the Pebbledale Substation via the Crews Lake Substation, and one line that interconnects with the Ariana Substation. The Peninsular Florida transmission grid in the region of the Osprey Energy Center is shown in Figure II-11.[3]

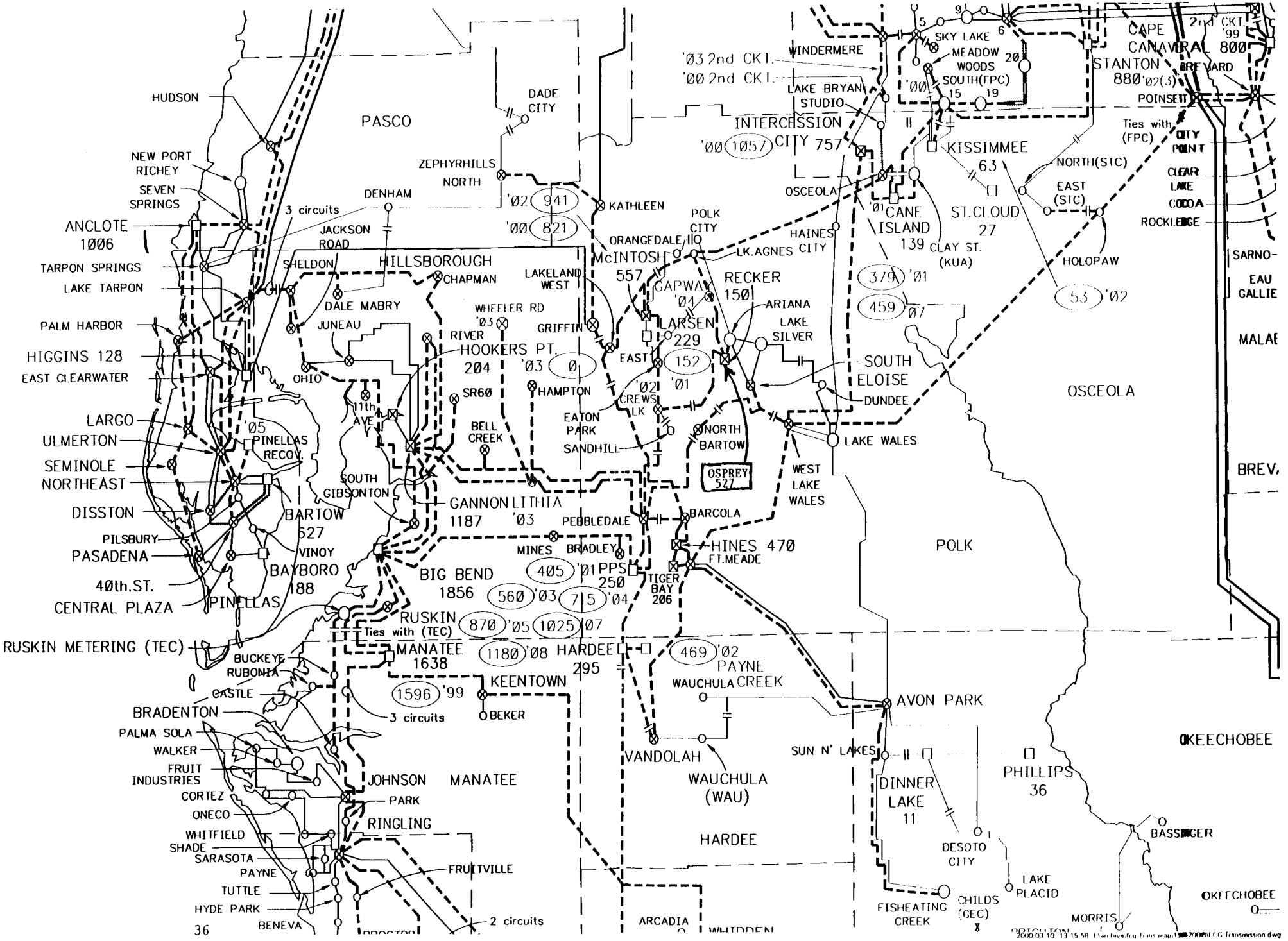
Transmission system impact studies prepared for Calpine included load flow analyses, transient stability analyses, and short circuit analyses. The transmission system impact studies indicate that, with certain upgrades of transmission facilities, the existing Peninsular Florida transmission grid will accommodate the delivery of the Osprey Project's net output for use in Peninsular Florida, regardless which Florida utilities purchase and receive the Project's output.[4] The studies also indicate that, under normal operating conditions, i.e., with all facilities in service, the Project will not materially burden the transmission system or violate any transmission constraints or contingencies in

---

[3] This information regarding transmission facilities and studies is provided to the Commission for informational purposes only. No transmission facilities are proposed in the Site Certification Application for the Osprey Energy Center.

[4]The transmission system impact studies were commissioned by Calpine and completed before Seminole and Calpine executed the MOU and the PPA. These studies confirm that, with upgrades pursuant to TECO's open access transmission tariff, the entire output of the Project can be delivered to Seminole without materially burdening the Peninsular Florida transmission system and without violating any transmission constraints or contingencies.

FIGURE II-11
REGIONAL TRANSMISSION MAP
OF WEST CENTRAL FLORIDA



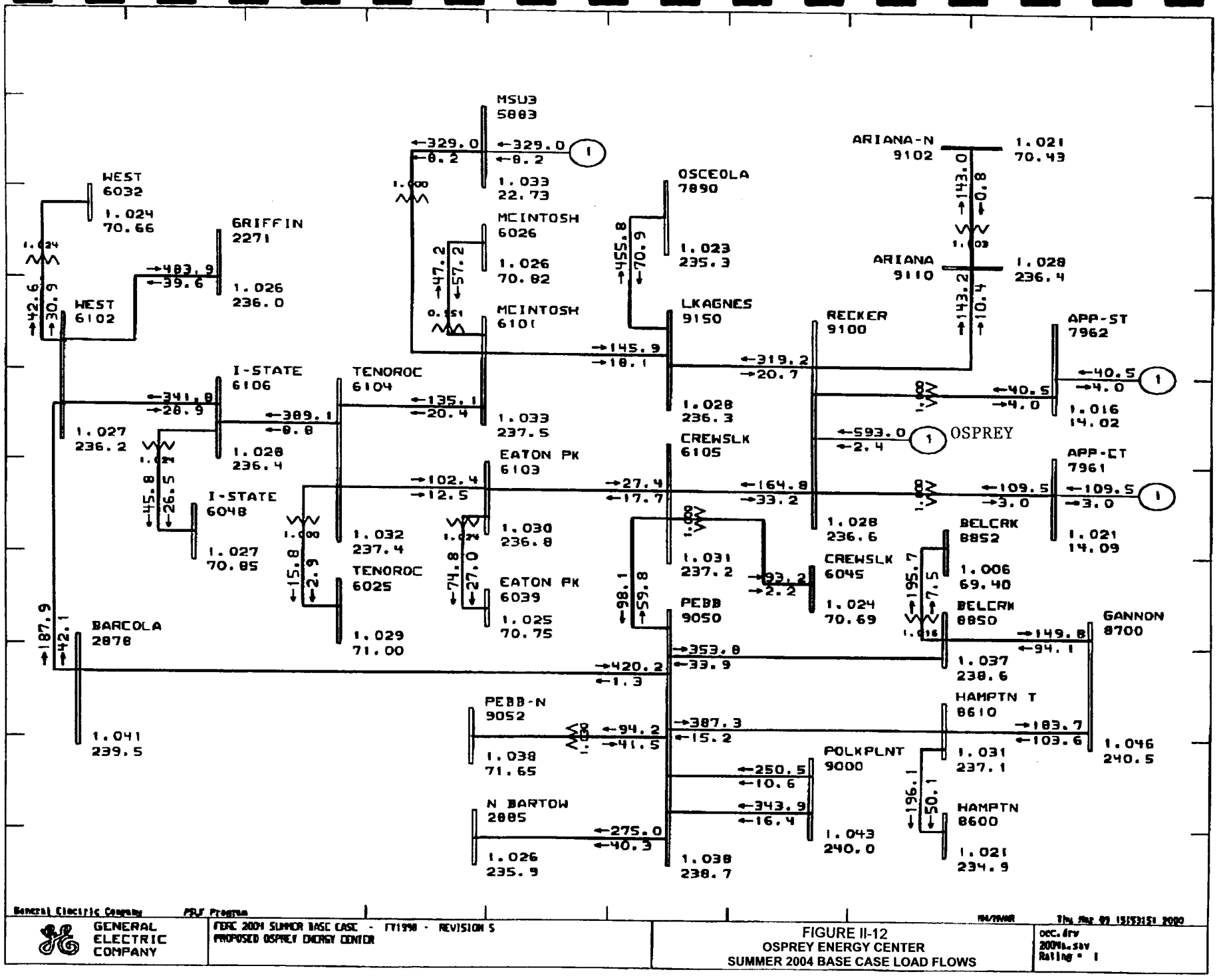
Peninsular Florida. The actual transmission upgrades required have been determined in accordance with TECO's open access transmission tariff. Pursuant to Calpine's request and TECO's tariff, TECO issued the Transmission Service Request Facilities Study report on August 31, 2000. The report estimated the cost to interconnect the Osprey Project to TECO's Recker Substation at $2.4 million. In addition, the cost of the network upgrades required to provide firm transmission service was estimated at $11.5 million. These figures, according to TECO, are based on detailed cost estimates prepared by TECO's engineering departments. Figure II-12 depicts projected load flows in the vicinity of the Osprey Project, with the Project in service, in the summer of 2004.[5]

E. Associated Facilities.

Natural gas will be provided to the Project through the trans-Florida pipeline being developed by Gulfstream Natural Gas System, L.L.C. Gulfstream will obtain all necessary permits for this pipeline in separate proceedings. The pipeline will run from the Mobile Bay area of Alabama and Mississippi across the Gulf of Mexico to its landfall on the southeastern shore of Tampa Bay. From there, the pipeline will run east and southeast to delivery points in west-central, central, and southeast Florida. See Figure

---

[5] The Osprey Project's output value shown in Figure II-12 is 593 MW, which differs slightly from the maximum summer output level (with duct-firing and power augmentation) of 575 MW shown in Table II-3. This difference resulted from the transmission load flow studies being performed using the preliminary summer output level for the Project.


MSU3
5803
1.033
22.73
WEST
6032
1.024
70.66
GRIFFIN
2271
1.026
236.0
WEST
6102
MCINTOSH
6026
1.026
70.82
MCINTOSH
6101
OSCEOLA
7890
1.023
235.3
LKAGNES
9150
1.028
236.3
ARIANA-N
9102
1.021
70.43
ARIANA
9110
1.028
236.4
RECKER
9100
1.028
236.6
APP-ST
7962
1.016
14.02
OSPREY
APP-CT
7961
1.021
14.09
I-STATE
6106
1.027
236.2
I-STATE
6048
1.027
70.85
TENOROC
6104
1.033
237.5
TENOROC
6025
1.029
71.00
EATON PK
6103
1.030
236.8
EATON PK
6039
1.025
70.75
CREWSLK
6105
1.031
237.2
CREWSLK
6045
1.024
70.69
BELCRK
8852
1.006
69.40
BELCRK
8850
1.037
238.6
GANNON
8700
1.046
240.5
HAMPTN T
8610
1.031
237.1
HAMPTN
8600
1.021
234.9
POLKPLNT
9000
1.043
240.0
PEBB
9050
1.038
238.7
PEBB-N
9052
1.038
71.65
N BARTOW
2885
1.026
235.9
BARCOLA
2878
1.041
239.5
General Electric Company PSLF Program
GENERAL ELECTRIC COMPANY
FERC 2004 SUMMER BASE CASE - FY1998 - REVISION 5
PROPOSED OSPREY ENERGY CENTER
FIGURE II-12
OSPREY ENERGY CENTER
SUMMER 2004 BASE CASE LOAD FLOWS
occ.drw
2004s.sav
Rating = 1

II-13. In the vicinity of the Osprey Project, the Gulfstream pipeline will run generally north through Polk County. See Figures II-13 and II-14. A 16-inch diameter lateral pipeline will be constructed by Gulfstream from Station number 430 to the boundary of the Osprey Energy Center site. Figure II-15 is a map of the Gulfstream pipeline's route in the local vicinity of the Project. The pipeline pressure at the Calpine site is guaranteed by Gulfstream to be a minimum of 650 psig.[6] Gas transportation will be pursuant to an executed Precedent Agreement between Calpine and Gulfstream. Pursuant to the Precedent Agreement, Gulfstream has committed to provide firm gas transportation service to operate the Project for a term of 20 years with renewal provisions beyond the initial term. A copy of the Precedent Agreement, redacted to protect confidential, proprietary business information, is included as Appendix B to these Amended Exhibits.

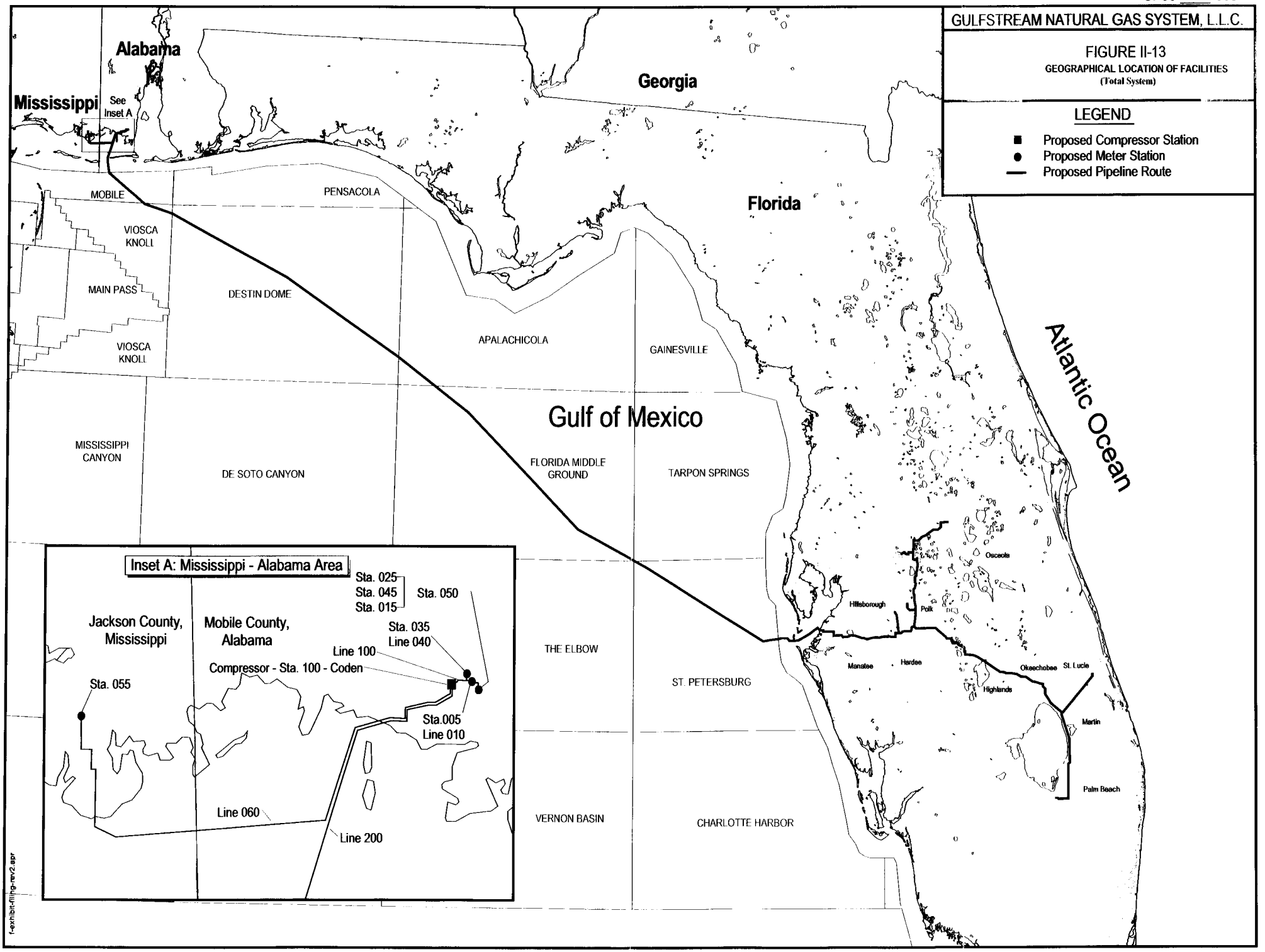
Reclaimed water will be provided to the Project from the City of Auburndale's Allred Municipal Wastewater Treatment Plant (the "Allred Plant"). A new pipeline will be required to connect the Project to the Allred Plant. The pipeline to the Allred Plant will be approximately one mile in length and will be constructed in existing public rights-of-way. Additionally, other minor pipeline modifications will be made to enhance discharge capability. The

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[6] Details of the natural gas transportation arrangements are provided for informational purposes only. Permitting of the pipeline will be sought by Gulfstream in a separate proceeding.

GULFSTREAM NATURAL GAS SYSTEM, L.L.C.

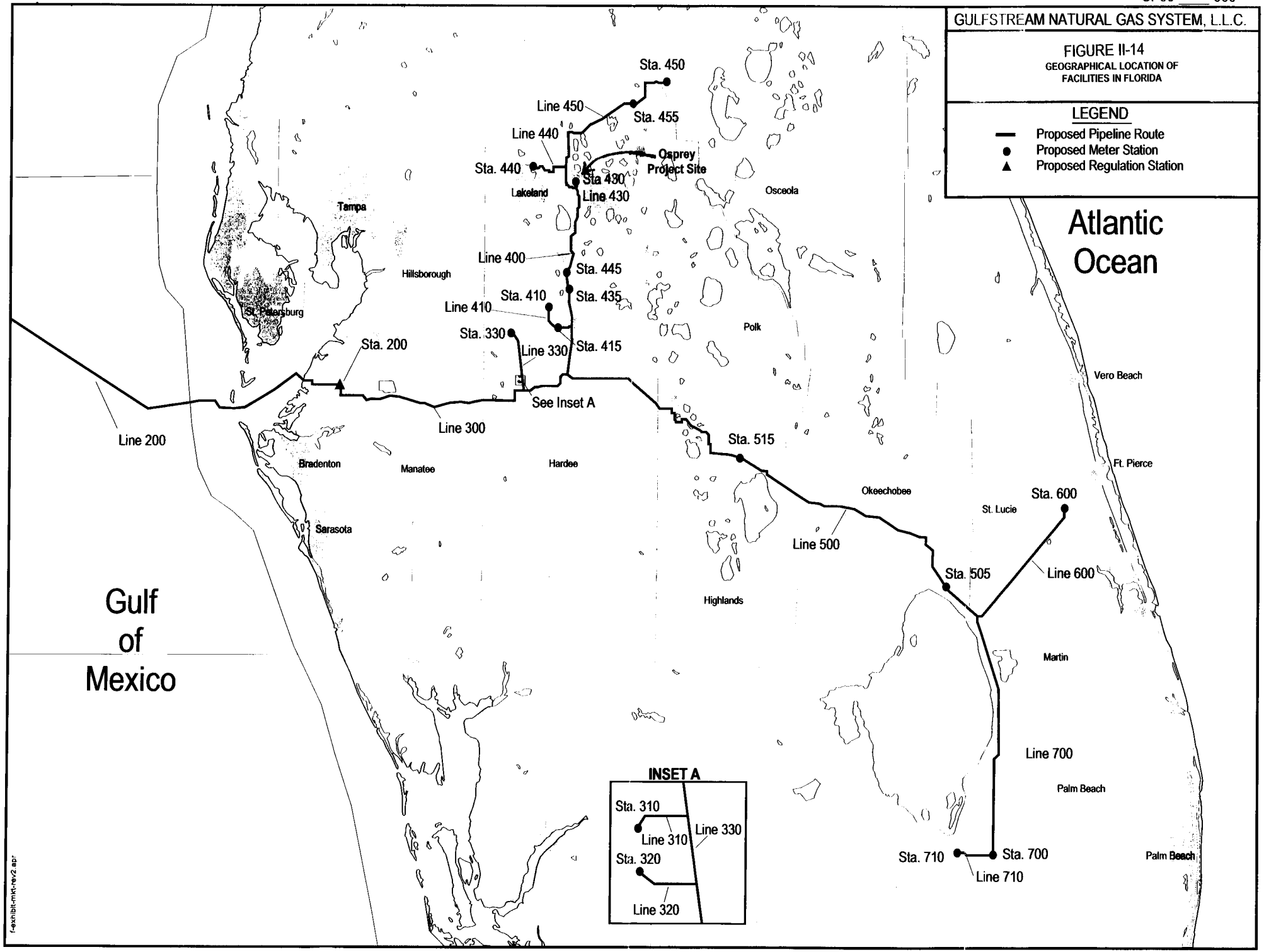
FIGURE II-13
GEOGRAPHICAL LOCATION OF FACILITIES
(Total System)

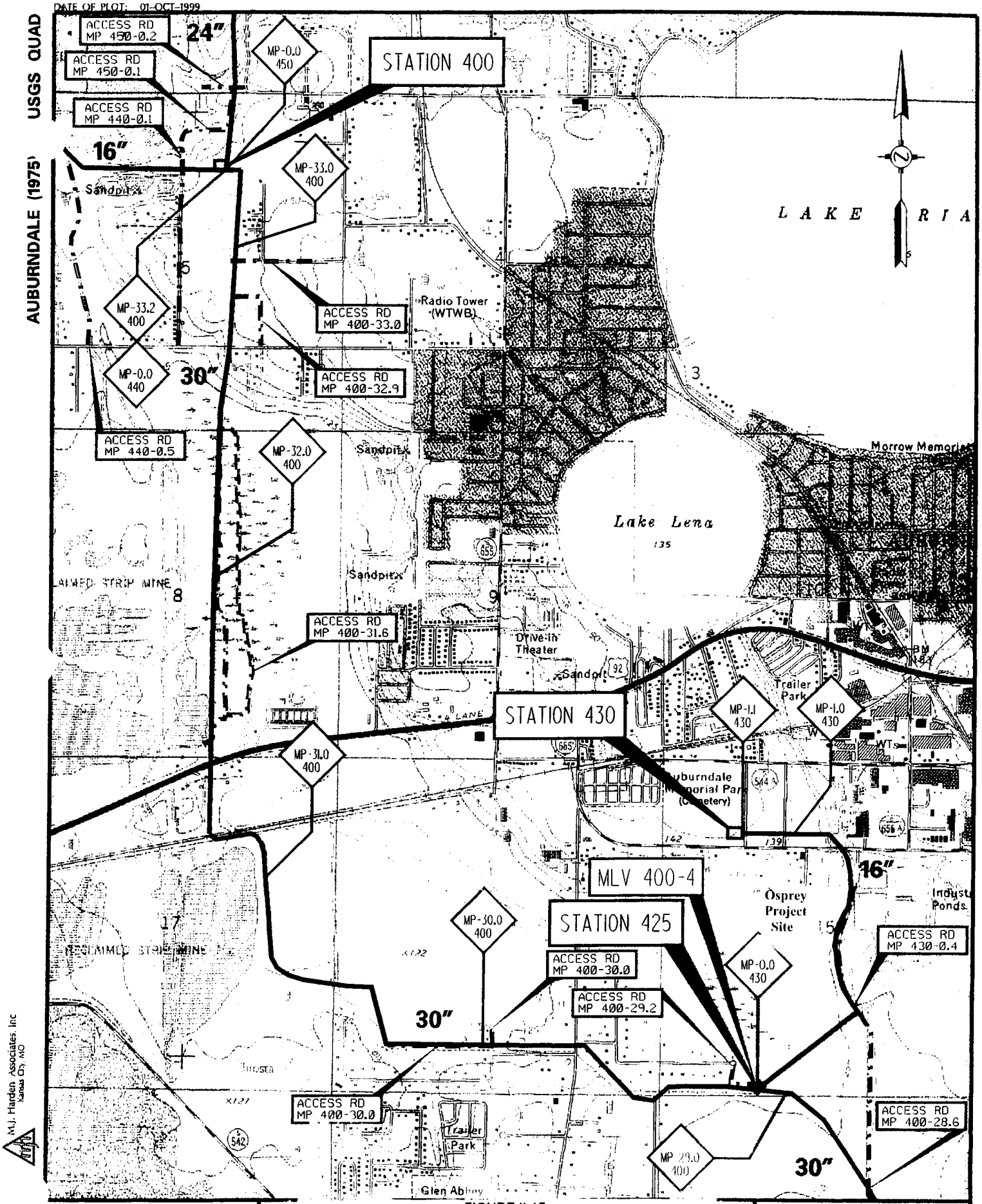


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GULFSTREAM NATURAL GAS SYSTEM, L.L.C.

FIGURE II-14
GEOGRAPHICAL LOCATION OF FACILITIES IN FLORIDA




DATE OF PLOT: 01-OCT-1999
USGS QUAD
AUBURNDALE (1975)
ACCESS RD MP 450-0.2
ACCESS RD MP 450-0.1
ACCESS RD MP 440-0.1
24"
16"
30"
MP-0.0 450
MP-33.0 400
MP-33.2 400
MP-0.0 440
MP-32.0 400
MP-31.0 400
MP-30.0 400
MP 29.0 400
STATION 400
STATION 430
STATION 425
MLV 400-4
ACCESS RD MP 400-33.0
ACCESS RD MP 400-32.9
ACCESS RD MP 440-0.5
ACCESS RD MP 400-31.6
ACCESS RD MP 400-30.0
ACCESS RD MP 400-29.2
ACCESS RD MP 400-30.0
ACCESS RD MP 430-0.4
ACCESS RD MP 400-28.6
MP-1.1 430
MP-1.0 430
MP-0.0 430
LAKE
Radio Tower (WTWB)
Lake Lena
Sandpit
Drive-In Theater
Trailer Park
Osprey Project Site
Glen Abbey
Morrow Memorial
Industrial Ponds
135
139
142
92
542
544
655
665
N
W
WT
LOCATION MAP
FIGURE II-15
GULFSTREAM NATURAL GAS SYSTEM, L.L.C.
GEOGRAPHICAL LOCATION OF FACILITIES
(Auburndale/Osprey Area)
LOC. POLK COUNTY, FLORIDA REV. 0
CKD. BY ENG. DATE 10-15-99 W.O.
DRN. BY SCALE 1"=2000' DWG. NO. 9 of 9
M.J. Harden Associates, Inc
Kansas City, MO
Gulfstream
Natural Gas System

reclaimed water supply and return pipelines to the Allred Plant will run along the north Recker Highway right-of-way to the Osprey Project site boundary. The reclaimed water supply and return pipelines to the Westside Plant are planned to run west along the Polk County Parkway right-of-way to U.S. Highway 92 and then on an existing City of Auburndale right-of-way east along Highway 92, to Recker Highway, to Derby Avenue, and onto the Osprey Project site. The City of Auburndale will obtain all necessary permits for the water supply and process water return pipelines in separate proceedings, and these pipelines will be paid for by Calpine.

F. Capital Cost of the Osprey Energy Center.

The direct construction cost of the Osprey Energy Center is expected to be approximately $194.8 million. The natural gas pipeline will be constructed by Gulfstream at its expense.

G. Project Financing.

The Project will be constructed and brought into commercial service with a combination of equity and debt, with the debt being structured by Calpine through its construction revolver.

H. Fuel Supply.

The fuel for the Project will be natural gas. Pursuant to an executed Precedent Agreement between Calpine and Gulfstream, Gulfstream will provide firm gas transportation service for sufficient gas volumes to meet the Project's total fuel requirements. Natural gas fuel supply for the Project will be provided to Gulfstream receipt points by natural gas marketing

companies or producers. Calpine will procure the natural gas supply for the Osprey Energy Center through an optimized combination of short-term contract purchases, long-term contract purchases, and spot market purchases. Specifically, Calpine will purchase natural gas from producers and marketing companies that have access to those natural gas treatment plants, processing plants, and interstate natural gas transmission systems with supply located in the vicinity of Mobile Bay, Alabama, and Pascagoula, Mississippi. In addition, Gulfstream proposes interconnections with the Mobile Bay Pipeline (Koch), the Destin Pipeline, the Dauphin Island Gathering Pipeline, the Mobile Bay Processing Partners' Plant (DIGS Plant), the Williams Plant, and the Mobil Mary Ann Plant. The ultimate capacity of the proposed Gulfstream system will be more than one billion cubic feet per day. The Project's natural gas suppliers will be responsible for delivery into the Gulfstream pipeline system.

I. **Projected Operational Reliability**.

The combined cycle generating unit utilizes high efficiency generation technology with high reliability and availability rates. With a heat rate of 6,800 Btu per kWh (based on the Higher Heating Value of natural gas) at ambient site conditions, the net thermal efficiency is expected to be approximately 50.2 percent. The Project is estimated to have an Equivalent Availability Factor of 94.5 percent, which is based on an estimated Forced Outage Rate of 2.0 percent per year and an average Planned Outage Rate of 3.5

percent per year. Based on production simulation analyses of the Osprey Project's operations within the Peninsular Florida power supply system, the Project is expected to operate at an annual average Capacity Factor of approximately 91 percent subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities. Basic operational reliability information for the Project is shown on the Project Profile. See Table II-2 above.

J. **Project Schedule**.

Conceptual engineering for the Project is complete. An in-depth site review has been completed. No areas of jurisdictional wetland vegetation were found on the site. No threatened or endangered species were found on the site. Detailed design and engineering for the Project are scheduled to begin in March 2001. Calpine has secured a significant number of Siemens-Westinghouse Model 501F combustion turbines by deposit and these components are in a delivery queue. As the permitting of the Osprey Project goes forward and the construction timetable becomes firmly established, two specific CTGs will be designated for use in the Osprey Project. Full release of the heat recovery steam generators and the steam turbine generators is projected to occur before construction begins. An engineering services provider has been selected and contract negotiations will be concluded at the appropriate time. A separate construction contract will be awarded (following bid solicitation and evaluation) to a contractor who will procure the

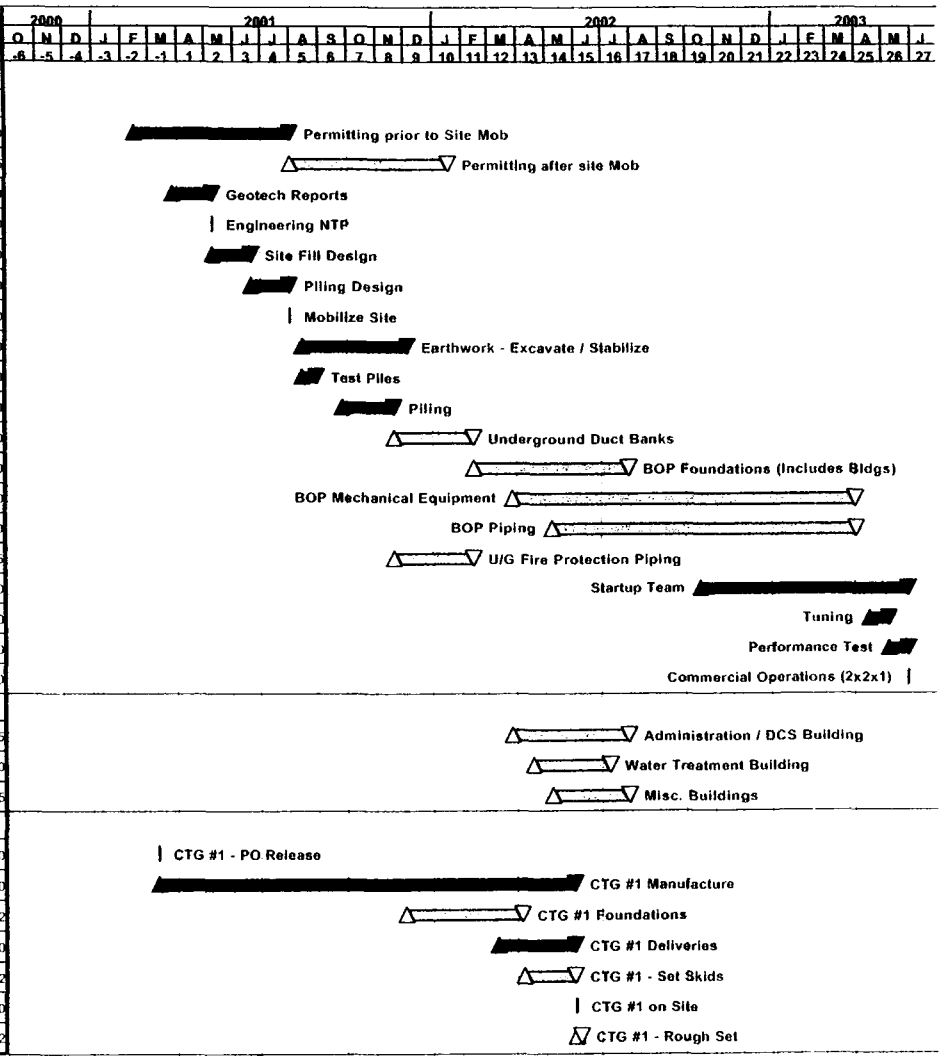
balance of plant equipment. This contract will be awarded prior to the issuance of the site certification, which is expected in August 2001. The Project is scheduled to achieve commercial in-service status by the second quarter of 2003. The Project engineering and construction schedule is depicted in Figure II-16.

K. Regulatory and Permitting Schedules.

The Joint Applicants filed their Amended Joint Petition on January 8, 2001, and the accompanying volumes of Amended Exhibits for the Project on January 10, 2001. The need determination hearing is expected to be held in February 2001. The Commission's order is expected in February or March 2001. Calpine filed the Site Certification Application ("SCA") for the Project on March 16, 2000, and the Department of Environmental Protection issued its notice that the SCA was complete on March 31, 2000. The only agency that filed insufficiency comments was the Southwest Florida Water Management District. Calpine responded to the District's questions in August 2000, and supplemented those responses in October 2000. Staff recommended approval of and the Governing Board of the Southwest Florida Water Management District approved the water use withdrawal plan on January 30, 2001. The land use hearing was held on January 23, 2001. The site certification hearing is expected to be held on April 17 and 18, 2001. Final certification by the Siting Board is expected by October 2001. Details of the site certification schedule are shown in Figure II-17 of these Amended Exhibits.

FIGURE II-16 (REVISED)
OSPREY ENERGY CENTER
PRELIMINARY PROJECT SCHEDULE

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish	Total Float
Osprey Power Center					
Balance of Plant					
0500	Permitting prior to Site Mob	120	14FEB01	31JUL01	0
0510	Permitting after site Mob	120	01AUG01	15JAN02	355
0900	Geotech Reports	30	28MAR01	08MAY01	0
1000	Engineering NTP	0	09MAY01		0
1010	Site Fill Design	30	09MAY01	19JUN01	0
1020	Piling Design	30	20JUN01	31JUL01	0
1200	Mobilize Site	0	01AUG01*		0
1210	Earthwork - Excavate / Stabilize	80	15AUG01*	04DEC01	0
1220	Test Piles	10	15AUG01*	28AUG01	0
1230	Piling	40	26SEP01	20NOV01	0
1240	Underground Duct Banks	60	21NOV01	12FEB02	40
1250	BOP Foundations (Includes Bldgs)	120	13FEB02	30JUL02	40
1260	BOP Mechanical Equipment	264	27MAR02	31MAR03	40
1270	BOP Piping	235	08MAY02	01APR03	40
1280	U/G Fire Protection Piping	60	21NOV01	12FEB02	275
5000	Startup Team	160	16OCT02	27MAY03	0
5010	Tuning	15	16APR03	06MAY03	0
5020	Performance Test	15	07MAY03	27MAY03	0
5030	Commercial Operations (2x2x1)	0		27MAY03	0
Buildings					
1300	Administration / DCS Building	90	27MAR02	30JUL02	175
1310	Water Treatment Building	60	17APR02	09JUL02	230
1320	Misc. Buildings	60	08MAY02	30JUL02	215
Combustion Turbine					
102000	CTG #1 - PO Release	0	12MAR01		0
102010	CTG #1 Manufacture	320	12MAR01	31MAY02	0
102020	CTG #1 Foundations	90	03DEC01	05APR02	52
102030	CTG #1 Deliveries	60	11MAR02	31MAY02	0
102040	CTG #1 - Set Skids	40	08APR02	31MAY02	52
102050	CTG #1 on Site	0	03JUN02*		0
102060	CTG #1 - Rough Set	5	03JUN02	07JUN02	52



Early Bar
Progress Bar
Critical Activity

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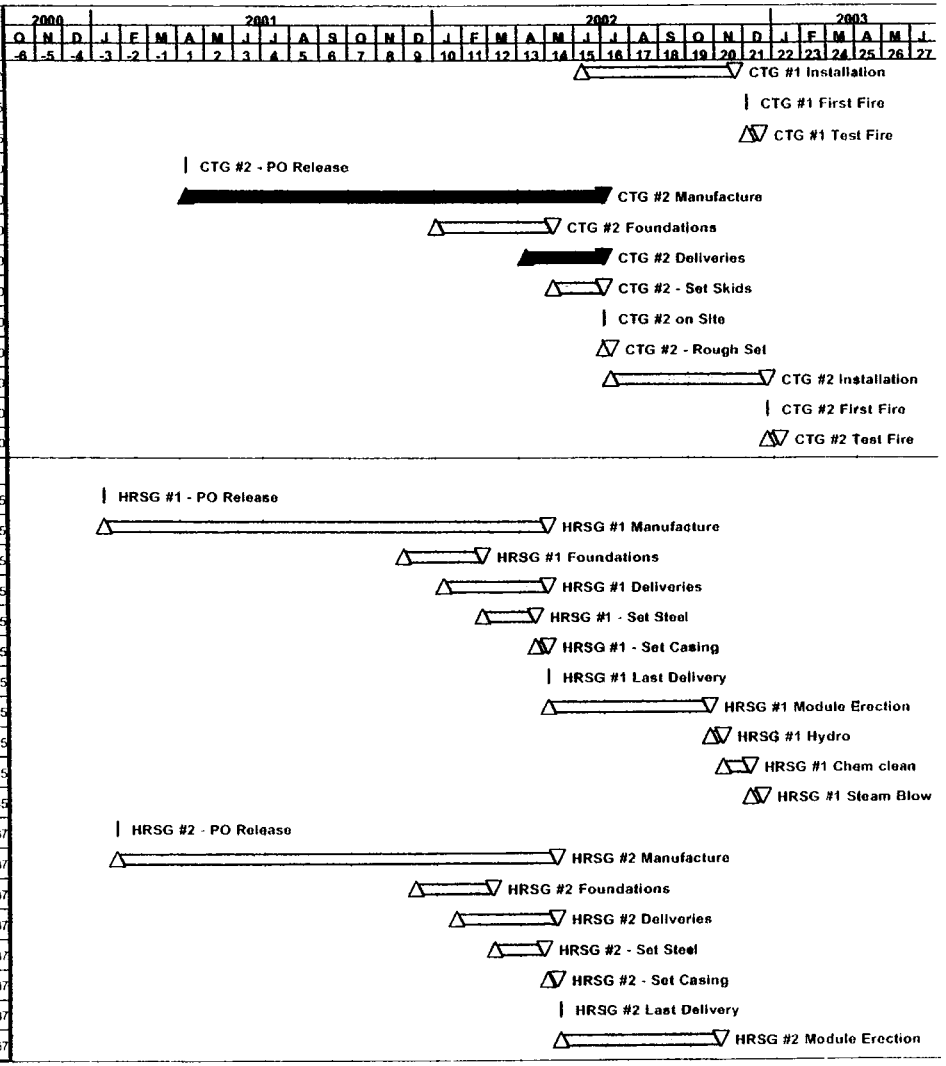
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CALPINE
Osprey Energy Center
Preliminary Schedule
Revision 1

Start Date	01AUG98
Finish Date	27MAY03
Data Date	29MAY00
Run Date	28NOV00 09:48

FIGURE II-16 (REVISED)
OSPREY ENERGY CENTER
PRELIMINARY PROJECT SCHEDULE
(continued)

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish	Total Float
102070	CTG #1 Installation	120	10JUN02	22NOV02	52
102080	CTG #1 First Fire	0	04DEC02		45
102090	CTG #1 Test Fire	10	04DEC02	17DEC02	45
202000	CTG #2 - PO Release	0	11APR01		0
202010	CTG #2 Manufacture	320	11APR01	02JUL02	0
202020	CTG #2 Foundations	90	02JAN02	07MAY02	30
202030	CTG #2 Deliveries	60	10APR02	02JUL02	0
202040	CTG #2 - Set Skids	40	08MAY02	02JUL02	30
202050	CTG #2 on Site	0	03JUL02*		0
202060	CTG #2 - Rough Set	5	03JUL02	09JUL02	30
202070	CTG #2 Installation	120	10JUL02	24DEC02	30
202080	CTG #2 First Fire	0	25DEC02		30
202090	CTG #2 Test Fire	10	25DEC02	07JAN03	30
Heat Recovery Steam Generator (HRSG)					
103000	HRSG #1 - PO Release	0	10JAN01		45
103010	HRSG #1 Manufacture	340	10JAN01	30APR02	45
103020	HRSG #1 Foundations	60	28NOV01	19FEB02	45
103030	HRSG #1 Deliveries	80	09JAN02	30APR02	45
103040	HRSG #1 - Set Steel	40	20FEB02	16APR02	45
103050	HRSG #1 - Set Casing	10	17APR02	30APR02	45
103060	HRSG #1 Last Delivery	0	01MAY02*		45
103070	HRSG #1 Module Erection	125	01MAY02	22OCT02	45
103080	HRSG #1 Hydro	10	23OCT02	05NOV02	45
103090	HRSG #1 Chem clean	20	06NOV02	03DEC02	15
103100	HRSG #1 Steam Blow	10	04DEC02	17DEC02	45
203000	HRSG #2 - PO Release	0	22JAN01		37
203010	HRSG #2 Manufacture	340	22JAN01	10MAY02	37
203020	HRSG #2 Foundations	60	10DEC01	01MAR02	37
203030	HRSG #2 Deliveries	80	21JAN02	10MAY02	37
203040	HRSG #2 - Set Steel	40	04MAR02	26APR02	37
203050	HRSG #2 - Set Casing	10	29APR02	10MAY02	37
203060	HRSG #2 Last Delivery	0	13MAY02*		37
203070	HRSG #2 Module Erection	125	13MAY02	01NOV02	37



Early Bar
Progress Bar
Critical Activity

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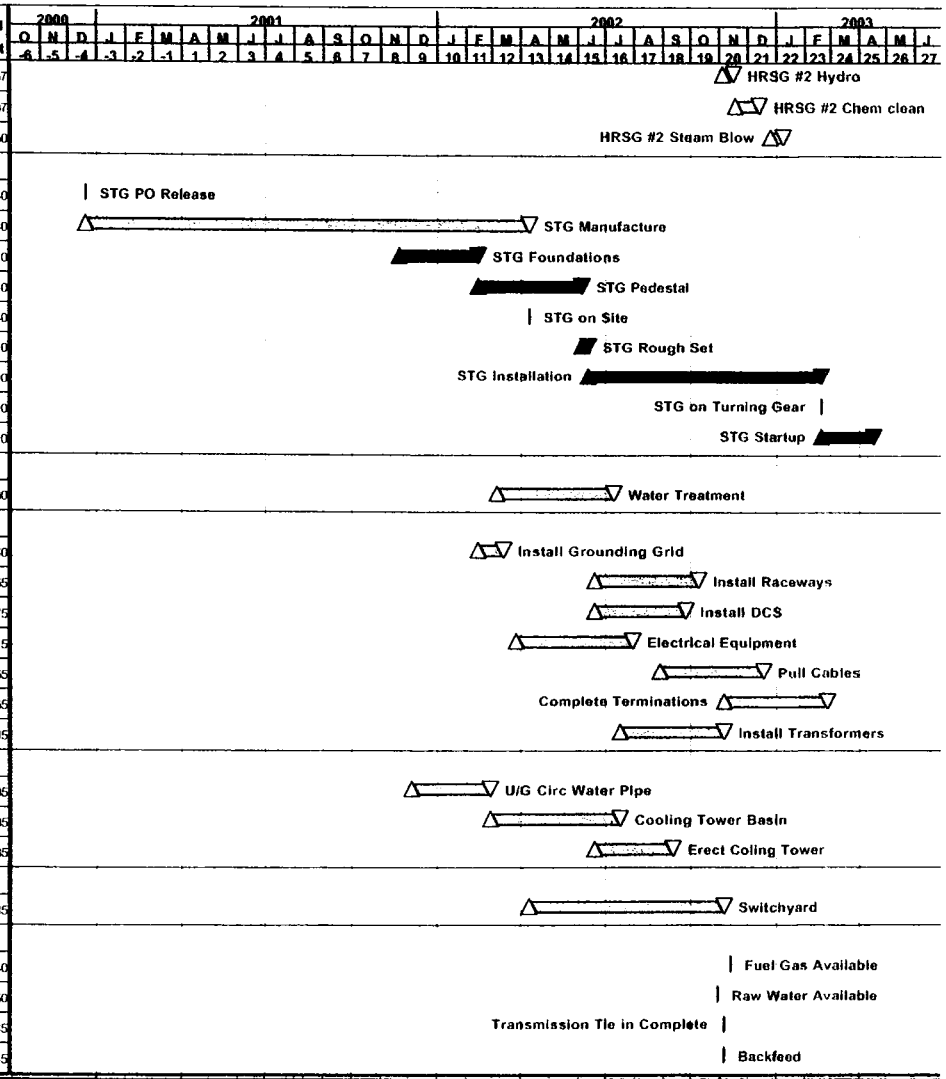
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CALPINE
Osprey Energy Center
Preliminary Schedule
Revision 1

Start Date	01AUG98
Finish Date	27MAY03
Data Date	29MAY00
Run Date	28NOV00 09:48

FIGURE II-16 (REVISED)
OSPREY ENERGY CENTER
PRELIMINARY PROJECT SCHEDULE
(continued)

Activity ID	Activity Description	Orig Dur	Early Start	Early Finish	Total Float
203080	HRSG #2 Hydro	10	04NOV02	15NOV02	37
203090	HRSG #2 Chem clean	20	18NOV02	13DEC02	37
203100	HRSG #2 Steam Blow	10	25DEC02	07JAN03	30
Steam Turbine					
104000	STG PO Release	0	20DEC00		40
104010	STG Manufacture	340	20DEC00	09APR02	40
104020	STG Foundations	60	21NOV01	12FEB02	0
104030	STG Pedestal	80	13FEB02	04JUN02	0
104040	STG on Site	0	10APR02*		40
104050	STG Rough Set	5	05JUN02	11JUN02	0
104060	STG Installation	180	12JUN02	18FEB03	0
104070	STG on Turning Gear	0	19FEB03		0
104080	STG Startup	40	19FEB03	15APR03	0
Chemical / Water Treatment					
1400	Water Treatment	90	06MAR02	09JUL02	230
Instrument & Electrical					
1500	Install Grounding Grid	20	13FEB02	12MAR02	140
1510	Install Raceways	80	19JUN02	08OCT02	65
1520	Install DCS	70	19JUN02	24SEP02	175
1530	Electrical Equipment	90	27MAR02	30JUL02	215
1540	Pull Cables	80	28AUG02	17DEC02	65
1550	Complete Terminations	80	06NOV02	25FEB03	65
1560	Install Transformers	80	17JUL02	05NOV02	145
Cooling Tower					
1600	U/G Circ Water Pipe	60	05DEC01	26FEB02	185
1610	Cooling Tower Basin	100	27FEB02	16JUL02	185
1620	Erect Coling Tower	60	19JUN02	10SEP02	185
Switchyard					
1800	Switchyard	150	10APR02	05NOV02	145
Linears					
1700	Fuel Gas Available	0	13NOV02		140
1710	Raw Water Available	0	30OCT02		150
1720	Transmission Tie in Complete	0	06NOV02		145
1730	Backfeed	0	06NOV02		145



Early Bar
Progress Bar
Critical Activity

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CALPINE
Osprey Energy Center
Preliminary Schedule
Revision 1

Start Date	01AUG98
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FIGURE II-17

PRELIMINARY SCHEDULE OF SITE CERTIFICATION PROCEEDING FOR CALPINE'S OSPREY ENERGY CENTER
DOAH Case No. 00-1288EPP
OGC Case No. 00-0740

Deadlines	Activities
March 20, 2000	Calpine's Site Certification Application (SCA), including application for Prevention of Significant Deterioration (PSD) permit, filed with DEP Siting Coordination Office (SCO)
March 28, 2000	SCO requested Division of Administrative Hearings (DOAH) to appoint Administrative Law Judge (Judge)
April 7, 2000	DEP issued notice that Calpine's SCA is complete
May 22, 2000	DEP issued notice that Calpine's SCA is insufficient
Aug. 15, Oct.12, and Nov. 9, 2000	Calpine filed supplemental information in response to DEP's notice of insufficiency
December 11, 2000	DEP issued notice that Calpine's SCA is sufficient
January 23, 2001	Land Use Hearing held by Judge
February 2001	PSC need determination hearing
February 2001	PSC issues Order on need determination petition
February 2001	DEP delivers Staff Analysis Report to Judge and Calpine
April 17-18, 2001	Certification Hearing held by Judge
May 2001	Hearing before Siting Board regarding land use issues
October 2001	Hearing before Siting Board concerning certification issues
October 2001	Final order issued by Siting Board; PSD permit issued by DEP

L. Operations and Maintenance Plan.

The Siemens-Westinghouse Model 501F turbines that will be used in the Project are extremely reliable. The Project's forced outage rate is expected to average only 2.0 percent per year. The maintenance or planned outage rate is expected to average approximately 3.5 percent per year. The Siemens-Westinghouse Model 501F turbines have an 8,000 hour maintenance cycle. A minor inspection, referred to as a combustor inspection, will be conducted at the end of each 8,000 hours of operation. A slightly more detailed inspection, referred to as a hot gas inspection, along with the combustor inspection, will be conducted at the end of 24,000 hours of operation. A major inspection will be conducted at 48,000 hours of operation. This cycle will be repeated for the life of the equipment. Combustor and hot gas inspections take approximately 7 days and 14 days respectively, and a major inspection will take approximately 21 days. Thus, the annual availability factor for the Osprey Energy Center is expected to average approximately 94.5 percent over the life of the Project.

IV. PENINSULAR FLORIDA'S NEED FOR AND CALPINE'S EXPECTED USE OF THE OSPREY ENERGY CENTER

The Osprey Energy Center will provide total net generation capability of 496 MW at summer peak conditions (95°F.) and 578 MW at winter peak conditions (32°F.) without power augmentation or duct-firing. The new capacity produced by the Project will meet the power supply needs of Seminole Electric Cooperative, Inc.[7] (and Calpine's need for resources with which to meet its contractual obligations to Seminole) and, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the Project will significantly increase the reliability and cost-effectiveness of power supply in Peninsular Florida.

A. Power Supply Needs of Peninsular Florida.

Peninsular Florida's firm winter peak demand is projected to increase from approximately 37,000 MW in 2000-2001 to more than 45,000 MW in 2009-2010. See Table II-4. Peninsular Florida's total winter peak demand is projected to increase from approximately 41,000 MW to approximately 49,000 MW in the same period. See Table II-8. Peninsular Florida's firm summer peak demand is projected to increase from approximately 35,000 MW in 2000 to more than 42,000 MW in 2009. See Table II-4 of these Amended Exhibits. Peninsular Florida's total summer peak demand is

[7]A complete discussion of Seminole's need for the Project is included in Volume I of these Amended Exhibits.

TABLE II-4

PENINSULAR FLORIDA, HISTORICAL AND PROJECTED SUMMER AND WINTER FIRM PEAK DEMANDS

1991-2012

ACTUAL PEAK DEMAND (MW)

	1991	1992	1993	1994	1995	1996	1997	1998
SUMMER	27,662	28,930	29,748	29,321	31,801	32,315	32,924	37,153
WINTER	28,179	27,215	28,149	32,618	34,552	34,762	30,932	35,907

PROJECTED FIRM PEAK DEMAND (MW)

	1999 (Actual)	2000	2001	2002	2003	2004	2005	2006
SUMMER	37,493	34,832	35,560	36,432	37,313	38,164	39,065	40,347
WINTER	40,178	36,814	37,753	38,679	39,592	40,551	41,585	42,541

PROJECTED FIRM PEAK DEMAND (MW)

	2007	2008	2009	2010	2011	2012
SUMMER	41,255	42,094	42,980	43,895	44,830	45,785
WINTER	43,445	44,386	45,316	46,281	47,266	48,272

Data Source:
Florida Reliability Coordinating Council,
1991-2009 values, 2000 Regional Load & Resource Plan, Peninsular Florida, July 2000.
2010-2012 values extrapolated at the FRCC projected average annual compond growth rates for 2006-2009.
1991-1999 actual peak demand values exclude interruptible load and load management reductions.
2000-2012 forecasted firm peak demand values include projected interruptible load and load management reduction values, and are non-coincident.

projected to increase from approximately 38,000 MW to approximately 46,000 MW over the same period. See Table II-7. Net Energy for Load in Peninsular Florida is projected to increase from approximately 196,000 GWH in 2000 to approximately 235,000 GWH in 2009 and to approximately 250,000 GWH in 2012. See Table II-5. As of January 1, 2000, total Peninsular Florida existing generating capacity was approximately 40,155 MW for the winter and 38,065 MW for the summer. See Table II-6. Tables II-7 and II-8 present projected capacity and reserve margin information for Peninsular Florida, with and without the capacity of the Osprey Energy Center.

The Osprey Energy Center will provide reliable and cost-effective power to Seminole or to other utilities that provide retail service in Peninsular Florida. Peninsular Florida needs approximately 12,000 MW of new generation capacity in order to maintain installed generation reserve margins between 7.0% and 15.5% for the winters of 2000-2001 through 2009-2010. (See Table II-8.) The Project will contribute meaningfully to Peninsular Florida's summer and winter reserve margins and to cost-effective power supply, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities.

Data extracted from the 2000 Regional Load & Resource Plan, dated July, 2000, prepared by the Florida Reliability Coordinating Council (the "FRCC 2000 Resource Plan"), show that without the Osprey Energy Center, Peninsular Florida's summer reserve margins

TABLE II-5

PENINSULAR FLORIDA, HISTORICAL AND PROJECTED NET ENERGY FOR LOAD AND NUMBER OF CUSTOMERS

1991 - 2012

ACTUAL NET ENERGY FOR LOAD (GWH)

	1991	1992	1993	1994	1995	1996	1997	1998
ENERGY	146,786	147,728	153,269	159,353	168,982	173,327	175,534	187,868
LOAD FACTOR	60.58%	58.29%	58.82%	62.04%	59.14%	57.26%	57.64%	57.72%
CUSTOMERS	6,155,380	6,269,358	6,410,797	6,550,760	6,687,155	6,812,603	6,948,888	7,091,803

PROJECTED NET ENERGY FOR LOAD (GWH)

	1999 (Actual)	2000	2001	2002	2003	2004	2005	2006
ENERGY	188,598	196,042	200,188	204,779	209,853	214,507	218,950	223,453
LOAD FACTOR	57.42%	55.70%	62.08%	61.92%	61.93%	61.85%	61.64%	61.34%
CUSTOMERS	7,555,341	7,517,881	7,688,054	7,832,016	7,974,676	8,113,738	8,249,138	8,380,749

PROJECTED NET ENERGY FOR LOAD (GWH)

	2007	2008	2009	2010	2011	2012
ENERGY	227,798	232,032	236,224	240,641	245,141	249,725
LOAD FACTOR	61.13%	60.97%	60.75%	59.36%	59.21%	58.89%
CUSTOMERS	8,510,779	8,640,757	8,771,153	8,905,288	9,041,474	9,179,743

Data Source:
Florida Reliability Coordinating Council,
1991-2009 Energy values, 2000 Regional Load & Resource Plan, Peninsular Florida, July 2000.
2010-2012 Energy values extrapolated at the FRCC projected average annual compound growth rates for 2006-2009.
Load factor values were calculated from these energy values and the peak demand values in Table 4.
1991-2009 Customer values, 2000 Regional Load & Resource Plan, Peninsular Florida, July 2000.
2010-2012 Customer values extrapolated at the FRCC projected average annual compound growth rates for 2006-2009.

TABLE II-6

PENINSULAR FLORIDA
SUMMARY OF EXISTING CAPACITY
AS OF JANUARY 1, 2000

UTILITY	NET CAPABILITY SUMMER	NET CAPABILITY WINTER
FLORIDA KEYS ELECTRIC COOPERATIVE ASSOC., INC	22	22
FLORIDA MUNICIPAL POWER AGENCY	498	527
FLORIDA POWER CORPORATION	7,525	8,277
FLORIDA POWER & LIGHT COMPANY	16,444	17,234
FORT PIERCE UTILITIES AUTHORITY	119	119
GAINESVILLE REGIONAL UTILITIES	550	563
CITY OF HOMESTEAD	60	60
JACKSONVILLE ELECTRIC AUTHORITY	2,626	2,749
UTILITY BOARD OF THE CITY OF KEY WEST	52	52
KISSIMMEE UTILITY AUTHORITY	172	190
CITY OF LAKELAND	615	650
CITY OF LAKE WORTH UTILITIES	127	138
UTILITIES COMMISSION OF NEW SMYRNA BEACH	24	24
OCALA ELECTRIC UTILITY	11	11
ORLANDO UTILITIES COMMISSION	1,028	1,072
REEDY CREEK IMPROVEMENT DISTRICT	48	49
SEMINOLE ELECTRIC COOPERATIVE INC.	1,331	1,345
CITY OF ST. CLOUD	22	21
CITY OF TALLAHASSEE	429	449
TAMPA ELECTRIC COMPANY	3,455	3,594
CITY OF VERO BEACH	150	155
TOTALS		
FRCC UTILITIES EXISTING CAPACITY	35,308	37,301
NON-UTILITY GENERATING FACILITIES (FIRM)	2,060	2,124
NON-UTILITY GENERATING FACILITIES (NON-FIRM)	74	85
MERCHANT PLANT FACILITIES (FIRM)	593	593
MERCHANT PLANT FACILITIES (NON-FIRM)	15	26
TOTAL PENINSULAR FLORIDA EXISTING CAPACITY	**38,050**	**40,129**

Data Source:
Florida Reliability Coordinating Council
2000 Regional Load & Resource Plan, Peninsular Florida, July 2000

TABLE II-7
SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK WITHOUT OSPREY ENERGY CENTER

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000	36,033	1,697	2,653	40,383	37,728	2,655	7.04	2,896	34,832	5,551	15.94
2001	38,244	1,699	2,653	42,596	38,445	4,151	10.80	2,885	35,560	7,036	19.79
2002	39,380	1,675	2,906	43,961	39,282	4,679	11.91	2,850	36,432	7,529	20.67
2003	41,484	1,583	3,221	46,288	40,157	6,131	15.27	2,844	37,313	8,975	24.05
2004	42,615	1,583	2,768	46,966	41,004	5,962	14.54	2,840	38,164	8,802	23.06
2005	43,211	1,583	2,658	47,452	41,905	5,547	13.24	2,840	39,065	8,387	21.47
2006	44,651	1,583	2,525	48,759	43,190	5,569	12.89	2,843	40,347	8,412	20.85
2007	45,364	1,583	2,220	49,167	44,097	5,070	11.50	2,842	41,255	7,912	19.18
2008	46,393	1,583	2,205	50,181	44,926	5,255	11.70	2,832	42,094	8,087	19.21
2009	47,100	1,583	2,096	50,779	45,810	4,969	10.85	2,830	42,980	7,799	18.15

NOTE: 1. 777 MW - 300 MW = 477 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 300 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF SUMMER PEAK WITH OSPREY ENERGY CENTER, 496 MW IN 2003

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000	36,033	1,697	2,653	40,383	37,728	2,655	7.04	2,896	34,832	5,551	15.94
2001	38,244	1,699	2,653	42,596	38,445	4,151	10.80	2,885	35,560	7,036	19.79
2002	39,380	1,675	2,906	43,961	39,282	4,679	11.91	2,850	36,432	7,529	20.67
2003	41,980	1,583	3,221	46,784	40,157	6,627	16.50	2,844	37,313	9,471	25.38
2004	43,111	1,583	2,768	47,462	41,004	6,458	15.75	2,840	38,164	9,298	24.36
2005	43,707	1,583	2,658	47,948	41,905	6,043	14.42	2,840	39,065	8,883	22.74
2006	45,147	1,583	2,525	49,255	43,190	6,065	14.04	2,843	40,347	8,908	22.08
2007	45,860	1,583	2,220	49,663	44,097	5,566	12.62	2,842	41,255	8,408	20.38
2008	46,889	1,583	2,205	50,677	44,926	5,751	12.80	2,832	42,094	8,583	20.39
2009	47,596	1,583	2,096	51,275	45,810	5,465	11.93	2,830	42,980	8,295	19.30

Notes: 1. THE INDICATED RESERVE MARGIN IMPROVEMENTS ARE SUBJECT TO THE PROJECT'S OUTPUT BEING CONTRACTUALLY COMMITTED TO SEMINOLE AND OTHER PENINSULAR FLORIDA LOAD-SERVING UTILITIES.
2. 496 MW OF OSPREY ENERGY CENTER ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2003
3. 777 MW - 300 MW = 477 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 300 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SOURCES: Florida Reliability Coordinating Council, 2000 Regional Load & Resource Plan, Peninsular Florida, July, 2000
Calpine Construction Finance Company, L.P.

TABLE II-8
SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK WITHOUT OSPREY ENERGY CENTER

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7.22	4,080	36,814	7,031	19.10
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7.07	4,058	37,753	7,012	18.57
2002/03	43,513	1,583	3,365	48,461	42,739	5,722	13.39	4,060	38,679	9,782	25.29
2003/04	45,329	1,583	2,912	49,824	43,663	6,161	14.11	4,071	39,592	10,232	25.84
2004/05	45,881	1,583	2,802	50,266	44,638	5,628	12.61	4,087	40,551	9,715	23.96
2005/06	46,845	1,583	2,669	51,097	45,694	5,403	11.82	4,109	41,585	9,512	22.87
2006/07	48,177	1,583	2,324	52,084	46,668	5,416	11.61	4,127	42,541	9,543	22.43
2007/08	49,520	1,583	2,309	53,412	47,573	5,839	12.27	4,128	43,445	9,967	22.94
2008/09	50,129	1,583	2,200	53,912	48,531	5,381	11.09	4,145	44,386	9,526	21.46
2009/10	51,316	1,583	1,778	54,677	49,478	5,199	10.51	4,162	45,316	9,361	20.66

NOTE: 1. 910 MW - 340 MW = 570 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002/03, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 340 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SUMMARY OF PENINSULAR FLORIDA CAPACITY, DEMAND, AND RESERVE MARGIN AT TIME OF WINTER PEAK WITH OSPREY ENERGY CENTER, 578 MW IN 2003/04

Year	INSTALLED CAPACITY (MW)	NET CONTRACT FIRM INTERCHG (MW)	PROJECTED FIRM NET TO GRID FROM NUG (MW)	TOTAL AVAILABLE CAPACITY (MW)	TOTAL PEAK DEMAND (MW)	RESERVE MARGIN W/O EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK	LOAD MGMT. & INT. (MW)	FIRM PEAK DEMAND (MW)	RESERVE MARGIN WITH EXERCISING LOAD MGMT. & INT. (MW)	% OF PEAK
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7.22	4,080	36,814	7,031	19.10
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7.07	4,058	37,753	7,012	18.57
2002/03	43,513	1,583	3,365	48,461	42,739	5,722	13.39	4,060	38,679	9,782	25.29
2003/04	45,907	1,583	2,912	50,402	43,663	6,739	15.43	4,071	39,592	10,810	27.30
2004/05	46,459	1,583	2,802	50,844	44,638	6,206	13.90	4,087	40,551	10,293	25.38
2005/06	47,423	1,583	2,669	51,675	45,694	5,981	13.09	4,109	41,585	10,090	24.26
2006/07	48,755	1,583	2,324	52,662	46,668	5,994	12.84	4,127	42,541	10,121	23.79
2007/08	50,098	1,583	2,309	53,990	47,573	6,417	13.49	4,128	43,445	10,545	24.27
2008/09	50,707	1,583	2,200	54,490	48,531	5,959	12.28	4,145	44,386	10,104	22.76
2009/10	51,894	1,583	1,778	55,255	49,478	5,777	11.68	4,162	45,316	9,939	21.93

NOTES: 1. THE INDICATED RESERVE MARGIN IMPROVEMENTS ARE SUBJECT TO THE PROJECT'S OUTPUT BEING CONTRACTUALLY COMMITTED TO SEMINOLE AND OTHER PENINSULAR FLORIDA LOAD-SERVING UTILITIES.
2. 578 MW OF OSPREY ENERGY CENTER ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2003/04
3. 910 MW - 340 MW = 570 MW OF OLEANDER POWER PROJECT ADDED TO THE INSTALLED CAPACITY COLUMN STARTING IN 2002/03, SEMINOLE ELECTRIC COOPERATIVE WILL PURCHASE 340 MW UNDER CONTRACT STARTING IN DECEMBER 2002.

SOURCES: Florida Reliability Coordinating Council, 2000 Regional Load & Resource Plan, Peninsular Florida, July, 2000
Calpine Construction Finance Company, L.P.

in 2003 through 2009 will range from 11.9 percent to 16.5 percent, without exercising load management and interruptible capabilities. With the Osprey Project, the summer reserve margins will be improved by up to 1.1 to 1.3 percent in each year, e.g., from 15.3 percent to 16.5 percent in 2003, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities. The annual summer reserve margins for Peninsular Florida, with and without the Project's capacity, are shown in Table II-7.

Similarly, data presented in the FRCC 2000 Resource Plan show that without the Osprey Energy Center, Peninsular Florida's winter reserve margins in 2003-2004 through 2009-2010 will range from 10.5 percent to 14.1 percent, without exercising load management and interruptible capabilities. With the Osprey Energy Center, the winter reserve margins will be improved by up to 1.2 to 1.3 percent in each year, e.g., from 14.1 percent without Osprey to 15.4 percent with Osprey in 2003-2004, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities. Winter reserve margins for Peninsular Florida, with and without the Project's capacity, and with and without exercising load management and interruptible resources, are shown in Table II-8.

Based on production simulation analyses prepared for Calpine of the Osprey Energy Center's operations within the Peninsular Florida power supply system, modeled on an economic dispatch basis,

and subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the Project is expected to operate at an average annual capacity factor of approximately 91 percent from 2003 through 2012, reflecting approximately 7,500 to 8,500 operating hours per year and approximately 4.0 million to 4.4 million MWH per year of net generation based on operations without duct-firing. See Table II-9. Sensitivity analyses prepared for Calpine of the Project's operations based on specified changes in fuel price forecasts and in Peninsular Florida load growth assumptions are shown in Tables II-10 and II-11, respectively.

Calpine projects that all of the sales from the Project will be made to Seminole and, in the event that Seminole does not purchase all of the Project's output, to other Florida utilities for resale to their retail electric customers in Peninsular Florida.

The advanced technology, natural gas-fired combined cycle design of the Project is consistent with the type of capacity being added by many other Peninsular Florida utilities. Table II-12, which presents data from utility ten-year site plans and other published sources, shows that from 1999 through 2008, other Peninsular Florida utilities are projecting the addition of nearly 7,000 MW of gas-fired combined cycle capacity.

The above-referenced analyses of the projected operations of the Osprey Energy Center in the Peninsular Florida power supply

TABLE II-9

OSPREY ENERGY CENTER
SUMMARY OF PROJECTED OPERATIONS
2003-2012

Year	PROJECTED GENERATION (GWH)	ANNUAL CAPACITY FACTOR %
2003	2,624	95.5%
2004	4,379	92.7%
2005	4,293	91.1%
2006	4,279	90.8%
2007	4,333	92.0%
2008	4,254	90.0%
2009	4,172	88.6%
2010	4,301	91.3%
2011	4,070	86.4%
2012	4,389	92.9%

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. The Project is scheduled to come into service on June 1, 2003. The annual capacity factor reported for 2003 is calculated on the basis of the Project's operations for the period June 1 - December 31, 2003.

2. The indicated capacity factors are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

TABLE II-10

OSPREY ENERGY CENTER
SUMMARY OF PROJECTED OPERATIONS, 2003-2012
HIGHER NATURAL GAS PRICE SENSITIVITY ANALYSIS

Year	PROJECTED GENERATION (GWH)	ANNUAL CAPACITY FACTOR %
2003	2,616	95.1%
2004	4,351	92.1%
2005	4,264	90.5%
2006	4,229	89.8%
2007	4,266	90.6%
2008	4,149	87.8%
2009	4,066	86.3%
2010	4,161	88.3%
2011	3,935	83.5%
2012	4,265	90.3%

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. The Project is scheduled to come into service on June 1, 2003. The annual capacity factor reported for 2003 is calculated on the basis of the Project's operations for the period June 1 - December 31, 2003.

2. The Base Case fuel price projections were developed by Slater Consulting based on actual data and the U. S. Energy Information Administration's 2000 Annual Energy Outlook Reference Case Forecast, but with the natural gas price escalations moderated to be more in keeping with the Standard & Poor's DRI forecast, which was included in the EIA's publication as a comparison forecast. The fuel prices for this sensitivity case were the same as for the Base Case except that the prices of natural gas were projected to escalate at the growth rates projected in the EIA Reference Case Forecast.

3. The indicated capacity factors are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

TABLE II-11

OSPREY ENERGY CENTER
SUMMARY OF PROJECTED OPERATIONS
LOAD GROWTH SENSITIVITY ANALYSES, 2003-2012

	LOW LOAD GROWTH		BASE LOAD		HIGH LOAD GROWTH	
	PROJECTED GENERATION	ANNUAL CAPACITY	PROJECTED GENERATION	ANNUAL CAPACITY	PROJECTED GENERATION	ANNUAL CAPACITY
Year	(GWH)	FACTOR %	(GWH)	FACTOR %	(GWH)	FACTOR %
2003	2,622	95.4%	2,624	95.5%	2,633	95.8%
2004	4,364	92.4%	4,379	92.7%	4,400	93.1%
2005	4,279	90.8%	4,293	91.1%	4,307	91.4%
2006	4,270	90.6%	4,279	90.8%	4,214	89.4%
2007	4,139	87.9%	4,333	92.0%	4,441	94.3%
2008	4,402	93.2%	4,254	90.0%	4,032	85.4%
2009	4,065	86.3%	4,172	88.6%	4,365	92.7%
2010	4,357	92.5%	4,301	91.3%	4,267	90.6%
2011	4,216	89.5%	4,070	86.4%	4,284	90.9%
2012	4,190	88.7%	4,389	92.9%	4,455	94.3%

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Note: The indicated output and capacity factor values are projected subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

Assumptions: The Base Case scenario was developed by Slater Consulting based on actual data and consideration of published sources, including the 1999 FRCC Regional Load & Resource Plan and Florida utilities' 2000 ten-year site plans. The Low Load Growth scenario reflects growth rates 0.5 percent per year less than in the Base Case. The High Load Growth scenario reflects growth rates 1.0 percent per year greater than in the Base Case.

TABLE II-12
COMPARISON OF PENINSULAR FLORIDA
PLANNED AND PROPOSED GENERATING UNITS

PLANNED & PROPOSED UTILITY/UNIT	IN-SERVICE YEAR	SUMMER CAPACITY MW	WINTER CAPACITY MW	PRIMARY FUEL	ALTERNATE FUEL	HEAT RATE (Btu/kWH)	EQUIVALENT AVAILABILITY FACTOR %	TOTAL INSTALLED COST ($/KW) 1/	DIRECT CONSTRUCTION COST ($/KW) 1/	TECHNOLOGY TYPE
OLEANDER 2/	2002	777	910	GAS	NO. 2	9,700	97	N/A	$235	COMBUSTION TURBINE
OSPREY ENERGY 3/	2003	496	578	GAS	NONE	6,800	94	N/A	$357	COMBINED CYCLE
FPL/MARTIN CT	2001	298	362	GAS	NO. 2	10,450	98	$371	$323	COMBUSTION TURBINE
FPL/FT.MYERS	2002	930	1,073	GAS	NONE	6,830	96	$557	$502	COMB. CYCLE/REPOWER
FPL/SANFORD 4-5	2002	1,132	1,342	GAS	NONE	6,860	96	$703	$591	COMB. CYCLE/REPOWER
FPL/FT.MYERS CT	2003	298	362	GAS	NO. 2	10,450	98	$378	$323	COMBUSTION TURBINE
FPL/MARTIN 5-6	2006	788	858	GAS	NO. 2	6,346	96	$679	$484	COMBINED CYCLE
FPL/UNSITED	2007	394	429	GAS	NO. 2	6,830	96	$783	$552	COMBINED CYCLE
FPL/UNSITED	2008	394	429	GAS	NO. 2	6,830	96	$798	$552	COMBINED CYCLE
FPL/UNSITED	2009	394	429	GAS	NO. 2	6,830	96	$812	$552	COMBINED CYCLE
TALLAH/PURDOM 8	2000	233	262	GAS	NO. 2	6,940	NR	$483	$434	COMBINED CYCLE
FPC/INTRCSS 12-14	2000	240	282	GAS	NO. 2	13,272	91	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
FPC/HINES 2	2003	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPC/HINES 3	2005	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPC/HINES 4	2007	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
FPC/HINES 5	2009	495	567	GAS	NO. 2	7,306	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
TECO/POLK 2	2000	155	180	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
TECO/POLK 3	2002	155	180	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
TECO/BAYSIDE 1	2003	698	796	GAS	NO. 2	7,080	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
TECO/BAYSIDE 2	2004	711	802	GAS	NO. 2	7,050	91	NOT REPORTED	NOT REPORTED	COMBINED CYCLE
TECO/POLK 4-6	2005	465	540	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
TECO/UNSITED	2009	155	180	GAS	NO. 2	10,580	94	NOT REPORTED	NOT REPORTED	COMBUSTION TURBINE
GVLLE/J.R. KELLY	2001	110	110	GAS	NO. 2	8,000	84	$375	$368	COMBINED CYCLE
SEC/PAYNE CRK 4/	2002	488	572	GAS	NO. 2	6,170	93	$412	$378	COMBINED CYCLE
FMPA-KUA CANE 3	2001	244	267	GAS	NO. 2	6,815	92	$430	$320	COMBINED CYCLE
LKLAND McINTSH 5	2002	337	384	GAS	NO. 2	6,523	91	$749	$671	COMBINED CYCLE
LKLAND McINTSH 4	2004	288	288	PET.COKE	COAL	8,452	81	$1,617	$1,317	PRESSURE FLUID BED
LKLAND McINTSH 6	2009	32	46	GAS	NO. 2	10,624	98	$992	$742	COMBUSTION TURBINE
JEA KENNEDY CT 7	2000	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$261	COMBUSTION TURBINE
JEA BANDY CT 1-3	2001	149	186	GAS	NO. 2	11,120	97	NOT REPORTED	$264	COMBUSTION TURBINE
JEA NORTHSID 1-2	2002	265	265	ET. COK	COAL	9,946	90	NOT REPORTED	$658	CIRCULATING FLUID BED

DATA SOURCES:

1/ TOTAL INSTALLED COST AND DIRECT CONSTRUCTION COST DATA IS REPORTED DIRECTLY FROM THE INDIVIDUAL UTILITY'S 2000 TEN-YEAR SITE PLAN, SCHEDULE 9.

2/ OLEANDER POWER PROJECT DATA IS BASED ON INFORMATION FILED IN THE APRIL 2000 TEN-YEAR SITE PLAN, AND INCLUDES THE COST OF DIRECTLY ASSOCIATED TRANSMISSION LINES.

3/ OSPREY ENERGY CENTER DATA IS BASED ON INFORMATION FROM NEED DETERMINATION AND TEN-YEAR SITE PLAN FILINGS AND INCLUDE THE COSTS OF DIRECTLY ASSOCIATED TRANSMISSION LINES. HEAT RATE IS CALCULATED BASED ON HIGHER HEATING VALUE (HHV).

4/ SEMINOLE ELECTRIC COOPERATIVE'S HEAT RATE FOR THE PAYNE CREEK UNIT 3 IS REPORTED BASED ON LOWER HEATING VALUE (LHV).

system were prepared for Calpine using the PROMOD IV® computer model. PROMOD IV® is a widely known and widely used probabilistic model that simulates the operations of electric power systems. PROMOD IV® is primarily used as a production costing model and can also be used to evaluate electric system reliability. A brief description of PROMOD IV® is included in Appendix C to these Amended Exhibits. PROMOD IV® can be used to prepare utility fuel budget forecasts, evaluate the economics and operations of proposed generating capacity additions, project utility operating costs, estimate the prices of firm power and energy in defined markets, project hourly marginal energy costs, and calculate avoided energy costs.

The inputs to PROMOD IV® include generating unit data for existing and planned power plants in a defined power supply system, fuel consumption and fuel cost data, load and other utility system data, and data regarding transactions within the system. The primary outputs are individual utility or system production costs, generation by unit, fuel usage, and reliability information. PROMOD IV® utilizes computationally efficient algorithms that yield results identical to those that would be produced with direct specification of values for all availability states of all units in a power supply system.

B. Calpine's Use of the Osprey Energy Center.

Calpine's business purpose with respect to the Osprey Energy Center is to develop the Project to provide reliable, competitively

priced, environmentally clean power to Seminole and its Member utility systems (and, in the event that Seminole does not purchase all of the Project's output, to other Florida load-serving utilities) without risk to Florida's retail electric customers. To that end, Calpine has entered into the PPA with Seminole by which Calpine commits to make the full output of the Osprey Project available to Seminole for an initial term of five years with renegotiation provisions pursuant to which Seminole may procure up to the full output of the Project from the Project's commercial in-service date through May 22, 2020. Specifically, Seminole will purchase 350 MW of firm capacity from the Osprey Project from June 1, 2004 through May 31, 2009; pursuant to the PPA, Seminole has the right to purchase up to the full amount of the Project's capacity, and all of its energy output, from the Project's commercial in-service date through May 31, 2009, to the extent that this additional capacity (i.e., the Project's capacity above 350 MW) has not been committed to other Florida utilities at the time that Seminole wishes to exercise this option. Accordingly, Calpine will use the Project to meet its contractual obligations to Seminole reliably and cost-effectively.

C. **Energy Efficiency and Environmental Impacts**.

Pursuant to Section 403.519, the Commission is charged to consider conservation measures that are available to mitigate the need for a proposed power plant subject to the Siting Act and to consider other matters within its jurisdiction that it deems

relevant to its decision. As a wholesale utility, Calpine does not engage in end-use conservation programs. The utilities to whom Calpine will sell the Osprey Project's output, such as Seminole,[8] generally have conservation programs and conservation goals approved by the Commission, however, and Calpine takes as given that those utilities' power supply needs are net of the effects of those conservation programs.

This is not the end of the energy conservation analysis, however. The Commission is charged under the Florida Energy Efficiency and Conservation Act, Sections 366.08-.85 and 403.519, Florida Statutes, with developing and adopting conservation goals, and that statute contains express statements of legislative intent with respect to energy efficiency. Specifically, Section 366.81 provides that

> The Legislature further finds and declares that ss. 366.80-366.85 and 403.519 are to be liberally construed in order to meet the complex problems of . . . increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; . . . and conserving expensive resources, particularly petroleum fuels.

The Osprey Project will specifically promote the achievement of these goals. Tables II-13.A and II-13.B present the heat rates (measured in Btu per kWh, a direct measure of a power plant's energy efficiency) and the estimated dispatch costs (as modeled in

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[8]A discussion of Seminole's Member cooperative utility systems' conservation programs and conservation goals is included in Volume I of these Amended Exhibits.

TABLE II-13.A

EFFICIENCY AND COST-EFFECTIVENESS OF PENINSULAR FLORIDA GENERATING UNITS, 2003

Plant	Unit	Summer Capacity (MW)	Average Annual Heat Rate (Btu/kwh)	Average Annual Dispatch Cost ($/MWh)
Nuclear				
CRYSTAL	3	805	Must Run at Maximum Available Capacity	
STLUCIE	1	839	Must Run at Maximum Available Capacity	
STLUCIE	2	839	Must Run at Maximum Available Capacity	
TURKEYPT	3	697	Must Run at Maximum Available Capacity	
TURKEYPT	4	697	Must Run at Maximum Available Capacity	
Coal and Petroleum Coke				
BIG BEND	1	421	9,965	30.29
BIG BEND	2	421	9,972	30.57
BIG BEND	3	428	9,956	28.72
BIG BEND	4	442	9,943	26.93
CRYSTAL	1	386	9,679	25.40
CRYSTAL	2	488	9,596	25.26
CRYSTAL	4	714	9,094	23.67
CRYSTAL	5	697	9,092	23.41
DEERHAVN	2	228	10,608	25.20
GANNON	1	0	9,688	31.24
GANNON	2	0	9,671	31.19
GANNON	6	362	10,246	35.01
MCINTOSH	3	338	9,093	23.65
NORTHSID	1	265	9,753	23.34
NORTHSID	2	265	13,156	29.42
SCHERER	4	846	9,949	24.53
SEMINOLE	1	638	10,041	26.38
SEMINOLE	2	638	10,041	26.28
ST JOHNS	1	624	9,179	22.26
ST JOHNS	2	638	9,258	22.88
STANTON	1	442	9,777	24.99
STANTON	2	446	9,079	22.85

New Gas Combined Cycle

BAYSIDE	1	707	7,236	29.38
BRANDY B	4	482	7,176	29.68
CANE IS	3	260	6,999	28.11
FT MYERS	3	1446	7,145	29.08
HINES EC	1	470	7,049	28.30
HINES EC	2	0	7,002	29.59
KELLEY	4	113	8,362	36.91
N SMYRNA	1	520	6,971	28.04
OKEECHOB	1	260	6,965	27.76
OKEECHOB	2	260	6,966	27.76
OSPREY	1	520	6,967	28.09
PAYNECRK	3	520	7,001	28.14
PURDOM	8	260	6,995	28.10
SANFORD	14	964	7,206	29.29
SANFORD	15	964	7,208	29.29

Other Units

ANCLOTE	1	503	10,952	69.84
ANCLOTE	2	503	10,485	66.36
AVONPKGT	1	29	No Significant Output	
AVONPKGT	2	29	No Significant Output	
BARTOW	1	115	9,982	39.38
BARTOW	2	117	9,983	39.81
BARTOW	3	208	9,975	38.84
BARTOWGT	1	46	No Significant Output	
BARTOWGT	2	46	No Significant Output	
BARTOWGT	3	46	No Significant Output	
BARTOWGT	4	49	No Significant Output	
BAYBROGT	1	47	No Significant Output	
BAYBROGT	2	47	No Significant Output	
BAYBROGT	3	47	No Significant Output	
BAYBROGT	4	47	No Significant Output	
BGBENDGT	1	12	No Significant Output	
BGBENDGT	2	61	11,635	75.05
BGBENDGT	3	61	11,635	75.10
BRANDY B	1	0	11,224	56.71
BRANDY B	2	0	11,266	56.96
BRANDY B	3	153	11,383	56.01
CANE GT	1	30	11,166	50.91
CANE ISL	2	108	9,583	42.41
CAPECNVR	1	405	9,437	40.46

CAPECNVR	2	408	9,441	40.66
CUDJOE D	1	5	No Significant Output	
CUTLER	5	71	11,720	45.14
CUTLER	6	144	11,741	45.33
DEBARYGT	1	54	No Significant Output	
DEBARYGT	2	54	11,730	76.32
DEBARYGT	3	54	No Significant Output	
DEBARYGT	4	54	No Significant Output	
DEBARYGT	5	54	No Significant Output	
DEBARYGT	6	54	No Significant Output	
DEBARYGT	7	88	11,890	76.92
DEBARYGT	8	88	11,890	76.97
DEBARYGT	9	88	11,880	76.91
DEBARYGT	10	88	11,880	77.09
DEERHAVN	1	85	10,604	45.57
DRHVN GT	1	18	14,471	68.60
DRHVN GT	2	18	14,471	68.80
DRHVN GT	3	75	14,471	68.15
EVERGL T	1	35	17,121	74.24
EVERGL T	2	35	17,121	74.10
EVERGL T	3	35	17,121	73.81
EVERGL T	4	35	17,121	73.86
EVERGL T	5	35	17,121	73.60
EVERGL T	6	35	17,121	73.92
EVERGL T	7	35	17,121	73.65
EVERGL T	8	35	17,121	73.39
EVERGL T	9	35	17,121	73.35
EVERGL T	10	35	17,121	73.46
EVERGL T	11	35	17,121	73.04
EVERGL T	12	35	No Significant Output	
EVERGLDS	1	221	9,550	38.49
EVERGLDS	2	221	9,557	38.63
EVERGLDS	3	375	9,944	39.71
EVERGLDS	4	410	9,925	39.66
FTMYER T	1	54	No Significant Output	
FTMYER T	2	54	No Significant Output	
FTMYER T	3	54	No Significant Output	
FTMYER T	4	54	No Significant Output	
FTMYER T	5	54	No Significant Output	
FTMYER T	6	54	No Significant Output	
FTMYER T	7	54	No Significant Output	
FTMYER T	8	54	No Significant Output	
FTMYER T	9	54	No Significant Output	
FTMYER T	10	54	No Significant Output	
FTMYER T	11	54	No Significant Output	

FTMYER T	12	54	No Significant Output	
FTMYERCT	13	153	11,302	52.34
FTMYERCT	14	153	11,311	52.38
GANNONGT	1	12	No Significant Output	
HANSELCC	2	48	9,817	46.24
HANSELIC	8	3	9,300	43.19
HANSELIC	14	2	9,300	43.23
HANSELIC	15	2	9,300	43.25
HANSELIC	16	2	9,300	43.25
HANSELIC	17	2	9,300	43.23
HANSELIC	18	2	No Significant Output	
HANSELIC	19	3	No Significant Output	
HANSELIC	20	3	9,300	43.25
HARDEE	1	224	7,300	34.54
HARDEECT	1	74	9,732	45.33
HIGGNSGT	1	29	No Significant Output	
HIGGNSGT	2	29	No Significant Output	
HIGGNSGT	3	35	No Significant Output	
HIGGNSGT	4	35	No Significant Output	
HOOKERS	1	0	No Significant Output	
HOOKERS	2	0	No Significant Output	
HOOKERS	3	0	No Significant Output	
HOOKERS	4	0	No Significant Output	
HOOKERS	5	0	No Significant Output	
HOPKINGT	1	12	14,029	60.59
HOPKINGT	2	24	13,597	63.57
HOPKINS	1	75	11,357	47.25
HOPKINS	2	238	10,652	41.92
IND RIVR	1	88	10,033	42.34
IND RIVR	2	201	9,982	39.50
IND RIVR	3	319	10,469	41.65
INDRVRGT	1	37	11,540	52.40
INDRVRGT	2	37	11,540	52.51
INDRVRGT	3	108	11,100	50.84
INDRVRGT	4	108	11,100	50.84
INTER GT	1	47	No Significant Output	
INTER GT	2	47	No Significant Output	
INTER GT	3	47	No Significant Output	
INTER GT	4	47	No Significant Output	
INTER GT	5	47	No Significant Output	
INTER GT	6	47	No Significant Output	
INTER GT	7	83	12,210	79.38
INTER GT	8	83	No Significant Output	
INTER GT	9	83	No Significant Output	
INTER GT	10	83	12,030	77.69

INTER GT	11	143	12,030	78.03
INTER GT	12	76	12,572	59.75
INTER GT	13	76	12,558	59.59
INTER GT	14	76	12,523	59.47
IVEY IC	1	4	9,300	42.70
IVEY IC	2	5	9,300	42.71
IVEY IC	3	9	12,280	54.15
IVEY IC	4	6	12,280	54.23
IVEY IC	5	4	9,300	42.70
IVEY IC	6	18	9,300	42.70
KELLY	7	23	16,441	68.60
KELLY GT	1	14	No Significant Output	
KELLY GT	2	14	No Significant Output	
KELLY GT	3	14	No Significant Output	
KENEDYGT	3	54	No Significant Output	
KENEDYGT	4	54	No Significant Output	
KENEDYGT	5	54	No Significant Output	
KENEDYGT	7	153	11,380	56.05
KING	5	8	10,483	42.59
KING	6	17	12,842	51.73
KING	7	32	12,858	54.99
KING	8	50	12,710	52.43
KING DSL	1	5	No Significant Output	
KING GT	9	23	10,500	51.01
LARSEN	8	102	10,610	42.77
LARSENGT	2	10	No Significant Output	
LARSENGT	3	10	No Significant Output	
LAUDER T	1	36	15,908	66.47
LAUDER T	2	35	15,908	66.46
LAUDER T	3	35	15,908	66.53
LAUDER T	4	35	15,908	66.47
LAUDER T	5	35	15,908	66.54
LAUDER T	6	35	15,908	66.44
LAUDER T	7	35	15,908	66.55
LAUDER T	8	35	15,908	66.59
LAUDER T	9	35	15,908	66.62
LAUDER T	10	35	15,908	66.61
LAUDER T	11	35	15,908	66.70
LAUDER T	12	35	15,908	66.71
LAUDER T	13	35	16,227	67.94
LAUDER T	14	35	16,227	67.94
LAUDER T	15	35	16,227	67.92
LAUDER T	16	35	16,227	68.11
LAUDER T	17	35	16,227	68.09
LAUDER T	18	35	16,227	68.04

LAUDER T	19	35	16,227	68.02
LAUDER T	20	35	16,227	68.19
LAUDER T	21	35	16,227	68.28
LAUDER T	22	32	16,227	68.21
LAUDER T	23	32	16,227	68.15
LAUDER T	24	35	16,227	68.35
LAUDERCC	4	440	7,640	32.83
LAUDERCC	5	440	7,654	33.48
MANATEE	1	819	9,928	39.50
MANATEE	2	819	9,909	39.50
MARATHON	1	8	No Significant Output	
MARATHON	2	5	9,300	42.70
MARATHON	3	8	12,280	54.18
MARTIN	1	814	8,904	36.37
MARTIN	2	816	8,939	36.16
MARTINCC	3	445	7,232	31.20
MARTINCC	4	445	7,235	31.08
MARTINCT	1	153	11,266	52.39
MARTINCT	2	153	11,266	52.38
MCINT GT	1	17	15,000	65.71
MCINT IC	1	5	No Significant Output	
MCINTOSH	1	87	10,815	43.98
MCINTOSH	2	103	10,274	40.96
MCINTOSH	5	310	7,262	30.03
NORTH GT	3	52	No Significant Output	
NORTH GT	4	52	No Significant Output	
NORTH GT	5	52	No Significant Output	
NORTH GT	6	52	No Significant Output	
NORTHSID	3	505	9,688	40.75
OLEAN GT	1	153	11,291	52.41
OLEAN GT	2	153	11,303	52.48
OLEAN GT	3	153	11,301	52.43
OLEAN GT	4	153	11,316	52.50
OLEAN GT	5	153	11,325	52.51
PHILLIPS	1	17	13,500	55.45
PHILLIPS	2	17	13,500	55.48
POLK CT	2	153	11,366	54.72
POLK CT	3	153	11,348	54.74
POLKIGCC	1	250	10,079	29.97
PURDOM	7	48	16,947	69.23
PURDOMGT	1	12	No Significant Output	
PURDOMGT	2	12	No Significant Output	
PUTNAMCC	1	249	9,115	39.31
PUTNAMCC	2	249	9,114	39.36
REEDYCRK	1	35	10,400	45.89

RIOPINGT	1	15	No Significant Output	
RIVIERA	3	290	9,729	37.23
RIVIERA	4	290	9,729	37.52
SANFORD	3	153	8,877	40.06
SEM CT	1	153	11,357	54.83
SMITH	1	7	18,840	75.52
SMITH	2	7	18,822	75.58
SMITH	3	22	16,777	70.99
SMITH	4	32	16,798	71.08
SMITH D	1	9	No Significant Output	
SMITH CC	1	32	10,400	48.43
SMITH GT	1	26	No Significant Output	
SMITH ST	1	3	No Significant Output	
SMITH ST	2	2	No Significant Output	
SMITH ST	3	6	No Significant Output	
ST CLOUD	1	4	No Significant Output	
ST CLOUD	2	6	No Significant Output	
ST CLOUD	3	6	No Significant Output	
ST CLOUD	4	12	10,696	73.23
STOCK DS	1	9	9,300	64.95
STOCK DS	2	9	9,300	65.06
STOCK GT	1	21	No Significant Output	
STOCK GT	2	16	No Significant Output	
STOCK GT	3	16	No Significant Output	
STOCK IC	1	6	No Significant Output	
SUWAN GT	1	54	No Significant Output	
SUWAN GT	2	54	No Significant Output	
SUWAN GT	3	54	No Significant Output	
SUWANNEE	1	33	11,729	51.07
SUWANNEE	2	32	11,733	51.09
SUWANNEE	3	80	11,750	51.17
SWOOPEIC	1	5	No Significant Output	
TIGERBAY	1	194	7,553	32.32
TURKEYIC	1	14	No Significant Output	
TURKEYPT	1	410	9,433	39.54
TURKEYPT	2	400	9,395	39.80
TURNERGT	1	15	No Significant Output	
TURNERGT	2	15	No Significant Output	
TURNERGT	3	65	No Significant Output	
TURNERGT	4	65	No Significant Output	
UNIV FLA	1	36	11,166	50.41
VERO BCH	1	13	13,041	52.60
VERO BCH	2	13	8,928	36.66
VERO BCH	3	33	13,141	54.47
VERO BCH	4	56	11,739	48.61
VERO BCH	5	35	11,171	45.71

NUGs		
AGRICHEM	1	6
AS-AVAIL	1	63
BAY CTY	1	11
BIOENRGY	1	10
BROWARDS	1	54
BROWARDS	2	56
CARGILL	2	15
CEDARBAY	1	250
CFRBIOGN	1	74
DADE CTY	1	43
ELDORADO	1	114
FLASTONE	1	133
HILLSBOR	1	26
INDIANTN	1	330
LAKE CTY	1	13
LAKECOGN	1	110
LFC JEFF	1	9
LFC MADS	1	9
MULB-FPC	1	79
ORANGE	1	22
ORLANDO	1	79
PALMBCH	1	44
PASCO	1	109
PASCOCTY	1	23
PINELLAS	1	40
PINELLAS	2	15
RIDGE	1	40
ROYSTER	1	31
TAMPACTY	1	19
JEA-QFs		17
External Purchases		
ENTERGY	1	23
SOUTHERN CO.		1615

Source: PROMOD IV(R) analyses prepared by Slater Consulting

TABLE II-13.B

EFFICIENCY AND COST-EFFECTIVENESS OF PENINSULAR FLORIDA GENERATING UNITS, 2008

Plant	Unit	Summer Capacity (MW)	Average Annual Heat Rate (Btu/kwh)	Average Annual Dispatch Cost ($/MWh)
Nuclear				
CRYSTAL	3	805	Must Run at Maximum Available Capacity	
STLUCIE	1	839	Must Run at Maximum Available Capacity	
STLUCIE	2	839	Must Run at Maximum Available Capacity	
TURKEYPT	3	697	Must Run at Maximum Available Capacity	
TURKEYPT	4	697	Must Run at Maximum Available Capacity	
Coal and Petroleum Coke				
BIG BEND	1	421	10,017	34.67
BIG BEND	2	421	10,018	35.01
BIG BEND	3	428	9,998	32.60
BIG BEND	4	442	9,980	30.78
CRYSTAL	1	386	9,682	28.16
CRYSTAL	2	488	9,600	28.04
CRYSTAL	4	714	9,124	26.57
CRYSTAL	5	697	9,121	26.10
DEERHAVN	2	228	10,609	28.60
MCINTOSH	3	338	9,099	26.95
MCINTOSH	4	288	8,492	24.19
NORTHSID	1	265	9,786	26.49
NORTHSID	2	265	13,421	34.04
SCHERER	4	846	9,969	27.53
SEMINOLE	1	638	10,089	29.97
SEMINOLE	2	638	10,077	29.62
ST JOHNS	1	624	9,204	25.31
ST JOHNS	2	638	9,288	25.77
STANTON	1	442	9,782	27.70
STANTON	2	446	9,086	26.03

New Gas Combined Cycle

BAYSIDE	1	707	7,221	34.15
BAYSIDE	2	715	7,186	34.01
BRANDY B	4	482	7,254	34.71
CANE IS	3	260	7,026	32.74
FT MYERS	3	1446	7,203	33.90
GREEN CC	1	260	6,979	32.57
HINES EC	1	470	7,082	32.95
HINES EC	2	520	7,005	32.69
HINES EC	3	520	7,016	32.67
HINES EC	4	520	7,020	32.74
KELLEY	4	113	8,536	43.43
MARTINCC	5	380	6,804	31.96
MARTINCC	6	380	6,804	31.96
N SMYRNA	1	520	6,992	32.62
OKEECHOB	1	260	6,978	32.44
OKEECHOB	2	260	6,977	32.56
OSPREY	1	520	6,984	32.57
PAYNECRK	3	520	7,037	32.76
PURDOM	8	260	7,009	32.69
SANFORD	14	964	7,276	34.17
SANFORD	15	964	7,282	34.17
SEMIN CC	4	260	7,010	32.67
SEMIN CC	5	260	7,011	32.67
UNKNOWCC	1	364	6,981	32.53
UNKNOWCC	2	364	6,990	32.63

Other Units

ANCLOTE	1	503	11,581	90.11
ANCLOTE	2	503	11,378	89.16
BARTOW	1	115	9,971	46.89
BARTOW	2	117	10,003	46.60
BARTOW	3	208	9,978	46.05
BARTOWGT	1	46	No Significant Output	
BARTOWGT	2	46	No Significant Output	
BARTOWGT	3	46	No Significant Output	
BARTOWGT	4	49	No Significant Output	
BGBENDGT	1	12	No Significant Output	
BGBENDGT	2	61	No Significant Output	
BGBENDGT	3	61	No Significant Output	
BRANDY B	3	153	11,464	65.79
CANE GT	1	30	11,166	59.41
CANE ISL	2	108	9,581	49.24
CAPECNVR	1	405	9,444	48.37
CAPECNVR	2	408	9,444	48.47
CUDJOE D	1	5	No Significant Output	

CUTLER	5	71	11,721	52.49
CUTLER	6	144	11,734	52.59
DEBARYGT	1	54	No Significant Output	
DEBARYGT	2	54	No Significant Output	
DEBARYGT	3	54	No Significant Output	
DEBARYGT	4	54	No Significant Output	
DEBARYGT	5	54	No Significant Output	
DEBARYGT	6	54	No Significant Output	
DEBARYGT	7	88	No Significant Output	
DEBARYGT	8	88	No Significant Output	
DEBARYGT	9	88	No Significant Output	
DEBARYGT	10	88	No Significant Output	
DEERHAVN	1	85	10,609	52.93
DRHVN GT	1	18	No Significant Output	
DRHVN GT	2	18	No Significant Output	
DRHVN GT	3	75	No Significant Output	
EVERGL T	1	35	No Significant Output	
EVERGL T	2	35	No Significant Output	
EVERGL T	3	35	No Significant Output	
EVERGL T	4	35	No Significant Output	
EVERGL T	5	35	No Significant Output	
EVERGL T	6	35	No Significant Output	
EVERGL T	7	35	No Significant Output	
EVERGL T	8	35	No Significant Output	
EVERGL T	9	35	No Significant Output	
EVERGL T	10	35	No Significant Output	
EVERGL T	11	35	No Significant Output	
EVERGL T	12	35	No Significant Output	
EVERGLDS	1	221	9,546	44.78
EVERGLDS	2	221	9,551	44.71
EVERGLDS	3	375	9,897	45.90
EVERGLDS	4	410	9,892	45.91
FTMYER T	1	54	No Significant Output	
FTMYER T	2	54	No Significant Output	
FTMYER T	3	54	No Significant Output	
FTMYER T	4	54	No Significant Output	
FTMYER T	5	54	No Significant Output	
FTMYER T	6	54	No Significant Output	
FTMYER T	7	54	No Significant Output	
FTMYER T	8	54	No Significant Output	
FTMYER T	9	54	No Significant Output	
FTMYER T	10	54	No Significant Output	
FTMYER T	11	54	No Significant Output	
FTMYER T	12	54	No Significant Output	
FTMYERCT	13	153	11,343	61.30
FTMYERCT	14	153	11,355	61.33
GANNONGT	1	12	No Significant Output	

HANSELCC	2	48	9,777	53.15
HANSELIC	8	3	9,300	50.48
HANSELIC	14	2	9,300	50.50
HANSELIC	15	2	9,300	50.41
HANSELIC	16	2	9,300	50.51
HANSELIC	17	2	9,300	50.42
HANSELIC	18	2	No Significant Output	
HANSELIC	19	3	No Significant Output	
HANSELIC	20	3	9,300	50.40
HARDEE	1	224	7,300	39.97
HARDEECT	1	74	9,732	52.50
HOPKINGT	1	12	No Significant Output	
HOPKINGT	2	24	No Significant Output	
HOPKINS	1	75	11,386	54.86
HOPKINS	2	238	10,636	48.54
IND RIVR	1	88	10,026	49.15
IND RIVR	2	201	9,971	45.80
IND RIVR	3	319	10,463	48.23
INDRVRGT	1	37	11,540	60.96
INDRVRGT	2	37	11,540	61.06
INDRVRGT	3	108	11,100	59.03
INDRVRGT	4	108	11,100	59.15
INTER GT	1	47	No Significant Output	
INTER GT	2	47	No Significant Output	
INTER GT	3	47	No Significant Output	
INTER GT	4	47	No Significant Output	
INTER GT	5	47	No Significant Output	
INTER GT	6	47	No Significant Output	
INTER GT	7	83	No Significant Output	
INTER GT	8	83	No Significant Output	
INTER GT	9	83	No Significant Output	
INTER GT	10	83	No Significant Output	
INTER GT	11	143	No Significant Output	
INTER GT	12	76	12,568	69.17
INTER GT	13	76	12,583	69.28
INTER GT	14	76	12,567	69.23
IVEY IC	1	4	9,300	50.59
IVEY IC	2	5	9,300	50.60
IVEY IC	3	9	12,280	64.70
IVEY IC	4	6	No Significant Output	
IVEY IC	5	4	9,300	50.58
IVEY IC	6	18	9,300	50.58
KELLY	7	23	16,878	81.75
KELLY GT	1	14	No Significant Output	
KELLY GT	2	14	No Significant Output	
KELLY GT	3	14	No Significant Output	
KENEDYGT	3	54	No Significant Output	

KENEDYGT	4	54	No Significant Output	
KENEDYGT	5	54	No Significant Output	
KENEDYGT	7	153	11,306	65.11
KING	5	8	10,479	49.55
KING	6	17	12,844	60.53
KING	7	32	12,942	64.15
KING	8	50	12,728	61.06
KING DSL	1	5	No Significant Output	
KING GT	9	23	10,500	59.26
LARSEN	8	102	10,610	49.95
LARSENGT	2	10	No Significant Output	
LARSENGT	3	10	No Significant Output	
LAUDER T	1	36	No Significant Output	
LAUDER T	2	35	No Significant Output	
LAUDER T	3	35	No Significant Output	
LAUDER T	4	35	No Significant Output	
LAUDER T	5	35	No Significant Output	
LAUDER T	6	35	No Significant Output	
LAUDER T	7	35	No Significant Output	
LAUDER T	8	35	No Significant Output	
LAUDER T	9	35	No Significant Output	
LAUDER T	10	35	No Significant Output	
LAUDER T	11	35	No Significant Output	
LAUDER T	12	35	No Significant Output	
LAUDER T	13	35	No Significant Output	
LAUDER T	14	35	No Significant Output	
LAUDER T	15	35	No Significant Output	
LAUDER T	16	35	No Significant Output	
LAUDER T	17	35	No Significant Output	
LAUDER T	18	35	No Significant Output	
LAUDER T	19	35	No Significant Output	
LAUDER T	20	35	No Significant Output	
LAUDER T	21	35	No Significant Output	
LAUDER T	22	32	No Significant Output	
LAUDER T	23	32	No Significant Output	
LAUDER T	24	35	No Significant Output	
LAUDERCC	4	440	7,667	38.21
LAUDERCC	5	440	7,680	38.95
MANATEE	1	819	9,857	46.72
MANATEE	2	819	9,695	45.92
MARATHON	1	8	No Significant Output	
MARATHON	2	5	9,300	50.59
MARATHON	3	8	12,280	64.24
MARTIN	1	814	8,941	42.10
MARTIN	2	816	8,970	42.34
MARTINCC	3	445	7,263	36.26
MARTINCC	4	445	7,265	36.26

MARTINCT	1	153	11,327	61.28
MARTINCT	2	153	11,335	61.29
MCINT GT	1	17	No Significant Output	
MCINT IC	1	5	No Significant Output	
MCINTOSH	1	87	10,814	50.91
MCINTOSH	2	103	10,282	47.50
MCINTOSH	5	310	7,460	35.57
NORTH GT	3	52	No Significant Output	
NORTH GT	4	52	No Significant Output	
NORTH GT	5	52	No Significant Output	
NORTH GT	6	52	No Significant Output	
NORTHSID	3	505	9,653	50.48
OLEAN GT	1	153	11,364	61.32
OLEAN GT	2	153	11,345	61.24
OLEAN GT	3	153	11,352	61.25
OLEAN GT	4	153	11,367	61.24
OLEAN GT	5	153	11,366	61.31
PHILLIPS	1	17	13,500	65.92
PHILLIPS	2	17	13,500	65.92
POLK CT	2	153	11,353	63.94
POLK CT	3	153	11,368	63.99
POLK CT	4	153	11,393	64.00
POLK CT	5	153	11,345	63.89
POLK CT	6	153	11,336	63.85
POLKIGCC	1	250	10,267	35.35
PURDOM	7	48	18,726	87.68
PURDOMGT	1	0	No Significant Output	
PURDOMGT	2	12	No Significant Output	
PUTNAMCC	1	249	9,114	45.67
PUTNAMCC	2	249	9,110	45.70
REEDYCRK	1	35	10,400	53.12
RIVIERA	3	290	9,728	43.93
RIVIERA	4	290	9,738	44.25
SANFORD	3	153	8,877	47.44
SEM CT	1	153	11,383	64.07
SEM CT	2	153	11,422	64.21
SEM CT	3	153	11,375	64.01
SMITH	1	7	No Significant Output	
SMITH	2	7	No Significant Output	
SMITH	3	22	16,685	82.15
SMITH	4	32	16,495	81.24
SMITH D	1	9	No Significant Output	
SMITH CC	1	32	10,400	56.17
SMITH GT	1	26	No Significant Output	
SMITH ST	1	3	No Significant Output	
SMITH ST	2	2	No Significant Output	
SMITH ST	3	6	No Significant Output	

ST CLOUD	1	4	No Significant Output	
ST CLOUD	2	6	No Significant Output	
ST CLOUD	3	6	No Significant Output	
ST CLOUD	4	12	No Significant Output	
STOCK DS	1	9	No Significant Output	
STOCK DS	2	9	No Significant Output	
STOCK GT	1	21	No Significant Output	
STOCK GT	2	16	No Significant Output	
STOCK GT	3	16	No Significant Output	
STOCK IC	1	6	No Significant Output	
SUWAN GT	1	54	No Significant Output	
SUWAN GT	2	54	No Significant Output	
SUWAN GT	3	54	No Significant Output	
SWOOPEIC	1	5	No Significant Output	
TIGERBAY	1	194	7,577	37.45
TURKEYIC	1	14	No Significant Output	
TURKEYPT	1	410	9,406	46.87
TURKEYPT	2	400	9,420	46.90
TURNERGT	3	65	No Significant Output	
TURNERGT	4	65	No Significant Output	
UNIV FLA	1	36	11,166	58.41
VERO BCH	1	13	13,115	61.76
VERO BCH	2	13	8,931	42.62
VERO BCH	3	33	13,164	63.46
VERO BCH	4	56	11,785	56.74
VERO BCH	5	35	11,183	53.25

NUGs

AS-AVAIL	1	63
BAY CTY	1	11
BROWARDS	1	54
BROWARDS	2	56
CARGILL	2	15
CEDARBAY	1	250
CFRBIOGN	1	74
DADE CTY	1	43
ELDORADO	1	114
HILLSBOR	1	26
INDIANTN	1	330
LAKE CTY	1	13
LAKECOGN	1	110
LFC JEFF	1	9
LFC MADS	1	9
MULB-FPC	1	79
ORANGE	1	22
ORLANDO	1	79

PALMBCH	1	44
PASCO	1	109
PASCOCTY	1	23
PINELLAS	1	40
PINELLAS	2	15
RIDGE	1	40
ROYSTER	1	31
TAMPACTY	1	19
JEA-QFs		17

External Purchases

ENTERGY	1	23
SOUTHERN CO.		1615

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

the PROMOD IV® analyses performed for Calpine) for most of the power plants in Peninsular Florida. With regard to cost-effectiveness, Table II-13.B shows that, comparing the units' annual average dispatch costs, calculated on an as-dispatched basis, the Osprey Project has a lower dispatch cost than approximately 38,000 MW of the approximately 47,000 MW of fossil-fueled generating capacity that is projected to be serving Peninsular Florida in 2008. Table II-13.B shows that on a pure energy efficiency basis, the Osprey Project is more efficient than all but approximately 1,900 MW of the fossil-fueled generating capacity projected to be serving Peninsular Florida in 2008.

Table II-14 presents data from the PROMOD IV® analyses that show the energy efficiency gains that the Project will provide if it is operated on an economic dispatch basis within Peninsular Florida and subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities. In this scenario, the Project would reduce the average heat rate of all Peninsular Florida power supply by approximately 24 to 44 Btu per kWh over the 2004-2012 period. The Project would thus result in a net saving of 6 to 9 trillion Btu (6,000,000 to 9,000,000 MMBtu) of primary energy that would have been used to provide electricity in Peninsular Florida. Tables II-15.A and II-15.B present data showing the impacts of adding the Osprey Project into the Peninsular Florida power supply system on the total

TABLE II-14

PENINSULAR FLORIDA, IMPACTS OF OSPREY ENERGY CENTER ON AVERAGE ELECTRICITY GENERATION HEAT RATES AND TOTAL FUEL CONSUMPTION, 2003-2012

	Average Heat Rate (btu/kwh)			Total Primary Energy (1000*mmbtu)		Osprey Net Energy
Year	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Savings (1000*mmbtu)
2003	8,864.4	8,837.4	27.0	1,850,893	1,845,257	5,636
2004	8,781.6	8,737.8	43.7	1,874,198	1,864,864	9,334
2005	8,747.8	8,707.6	40.2	1,905,197	1,896,431	8,766
2006	8,662.8	8,626.6	36.2	1,925,724	1,917,686	8,038
2007	8,606.0	8,567.4	38.7	1,949,829	1,941,069	8,760
2008	8,576.2	8,540.5	35.7	1,976,351	1,968,125	8,226
2009	8,536.7	8,512.4	24.3	2,003,095	1,997,395	5,700
2010	8,546.1	8,518.9	27.3	2,041,883	2,035,372	6,511
2011	8,553.6	8,517.0	36.6	2,081,005	2,072,094	8,911
2012	8,575.3	8,540.2	35.1	2,124,464	2,115,761	8,703

Source: PROMOD IV(R) analyses prepared by Slater Consulting.
Note: The estimated energy savings are projections subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

TABLE II-15.A

PENINSULAR FLORIDA FUEL CONSUMPTION
IMPACTS OF OSPREY ENERGY CENTER, 2003-2012

(All Values in 1,000 x MMBtu)

	Nuclear			Coal and Other Solid Fuels			Natural Gas			No. 6 Oil			No. 2 Oil		
Year	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference
2003	295,404	295,404	0	769,940	766,231	3,709	663,815	669,766	(5,951)	118,105	110,713	7,392	3,629	3,143	486
2004	321,616	321,616	0	754,909	740,695	14,214	704,970	723,490	(18,520)	89,530	76,408	13,122	3,173	2,655	518
2005	316,996	316,996	0	751,478	743,067	8,411	745,061	755,649	(10,588)	88,372	77,868	10,504	3,290	2,851	439
2006	303,928	303,928	0	743,161	733,395	9,766	791,044	801,777	(10,733)	84,927	76,126	8,801	2,664	2,460	204
2007	312,117	312,117	0	716,668	705,680	10,988	829,301	846,518	(17,217)	89,310	74,427	14,883	2,433	2,327	106
2008	326,697	326,697	0	711,361	703,313	8,048	863,388	874,371	(10,983)	72,295	61,396	10,899	2,610	2,348	262
2009	294,962	294,962	0	716,748	712,157	4,591	897,024	905,427	(8,403)	91,584	82,485	9,099	2,777	2,364	413
2010	321,069	321,069	0	716,779	708,527	8,252	917,233	927,076	(9,843)	84,616	76,538	8,078	2,186	2,162	24
2011	316,945	316,945	0	723,043	709,318	13,725	937,705	952,935	(15,230)	100,807	90,683	10,124	2,505	2,213	292
2012	331,247	331,247	0	734,896	723,896	11,000	946,332	957,427	(11,095)	108,899	100,566	8,333	3,090	2,625	465

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Note: The project's estimated primary fuel consumption impacts shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

TABLE II-15.B

PENINSULAR FLORIDA, FUEL CONSUMPTION IMPACTS OF OSPREY ENERGY CENTER, 2003-2012

(All Values in GWh)

	Nuclear			Coal and Other Solid Fuels			Natural Gas			No. 6 Oil			No. 2 Oil		
Year	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference	Without Osprey	With Osprey	Difference
2003	28,539	28,539	0	79,879	79,444	435	87,441	88,664	(1,223)	12,061	11,331	730	357	311	46
2004	31,071	31,071	0	78,413	76,929	1,484	94,014	96,914	(2,900)	9,169	7,831	1,338	310	263	47
2005	30,625	30,625	0	78,211	77,290	921	99,111	101,185	(2,074)	9,076	7,995	1,081	318	278	40
2006	29,362	29,362	0	77,429	76,407	1,022	106,125	108,042	(1,917)	8,702	7,840	862	262	243	19
2007	30,153	30,153	0	74,651	73,490	1,161	111,992	114,720	(2,728)	9,139	7,641	1,498	242	231	11
2008	31,562	31,562	0	74,029	73,254	775	116,868	118,757	(1,889)	7,394	6,328	1,066	256	232	24
2009	28,496	28,496	0	74,744	74,131	613	121,351	122,947	(1,596)	9,385	8,471	914	271	234	37
2010	31,018	31,018	0	74,622	73,742	880	124,057	125,815	(1,758)	8,652	7,832	820	209	204	5
2011	30,620	30,620	0	75,216	73,803	1,413	126,515	129,017	(2,502)	10,292	9,271	1,021	235	207	28
2012	32,001	32,001	0	76,502	75,472	1,030	127,443	129,382	(1,939)	11,093	10,254	839	291	247	44

Source: PROMOD IV(R) analyses perpared by Slater Consulting.

Note: The Project's estimated primary fuel consumption impacts shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

consumption of each major generating fuel type--coal, natural gas, No. 2 oil, and No. 6 oil, again subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities.[9]

Directly associated with these reductions in primary fuel consumption are reductions in total SO_2 and NO_x emissions. Using data from the PROMOD IV® analyses, Table II-16 shows the impacts of the Osprey Project on the emissions of these two major pollutants from electricity generation in Florida. Generally, over the study period, and subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the Project is expected to reduce total SO_2 emissions from the generation of Peninsular Florida's electricity supply by 4,600 to 16,000 tons per year and reduce total NO_x emissions by 3,900 to 7,000 tons per year.

D. **Strategic Considerations**.

The Project is also consistent with strategic factors that may be considered in developing power plants from Calpine's perspective and in evaluating proposed power plants from the Commission's

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[9]Tables II-13.A, II-13.B, II-14, II-15.A, II-15.B, and II.16 were prepared by Slater Consulting before Calpine and Seminole executed the PPA. Accordingly, they are based on a scenario in which the Osprey Project was added into a system that included Seminole's planned 2004 combined cycle capacity, which, of course, is now being replaced by the Osprey Project. Accordingly, the results shown in these tables will slightly understate the benefits provided by the Osprey Project, as the Osprey Project will now be operating within a slightly less efficient power supply system.

TABLE II-16

PENINSULAR FLORIDA EMISSIONS IMPACTS OF OSPREY ENERGY CENTER, 2003-2012

(All Values in 1000's lbs)

	Sulfur Dioxide		Nitrogen Oxides	
Year	Without Osprey	With Osprey	Without Osprey	With Osprey
2003	759,691	767,350	458,702	452,861
2004	702,289	669,806	426,740	412,805
2005	695,946	674,697	423,137	413,850
2006	677,817	654,902	417,541	405,467
2007	658,449	632,952	405,652	392,771
2008	639,130	611,603	391,615	382,230
2009	669,806	660,623	408,957	401,142
2010	679,140	657,030	410,514	400,657
2011	702,883	677,446	418,612	407,683
2012	743,653	720,617	437,591	426,875

Source: PROMOD IV(R) analyses prepared by Slater Consulting.
Note: The estimated emission impacts shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

perspective considering the State as a whole. The Project will be fueled by domestically produced natural gas, rather than by an imported fuel that is subject to delivery interruption due to political or other events. The Project will also provide a significant impetus to the construction of a second major trans-Florida natural gas pipeline. The Project has a low installed cost relative to similar projects and a highly efficient heat rate, assuring its long-term economic viability. The Project's availability to Seminole and those whom Seminole serves will yield favorable risk reduction benefits to Seminole and those served by Seminole. Subject to the Project's output being contractually committed to other Peninsular Florida utilities, the Project will provide similar risk reduction benefits to such other utilities and their ultimate consumers. The Project's gas-fired combined cycle technology is exceptionally clean environmentally, protecting against risks associated with future changes in environmental regulations while improving the overall environmental profile of electricity generation in Florida.

V. COST-EFFECTIVENESS OF THE OSPREY ENERGY CENTER

The Osprey Energy Center is the most cost-effective alternative available to Seminole[10] to meet its needs and the needs of its Member cooperatives. The Project is also the most cost-effective alternative available to Peninsular Florida for meeting its future power supply needs. The Osprey Project is also the most cost-effective alternative available to Calpine for meeting its contractual obligations to Seminole. Moreover, based on its highly efficient heat rate and low direct construction cost, the Project is demonstrably cost-effective relative to virtually all other gas-fired combined cycle power plants proposed for Florida over the next ten years. Accordingly, the Project is expected to provide cost-effective power to Peninsular Florida.

A. Cost-Effectiveness to Peninsular Florida Electric Customers.

Calpine is committed to providing the Project's output to Florida utilities, such as Seminole, for the benefit of those utilities' retail customers in Florida. For the reasons set forth in Volume I of these Amended Exhibits, the Project will be cost-effective to Seminole's Member utility systems and those systems' member-consumers.

Additionally, the Project's costs and efficiency compare favorably to other gas-fired combined cycle generating units planned or proposed by other utilities in Peninsular Florida.

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[10]A discussion of the Project's cost-effectiveness to Seminole is included in Volume I of these Amended Exhibits.

Table II-12, which presents data from the utilities' 2000 ten-year site plans and other published sources, shows that of all the new gas-fired combined cycle power plants proposed by Peninsular Florida utilities, only the Cane Island 3 unit, a joint project of the Florida Municipal Power Agency and the Kissimmee Utilities Authority, is expected to have direct construction costs comparable to those of the Osprey Energy Center. The other combined cycle plants with generally comparable heat rates reflect direct construction costs, on a dollars-per-kW basis, significantly greater than those of the Osprey Project.

Finally, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the presence and operation of the Osprey Energy Center will suppress wholesale power prices in Peninsular Florida. Analyses performed for Calpine by Slater Consulting, Inc. using the PROMOD IV® model indicate that the Project, if operated on an economic dispatch basis within Peninsular Florida, and subject to the Project's output being contractually committed to Seminole or other Peninsular Florida load-serving utilities, will generally reduce average Peninsular Florida production costs by about $0.54 to $0.84 per MWH, for each year of the analysis period, yielding total estimated power supply cost reductions of approximately $794 million (NPV at a 10 percent discount rate) over the first ten years of the Project's operation. See Table II-17 of these Amended

TABLE II-17

PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, BASE CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	208,800	32.83	33.37	0.54	113	85
2004	213,424	31.81	32.55	0.74	158	193
2005	217,791	32.92	33.67	0.75	163	294
2006	222,299	33.36	33.96	0.60	133	369
2007	226,565	33.75	34.48	0.73	165	454
2008	230,447	34.34	34.96	0.62	143	521
2009	234,645	35.85	36.60	0.75	176	595
2010	238,924	36.77	37.51	0.74	177	664
2011	243,289	38.81	39.65	0.84	204	735
2012	247,742	40.27	41.02	0.75	186	794

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Note: The estimated wholesale energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

Exhibits. The estimated wholesale price suppression effects and production cost savings from the Osprey Energy Center under fuel price and load growth sensitivity cases are shown in Tables II-18.A, II-18.B, and II-18.C.

B. Cost-Effectiveness to Calpine Construction Finance Company, L.P.

The Osprey Energy Center also represents the most cost-effective alternative available to Calpine Construction Finance Company, L.P. for meeting its contractual obligations to Seminole. Table II-19 shows the generating alternatives evaluated by Calpine. Screening analyses conducted for Calpine by R.W. Beck & Associates considered gas-fired and oil-fired combustion turbines, gas-fired and oil-fired combined cycle units, gas-fired steam generation units, conventional pulverized coal steam units, nuclear steam units, renewable energy, and integrated coal gasification combined cycle units.

Table II-20 presents the results of cost screening analyses for these various technologies. These evaluations clearly indicate that the best choice for Calpine, considering economics, cost-effectiveness, reliability, long-term flexibility, and strategic factors is gas-fired combined cycle capacity. This is supported by the fact that other Florida utilities are planning to add similar capacity, and by the fact that this type of unit is the technology of choice, for base-load applications, for the majority of new power plant capacity planned in the United States.

TABLE II-18.A

PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, HIGHER FUEL PRICE SENSITIVITY CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	208,800	32.88	33.43	0.55	115	86
2004	213,424	31.92	32.59	0.67	143	184
2005	217,791	33.06	33.81	0.75	163	285
2006	222,299	33.71	34.35	0.64	142	366
2007	226,565	34.49	35.22	0.73	165	451
2008	230,447	35.43	36.09	0.66	152	522
2009	234,645	37.29	38.03	0.74	174	595
2010	238,924	38.76	39.53	0.77	184	666
2011	243,289	41.04	41.87	0.83	202	737
2012	247,742	42.63	43.51	0.88	218	806

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. The Base Case fuel price projections were developed by Slater Consulting based on actual data and the U. S. Energy Information Administration's 2000 Annual Energy Outlook Reference Case Forecast, but with the natural gas price escalations moderated to be more in keeping with the Standard & Poor's DRI forecast, which was included in the EIA's publication as a comparison forecast. The fuel prices for this sensitivity case were the same as for the Base Case except that the prices of natural gas were projected to escalate at the growth rates projected in the EIA's Reference Case Forecast.

2. The estimated wholesale energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

TABLE II-18.B

PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, LOW LOAD GROWTH SENSITIVITY CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	205,684	32.46	32.69	0.23	47	36
2004	209,187	30.97	31.62	0.65	136	128
2005	212,400	32.10	32.84	0.74	157	226
2006	215,713	32.26	32.85	0.59	127	298
2007	218,754	32.58	33.14	0.56	123	361
2008	221,389	33.09	33.56	0.47	104	409
2009	224,295	34.12	34.75	0.63	141	469
2010	227,242	34.96	35.56	0.60	136	522
2011	230,238	36.64	37.08	0.44	101	557
2012	233,280	37.46	38.40	0.94	219	627

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. This Low Load Growth scenario reflects growth rates 0.5 percent per year less than in the Base Case.

2. The estimated wholesale energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utilities.

TABLE II-18.C

PENINSULAR FLORIDA, SUMMARY OF PROJECTED WHOLESALE ENERGY COST SAVINGS DUE TO OSPREY ENERGY CENTER, HIGH LOAD GROWTH SENSITIVITY CASE, 2003-2012

YEAR	FRCC NET ENERGY FOR LOAD (GWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITH OSPREY ($/MWH)	AVERAGE ANNUAL MARGINAL ENERGY COST WITHOUT OSPREY ($/MWH)	WHOLESALE PRICE SUPPRESSION ($/MWH)	ESTIMATED SAVINGS FROM OSPREY ($MILLION)	CUMULATIVE NPV @ 10% 2000 DOLLARS ($MILLION)
2003	215,127	34.16	34.57	0.41	88	66
2004	222,089	33.44	34.29	0.85	189	195
2005	228,900	35.07	35.99	0.92	211	326
2006	235,976	35.94	36.75	0.81	191	434
2007	242,907	36.59	37.43	0.84	204	539
2008	249,539	38.02	39.04	1.02	255	657
2009	256,627	40.26	41.26	1.00	257	766
2010	263,921	42.51	43.51	1.00	264	868
2011	271,429	46.36	47.63	1.27	345	989
2012	279,162	49.17	50.64	1.47	410	1,119

Source: PROMOD IV(R) analyses prepared by Slater Consulting.

Notes: 1. This High Load Growth scenario reflects growth rates 1.0 percent per year greater than in the Base Case.

2. The estimated energy cost reductions shown here are subject to the Project's output being contractually committed to Seminole and other Peninsular Florida load-serving utlities.

TABLE II-19

OSPREY ENERGY CENTER
GENERATING ALTERNATIVES
EVALUATED BY CALPINE

GENERATING TECHNOLOGIES CONSIDERED

COMBUSTION TURBINE-OIL

COMBUSTION TURBINE-GAS

COMBINED CYCLE-GAS

COMBINED CYCLE-OIL

PULVERIZED COAL STEAM

CONVENTIONAL GAS STEAM

COAL GASIFICATION-COMBINED CYCLE

NUCLEAR STEAM

RENEWABLE ENERGY

TABLE II-20

OSPREY ENERGY CENTER, CALPINE'S COST-EFFECTIVENESS ANALYSES OF ALTERNATIVE GENERATION TECHNOLOGIES

Comparison of Generation Alternatives

Technology Type	Levelized Life-Cycle Cost at Assumed Capacity Factor (2000 $/MWh)		
	Peaking Operation (10% CF)	Intermediate Oper. (50% CF)	Base Load Oper. (90% CF)
Combined Cycle - Gas Fired	$ 98 - 118	$ 37 - 45	$ 30 - 37
Combined Cycle - Oil Fired	111 - 134	50 - 61	43 - 53
Simple Cycle - Gas Fired	85 - 116	52 - 73	45 - 68
Simple Cycle - Oil Fired	110 - 144	71 - 101	64 - 97
Steam - Coal	200 - 220	52 - 59	35 - 42
Steam - Gas	124	53	45
Steam - Nuclear	283	61	36
IGCC Technology	196 - 245	49 - 61	32 - 40
Renewable Energy	121 - 1072	67 - 240	47 - 147

Source: R. W. Beck and Associates

VI. CONSEQUENCES OF DELAY

Delaying the construction and operation of the Osprey Energy Center will adversely affect Seminole,[11] will adversely affect the reliability of the Peninsular Florida bulk power supply system, will adversely affect the availability in Peninsular Florida of adequate electricity at a reasonable cost, will adversely affect the cost-effectiveness of electricity generation in Peninsular Florida, and will adversely affect the environment of Florida, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities.

A. Reliability Consequences of Delay.

The Osprey Energy Center will be a highly reliable and highly efficient gas-fired combined cycle power plant. It will use proven, state-of-the-art technology. The Project's high reliability--an Equivalent Availability Factor greater than 94 percent--assures its contributions to improving the reserve margins and reliability of the Peninsular Florida power supply system, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities.

Tables II-7 and II-8 demonstrate that the Project will improve Peninsular Florida's summer and winter reserve margins by up to 1.1

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[11]Volume I of the Amended Exhibits discusses the consequences of delaying the construction and operation of the Project to Seminole.

to 1.3 percent in each year beginning with the Project's in-service date in the second quarter of 2003 and continuing throughout the period covered in the FRCC 2000 Resource Plan, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities.

The availability of this additional capacity to Seminole or to other Peninsular Florida load-serving utilities -- 496 MW at summer peak, 578 MW at winter peak -- is expected to improve reliability and reduce Peninsular Florida's exposure to outages due to extreme weather or unanticipated events such as major generation outages. The presence of this capacity will mean that, in an extreme cold weather event, approximately 578 MW (32° F. ambient conditions without duct-firing) of load will be served that would not otherwise be served, subject to the Project's output being contractually committed to Seminole or other Peninsular Florida load-serving utilities. This means that the Project would enable Florida's retail-serving utilities, including Seminole's Member cooperatives, to maintain service to approximately 115,000 to 165,000 residential customers (or equivalent load), assuming a coincident peak demand of 3.5 kW to 5 kW per household) during such conditions. The Project's enhanced capacity from duct-firing and power augmentation would enable Florida retail-serving utilities, including Seminole's Member cooperatives, to maintain service to another 17,000 to 25,000 households.

If the Osprey Energy Center is not constructed and brought into commercial operation in 2003 as proposed, these reliability

benefits will be lost, and Florida electric customers will be exposed to a greater probability of service interruption than they would experience if the Project were built as proposed by Calpine.

B. Power Supply Cost Consequences of Delay.

The Osprey Energy Center will be a highly reliable and highly efficient gas-fired combined cycle power plant using proven technology. The Project's high efficiency assures its contributions to reducing wholesale power supply costs in Peninsular Florida. If operated on an economic dispatch basis and subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the Project would be expected to reduce the total cost of electricity generation in Peninsular Florida and will reduce power supply costs to those specific utilities, such as Seminole, that purchase the Project's output, thereby reducing the retail electric rates paid by those utilities' customers.

The presence of the Osprey Energy Center will reduce generation costs and will also suppress wholesale power prices, to at least some degree, in Peninsular Florida, subject to the Project's output being contractually committed to Seminole or to other Peninsular load-serving utilities. This is the simple economic result of an increase in supply, i.e., an outward shift in the supply curve for bulk power. Even at nominal differences in the wholesale cost of power with and without the Project, the savings can be expected to be substantial. Moreover, the Project will provide real, tangible economic benefits--real reductions in

the amount of primary fuels used to generate the same amounts of electricity--to Florida and to society in general by virtue of the Project's more efficient use of fuel.

If the Osprey Energy Center is not constructed and brought into commercial operation in 2003 as planned and sought, these economic benefits will be lost, and, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, Florida electric customers will pay more for their power service than they would otherwise, and more for their power service than they have to.

C. **Environmental Consequences of Delay**.

The Osprey Energy Center will be a highly efficient state-of-the-art, natural gas-fired combined cycle electric generating facility. Because of its high efficiency and the use of clean-burning natural gas as its fuel, the Project will bring net air emissions benefits to Florida. Subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the Project will displace production from older, less efficient and less environmentally desirable power plants, e.g., less efficient oil-fired steam generating plants, less efficient gas-fired steam generating units, and combustion turbine plants fired by oil or gas. This displacement will result in substantial savings in primary fuel consumption for electricity generation (see Tables II-15.A and II-

15.B), thus resulting in reduced air emissions from power production in Florida. See Table II-16.

The projections prepared for Calpine, subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, indicate that the Project's generation will generally displace production from older steam generating units fired by heavy fuel oil and natural gas, which generally have heat rates in the range of 10,000 to 11,000 Btu per kWh. Regardless of the type of primary fuel displaced, the Project's operations will result in significant fuel savings; because of its better heat rate, the Project uses approximately 35 percent less primary fuel energy (measured in Btus) than conventional steam generation units to produce the same amount of electricity.

In addition, under reasonable assumptions regarding the types of marginal fuels displaced by the Osprey Energy Center's operations, reasonably assuming that the displaced oil-fired and gas-fired generation will not be sold outside Florida, and subject to the Project's output being contractually committed to Seminole or to other Peninsular Florida load-serving utilities, the Project's operations are expected to improve the overall environmental profile of electricity generation in Florida. When the Project's output displaces generation using heavy fuel oil, there should be significant reductions in emissions of SO_2, NO_x, and CO, and measurable reductions in CO_2 emissions. Even when the

Project displaces gas-fired steam generation, there should be reductions in emissions due to the Project's better heat rate, newer turbine design, and emissions controls, resulting in lower emissions of NO_x, SO_2, and CO, and measurable reductions in CO_2 emissions. If the Project is not constructed and brought into commercial operation in 2003 as planned and sought, these environmental benefits will be lost, and pollution from electric generation in Florida will be significantly greater than it would otherwise be.

APPENDICES

APPENDIX II-A

FERC ORDER GRANTING MARKET-BASED RATE AUTHORITY TO CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

RIMS Doc ID 2032133

90 FERC ¶ 61,164

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

February 23, 2000

Docket Nos. ER00-939-000
ER00-1049-000
ER00-1115-000

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Dear Sirs:

You submitted for filing with the Commission rate schedules under which applicants will engage in wholesale electric power and energy transactions at market-based rates. Your submittals, as modified below, comply with the Commission's requirements for market-based rates and are accepted for filing. They are designated and made effective as indicated in Appendix A to this order.

Calpine Construction Finance Company, L.P. (Calpine) requests authority to engage in the sale of certain ancillary services (listed in its proposed rate schedule) at market-based rates into the markets administered by the California ISO, the New England Power Pool markets administered by ISO New England, Inc., the New York Power Pool markets administered by the New York Independent System Operator, and into the

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FEB 23 2000

ER00-939-000, 1049-000, 1115-000

Pennsylvania-New Jersey-Maryland Interchange Energy Market.[1] We will grant this request.[2]

Any waivers or authorizations requested by the applicants are granted to the extent specified in Appendix B to this order. Waiver of the prior or advance notice requirements, if requested, is granted to the extent specified in Appendix A. The applicants must comply with the reporting requirements and other requirements specified in Appendix B to this order.[3]

The codes of conduct submitted by the applicants are accepted if consistent with Appendix C, which reflects requirements adopted in previous Commission orders. Any code of conduct inconsistent with Appendix C is rejected and in such case Appendix C has been designated as the applicant's code of conduct. The codes of conduct submitted by the applicants covered by this order are consistent with Appendix C.

Calcasieu Power, L.L.C.'s (Calcasieu) proposed rate schedule fails to include a prohibition on power sales to affiliates, absent prior Commission approval under section

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[1]Calpine also proposes to provide Replacement Reserve service at market-based rates. The Commission has determined that Replacement Reserve service is not an ancillary service, and the granting of market-based rate authority for sales of energy and capacity includes the granting of market-based rate authority for Replacement Reserve service. See, e.g., AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 at 61,452, 61,464 (1998), order on reh'g, 87 FERC ¶ 61,208 (1999) (AES).

[2]See AES; New England Power Pool, 85 FERC ¶ 61,379 (1998), reh'g pending; Central Hudson Gas & Electric Corporation, et al., 86 FERC ¶ 61,062, order on reh'g, 88 FERC ¶ 61,138 (1999); Atlantic City Electric Company, et al., 86 FERC ¶ 61,248, clarified, 86 FERC ¶ 61,310 (1999).

[3]On May 27, 1999, the Commission issued an order in which it modified the reporting requirements for long-term transactions applicable to public utilities without ownership or control over generation or transmission facilities that are authorized to sell power at market-based rates (power marketers). Southern Company Services, et al., 87 FERC ¶ 61,214 (1999), reh'g pending (Southern). Specifically, with respect to any long-term transaction agreed to by a power marketer after 30 days from the date of issuance of a final order in the Southern case, the power marketer must file a service agreement with the Commission within 30 days after service commences, rather than reporting transactions thereunder in its quarterly transaction summaries.

205 of the Federal Power Act (FPA), 16 U.S.C. § 824d (1994). Calcasieu is directed, within 30 days of the date of this order, to revise its rate schedule accordingly.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1999), an entity's filing of a timely notice of intervention or a timely, unopposed motion to intervene in a proceeding makes it a party to that proceeding.

Should an applicant or any of its affiliates deny, delay, or require unreasonable terms, conditions, or rates for natural gas fuel or services to a potential electric competitor in bulk power markets, then that electric competitor may file a complaint with the Commission that could result in the applicant's or its affiliate's authority to sell power at market-based rates being suspended.[4]

Sales of accounts receivable are not dispositions of jurisdictional facilities and are not within the scope of section 203 of the FPA. To the extent an applicant seeks a case-specific finding on this or any related point, it may file a petition for a declaratory order with the Commission.

Calcasieu and Lake Worth Generation L.L.C. (Lake Worth) seek Commission approval to reassign transmission capacity. We find their requests to be consistent with our requirements.

Lake Worth and Calcasieu must inform the Commission of the dates service commences.

By direction of the Commission.

Linwood A. Watson, Jr.,
Acting Secretary.

[4] See, e.g., Louisville Gas & Electric Co., 62 FERC ¶ 61,016 at 61,148 (1993).

APPENDIX A

Applicants are hereby informed of the following rate schedule designations:

Lake Worth Generation L.L.C.
Docket No. ER00-939-000
Rate Schedule Designation
Effective Date: Date Service Commences

Designation	Description
FERC Electric Tariff, Original Volume No. 1, Original Sheet No. 1	Market-Based Rate Tariff

Calcasieu Power, LLC
Docket No. ER00-1049-000
Rate Schedule Designations
Effective Date: Date Service Commences

Designation	Description
FERC Electric Tariff, Original Volume No. 1 Original Sheet Nos. 1-2	Market-Based Rate Tariff and Code of Conduct

Calpine Construction Finance Company, L.P.
Docket No. ER00-1115-000
Rate Schedule Designation
Effective Date: March 14, 2000

Designation	Description
FERC Electric Tariff, Original Volume No. 1 Original Sheet Nos. 1-2	Market-Based Rate Tariff

APPENDIX B

(1) If requested, waiver of Parts 41, 101, and 141 of the Commission's regulations, with the exception of 18 C.F.R. §§ 141.14, .15 (1999), is granted. Licensees remain obligated to file the Form No. 80 and the Annual Conveyance Report.

(2) Within 30 days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liabilities by those applicants who have sought such approval should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211 and 385.214.

(3) Absent a request to be heard within the period set forth in Paragraph (2) above, if the applicants have requested such authorization, the applicants are hereby authorized to issue securities and assume obligations or liabilities as guarantor, indorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the applicants, compatible with the public interest, and reasonably necessary or appropriate for such purposes.

(4) If requested, until further order of this Commission, the full requirements of Part 45 of the Commission's regulations, except as noted below, are hereby waived with respect to any person now holding or who may hold an otherwise proscribed interlocking directorate involving the applicants. Any such person instead shall file a sworn application providing the following information:

(a) full name and business address; and

(b) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(5) The Commission reserves the right to modify this order to require a further showing that neither the public nor private interests will be adversely affected by continued Commission approval of the applicants' issuances of securities or assumptions of liabilities, or by the continued holding of any affected interlocks.

(6) If requested, waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15 and 35.16, is granted for transactions under the rate schedules at issue here.

(7) (a) Applicants who own generating facilities may file umbrella service agreements for short-term power sales (one year or less) within 30 days of the date of commencement of short-term service, to be followed by quarterly transaction summaries of specific sales (including risk management transactions if they result in actual delivery of electricity). For long-term transactions (longer than one year), applicants must submit the actual individual service agreement for each transaction within 30 days of the date of commencement of service. To ensure the clear identification of filings, and in order to facilitate the orderly maintenance of the Commission's files and public access to documents, long-term transaction service agreements should not be filed together with short-term transaction summaries. For applicants who own, control or operate facilities used for the transmission of electric energy in interstate commerce, prices for generation, transmission and ancillary services must be stated separately in the quarterly reports and long-term service agreements.

(b) Applicants who do not own generating facilities must file quarterly reports detailing the purchase and sale transactions undertaken in the prior quarter (including risk management transactions if they result in actual delivery of electricity). Applicants who are power marketers should include in their quarterly reports only those risk management transactions that result in the actual delivery of electricity.

(8) The first quarterly report filed by an applicant in response to Paragraph (7) above will be due within 30 days of the end of the quarter in which the rate schedule is made effective.

(9) Each applicant must file an updated market analysis within three years of the date of this order, and every three years thereafter. The Commission reserves the right to require such an analysis at any time. The applicants must also inform the Commission promptly of any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing. These include, but are not limited to: (a) ownership of generation or transmission supplies; or (b) affiliation with any entity not disclosed in the applicants' filing that owns generation or transmission facilities or inputs to electric power production, or affiliation with any entity that has a franchised service area. Alternatively, the applicants may elect to report such changes in conjunction with the updated market analysis required above. Each applicant must notify the Commission of which option it elects in the first quarterly report filed pursuant to Paragraph (7) above.

APPENDIX C

[APPLICANT]
SUPPLEMENT NO. _ TO RATE SCHEDULE NO. _

STATEMENT OF POLICY
AND CODE OF CONDUCT
WITH RESPECT TO THE RELATIONSHIP BETWEEN
[POWER MARKETER] AND [PUBLIC UTILITY]

Marketing of Power

1. To the maximum extent practical, the employees of [Power Marketer] will operate separately from the employees of [Public Utility].

2. All market information shared between [Public Utility] and [Power Marketer] will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. Shared employees in a support role are not bound by this provision, but they may not serve as an improper conduit of information to non-support personnel.

3. Sales of any non-power goods or services by [Public Utility], including sales made through its affiliated EWG's or QF's, to [Power Marketer] will be at the higher of cost or market price.

4. Sales of any non-power goods or services by the [Power Marketer] to [Public Utility] will not be at a price above market.

Brokering of Power

To the extent [Power Marketer] seeks to broker power for [Public Utility]:

5. [Power Marketer] will offer [Public Utility's] power first.

6. The arrangement between [Power Marketer] and [Public Utility] is non-exclusive.

7. [Power Marketer] will not accept any fees in conjunction with any Brokering services it performs for [Public Utility].

APPENDIX II-B

PRECEDENT AGREEMENT BETWEEN CALPINE EAST FUELS, L.L.C.
AND
GULFSTREAM NATURAL GAS SYSTEM, L.L.C.

PRECEDENT AGREEMENT

This Precedent Agreement ("Agreement"), is made and entered into as of this 8th day of October, 1999, by and between Calpine East Fuels, L.L.C., a Delaware limited liability company ("Shipper"), and Gulfstream Natural Gas System, L.L.C., a limited liability company formed under the laws of the State of Delaware ("Gulfstream") (hereinafter Shipper and Gulfstream are sometimes referred to individually as a "Party" or collectively as the "Parties").

WITNESSETH:

WHEREAS, Gulfstream intends to design, construct, own and operate a natural gas pipeline that will extend from interconnections with the facilities of various natural gas treatment plants, processing plants and interstate natural gas transmission systems in the vicinity of Mobile, Alabama and southeastern Mississippi to various delivery points in peninsular Florida ("Gulfstream Project"); and

WHEREAS, Shipper intends to design, construct, own and operate a natural gas fired electric generating plant in Polk County, Florida ("Plant") which Shipper plans to have in-service on or before and desires to receive firm transportation service(s) from Gulfstream on the Gulfstream Project for the natural gas supply required for the Plant; and

WHEREAS, subject to the terms and conditions set forth in this

Agreement, Gulfstream is willing to proceed with its efforts to develop the Gulfstream Project for the provision of the firm transportation service(s) hereinafter described, and Shipper is willing to subscribe for such transportation services.

NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, and intending to be bound, Shipper and Gulfstream agree as follows:

1. Notice of Intent to Proceed. This Agreement is subject to (i) the outcome of an open season for the Gulfstream Project, and (ii) the determination by Gulfstream, in the exercise of its sole discretion, whether or not to proceed with the filing and prosecution of application(s) for the governmental and regulatory authorization(s) described in Paragraph 2 below. Within a reasonable time following execution and delivery of this Agreement by Shipper, Gulfstream will proceed with the filing and prosecution of such application(s) with respect to the Gulfstream Project. To facilitate Gulfstream's ability to develop the Gulfstream Project, Shipper will refrain from committing to obtain any transportation service(s) from other person(s) which service(s) would be in lieu of the transportation services provided for herein.

2. Regulatory Authorizations To Be Sought By Gulfstream. Subject to the other terms and conditions of this Agreement, Gulfstream will proceed with due diligence to apply for and attempt to obtain all governmental and regulatory authorizations, including without limitation authorizations from the Federal Energy

Regulatory Commission ("FERC"), which Gulfstream determines are necessary for Gulfstream to (i) construct, own and operate (or cause to be constructed and operated) the Gulfstream Project, (ii) render the transportation service(s) contemplated in this Agreement and all of the precedent agreements with other shippers for transportation service(s) to be provided utilizing the Gulfstream Project and (iii) perform its obligations as contemplated in this Agreement. Gulfstream will request that the FERC issue a preliminary determination on the non-environmental aspects of the Gulfstream Project. Gulfstream reserves the right to file and prosecute any and all applications for such authorizations (and any supplements and amendments thereto) and, if necessary, institute any court review with respect thereto, in such manner as it deems to be in its best interest. Shipper agrees to support and cooperate in the efforts of Gulfstream to obtain all authorizations which Gulfstream determines are necessary for Gulfstream to construct, own and operate the Gulfstream Project and render the transportation service(s) contemplated in this Agreement, including, at the sole discretion of Shipper, the filing of an intervention or other pleading in support of the Gulfstream Project. If the FERC determines that information related to Shipper's markets, gas supply or upstream or downstream transportation arrangements is required from Gulfstream, Shipper agrees to provide Gulfstream with such information in a timely manner to enable Gulfstream to respond within the time required by

FERC; provided that Gulfstream will use reasonable best efforts to obtain a protective order from the FERC for any commercially sensitive or confidential information identified by Shipper.

3. Shipper's Regulatory Authorizations.

Subject to the other terms and conditions of this Agreement, Shipper shall proceed with due diligence to apply for and attempt to obtain from all governmental and regulatory authorities having jurisdiction all authorizations necessary for Shipper to (i) construct, own and operate (or cause to be constructed and operated) the Plant and all other facilities necessary to enable Shipper to utilize the transportation service(s) contemplated in this Agreement and (ii) perform its obligations as contemplated in this Agreement. Shipper reserves the right to file and prosecute applications for such authorizations (and any supplements and amendments thereto) and, if necessary, institute any court review with respect thereto, in such manner as it deems to be in its best interest; provided, however, that Shipper shall prosecute such applications (and any supplements and amendments thereto or court appeals) in a timely manner and in no event shall Shipper take any action that would obstruct, interfere with or delay the receipt by Gulfstream of the authorizations described in Paragraph 2 above. Gulfstream agrees to support and cooperate in the efforts of Shipper to obtain all authorizations necessary for Shipper to utilize the transportation service(s) contemplated herein. Subject to its receipt of all such necessary authorizations and subject to

the satisfaction of each of the conditions precedent set forth in Paragraph 6 below (or written waiver of the same by the Party on whose behalf such condition is imposed), Shipper agrees to proceed with due diligence to construct, or cause to be constructed, the Plant and all other facilities necessary for Shipper to utilize the transportation service(s) contemplated herein.

4. Service Agreement.

(a) Service Agreement. Shipper and Gulfstream agree to execute, within ten (10) business days after the date each Party gives the other Party written notice that each of the conditions precedent imposed on behalf of such Party in Paragraph 6 hereof has been satisfied or waived by such Party, the Firm Transportation Service Agreement attached hereto as Attachment 1, as such Agreement may be amended from time to time to conform to changes approved by the FERC to Gulfstream's FERC Gas Tariff ("Service Agreement"). Service under the Service Agreement will commence as set forth in Paragraph 4(b) below.

(b) Commencement and Term of Service. Shipper will give Gulfstream written notice of the date Shipper plans to place the Plant in-service no less than months prior to such date (the "Plant In-Service Date"); provided that Shipper shall give Gulfstream timely written notice thereafter of any change(s) to the Plant In-Service Date which change(s) shall not delay the Plant In-Service Date by more than months and, if such written notice is provided, the date specified therein shall become

the new Plant In-Service Date; and further provided that the Plant In-Service Date shall be no later than . Transportation service(s) under the Service Agreement will commence on the date specified by Gulfstream in the written notice to be provided to Shipper pursuant to Paragraph 4(c) below. After transportation service(s) commences under the Service Agreement, such service(s) will continue for the primary term set forth therein and year to year thereafter subject to termination in accordance with the provisions of the Service Agreement. Nothing in this Subparagraph 4(b) shall modify or otherwise change Shipper's right, as set forth in Subparagraph 5(b), to terminate this Agreement or the Service Agreement, as the case may be, if Gulfstream does not commence service on or before

(c) Notice of Commencement of Transportation Service(s). No less than thirty (30) days prior to the date Gulfstream is ready to commence transportation service(s) under the Service Agreement, Gulfstream will notify Shipper in writing that such transportation service(s) will commence on a date certain, which date will be the later to occur of (1) June 1, 2002 or (2) the Plant In-Service Date (the "Commencement Date"). As of the Commencement Date, Gulfstream

will stand ready to provide firm transportation service(s) to Shipper pursuant to the provisions of the Service Agreement, and Shipper will pay to Gulfstream all applicable charges provided for in the Service Agreement.

(d) Test Gas

5. Construction of Facilities.

(a) Design and Construction. Upon execution and delivery of this Agreement by Shipper, Gulfstream will undertake the preliminary design of the facilities for the Gulfstream Project and any other preparatory actions required for Gulfstream to complete and file application(s) with the FERC and other governmental or regulatory agencies having jurisdiction for the authorizations which Gulfstream determines are necessary for Gulfstream to (i) construct, own and operate (or cause to be constructed and operated) the Gulfstream Project, (ii) render the transportation service(s) contemplated in this Agreement and all of the precedent agreements with other shippers for transportation service(s) to be provided utilizing the Gulfstream Project and (iii) perform its obligations as contemplated in this Agreement. Upon satisfaction of each of the conditions precedent set forth in Paragraph 6 below,

or written waiver of the same by the Party on whose behalf such condition is imposed, and subject to the continuing commitments of Shipper and all of the other shippers who have executed precedent agreements for transportation service(s) to be provided utilizing the Gulfstream Project, Gulfstream will proceed with due diligence to construct the pipeline and other facilities (as authorized by the FERC and other governmental or regulatory agencies having jurisdiction) which are necessary for the provision of the firm transportation service(s) contemplated in this Agreement. Notwithstanding Gulfstream's due diligence, if Gulfstream is unable to commence the transportation service(s) for Shipper as contemplated herein by the Plant In-Service Date, Gulfstream will continue to proceed with due diligence to complete construction of such necessary pipeline and other facilities, and commence transportation service(s) for Shipper at the earliest practicable date thereafter.

(b) Limitation of Liability. Gulfstream will neither be liable to Shipper nor will this Agreement or the Service Agreement be subject to cancellation (except as hereinafter provided) if Gulfstream is unable to complete the construction of such pipeline and other facilities and commence the firm transportation service(s) contemplated herein by the Plant In-Service Date; provided, however, Gulfstream will continue to proceed with due diligence to complete construction of such pipeline and other facilities, and commence such transportation service(s) for Shipper

at the earliest practicable date thereafter. If Gulfstream is unable to commence the transportation service(s) for Shipper as contemplated herein by the Plant In-Service Date which shall not be earlier than . Shipper, in its sole discretion, will have the option not to commence the transportation service(s) until and, in that event, applicable charges under the Service Agreement will not commence until .

If Gulfstream is unable to commence the transportation service(s) for Shipper by four (4) months prior to the Plant In Service Date, Shipper, in its sole discretion, will have the option to terminate this Agreement and will have no further liability to Gulfstream.

6. Conditions Precedent.

The commencement of transportation service(s) under the Service Agreement, and Gulfstream's and Shipper's respective rights and obligations hereunder and under the Service Agreement, are expressly made subject to the satisfaction of each of the following conditions precedent; provided, however, that each such condition may be waived in writing by the Party on whose behalf the condition is imposed:

(a) Conditions Precedent Imposed On Behalf Of Gulfstream:

(b) Conditions Precedent Imposed On Behalf Of Shipper:

7. Rates and Rate Design Methodology. Shippers electing a negotiated rate agree to pay such rate without regard to any action or determination of the FERC with respect to Gulfstream's FERC-approved, filed rates. Shippers electing recourse rates agree to pay such rates, subject to changes determined by the FERC from time to time. Recourse rates will be the rates filed with and approved by the FERC, pursuant to the Natural Gas Act or successor legislation.

8. Representations and Warranties.

(a) Gulfstream. Gulfstream represents and warrants that (i) it is duly organized and validly existing under the laws of the State of Delaware and has all requisite legal power and authority to execute this Agreement and carry out the terms, conditions and provisions hereof; (ii) this Agreement constitutes the valid, legal and binding obligation of Gulfstream, enforceable in accordance with the terms hereof, (iii) there are no actions, suits or proceedings pending or, to Gulfstream's knowledge, threatened against or affecting Gulfstream before any Court or administrative

body that might materially adversely affect the ability of Gulfstream to meet and carry out its obligations hereunder; and (iv) the execution and delivery by Gulfstream of this Agreement has been duly authorized by all requisite limited liability company action.

(b) Shipper. Shipper represents and warrants that (i) it is duly organized and validly existing under the laws of the State of Delaware and has all requisite legal power and authority to execute this Agreement and carry out the terms, conditions and provisions hereof; (ii) this Agreement constitutes the valid, legal and binding obligation of Shipper, enforceable in accordance with the terms hereof, (iii) there are no actions, suits or proceedings pending or, to Shipper's knowledge, threatened against or affecting Shipper before any Court or administrative body that might materially adversely affect the ability of Shipper to meet and carry out its obligations hereunder; (iv) the execution and delivery by Shipper of this Agreement has been duly authorized by all requisite corporate action, and (v) upon execution and delivery of the Service Agreement, Shipper will satisfy the Agreed Creditworthiness Requirements

9. Term. This Agreement shall become effective when executed by both Gulfstream and Shipper, and shall remain in effect unless and until terminated as hereinafter provided.

(a) Termination of Precedent Agreement. In the event each of the conditions precedent set forth in Paragraph 6 above has not

been satisfied or waived by the Party on whose behalf such condition is imposed by the date specified in such Paragraph, then such Party may terminate this Agreement by giving written notice of termination to the other Party within thirty (30) days of such date.

(b) Commencement of Transportation Service(s). If this Agreement is not terminated pursuant to Paragraph 5(b) or Paragraph 9(a) above, then this Agreement will terminate by its express terms on the Commencement Date, and thereafter Gulfstream's and Shipper's respective rights and obligations related to the transactions contemplated herein shall be determined pursuant to the terms and conditions of the Service Agreement and the terms and conditions of Gulfstream's FERC Gas Tariff, as in effect from time to time.

10. Assignment. This Agreement shall be binding upon Gulfstream, Shipper and their respective successors and assigns; provided, however, that neither Party shall assign this Agreement or any rights or obligations hereunder without first obtaining the prior written consent of the other Party (which consent shall not be unreasonably withheld), the consent of Gulfstream's lenders if required, and any necessary governmental and regulatory authorizations. Nothing contained herein shall prevent Gulfstream from pledging, mortgaging or assigning its rights as security for its indebtedness and Gulfstream may assign to the pledgee or mortgagee (or to a trustee for a holder of such indebtedness) any monies due or to become due under the Service Agreement. Subject

to the provision of adequate credit support in Gulfstream's and, if required, Gulfstream's Lenders, reasonable judgment, Shipper may assign this Agreement to any direct or indirect subsidiary or affiliate of Shipper. Shipper may also assign this Agreement as security for financing to any person or persons providing debt or equity financing to Shipper to provide funds for the development, design, construction and operation of the Plant.

11. Modification or Waiver.

No modification or waiver of the terms and conditions of this Agreement shall be made except by the execution by the Parties of a written amendment to this Agreement.

12. Notices.

All notices, requests, demands, instructions and other communications required or permitted to be given hereunder shall be in writing and shall be delivered personally or mailed by certified mail, postage prepaid and return receipt requested or by facsimile, as follows:

If to Gulfstream:

Gulfstream Natural Gas System, L.L.C.
500 Renaissance Center
Detroit, Michigan 48243
Attention: Stanley A. Babiuk
Senior Vice President
Telephone: (313) 496-5653
Facsimile: (313) 496-5052

If to Shipper:

Calpine East Fuels, L.L.C.
Michael D. Petit
Director of Fuels Management - Eastern Region

The Pilot House, 2nd Floor
Lewis Wharf
Boston, Massachusetts 02110
Telephone: 617-723-7200 ext. 106
Facsimile: 617-723-7635

or to such other place within the United States of America as either Party may designate as to itself by written notice to the other Party. All notices given by personal delivery or mail shall be effective on the date of actual receipt at the appropriate address. Notice given by facsimile shall be effective upon actual receipt if received during recipient's normal business hours or at the beginning of the next business day after receipt if received after the recipient's normal business hours.

13. Limitation of Liability. Each Party agrees that any and all claims, demands and causes of action that it may bring against the other Party shall be limited to the assets of the other Party. Execution of this Agreement does not bind any Member of Gulfstream or any of its affiliates (or Shipper or any of its affiliates) or require any Member of Gulfstream or any of its affiliates (or Shipper or any of its affiliates) to undertake any obligation in connection with this Agreement. Accordingly, each Party waives its rights to proceed against, in the case of Shipper, the Members of Gulfstream or any of their respective affiliates or in the case of Gulfstream, any of Shipper's affiliates. Shipper and Gulfstream further agree that neither Party shall be liable to the other Party for consequential, incidental, indirect or punitive damages, whether arising in contract, tort or otherwise. As used in this

Paragraph 13, the term "affiliates" means with respect to a Party, a person that, directly or indirectly through one or more intermediaries, controls or is controlled by or is under common control with such Party.

14. No Third Person Beneficiary. This Agreement shall not create any rights in third parties, and no provision hereof shall be construed as creating any obligations for the benefit of, or rights in favor of, any person or entity other than Gulfstream and Shipper.

15. Governing Law. THE CONSTRUCTION, INTERPRETATION, AND ENFORCEMENT OF THIS AGREEMENT SHALL BE GOVERNED BY THE LAWS OF THE STATE OF DELAWARE, EXCLUDING ANY CONFLICT OF LAW OR RULE WHICH WOULD REFER ANY MATTER TO THE LAWS OF A JURISDICTION OTHER THAN THE STATE OF DELAWARE.

16. Multiple Counterparts. This Agreement may be executed by the Parties in any number of counterparts, each of which shall be deemed an original instrument, but all of which shall constitute but one and the same agreement.

17. Effect of Invalid Provision. Except as otherwise expressly stated herein, in the event any provision contained in this Agreement shall for any reason be held invalid, illegal or unenforceable by a court or regulatory agency of competent jurisdiction by reason of a statutory change or enactment, such invalidity, illegality or unenforceability shall not affect the remaining provisions of this Agreement.

18. Confidentiality. Except as hereinafter provided, neither Gulfstream nor Shipper, nor their respective affiliates, directors, officers, and employees, advisors and representatives shall disclose to any third person the terms and conditions of this Agreement, or any confidential or proprietary information, whether written or verbal, disclosed by either Party at any time in connection with the transaction contemplated herein and clearly designated at the time of disclosure as confidential or proprietary, without the other Party's prior written consent to such disclosure. This Paragraph 18 shall not apply to disclosures that, in the opinion of Gulfstream's or Shipper's counsel, as the case may be, are required by state or federal laws, rules or regulations or are required by the FERC in respect of the Gulfstream Project or by the Florida Public Service Commission in respect of the Plant (in which case, the Party so required to make such disclosure shall advise the other Party prior to such disclosure and, if requested by the other Party, shall use every reasonable effort to maintain the confidentiality of this Agreement, including, without limitation, seeking a protective order). The provisions of this Paragraph 18 shall not apply to any bank, lender or financial institution providing funds to Gulfstream in connection with the financing of the Gulfstream Project or to Shipper in connection with the financing of Shipper's Plant (in which case, the Party making the disclosure shall advise the other

Party prior to such disclosure and, if requested by the other Party, shall use every reasonable effort to maintain the confidentiality of this Agreement). The disclosure of any information pertaining to this Agreement within Gulfstream's or Shipper's internal organization (including affiliates) and within the organization of any third person to which disclosure is authorized by Gulfstream or Shipper shall be limited to those personnel whose duties require their review or counsel with respect to this Agreement and the Party making such disclosure shall instruct such personnel to maintain the confidentiality of this Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed in multiple originals by their duly authorized officers as of the date first written above.

GULFSTREAM NATURAL GAS SYSTEM, L.L.C.

By: _____
Name: Stanley A. Babiuk
Title: Senior Vice President

CALPINE EAST FUELS, L.L.C.

By: _____
Name: Robert K. Alff
Title: Vice President
East Coast Region

Attachment 1

FORM OF AGREEMENT
Rate Schedule FTS

Date: _____,__ Contract No._____

SERVICE AGREEMENT

This AGREEMENT is entered into by Gulfstream Natural Gas System, L.L.C. ("Transporter") and Calpine East Fuels, L.L.C. ("Shipper").

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below, together with the terms and conditions of Transporter's applicable Rate Schedule and General Terms and Conditions of Transporter's FERC Gas Tariff constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. AUTHORITY FOR TRANSPORTATION SERVICE WILL BE UNDER SECTION 284G.

2. RATE SCHEDULE: FTS

3. CONTRACT DATA:

   Note: List Receipt Point(s), Delivery Point, MDQ, MHQ, Receipt Point MDQ and delivery pressure on Exhibit A.

   Such Contract Quantities shall be reduced for scheduling purposes, but not for billing purposes, by the Contract Quantities that Shipper has released through Transporter's capacity release program for the period of any release.

4. TERM:

   This Agreement shall be effective on the Plant In-Service Date.

Transporter will stand ready to provide firm transportation service(s) to Shipper pursuant to the provisions of this Agreement, and Shipper will pay to Transporter all applicable charges provided for in this Agreement. If Gulfstream is unable to commence the transportation service(s) for Shipper as contemplated herein by the Plant In-Service Date which shall not be earlier than November 1, 2002, Shipper, in its sole discretion, will have the option not to commence the transportation service(s) until November 1, 2003, and, in that event, applicable charges under the Service Agreement will not commence until November 1, 2003.

c e(s)
ie dis

1. This Agreement shall remain in force and effect for a primary term of 20 years

5. RATES:

6. INCORPORATION BY REFERENCE:

The provisions of Transporter's applicable Rate Schedule and the General Terms and Conditions of Transporter's FERC Gas Tariff are specifically incorporated herein by reference and made a part hereof.

7. NOTICES:

All notices can be given by telephone or other electronic means, however, such notice shall be confirmed in writing at the addresses below or through Transporter's EBB. Shipper or Transporter may change the addresses below by written notice to the other without the necessity of amending this Agreement:

TRANSPORTER:

Gulfstream Natural Gas System, L.L.C.
500 Renaissance Center
Detroit, MI 48243
Attention: Gas Control (Nominations)
Volume Management (Statements)
Cash Control (Payments)
System Marketing (All Other Matters)

SHIPPER:

Calpine East Fuels, L.L.C.
Michael D. Petit
Director of Fuels Management - Eastern Region
The Pilot House, 2nd Floor
Lewis Wharf
Boston, Massachusetts 02110
Telephone: 617-723-7200 ext 106
Facsimile: 616-723-7635

INVOICES AND STATEMENTS:

Same as above

NOMINATIONS:

Same as above

8. FURTHER AGREEMENT:

This Agreement shall be binding upon Transporter, Shipper and their respective successors and assigns; provided, however, that neither Party shall assign this Agreement or any rights or obligations hereunder without first obtaining the prior written consent of the other Party (which consent shall not be unreasonably withheld), the consent of Transporter's lenders if required, and any necessary governmental and regulatory authorizations. Nothing contained herein shall prevent Transporter from pledging, mortgaging or assigning its rights as security for its indebtedness and Transporter may assign to the pledgee or mortgagee (or to a trustee for a holder of such indebtedness) any monies due or to become due under this Agreement. Subject to the provision of adequate credit support in Transporter's and, if required, Transporter's Lenders, reasonable judgment, Shipper may assign this Agreement to any direct or indirect subsidiary or affiliate of Shipper. Shipper may also assign this Agreement as security for financing to any person or persons providing debt or equity financing to Shipper to provide funds for the development, design, construction and operation of the Plant (as such term is defined in the Precedent Agreement).

9. OPERATIONAL FLOW ORDERS:

Transporter has the right to issue an effective Operational Flow Order pursuant to Section 13 of the General Terms and Conditions.

10. SPECIFICATION OF NEGOTIATED RATE (See Exhibit B):

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be signed by their respective Officers or Representatives thereunto duly authorized to be effective as of the date stated above.

Calpine East Fuels, L.L.C.SHIPPER:_____

TRANSPORTER: Gulfstream Natural Gas System, L.L.C.

By: _____ By: _____

Title: _____ Title: _____

Date: _____ Date: _____

EXHIBIT A

FORM OF AGREEMENT
Transporter's Rate Schedule FTS
(Continued)

BETWEEN GULFSTREAM NATURAL GAS SYSTEM AND CALPINE EAST FUELS, L.L.C.

CONTRACT NUMBERS: _____

CONTRACTED CAPACITY: Dth/d

ORIGINAL CONTRACT DATE: _____

AMENDMENT DATE: _____

Primary Delivery Points: Shipper's when constructed and placed in-service or other plants that Calpine or its affiliates own or operate along the primary path.

Total Delivery Point MDQ: Dth/d

MHQ at Primary Delivery Point: of MDQ . Shipper may vary the flow rate at any of the Primary Delivery Points from per hour to Dth per hour, as long as the cumulative hourly flow rate at Primary Delivery Points does not exceed (1) Dth per hour and (2) the quantities nominated and scheduled for the day under this Agreement. In addition, the cumulative hourly flow rate under the firm Service Agreements between Shipper and Transporter may not exceed per hour at

Minimum Delivery Pressure: 650 psig

Contract Number/ Primary Route	Primary Receipt Point (1)	Primary Receipt Point MDQ

(1) All receipt points added in the Mobile Bay, Alabama area will be available to Shipper. Gulfstream will use reasonable best efforts to obtain interconnections with DIGS Process Plant, Mobil's Maryann Plant, Williams Process Plant, Mobile Bay Pipeline, Destin Pipeline and WGP-Transco.

EXHIBIT B

STATEMENT OF NEGOTIATED RATES

Shipper	Contract Number	Contract Term	Rate Schedule	Reservation Charge	Commodity Charge	Receipt Points	Delivery Points	Quantity	
		20yrs				See Ex .A	See Ex.A		Dth/d

Clean Energy For Florida's Future

Gulfstream
Natural Gas System

July 21, 2000

Mr. Michael D. Petit
Director of Fuels Management
Calpine Eastern
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

Dear Mr. Petit:

You requested that I update you regarding the status of the Gulfstream Natural Gas System L. L. C. project ("Gulfstream"). Gulfstream filed its application with the Federal Energy Regulatory Commission ("FERC") On October 15, 1999 for a certificate of public convenience and necessity to construct, own and operate an interstate natural gas pipeline.

As required by the FERC, the filing includes a comprehensive environmental report that reflects extensive research and field activities relating to Gulfstream's route. This includes surveys for endangered species, cultural resources, wetlands, and other land features. Gulfstream is determined to develop a project that respects, protects, and where possible, enhances the environment. Furthermore, in preparing the filing, Gulfstream developed a route that took into account the needs and desires of affected landowners. To accomplish this, early in the pipeline's planning stages, Gulfstream invited the views of the landowners, government agencies, environmental groups and others with respect to the best possible route for the pipeline. Gulfstream narrowed the route from an original study corridor of ten miles, to a three mile study corridor, and later, to a 1000 foot study corridor. The corridor was finally narrowed to 300 feet for the filing and has been further refined. Since the filing Gulfstream has worked with affected landowners and communities on refining the route. The original route has been slightly modified to accommodate the wishes of those affected. Indeed, Gulfstream believes that the collaborative process engaged in with landowners, government agencies, environmental groups and others has resulted in unprecedented support for the project.

Gulfstream obtained a preliminary determination, on its application to build the Gulfstream project, from the FERC on April 28, 2000. The preliminary determination covers all non-environmental aspects of Gulfstream's application, such as rates and other business issues. A draft environmental impact statement is expected to be issued by FERC staff this summer.

Based upon the timelines in other cases, and given the completeness of the application that was filed, Gulfstream projects that it will have a certificate by the first quarter of 2001, and will be in service by June 2002.

If you need any additional information, please call me at (813) 288-1811.

Sincerely,

George E. Matzke
Executive Director Business Development

Gulfstream Natural Gas System, L. L. C.
2502 Rocky Point Drive • Suite 1040 • Tampa, FL 33607 • (813) 288-1811 • Fax (813) 289-4438 • www.gulfstreamgas.com

APPENDIX II-C

DESCRIPTION OF PROMOD IV®

DESCRIPTION OF PROMOD IV®

The Projected operations of the Osprey Energy Center in the Peninsular Florida power supply system were analyzed using the PROMOD IV® computer model. PROMOD IV® is a widely known and widely used probabilistic computer model that simulates the operations of electric power systems. PROMOD IV® is primarily used as a production costing model and can also be used to evaluate electric system reliability. PROMOD IV® can be used to prepare utility fuel budget forecasts, evaluate the economics and operations of proposed generating capacity additions, project utility operating costs, estimate the prices of firm power and energy in defined markets, project hourly marginal energy costs, and calculate avoided energy and capacity costs.

The inputs to PROMOD IV® include generating unit data for existing and planned power plants in a defined power supply system (in this case Peninsular Florida), fuel consumption and fuel cost data, load and other utility system data, and data regarding transactions within the system. The primary outputs are individual utility or system production costs, generation by unit, fuel usage, other unit characteristics, and reliability information. PROMOD IV® utilizes computationally efficient algorithms that yield results identical to those that would be produced with direct specification of values for all availability states of all units in a power supply system.

EXHIBIT NO._____

DOCKET NO.: 001748-EC

PARTIES: SEMINOLE ELECTRIC COOPERATIVE AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

DESCRIPTION: COMPOSITE EXHIBIT: 1) RESPONSES TO STAFF'S INTERROGATORIES; 2) LATE-FILED DEPOSITION EXHIBITS; 3) PURCHASED POWER AGREEMENT (REDACTED VERSION); 4) DEPOSITIONS OF WITNESSES EAVES, SLATER, WOODBURY, & ZIMMERMAN; 5) AFFIDAVIT OF PUBLICATION OF NOTICE

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001748-EC EXHIBIT NO. 13
COMPANY/ WITNESS: FPSC Staff
DATE 2-12-01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Determination of Need for an Electrical Power Plant in Polk County by Calpine Construction Finance Company, L.P.	)	DOCKET NO. 000442-EI
	)	FILED: NOVEMBER 13, 2000

CALPINE CONSTRUCTION FINANCE COMPANY'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-31)

Calpine Construction Finance Company, L.P., ("Calpine"), pursuant to Uniform Rule 28-106.206, Florida Administrative Code, and the Commission's Order Establishing Procedure, as revised, hereby responds to Staff's First Set of Interrogatories (Nos. 1-31). Calpine's responses are attached.

Affidavits from the individuals who assisted in the preparation of these responses will be provided to Staff counsel under separate cover.

NOV 13 2000

INTERROGATORIES

1. Please indicate and describe in detail the status of the Osprey Energy Center's Site Certification Application with the Florida Department of Environmental Protection (DEP). In your response, please provide an update on the current expected time line of the proceedings at DEP necessary to complete the certification process. Also, please indicate whether and how the water concerns expressed by the Southwest Florida Water Management District have been resolved.

A. Golder and Calpine believe that the SCA Application should be declared sufficient in the near future.

The application received requests for additional information from the FDEP Bureau of Air Regulation ("Bureau") and the Southwest Florida Water Management District ("SWFWMD" or "District"). On behalf of Calpine, Golder submitted a document to the Bureau. The Bureau found the application and response sufficient and issued a draft PSD permit on may 10, 2000. EPA provided comments on June 21, 2000. Golder responded on September 9, 2000. EPA provided comments on June 21, 2000. Golder responded on September 9, 2000. As a result of the EPA comments and applicant responses, the Bureau issued an updated draft PSD permit on October 4, 2000. Golder reviewed the updated draft PSD permit and responded to the Bureau on October 11, 2000, in order to obtain a final draft PSD permit.

Regarding SWFWMD's requests for additional information, Golder submitted two documents in response to SWFWMD's comments on August 14, 2000 and October 12, 2000. Following the October 12 submittal, Calpine, Golder and the SWFWMD staff met to discuss the Project, and Golder submitted supplemental information. It is believed that the responses provided and the information submitted are sufficient to declare the Application sufficient from the SWFWMD's perspective.

The issues of the District were related to clarifying the requested quantities of groundwater and identifying their specific use, groundwater modeling assumptions, the availability of reclaimed water, and the ability to increasingly rely on reclaimed water over the duration of the Project. These issues were resolved through provisions of supplemental data, clarifying the proposed overall water use plan, and obtaining commitments from the City of Auburndale for reclaimed water.

The anticipated timeline for certification is as follows:

Need Determination Hearing: January 2001

Land Use Hearing: January 23, 2001

Certification Hearing: April 17-19, 2001

Certification: 3rd Quarter 2001

(Zwolak)

2. Please explain the impact of Florida being one of the only Southeastern states that is not in an EPA non-attainment zone for ozone on Calpine's decision to locate the proposed Osprey Energy Center in Florida.

A. The fact that Florida was not a non-attainment area had no impact on Calpine's decision to locate in Florida. Calpine selected Florida on the basis of the present need for power and growth in the State. Once preliminary sites were identified, Calpine retained Golder to determine the environmental feasibility of the site. The feasibility review included identifying the attainment status of the County in which the site is located.

(Eves)

3. Please indicate whether Calpine has entered into any contracts or agreement to provide firm capacity from its proposed Osprey Energy Center. Please provide details of any such arrangements, including but not limited to the name of the purchasing entity, the amount of capacity being provided, and the term of the contract.

A. Yes. On October 16, 2000, Calpine entered into an agreement to provide firm capacity from the Osprey Project to Seminole Electric Cooperative, Inc. The agreement between Calpine and Seminole is embodied in a Memorandum of Understanding (the "MOU") which Calpine filed under cover of a request for specified confidential treatment on October 17, 2000. The MOU provides for Seminole to buy, and Calpine to sell, 350 MW of firm capacity from the Osprey Project for a minimum of five years, from June 1, 2004 through May 31, 2009, and provides additional options whereby Seminole may buy up to the full amount of the Osprey Project's firm capacity, and all associated energy produced by the Project, from the Osprey Project's commercial in-service date through May 31, 2009. The MOU also provides for Calpine and Seminole to negotiate in good faith toward renewals of the power sales arrangements for the period from June 1, 2009 through May 22, 2020, which is the termination date of the MOU.

(Eves)

4. Please indicate whether Calpine is currently involved in any discussions or negotiations with potential buyers of firm capacity from the proposed Osprey Energy Center. Please provide details of any such discussions or negotiations, including the potential buyers, the amount or approximate amount of capacity under consideration, and the term that such capacity would be provided.

A. No. The full output of the Osprey Energy Center is committed to Seminole Electric Cooperative, Inc., under the terms of the MOU, and Calpine is not presently pursuing any other power sales from the Osprey Project.

(Eves)

5. Please indicate and describe in detail the status of Calpine's contract to obtain the two Siemans-Westinghouse Model 501F natural gas turbines for the Osprey Energy Center. In your response, please provide the expected delivery date, if any, of the gas turbines. Also, discuss whether any deposits have been required to secure the two natural gas turbines.

A. Calpine has binding agreements in place for the purchase and delivery of the two Siemens-Westinghouse Model 501F natural gas turbines for the Osprey Energy Center. The expected delivery dates for these turbines are June 2002 and July 2002. Pursuant to Calpine's agreement to purchase the turbines, Calpine has paid the required deposits/initial payments for both turbines.

(Eves)

6. On page 9 through 10 of his testimony, Michael Petit discusses the problems if the Gulfstream pipeline system is not constructed. Assuming the pipeline is not constructed, or is delayed beyond the in service date of the Osprey Energy Center, please discuss Calpine's plans for an alternative natural gas delivery source. Discuss any efforts made to determine the availability of an alternative natural gas delivery source if this becomes necessary.

A. Calpine has every confidence that the Gulfstream pipeline will be constructed. Calpine has had preliminary discussions with both Florida Gas Transmission (FGT) and Buccaneer Pipeline regarding potential service in the event that the Gulfstream pipeline is not constructed. The developers of both pipelines have expressed an interest in providing service to the Osprey Energy Center. To meet the fuel requirements of the facility, FGT would construct an approximate 4 mile lateral from its existing system. Buccaneer would construct an approximate 2 mile lateral from its proposed route to meet the fuel requirements of the facility.

(Petit)

7. Please indicate the status of the permitting process for the Gulfstream Natural Gas System. Given the status of this permitting process, is the Gulfstream project expected to be operational prior to the planned in service date of the Osprey Energy Center?

Please refer to the attached letter from Gulfstream addressing the permitting process. The planned in-service date of the Gulfstream Natural Gas System is June 1, 2002, which is several months in advance of when the gas is required to support startup and testing activities required to meet the planned in-service date of the Osprey Project. Given the current status of the Gulfstream permitting process, Gulfstream's projected June 2002 in-service date is entirely realistic, and both Calpine and Gulfstream expect the pipeline to be fully operational in time to support the Osprey Project's commercial in-service date.

(Petit)

Clean Energy For Florida's Future



November 9, 2000

Mr. Michael D. Petit
Calpine Eastern
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

RE: Regulatory/Permitting Status of Gulfstream

Dear Mike:

Gulfstream filed its certificate application with the Federal Energy Regulatory Commission (FERC) on October 15, 1999. The Notice of Intent to prepare an Environmental Impact Statement (EIS) was issued by FERC on December 6, 1999. The FERC issued a preliminary determination addressing all non-environmental aspects of the project on April 28, 2000, The Draft Environmental Impact Statement (DEIS) was issued by FERC August 31, 2000.

We anticipate receiving final certificate authorization from FERC in February, 2001. The date satisfies our timeline requirements to meet a June 1, 2002 in-service date.

Attached is a detailed summary/status of major permits, licenses and certifications required for the project.

If you need any other information, do not hesitate to call me.

Sincerely,

Stanley A. Babiuk
Senior Vice President

Gulfstream Natural Gas System, L. L. C.
2502 Rocky Point Drive • Suite 1040 • Tampa, FL 33607 • (813) 288-1811 • Fax (813) 289-4438 • www.gulfstreamgas.com

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TABLE 1
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
Federal			
Review of project features that affect cultural resources that are either listed on or eligible for listing on the NRHP	**Advisory Council on Historic Preservation**	State SHPO Field survey reports filed October 15, 1999. Supplemental Filing Submitted 2/29/00.	AL/MS Clearances are complete.
Certificate of Public Convenience and Necessity	**Federal Energy Regulatory Commission**	Filing submitted October 15, 1999. Supplemental Filing submitted 2/29/00. Northern Highlands Alternative filing submitted May 15, 2000. DEIS Comments and updates filed 10/24/00. FEIS expected January 2001.	Certificate Expected February 2001
	U.S. Department of the Army		
Section 10 Permit, Fairway crossings Approval Section 404 Permit	Army Corps of Engineers (Mobile and Jacksonville)	Consolidated Permit in Florida filed February 29, 2000. Jacksonville District Permit filed 2/29/00. Mobile District section 10 and 404 permit to be filed December, 2000.	Jacksonville District permit expected February 2001 Mobile District permit expected April, 2001.
	U.S. Department of the Interior		
Section 7, Endangered and Threatened Species Consultation	Fish and Wildlife Service (Daphne, Vero Beach, Jacksonville)	Biological Assessment (BA) Filed with FWS October 15, 1999. Supplemental Survey Report filed 2/29/00. Updated BA Report filed 8/10/00 and 10/24/00. Expecting BO process complete January 2001.	Alabama/Mississippi Clearance letter dated January 31, 2000 Received. Florida pending review
Right-of-Way Permit	Minerals Management Service	Permit application filed October 15, 1999. Supplemental video survey report filed March 8, 2000. Submitted Live Bottom survey report July 28 and October 24, 2000.	Expected May 2001 (after COE Permit issuance)
Hydrostatic Test Water Discharge Permit Offshore Gulf of Mexico	U.S. Environmental Protection Agency	Permit to be filed in November, 2000.	Expected February 2001
NPDES General Stormwater discharge permit in Florida	U.S. Environmental Protection Agency/FDEP	Permit to be filed in November, 2000.	Expected February 2001

October 31, 2000

TABLE 1
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
	U.S. Department of Commerce		
Section 7, Endangered and Threatened Species Consultation	National Marine Fisheries Service	Clearance requested October 15, 1999. Live Bottom survey report submitted July 28, 2000.	Clearance expected January 2001
Mississippi			
Section 401 Water Quality Certification Storm Water Discharge Permit (Section 4.2, NPDES) Notice of Construction General Discharge Permit (hydrostatic testing)	Mississippi Department of Environmental Quality	General permit to be filed in December 2000. 401 certificate tied to coastal wetlands permit (Joint USACOE Permit Mobile District).	Expected April 2001
Easement to cross offshore bottom lands	Mississippi Secretary of State	To be filed December, 2000 (jointly with USACOE permit).	Expected April 2001
Coastal Wetlands Permit Coastal Zone Management Act Consistency Determination	Mississippi Department of Marine Resources	Gulfstream's determination filed 10/15/99. To be filed December, 2000 (jointly with USACOE permit).	Expected April 2001
Mississippi (cont.)			
Section 106 NHPA consultation	Mississippi Department of Archives and History	Survey methods approved June 15, 1999. Field survey report filed October 15, 1999. Clearance granted October 25, 1999. Supplemental Report for Line changes filed February 29, 2000.	Clearance granted October 25, 1999.
Alabama			
Storm Water Discharge Permit, Air Permitting, NPDES General Discharge Permit (hydrostatic testing), Coastal Zone Management Act consistency determination	Alabama Department of Environmental Management	Air permit filed October 15, 1999. Air Permit update report filed June 2000. NPDES General hydrostatic testing permits to be filed in December 2000. Gulfstream's request for coastal zone consistency determination filed 10/15/99 (offshore). Coastal Zone determination for onshore and state waters to be filed concurrent with USACOE Section 10/404 permit application.	Air Permit Expected January 2001 NPDES Permit Expected March 2001 Offshore CZM Consistency expected concurrent with MMS ROW Permit (Expected April 2001).

TABLE 1 (cont.)
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
Easement to cross offshore bottom lands, listed species, fisheries, wetlands review and consultation	Alabama Department of Conservation and Natural Resources	To be filed December, 2000 (jointly with USACOE permit).	Expected April 2001
Section 106 NHPA consultation	Alabama Historical Commission	Survey methods approved July 1, 1999. Field survey report filed October 15, 1999.	Onshore Clearance Letter received November 18, 1999. Offshore Clearance Letter Received July 3, 2000.
Florida			
Environmental Resource Permit (ERP), Easement to cross state-owned uplands and sovereign submerged lands	Department of Environmental Protection (FDEP)	Consolidated Permit filed February 29, 2000. Easements filed February 29, 2000.	Permit and Easements expected January 2001
Coastal Zone consistency determination	FDEP	Request for Determination filed 10/15/00 (FERC Filing) and 2/29/00 (Florida Consolidated Permit Application).	Expected January 2001
Letter of acknowledgment for completion of cultural resource investigations recommended for the project area	Department of State, Division of Historical Resources	Survey methods approved July 20, 1999 and Unanticipated Finds Plan approval on September 14, 1999. Field survey reports filed October 15, 1999. SHPO comments received December 20, 1999 (onshore Florida) and December 10, 1999 (offshore Florida). Supplemental Report for onshore Line changes filed February 29, 2000, additional Phase II report filed May, 2000. Florida offshore phase II survey report filed October, 2000.	Offshore Clearance received October 16, 2000. Florida onshore letter of acknowledgement received from SHPO on December 20, 2000, May 1 and 3, 2000, April 5, 2000, and June 9, 2000.
Natural heritage inventory review	Florida Natural Areas Inventory	Received T/E database information from Florida Natural Areas Inventory and Alabama/Mississippi Natural Heritage Program.	No clearance required

TABLE 1 (cont.)
MAJOR PERMITS, LICENSES, APPROVALS, AND CERTIFICATIONS REQUIRED FOR CONSTRUCTION, OPERATION AND MAINTENANCE OF THE PROPOSED GULFSTREAM NATURAL GAS SYSTEM

Permit/Approval	Administering Agency	Status a/	Permit Expected
Review of impacts to endangered and threatened species. Species Relocation permits (if necessary)	Florida Fish and Wildlife Conservation Commission	Field survey reports filed October 15, 1999. Supplemental follow-up report filed February 29, 2000. Northern Highlands Alternative Report filed 5/15/00. BA filed 8/10/00. 10/24/00	Clearance to be Granted January 2001
Consumptive Use permit for hydrostatic test water withdrawal.	Southwest Florida Water Management District, South Florida Water Management District, St. Johns River WMD	General permits filed in November 2000.	Expected March 2001
Industrial Wastewater Permit for Hydrostatic Testwater Discharge	Florida Department of Environmental Protection (FDEP)	Permits to be filed in November 2000.	Expected March 2001
General Permit for Geotechnical Borings	Florida Department of Environmental Protection (FDEP)	Issued June, 1999 and January 2000.	SW District Permits issued: 1) July 1, 1999 2) December 23, 1999 3) January 12, 2000 4) May 12, 2000 5) June 14, 2000 South District 1) February 2, 2000 2) April 12, 2000 Southeast District 1) February 3, 2000
Local Submerged Lands Easement	Tampa Port Authority	Filed jointly with Consolidated Permit February 29, 2000.	Expected January 2001

8. Please indicate the status of negotiations to obtain firm natural gas contracts to fuel the Osprey Energy Center. Provide details on the providers and term of these contracts.

Gulfstream will have approximately 2.0 BCF per day of production connected to the pipeline. This amount is approximately twice the projected capacity of the pipeline. Calpine has been in contact with several producers and marketing entities regarding providing supply to the Osprey facility. The suppliers have indicated serious interest in providing firm supply to the project. A list of Gulfstream interconnections and producers which will have access to Gulfstream is attached.

Discussions for firm supply are in the preliminary stages. Calpine expects to contract with reliable suppliers, including those listed on the attachment, on commercially reasonable and industry standard terms. Calpine's fuel plan contemplates a portfolio of term and spot contracts to ensure reliable low cost natural gas supply. Calpine has not, at this early date, negotiated any specific, detailed terms of its fuel supply contracts. However, Calpine does not envision any difficulties in contracting for natural gas supply for the Osprey Project.

(Petit)

Gulfstream Interconnections

Mobile / Pascagoula	Capacity	
DIGP Plant	600	MMcf/d
Destin Plant	600	
Williams Plant	300	
DIGP 20-inch	300	
Mary Ann Plant	150	
Sub Total	1,950	MMcf/d
Other		
Koch-Gateway	250	
Grand Total	2,200	MMcf/d



Gulfstream Supply Area Top Producers

Amerada Hess
BP Amoco
Callon
Chevron
CNG Producing
Coastal Oil & Gas
Elf Aquitaine
Enron Oil & Gas
Exxon
Flextrend Development
Kerr-McGee
Mobil
Murphy
Ocean Energy
Petsec
Santa Fe Snyder
Shell
Texaco
Unocal
Vastar
Walter Oil & Gas



Gulfstream
Natural Gas System

9. Please indicate and describe in detail the status of Calpine's efforts to enter into an agreement for the purchase of the proposed 19.5 acre site located in Polk County. In your response, please indicate whether Calpine has exclusive rights to the total 19.5 acre site.

A. Calpine has a binding option agreement pursuant to which Calpine has the exclusive right to purchase the entire 19.5 acre site of the Osprey Energy Center.

(Eves)

10. Calpine's filing indicates a capacity factor of 91 percent. The expected capacity factor of the Osprey Energy Center appears to be substantially higher than similar utility projects recently filed before the Commission. Please discuss the relatively high projected capacity factor for the Osprey Energy Center.

A. The Calpine analysis was performed by Slater Consulting using PROMOD IV®. In this PROMOD analysis, all units were dispatched to serve the needs of peninsular Florida, not just the needs of a single utility.

The capacity factor achieved by a generating unit in this dispatch depends upon the total load being served and upon the following items of data for that unit, and the same data items for all other units in the system.

- Heat Rate characteristics
- Fuel Price
- Variable O&M Cost
- Start-up fuel consumption
- Minimum Downtime
- Unit Availability (defined by maintenance needs & FOR)

So as not to give the Osprey unit an unwarranted advantage over other new combined cycle units of the same technology, Osprey and all new combined cycle units of the same technology as Osprey, were given identical heat rate characteristics, fuel prices, variable O&M costs, start-up fuel consumptions and minimum downtimes. In addition, because PROMOD deals with generating units with identical dispatch costs by dispatching them in the order in which they are encountered in the data, the Osprey unit has been positioned in the data so that it is dispatched in the middle of this group of units with identical dispatch cost characteristics.

The group of units modeled with identical dispatch cost characteristics include the following.

- Hines EC 2, 3, 4 & 5
- Okeechobee 1 & 2
- Purdom 8
- Green combined cycle 1

- Seminole combined cycle 4 & 5
- Osprey
- New Smyrna 1
- Cane Island 3
- Payne Creek 3
- Three "Unknown" combined cycle's.

Repowered utility combined cycle units were considered to have heat rates slightly greater than those of totally new combined cycle units of the same technology.

By treating the Osprey unit and the other units in this way, the only data choice that can influence the achieved capacity factor is that of the availability. Our modeling has used availabilities for the new combined cycle units derived mainly from 10-year Site Plans. The group of units, with dispatch cost characteristics identical with those of Osprey, have been modeled with average annual availabilities between 90.9% and 95.8%. Osprey's average annual availability is 94.5%.

All this having been said, it appears that the differences between the dispatch analysis performed by Slater Consulting and the analyses reflected in some of the utility filings, which show substantially lower capacity factors for the units in question, is that the Slater Consulting analysis dispatches the units in a total Peninsular Florida power system, whereas some of the utility dispatch analyses only dispatch the units in the owning utilities' systems.

(Slater)

11. Please indicate what costs were considered in determining the average annual dispatch cost (for example, $28.09 for year 2003) for the proposed Osprey Energy Center, as indicated in Tables 14.A and 14.B of the revised exhibits to the petition. Also, discuss the data source and types of costs included in the average annual dispatch cost estimates for other utility generating units.

A. The average annual dispatch cost of any given unit, as presented in Tables 14.A & 14.B, was determined by summing the fuel and variable O&M costs for the year, and dividing by the annual energy production. This annual average dispatch cost of a unit is therefore the result of the dispatch regime experienced by that particular unit within the dispatch of all Peninsular Florida units against the total Peninsular Florida load.

In this dispatch, for existing units, the heat rate characteristics were determined from EIA Form 860 full load heat rate values combined with known heat rate curves from similar units in other jurisdictions. Start-up fuel use and minimum downtime values were also obtained from known characteristics of similar units. Variable O&M costs were estimated from values used in other jurisdictions for similar units.

For new units, these same data were obtained from 10-year Site Plans. However, as discussed in the answer to Interrogatory No. 10, some adjustment to individual data items (from the ten-year site plans) was necessary in order to remove unaccountable differences among similar plants.

Future fuel costs were developed from 1998 & 1999 FERC Form 423 records of actual fuel prices and forecast price increases from the 2000 edition of EIA Energy Outlook.

(Slater)

12. Page 96 of the revised exhibits to the petition indicates that the project is expected to suppress wholesale prices by about $0.54 to $0.84 per MWH. Discuss the assumptions used in this calculation. For example, how was capacity and energy priced in the model?

A. The calculation of wholesale price suppression was performed under the assumption that wholesale energy prices in the Peninsular Florida system would reflect the hour-by-hour marginal energy prices on the Peninsular Florida system. Therefore, the average hourly marginal energy cost for the peninsular Florida system was determined with and without the presence of the Osprey Project. The difference between these two values was recorded as the suppression in wholesale energy prices. No suppression of wholesale capacity prices was assumed.

(Slater)

13. Referring to page 96 of the exhibits, what is the rationale for the 10% discount rate?

Were any other discount rates used in evaluating the Osprey Energy Center? If so, please explain.

A. The 10% discount rate used for calculating the present value of the year-by-year savings in wholesale energy prices was not determined from any particular financing or borrowing costs. Based on Slater Consulting's experience in and knowledge of the power industry, this value was chosen as a representative value for purposes of this evaluation. No other discount rate was used in evaluating the Osprey Energy Center.

(Slater, Eves)

14. What is the assumed rate of inflation used in evaluating the Osprey Energy Center? What is the data source for the estimated inflation rate?

A. The general inflation rate used in the evaluation of the Osprey Energy Center was 3% per year. This value was chosen by Slater Consulting because it is slightly higher than the rate experienced in recent years. This could be a reasonable response to a continuation of relatively higher gas and oil prices.

(Slater)

15. Referring to pages 5, 6, and 42 of the exhibits, what is the interest rate for the "construction revolver" and how is it determined?

A. Please refer to Calpine's response to Staff's Request for Production No. 5. The interest rate for financing pursuant to the construction revolver is competitively sensitive, confidential, proprietary business information, both to Calpine and to the lending institutions participating in the revolver. Calpine will make this information available for review by the Commission Staff pursuant to an appropriate protective order (if necessary) that protects the confidentiality of this information.

(Eves)

16. Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide the delivered prices for each fuel associated with the evaluation of the following generation alternatives for each year in the evaluation period

A) combined cycle - gas fired

B) combined cycle - oil fired

C) simple cycle - gas fired

D) simple cycle - oil fired

E) steam - coal

F) steam - gas

G) steam - nuclear

H) IGCC technology

I) renewable energy

A. Calpine's response to this Interrogatory has been delayed due to electronic communications problems and will be filed as soon as possible.

(Davis, Arsuaga)

17. Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide a present worth analysis for each of the following generation alternatives. For each year in the evaluation period, provide the annual and cumulative present worth values for each of the following components: capital, fixed operations and maintenance (O&M); non-fuel variable O&M; fuel; purchased power; and total costs.

A) combined cycle - gas fired

B) combined cycle - oil fired

C) simple cycle - gas fired

D) simple cycle - oil fired

E) steam - coal

F) steam - gas

G) steam - nuclear

H) IGCC technology

I) renewable energy

A. Calpine's response to this Interrogatory has been delayed due to electronic communications problems and will be filed as soon as possible.

(Davis, Arsuaga)

18. Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide a present worth analysis for each of the following generation alternatives using Calpine's high natural gas price forecast. For each year in the evaluation period, provide the annual and cumulative present worth values for each of the following components: capital, fixed operations and maintenance (O&M); non-fuel variable O&M; fuel; purchased power; and total costs.

A) combined cycle - gas fired

B) combined cycle - oil fired

C) simple cycle - gas fired

D) simple cycle - oil fired

E) steam - coal

F) steam - gas

G) steam - nuclear

H) IGCC technology

I) renewable energy

A. Calpine's response to this Interrogatory has been delayed due to electronic communications problems and will be filed as soon as possible.

(Davis, Arsuaga)

19. Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide a present worth analysis for each of the following generation alternatives in which the current differential price of oil and natural gas with coal is held constant during the evaluation period. For each year in the evaluation period, provide the annual and cumulative present worth values for each of the following components: capital, fixed operations and maintenance (O&M); non-fuel variable O&M; fuel; purchased power; and total costs.

A) combined cycle - gas fired

B) combined cycle - oil fired

C) simple cycle - gas fired

D) simple cycle - oil fired

E) steam - coal

F) steam - gas

G) steam - nuclear

H) IGCC technology

I) renewable energy

A. Calpine's response to this Interrogatory has been delayed due to electronic communications problems and will be filed as soon as possible.

(Davis, Arsuaga)

20. Have the projected water usage requirements for the Osprey Energy Center (as discussed on pages 10-12 of Richard Zwolak's testimony) been approved by the appropriate water management district and other relevant state and local agencies?

A. The projected Osprey Energy Center water use requirements are in the process of being approved by SWFWMD. There is no other state or local agency that requires water use approval.

(Zwolak)

21. On page 16 of Richard Zwolak's testimony, direct economic benefits of the plant are estimated at between $0.8 and $1.16 million annually. How were these estimates calculated?

A. The direct economic benefit of $0.8 million to $1.16 million (year 2000 dollar values) represents ad valorem tax revenue generated by the Project that is paid to Polk County. The Project has an estimated taxable value of $100 million to $145 million. The Polk County 1999 millage rate (the most current rate available at the time the Application was submitted) for the Project location is 7.977 per $1000 assessed value. Ad valorem revenue for the Project may range from $0.8 million (.007977 x $100,000,000) to $1.16 million (.007977 x $145,000,000), depending upon the taxable value of the Project as determined by Polk County.

(Zwolak)

22. Page 12 of Kenneth Slater's testimony discusses the inputs to the PROMOD IV, which include generating unit data for existing and planned power plants. If different from the units included in Tables 14.A and 14.B of the exhibits, please provide a list of the existing and planned power plants used as inputs in the PROMOD IV runs.

A. Tables 14.A & 14.B contain all Peninsular Florida units which were in-service during the specific years covered by these tables. Units that were not in-service during these years are, of course, not included. The EXCEL table Q22-tab.xls (attached) contains all units included in the analyses.

(Slater)

Plant	Unit	In Service Date	Retirement Date
Nuclear			
CRYSTAL	3		
STLUCIE	1		
STLUCIE	2		
TURKEYPT	3		
TURKEYPT	4		
Coal and Petroleum Coke			
BIG BEND	1		
BIG BEND	2		
BIG BEND	3		
BIG BEND	4		
CRYSTAL	1		
CRYSTAL	2		
CRYSTAL	4		
CRYSTAL	5		
DEERHAVN	2		
GANNON	1		20030430
GANNON	2		20030430
GANNON	3		20020801
GANNON	4		20020801
GANNON	5		20011001
GANNON	6		20041231
MCINTOSH	3		
MCINTOSH	4	20050601	
NORTHSID	1		
NORTHSID	2	20020401	
SCHERER	4		
SEMINOLE	1		
SEMINOLE	2		
ST JOHNS	1		
ST JOHNS	2		
STANTON	1		
STANTON	2		
New Gas Combined Cycle			
HINES EC	2	20031101	
HINES EC	5	20091101	
OKEECHOB	1	20030401	
OKEECHOB	2	20030401	
UNKNOWCC	1	20070601	
PURDOM	8	20000515	
GREEN CC	1	20060602	
SEMIN CC	4	20040601	
SEMIN CC	5	20061101	
OSPREY	1	20030601	
HINES EC	3	20051101	

HINES EC	4	20071101	
N SMYRNA	1	20020601	
UNKNOWCC	2	20080601	
UNKNOWCC	3	20090601	
CANE IS	3	20010602	
PAYNECRK	3	20020101	
FT MYERS	3	20010101	
SANFORD	14	20021201	
SANFORD	15	20021201	
MARTINCC	5	20060601	
MARTINCC	6	20060601	
BAYSIDE	1	20030501	
BAYSIDE	2	20040501	
BRANDY B	4	20030601	
KELLEY	4	20010201	
HINES EC	1	19990401	

Other Units

ANCLOTE	1		
ANCLOTE	2		
AVONPKGT	1		20061201
AVONPKGT	2		20061201
BARTOW	1		
BARTOW	2		
BARTOW	3		
BARTOWGT	1		
BARTOWGT	2		
BARTOWGT	3		
BARTOWGT	4		
BAYBROGT	1		20041201
BAYBROGT	2		20041201
BAYBROGT	3		20041201
BAYBROGT	4		20041201
BGBENDGT	1		
BGBENDGT	2		
BGBENDGT	3		
BRANDY B	1	20010101	20030511
BRANDY B	2	20010101	20030511
BRANDY B	3	20011201	
CANE GT	1		
CANE ISL	2		
CAPECNVR	1		
CAPECNVR	2		
CUDJOE D	1		
CUTLER	5		
CUTLER	6		
DEBARYGT	1		
DEBARYGT	2		
DEBARYGT	3		

DEBARYGT	4		
DEBARYGT	5		
DEBARYGT	6		
DEBARYGT	7		
DEBARYGT	8		
DEBARYGT	9		
DEBARYGT	10		
DEERHAVN	1		
DRHVN GT	1		
DRHVN GT	2		
DRHVN GT	3		
EVERGL T	1		
EVERGL T	2		
EVERGL T	3		
EVERGL T	4		
EVERGL T	5		
EVERGL T	6		
EVERGL T	7		
EVERGL T	8		
EVERGL T	9		
EVERGL T	10		
EVERGL T	11		
EVERGL T	12		
EVERGLDS	1		
EVERGLDS	2		
EVERGLDS	3		
EVERGLDS	4		
FTMYER T	1		
FTMYER T	2		
FTMYER T	3		
FTMYER T	4		
FTMYER T	5		
FTMYER T	6		
FTMYER T	7		
FTMYER T	8		
FTMYER T	9		
FTMYER T	10		
FTMYER T	11		
FTMYER T	12		
FTMYERCT	13	20030401	
FTMYERCT	14	20030501	
FTMYERS	1		20001031
FTMYERS	2		20001031
GANNONGT	1		
GREEN GT	1	20090601	
HANSELCC	2		
HANSELIC	8		
HANSELIC	14		
HANSELIC	15		

HANSELIC	16	
HANSELIC	17	
HANSELIC	18	
HANSELIC	19	
HANSELIC	20	
HARDEE	1	
HARDEECT	1	
HIGGNSGT	1	20051201
HIGGNSGT	2	20051201
HIGGNSGT	3	20051201
HIGGNSGT	4	20051201
HOOKERS	1	20030101
HOOKERS	2	20030101
HOOKERS	3	20030101
HOOKERS	4	20030101
HOOKERS	5	20030101
HOPKINGT	1	
HOPKINGT	2	
HOPKINS	1	
HOPKINS	2	
IND RIVR	1	
IND RIVR	2	
IND RIVR	3	
INDRVRGT	1	
INDRVRGT	2	
INDRVRGT	3	
INDRVRGT	4	
INTER GT	1	
INTER GT	2	
INTER GT	3	
INTER GT	4	
INTER GT	5	
INTER GT	6	
INTER GT	7	
INTER GT	8	
INTER GT	9	
INTER GT	10	
INTER GT	11	
INTER GT	12	20001201
INTER GT	13	20001201
INTER GT	14	20001201
IVEY IC	1	
IVEY IC	2	
IVEY IC	3	
IVEY IC	4	
IVEY IC	5	
IVEY IC	6	
J BLUFF	1	
J BLUFF	2	

J BLUFF	3		
KELLY	7		
KELLY	8		20000901
KELLY GT	1		
KELLY GT	2		
KELLY GT	3		
KENEDYGT	3		
KENEDYGT	4		
KENEDYGT	5		
KENEDYGT	7	20000601	
KENNEDY	10		20000401
KING	5		
KING	6		
KING	7		
KING	8		
KING DSL	1		
KING GT	9		
LARSEN	6		20000701
LARSEN	7		20010301
LARSEN	8		
LARSENGT	2		
LARSENGT	3		
LAUDER T	1		
LAUDER T	2		
LAUDER T	3		
LAUDER T	4		
LAUDER T	5		
LAUDER T	6		
LAUDER T	7		
LAUDER T	8		
LAUDER T	9		
LAUDER T	10		
LAUDER T	11		
LAUDER T	12		
LAUDER T	13		
LAUDER T	14		
LAUDER T	15		
LAUDER T	16		
LAUDER T	17		
LAUDER T	18		
LAUDER T	19		
LAUDER T	20		
LAUDER T	21		
LAUDER T	22		
LAUDER T	23		
LAUDER T	24		
LAUDERCC	4		
LAUDERCC	5		
MANATEE	1		

MANATEE	2		
MARATHON	1		
MARATHON	2		
MARATHON	3		
MARTIN	1		
MARTIN	2		
MARTINCC	3		
MARTINCC	4		
MARTINCT	1	20010601	
MARTINCT	2	20010601	
MCINT CT	6	20090601	
MCINT GT	1		
MCINT IC	1		
MCINTOSH	1		
MCINTOSH	2		
MCINTOSH	5	20000401	
NORTH GT	3		
NORTH GT	4		
NORTH GT	5		
NORTH GT	6		
NORTHSID	3		
OLEAN GT	1	20020601	
OLEAN GT	2	20020601	
OLEAN GT	3	20020601	
OLEAN GT	4	20020601	
OLEAN GT	5	20020601	
PHILLIPS	1		
PHILLIPS	2		
POLK CT	2	20000901	
POLK CT	3	20020501	
POLK CT	4	20050101	
POLK CT	5	20060101	
POLK CT	6	20080101	
POLKIGCC	1		
PURDOM	5		19991201
PURDOM	6		19991201
PURDOM	7		20110301
PURDOMGT	1		20080301
PURDOMGT	2		20090301
PUTNAMCC	1		
PUTNAMCC	2		
REEDYCRK	1		
RIOPINGT	1		20051201
RIVIERA	3		
RIVIERA	4		
SANFORD	3		
SANFORD	4		20020131
SANFORD	5		20010831
SEM CT	1	20021101	

SEM CT	2	20050601	
SEM CT	3	20070601	
SMITH	1		
SMITH	2		
SMITH	3		
SMITH	4		
SMITH D	1		
SMITH CC	1		
SMITH GT	1		
SMITH ST	1		
SMITH ST	2		
SMITH ST	3		
SOUTHSID	3		19980901
SOUTHSID	4		20011001
SOUTHSID	5		20011001
ST CLOUD	1		
ST CLOUD	2		
ST CLOUD	3		
ST CLOUD	4		
STOCK DS	1		
STOCK DS	2		
STOCK GT	1		
STOCK GT	2		
STOCK GT	3		
STOCK IC	1		
SUWAN GT	1		
SUWAN GT	2		
SUWAN GT	3		
SUWANNEE	1		20031201
SUWANNEE	2		20031201
SUWANNEE	3		20031201
SWOOPEIC	1		
TIGERBAY	1		
TURKEYIC	1		
TURKEYPT	1		
TURKEYPT	2		
TURNERGT	1		20061201
TURNERGT	2		20061201
TURNERGT	3		
TURNERGT	4		
UNIV FLA	1		
UNKNOWNT	1	20090101	
VERO BCH	1		
VERO BCH	2		
VERO BCH	3		
VERO BCH	4		
VERO BCH	5		

NUGs

AGRICHEM	1	20061031
AS-AVAIL	1	
BAY CTY	1	20100331
BIOENRGY	1	20041231
BROWARDS	1	20090731
BROWARDS	2	20101231
CARGILL	2	20100331
CEDARBAY	1	
CFRBIOGN	1	
DADE CTY	1	20100331
ELDORADO	1	
FLASTONE	1	20051031
HILLSBOR	1	20100301
INDIANTN	1	
LAKE CTY	1	20100331
LAKECOGN	1	
LFC JEFF	1	
LFC MADS	1	
MULBERRY	1	20020331
MULBERRY	2	20020331
MULB-FPC	1	
ORANGE	1	
ORLANDO	1	
PALMBCH	1	20100331
PASCO	1	
PASCOCTY	1	20100331
PINELLAS	1	20100331
PINELLAS	2	20100331
RIDGE	1	20100331
ROYSTER	1	20100331
TAMPACTY	1	20090301
TIMBER	1	20020331
JEA-QFs		

23. Page 13 of Kenneth Slater's testimony states that the "Osprey Project would in fact be slightly more cost-effective than nearly all of the other planned gas-fired combined cycle units." What evidence does Calpine have to support this statement?

A. By virtue of Calpine's ownership, operation, and maintenance of multiple units of this same technology, Calpine believes that Osprey will have lower capital and fixed O&M costs than other projects.

Referring to the answer to Interrogatory No. 10, there is only one planned project of the same technology, the Duke/New Smyrna Beach Project, that has a better availability than Osprey. Further, there are only two planned projects, both FP&L with "H" type units, with more advanced technology than Osprey.

(Eves, Slater)

24. Exhibit KJS-11 (discussed on page 22 of Kenneth Slater's testimony) shows the modeled impacts of the project's operations on other units supplying Peninsular Florida during two representative days in 2005, one a June weekday and one a December weekday. Please recreate this Exhibit using July, August, January and February weekdays.

A. Three EXCEL workbooks (attached) have been prepared with the impact graphs all created to the same MW scale.

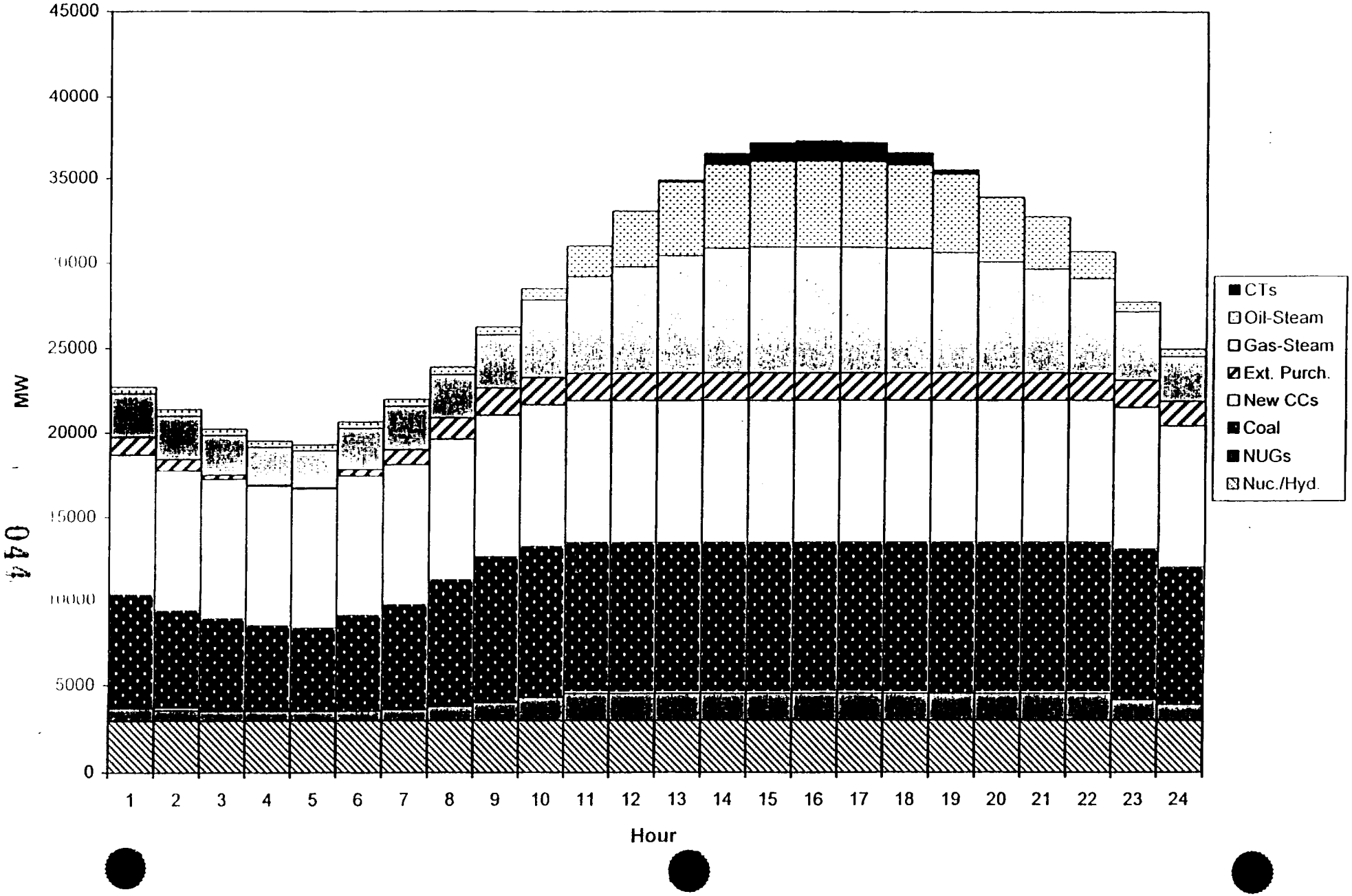
Q24-a.xls contains the original graphs for June 2005 and December 2005.
Q24-b.xls contains the new graphs for January 2005 and February 2005.
Q24-c.xls contains the new graphs for July 2005 and August 2005.

(Slater)

ILLUSTRATION OF IMPACTS OF OSPREY ENERGY CENTER ON OPERATIONS OF PENINSULAR FLORIDA POWER PLANTS

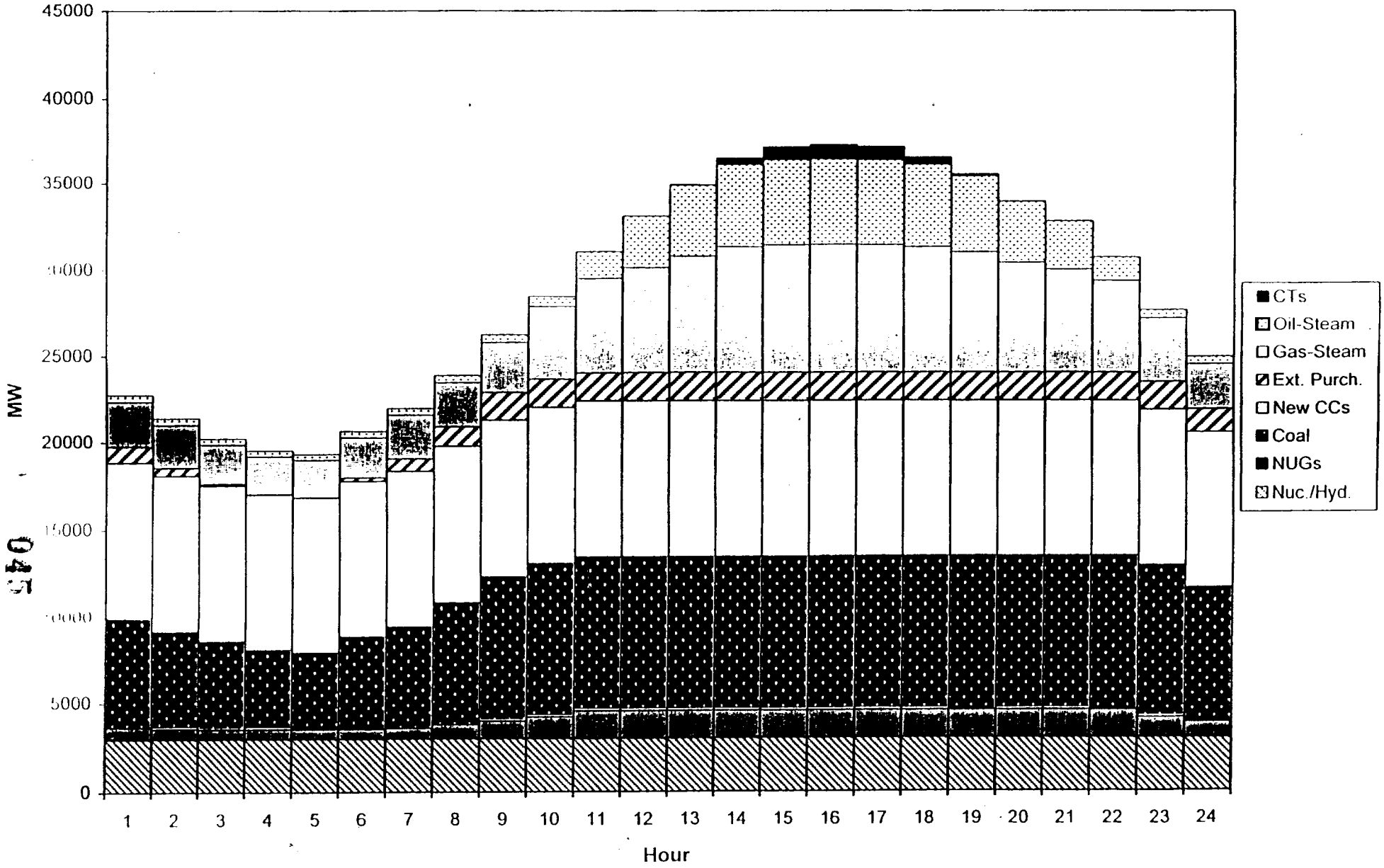
Page 2 Typical Weekday in June, 2005 without Osprey
Page 3 Typical Weekday in June, 2005 with Osprey
Page 4 Typical Weekday in December, 2005 without Osprey
Page 5 Typical Weekday in December, 2005 with Osprey

PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday June 2005

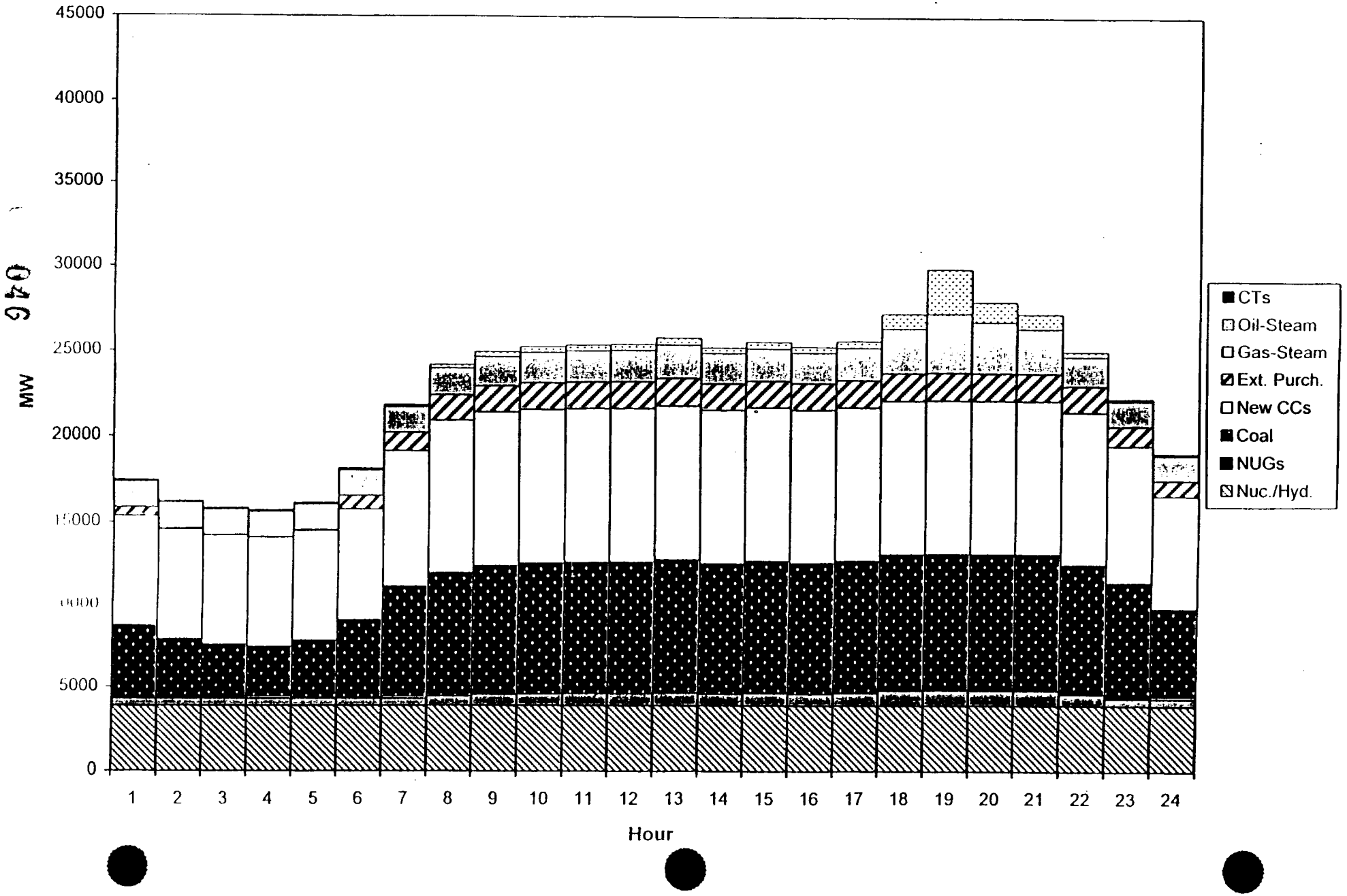


044

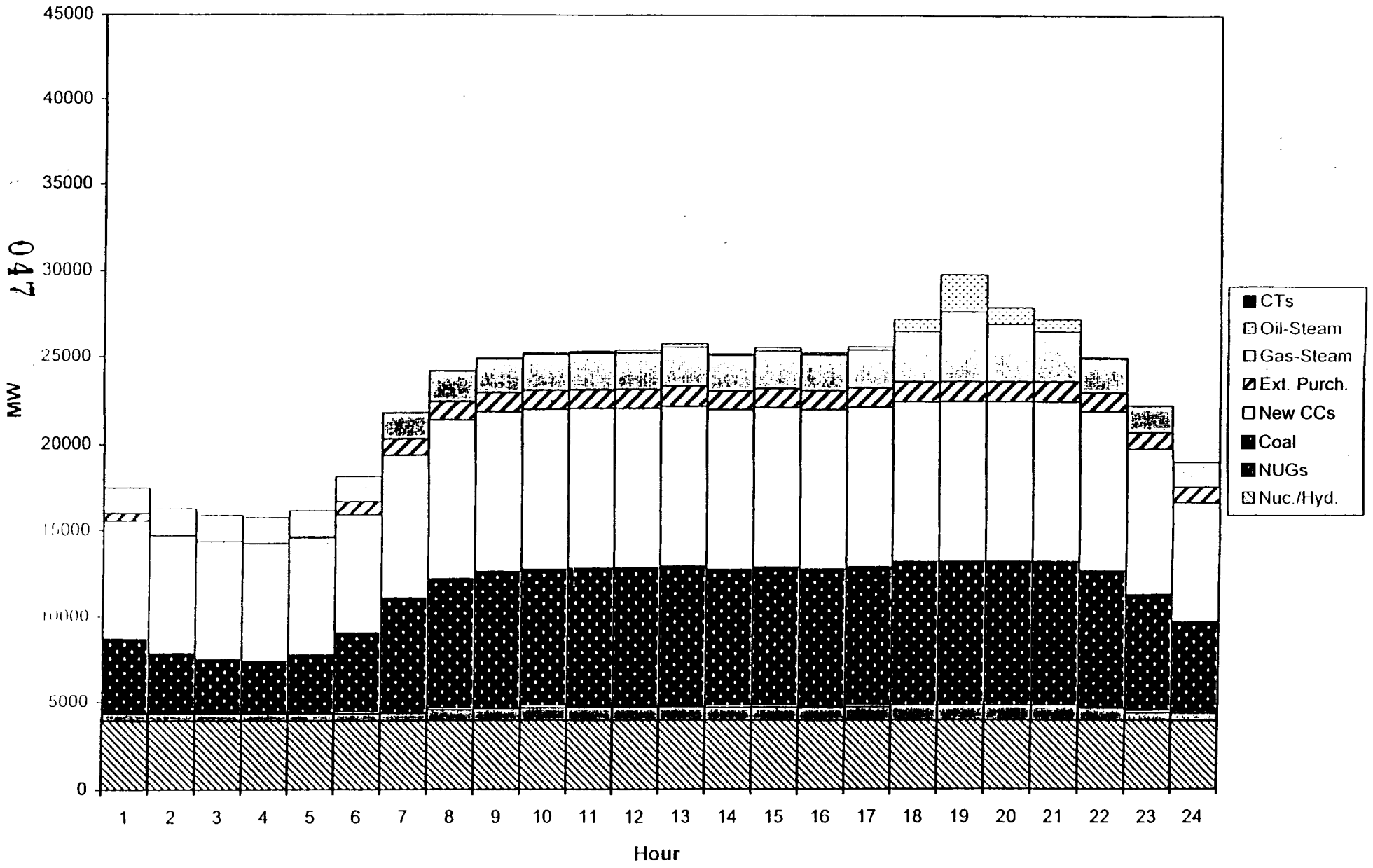
PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday June 2005



PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday December 2005



PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday December 2005

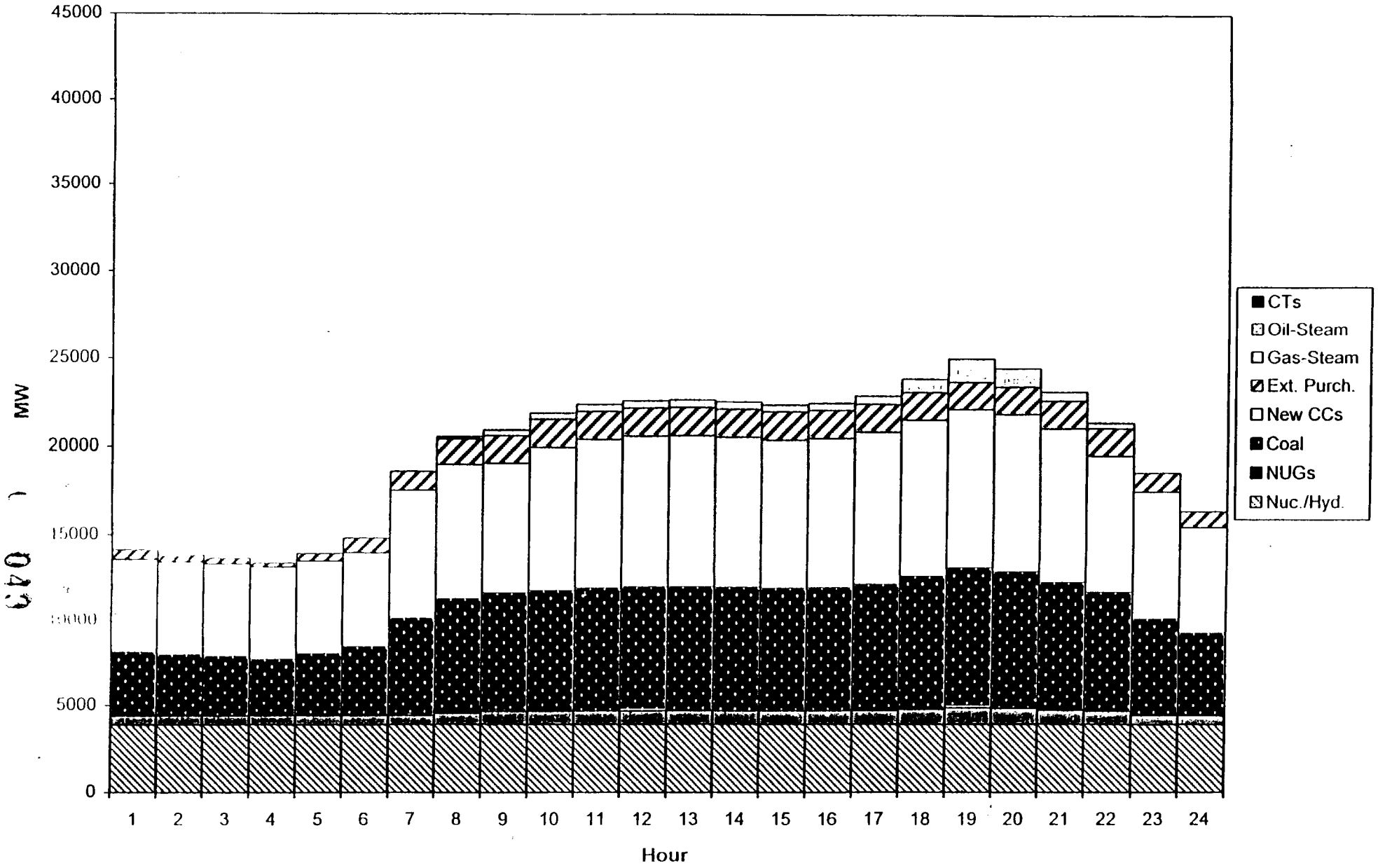


047

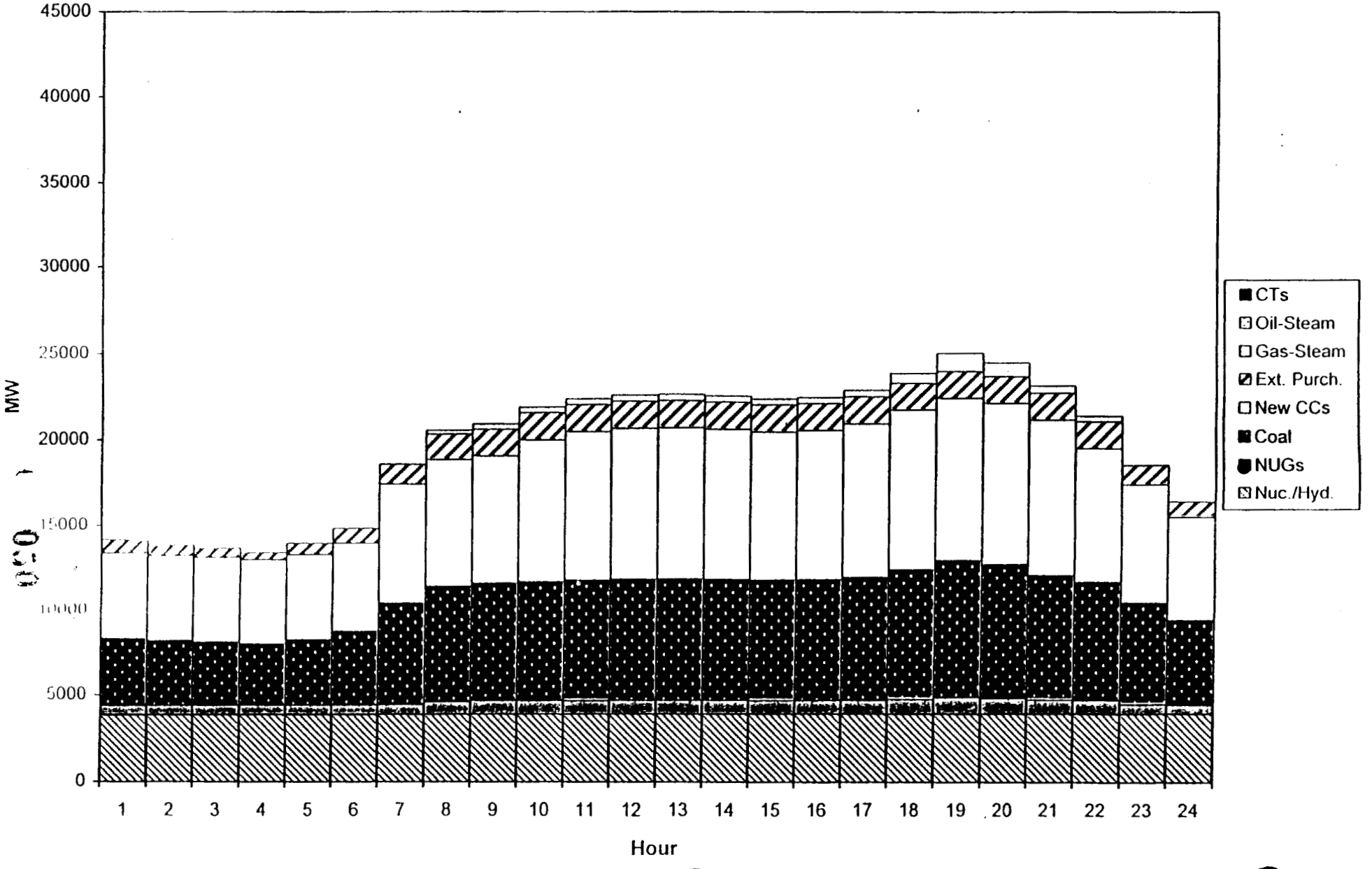
ILLUSTRATION OF IMPACTS OF OSPREY ENERGY CENTER ON OPERATIONS OF PENINSULAR FLORIDA POWER PLANTS

Page 2 Typical Weekday in January, 2005 without Osprey
Page 3 Typical Weekday in January, 2005 with Osprey
Page 4 Typical Weekday in February, 2005 without Osprey
Page 5 Typical Weekday in February, 2005 with Osprey

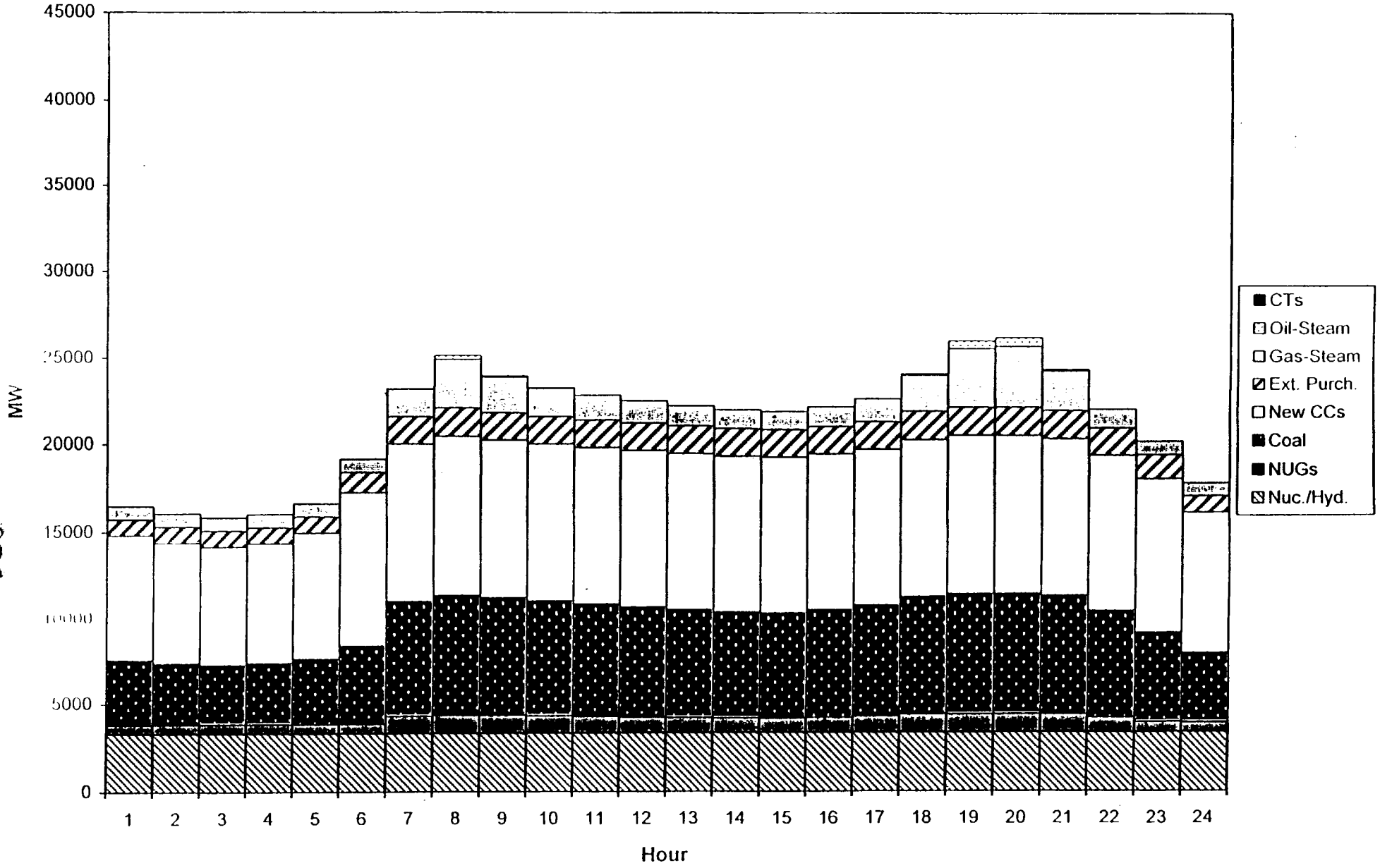
PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday January 2005



PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday January 2005



PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday February 2005



PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday February 2005

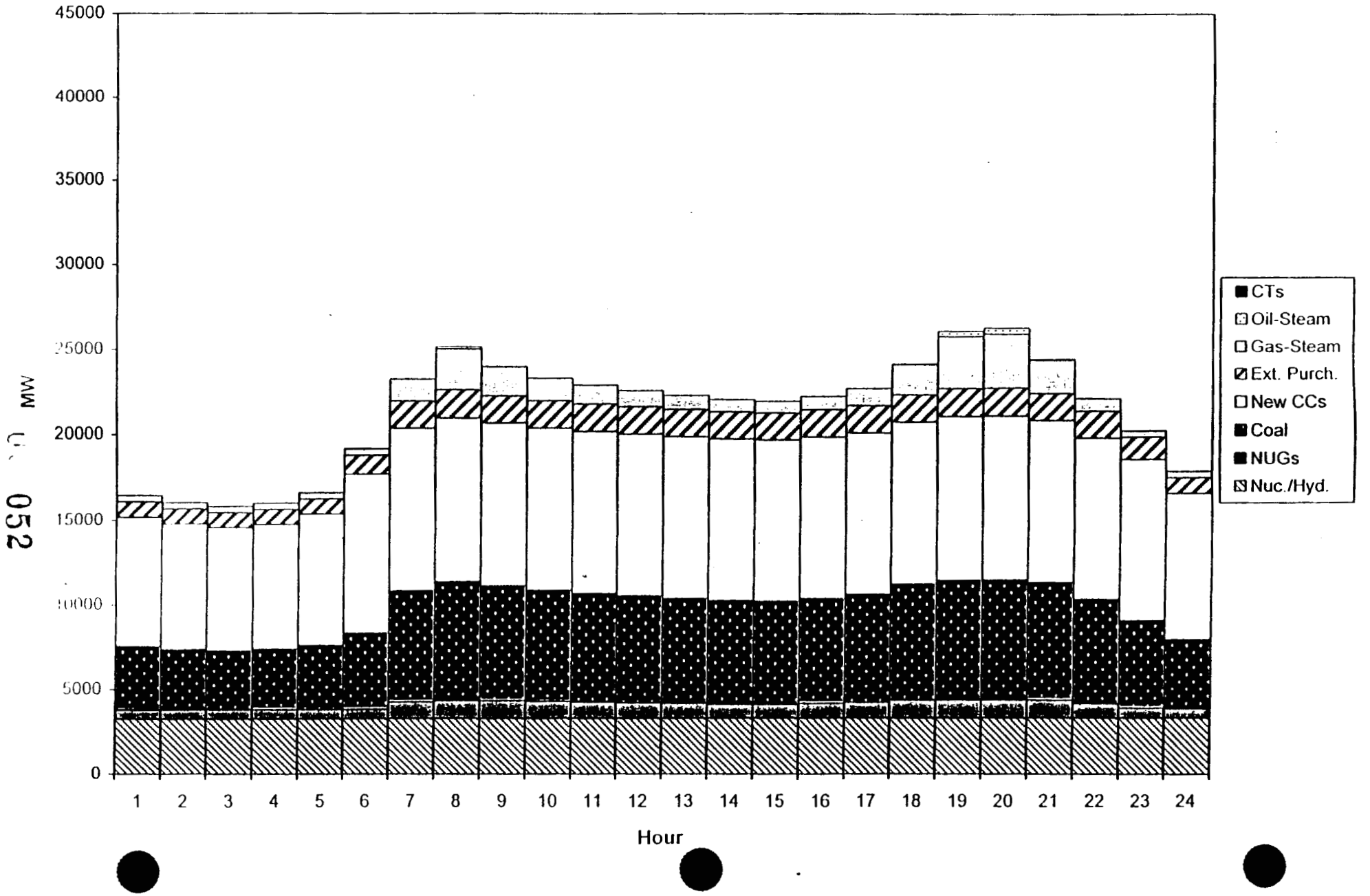
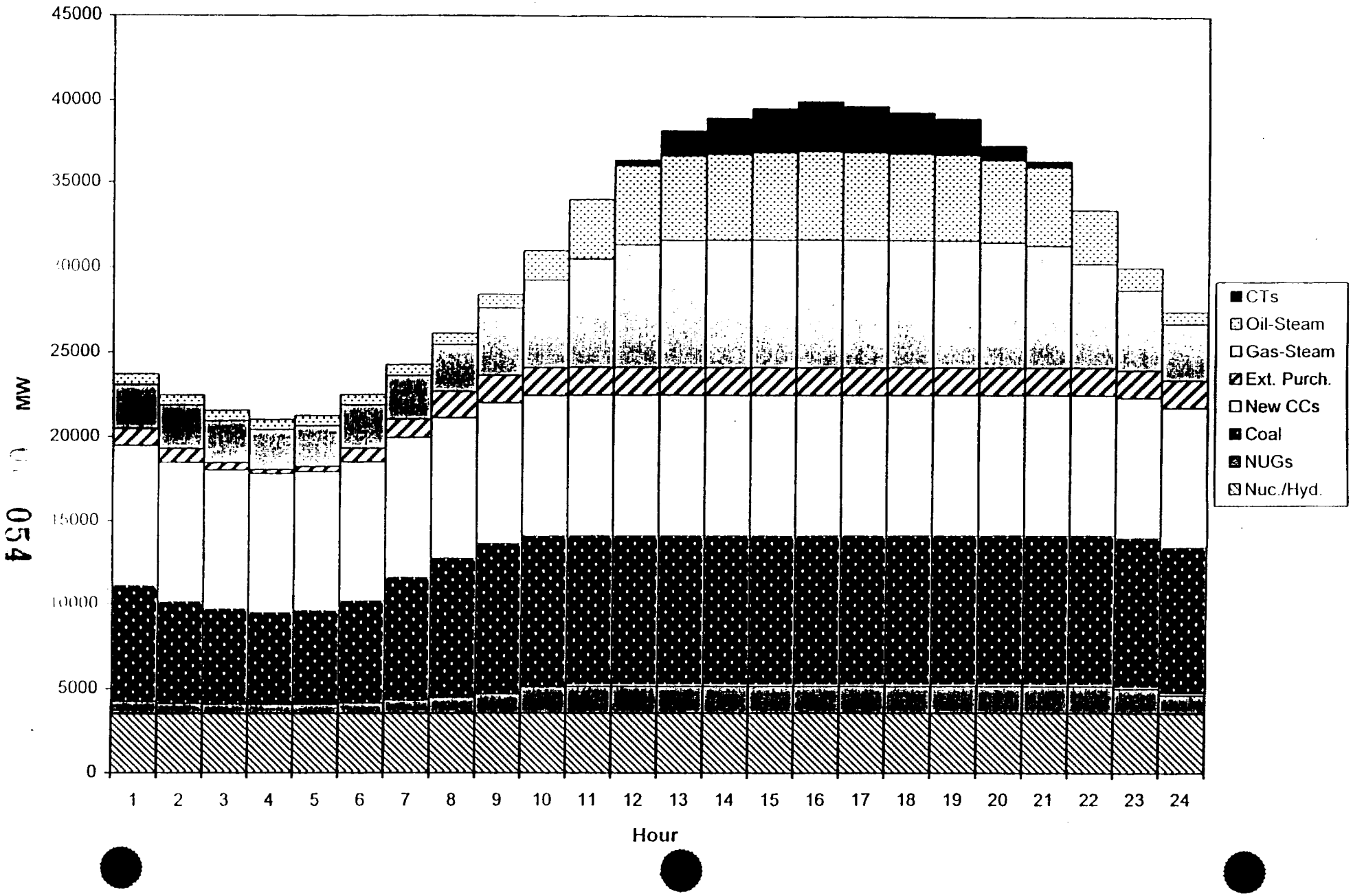


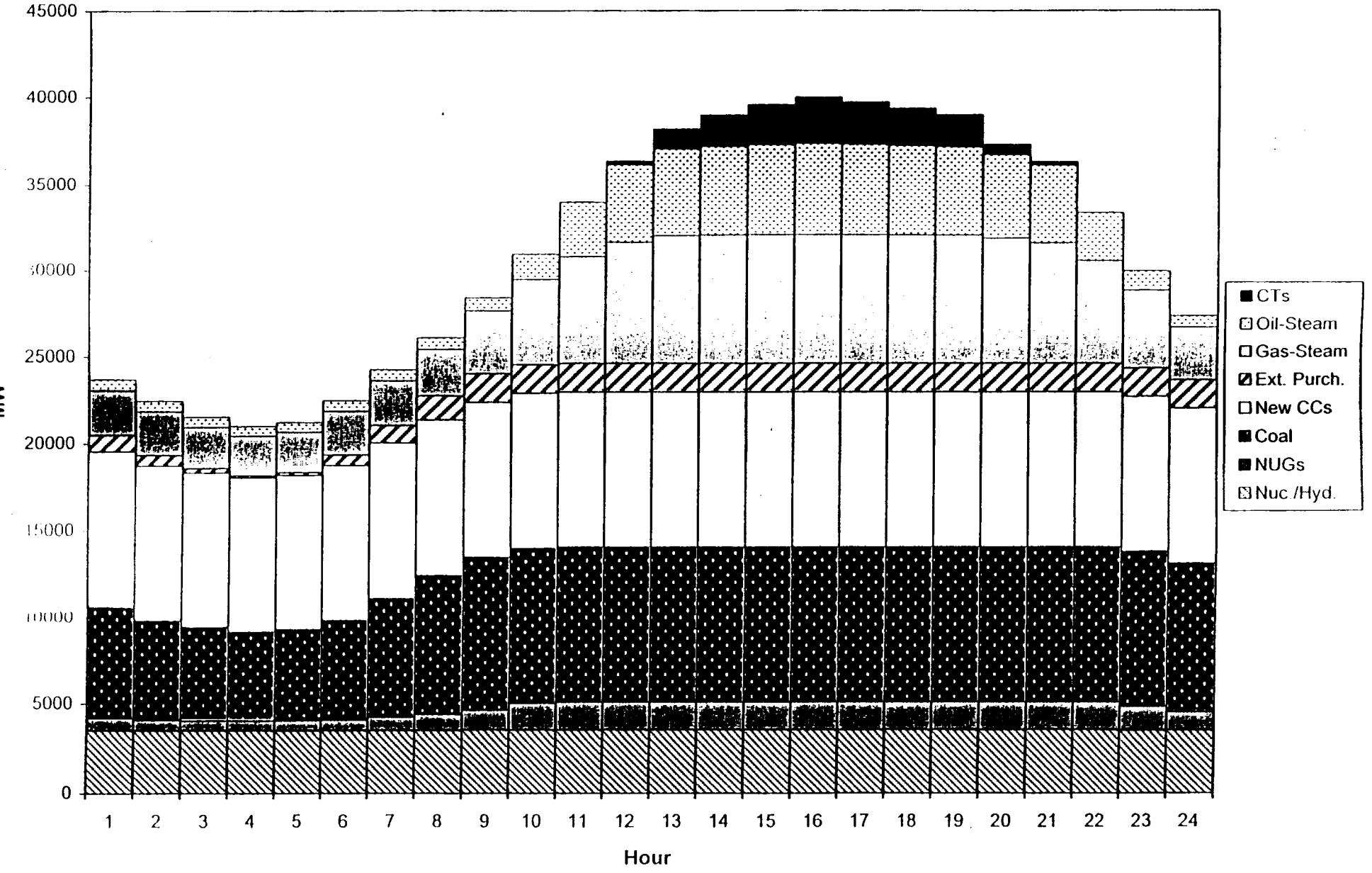
ILLUSTRATION OF IMPACTS OF OSPREY ENERGY CENTER ON OPERATIONS OF PENINSULAR FLORIDA POWER PLANTS

Page 2 Typical Weekday in July, 2005 without Osprey
Page 3 Typical Weekday in July, 2005 with Osprey
Page 4 Typical Weekday in August, 2005 without Osprey
Page 5 Typical Weekday in August, 2005 with Osprey

PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday July 2005



PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday July 2005

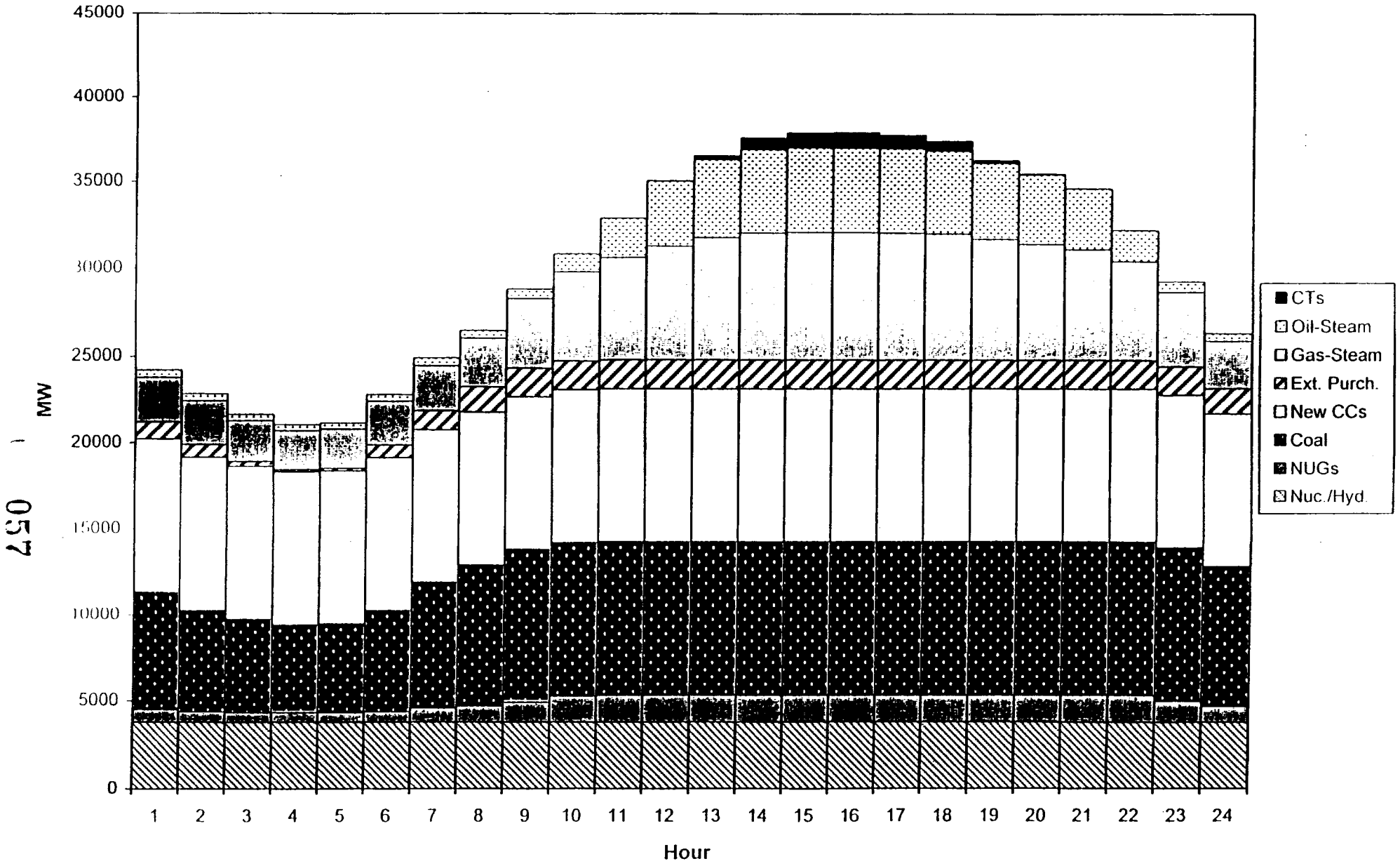


PENINSULAR FLORIDA GENERATION - WITHOUT OSPREY
Weekday August 2005



056

PENINSULAR FLORIDA GENERATION - WITH OSPREY
Weekday August 2005



25. Does Calpine foresee any transmission constraints that could make the project non-cost-effective?

A. No. All known transmission constrained paths in Florida were simulated and monitored for all eighteen (18) base cases used to conduct our contingency analysis. The results--listed in Appendix IV of Exhibit ___ (MPA-2)--show that there is no significant increase in constrained path flows from the original FRCC Base Case when the Osprey Energy Center was dispatched. We do not believe that the plant output will be constrained due to transmission limitations.

(Armand)

The Calpine analysis was performed with the PROMOD IV Production Cost Simulation Model that captures the impact of area-to-area transmission constraints without requiring detailed bus level transmission data. Bi-directional transmission interface flow limits that vary by subperiod may be defined between any two areas modeled. To determine the appropriate Florida Reliability Coordinating Council (FRCC) area-to-area transmission constraints, the following publicly available information was examined.

- 1999 North American Electric Reliability Council Summer Assessment
- 1999/2000 North American Electric Reliability Council Winter Assessment
- 1999 Federal Energy Regulatory Commission 715 Submittal
- Joint FRCC-Southern 1998 Summer & 1997/98 Winter Study
- FRCC Transmission Line Load Relief Event Log

No significant FRCC area-to-area interface constraints were clearly identified in the material reviewed. In fact, the 1999 North American Electric Reliability Council (NERC) Summer Assessment reported that; "the Florida Reliability Coordinating Council (FRCC) bulk transmission system is expected to perform adequately over various system conditions." The analysis was based on results of the 1999 Summer FRCC Transmission Study that evaluated three different operating scenarios. The NERC assessment indicated that; "any thermal or voltage violations can be managed successfully by operator intervention." Similar results were reported for FRCC in the NERC 1999/2000 Winter Assessment. The winter

assessment states that the Florida winter peak typically lasts for only three or four hours. The NERC assessment reports that the 1999/2000 FRCC Winter Transmission Study results indicate that; "any thermal or voltage violations can be successfully managed for such short periods by operator intervention."

The 1999 Federal Energy Regulatory Commission's (FERC) 715 submittals confirm the NERC assessments. Part 6 of the Federal Energy Regulatory Commission's (FERC) 715 submittal requires that transmission owners provide a "clear understanding of existing and likely future transmission constraints, their sources, how it identified these constraints, and a description of any plans to mitigate the constraints." Most of the participants indicated that based upon current planning studies and transmission construction programs, they expect no transmission constraints that violate the submitted performance criteria. Several of the participants, listed specific contingencies that could potentially result in overloads on other system elements. In almost all cases, the limitations listed could be mitigated either by previously defined operating practices or budgeted transmission upgrades. The remaining contingency overloads appeared to be local problems that required additional study.

The only inter-area transmission interface limit that was clearly defined in the material reviewed was the Georgia/Florida interface. The Georgia/Florida interface is the connection between the Southern Company control area and peninsular Florida utilities. In the NERC assessments, the total transfer capability from the Southern Company control area to the FRCC Region (Florida) is reported to be 3600 MW for summer conditions and 3700 MW for winter conditions. Total transfer capabilities from Florida to the Southern Company control area were 2500 MW for summer conditions and 2700 MW for winter conditions. This transmission interface limit was also referenced in the joint FRCC-Southern 1998 Summer & 1997/98 Winter Study that we purchased through the Southeastern Electric Reliability Council (SERC). The analysis assumed winter 1997/98 and summer 1998 bulk supply conditions and was performed at the request of the Southern/Florida Planning Task Force.

The FRCC Transmission Loading Relief (TLR) events were reviewed to determine if significant impediments to inter-area transmission had actually occurred in 1999. The FRCC Security Coordinator uses Transmission Loading Relief Procedures to reduce loading on key transmission facilities to prevent line overloads, voltage collapse, or stability problems from occurring either in real time or that would result from a

"next contingency" event on the bulk power transmission system. Events that hold interchange transactions at present levels or curtail interchange transactions to maintain system security are logged and posted on the NERC and FRCC websites. The results of the NERC Summer and Winter Assessments and the FERC 715 submittal's evaluation of transmission system performance are confirmed by the 1999 TLR log. No significant FRCC area-to-area interface constraints were logged. Only two transmission line load relief events were recorded on the FRCC website for 1999. The events impacted the system for a total of six hours. One event occurred in February as the result of a 230 kV line outage. In April, the second event was caused by a combination of market activity and reduced East Coast generation.

The publicly available information reviewed did not clearly indicate the existence of significant impediments to FRCC area-to-area interchange. With expected transmission construction and the prudent use of current operating procedures, the FRCC bulk transmission system is expected to perform adequately over various system conditions. As a result, our production cost simulation model included the only clearly defined interface constraint, the Georgia/Florida interface. Imports from the Southern Company system were limited to 3600 MW according to the 1999 NERC Summer Assessment. In our production cost analysis, the Georgia/Florida interface constraint did not adversely impact the operation of the Calpine Project.

(Slater)

26. Did Calpine model the transmission upgrade requirements if sales are made out-of-state? What transmission constraints does Calpine foresee if sales are made out-of-state?

A. Calpine did not model sales of the unit's output to entities out-of-state because Calpine plans and expects to sell its wholesale power within Peninsular Florida. Accordingly, Calpine did not model any transmission upgrades that might be required for selling power outside Florida. In the unlikely event that Calpine were to make sales out of state, potential transmission constraints would include the seasonal limits on Florida-to-Georgia export capability as well as potential constraints arising from prior commitments of the relevant transmission capacity to other utilities.

(Eves)

Navigant Consulting was not asked to perform any power flow assessment for any sales outside of Peninsular Florida.

(Armand)

27. Exhibit KJS-13 displays average heat rates with and without the Osprey Energy Center. How were these heat rates calculated?

A. The Peninsular Florida system average heat rate values displayed in Exhibit KJS-13 were calculated from values taken from PROMOD standard output reports. These calculations were performed as follows.

Heat Rate (btu/kwh) = Total Primary Energy (1000 * mmbtu) * 1000 / Annual Native Load (GWH)

(Slater)

28. Please provide cost data related to the additional transmission upgrades recommended by Tampa Electric Company's preliminary transmission service request facilities study.

A. Tampa Electric Company issued the Transmission Service Request Facilities Study report on August 31, 2000. The report estimated the cost to interconnect the Osprey Project to TECO's Recker Substation at $2.4 million.

In addition, the cost of the network upgrades required to provide firm transmission service was estimated at $11.5 million. These figures, according to TECO, are based on detailed cost estimates prepared by TECO's engineering departments.

(Baldwin)

29. Please provide the approximate average variable operating and maintenance cost, including fuel, per MWH in constant dollars for the proposed Osprey Energy Center. Please list each individual component of this cost and the amount attributed to each component.

A. The following table sets out the total year-by-year variable cost of the Osprey unit in constant 2000 $, together with each component of this cost. The "base fuel costs" represent the total costs of fuel, including any component that might be regarded as fixed (e.g. firm transportation cost). The "fuel handling" costs represent the costs of emission allowances for the SOx and NOx emissions of the plant.

Osprey	$/MWH	GWH	Fuel Costs		VO&M (K$)	Base Fuel Costs	Fuel Handling Costs	VO&M $/MWH
			Base Costs (K$)	Handling Costs (K$)				
2003	25.56	2624.0	62112	111	4849	23.67	0.04	1.85
2004	25.71	4379.4	104353	137	8093	23.83	0.03	1.85
2005	25.58	4293.3	101766	133	7929	23.70	0.03	1.85
2006	25.55	4278.8	101301	129	7903	23.68	0.03	1.85
2007	25.65	4332.9	103008	124	8005	23.77	0.03	1.85
2008	25.72	4253.5	101411	121	7863	23.84	0.03	1.85
2009	25.71	4171.7	99440	117	7703	23.84	0.03	1.85
2010	25.85	4301.3	103143	114	7949	23.98	0.03	1.85
2011	25.83	4070.1	97492	111	7514	23.95	0.03	1.85
2012	25.98	4389.3	105831	107	8110	24.11	0.02	1.85

(Slater)

30. Page 19 of Kenneth J. Slater's testimony describes the assumptions made regarding the effects of energy conservation and demand-side management programs in modeling the proposed Osprey Energy Center. On lines 15-18, Mr. Slater states that the net energy for load projections were adjusted upward to reflect "more realistic energy consumption levels where necessary." What would be the result if these upward adjustments were not assumed, i.e., if the FRCC and Ten-Year Site Plan projections were used as is?

A. The load forecast used in the PROMOD IV® analyses of the Osprey project was developed from all available sources, which included actual load data as reported by the peninsular Florida utilities to the FPSC, FERC, and NERC, and forecast values appearing in the NERC ES&D report for the FRCC and the individual utility ten-year site plans filed with the FPSC. The "upward adjustment" referred only to changes in the ten-year site plan load forecast of one of the major IOUs to reduce the assumed impact of load management from the maximum possible reduction in load served (as assumed in the IOU's ten-year site plan) to a level which reflected the actual reductions achieved in the past. Without this adjustment, the forecasts of individual utilities would not have been consistent, nor would the sum of the forecast company loads have matched the forecast of total FRCC load.

To determine exactly what the results would have been without this adjustment would require the completion of a new load forecast, the rerunning of all PROMOD analyses and the recalculation of all tables and exhibits.

However, without this load management adjustment, another adjustment would have been necessary in order for our forecast to match the overall FRCC forecast. Because of this, it is safe to say that there has been no noticeable impact of our load management adjustment on the results of the Osprey analyses.

(Slater)

31. Exhibit KJS-11, does not appear to represent a typical winter day load profile. Provide the data source for this exhibit.

A. The illustrations, as in Exhibit KJS-11, were meant to represent individual days in the typical weeks used to represent particular monthly loads in PROMOD IV®. As such they do not purport to be "typical winter" or "typical summer" days. The load shape information provided to PROMOD was derived from actual monthly load shapes from FERC Form 714 filings by FRCC utilities. For the month of December, the utility load shapes came from December 1997, because that December was the December during the period 1996 through 1998 for which the utility load shapes best matched the forecast load factors implied by monthly peak/energy forecasts. For each month of forecast years, the "starting" load shapes were the historical load shapes as shown in the following table.

Month	Load Shapes Used
Jan	1997
Feb	1998
Mar	1998
Apr	1998
May	1998
Jun	1998
Jul	1998
Aug	1998
Sep	1998
Oct	1996
Nov	1998
Dec	1997

Because a small number of these load shapes' load factors did not match sufficiently the load factors inherent in the peak/energy forecasts (which were derived from the ten-year site plans), some minor adjustments to the historical shapes were required in order to achieve this match.

The data used to create the Exhibit KJS-11 came from PROMOD runs with and without the Osprey project, and this data is shown in tabular form in the EXCEL workbook Q31.xls (attached). (Slater)

Jun	Nuc./Hyd.	NUGs	Coal	New CCs	Ext. Purch.	Gas-Stea	Oil-Steam	CTs
1	2958	715	6680	8378	1011	2584	420	0
2	2958	586	5831	8369	698	2546	396	0
3	2958	546	5372	8361	243	2369	363	0
4	2958	539	4961	8359	93	2250	346	0
5	2958	539	4807	8359	69	2216	343	0
6	2958	553	5543	8363	379	2448	376	0
7	2958	630	6133	8374	889	2568	404	0
8	2958	810	7455	8379	1240	2599	448	0
9	2958	1026	8634	8379	1633	3147	462	0
10	2958	1306	8972	8379	1638	4565	695	0
11	2958	1546	8976	8379	1642	5716	1818	0
12	2958	1546	8976	8379	1654	6278	3330	4
13	2958	1546	8976	8379	1655	6947	4362	117
14	2958	1546	8976	8379	1655	7389	4941	712
15	2961	1546	8976	8379	1655	7466	5071	1173
16	2968	1546	8976	8379	1655	7476	5090	1270
17	2968	1546	8976	8379	1655	7468	5075	1191
18	2968	1546	8976	8379	1655	7395	4952	743
19	2965	1546	8976	8379	1655	7156	4639	267
20	2958	1546	8976	8379	1655	6595	3847	22
21	2958	1546	8976	8379	1653	6178	3139	1
22	2958	1544	8976	8379	1641	5622	1624	0
23	2958	1164	8932	8379	1638	4080	558	0
24	2958	892	8089	8379	1451	2711	451	0

Dec	Nuc./Hyd.	NUGs	Coal	New CCs	Ext. Purch.	Gas-Stea	Oil-Steam	CTs
1	3869	429	4394	6683	488	1489	118	0
2	3869	429	3589	6679	99	1489	118	0
3	3869	429	3232	6679	46	1489	118	0
4	3869	429	3106	6679	32	1489	118	0
5	3869	429	3473	6679	78	1489	118	0
6	3869	429	4735	6698	788	1489	118	0
7	3869	430	6863	7976	1064	1489	121	0
8	3880	572	7541	8914	1472	1598	213	0
9	3880	673	7858	8973	1539	1732	285	0
10	3880	721	7962	8980	1558	1819	330	0
11	3880	737	7995	8981	1561	1851	347	0
12	3880	744	8008	8981	1561	1866	356	0
13	3880	785	8102	8986	1638	1978	421	0
14	3880	715	7948	8979	1556	1806	324	0
15	3872	768	8058	8984	1563	1920	388	0
16	3869	725	7970	8980	1559	1826	333	0
17	3877	771	8064	8984	1607	1926	392	0
18	3880	914	8290	8997	1639	2659	887	0
19	3880	934	8299	8997	1639	3529	2628	0
20	3880	918	8298	8997	1639	3063	1185	0
21	3880	914	8290	8997	1639	2660	888	0
22	3880	686	7886	8977	1546	1751	296	0

23	3873	436	7021	8133	1145	1489	126	0
24	3869	429	5400	6795	907	1489	118	0

Total
22745.5
21384.4
20212.7
19506.1
19291.0
20619.5
21955.2
23888.0
26237.5
28512.4
31033.9
33122.6
34937.5
36554.6
37225.6
37359.4
37258.3
36613.9
35583.1
33976.0
32827.9
30743.1
27707.3
24929.4

Total
17469.9
16271.2
15861.3
15720.9
16134.6
18125.5
21811.6
24190.2
24940.4
25248.7
25352.4
25396.0
25790.3
25207.3
25552.2
25262.2
25620.0
27264.4
29905.4
27979.0
27266.5
25020.8

22222.7
19006.3

Jun	Nuc./Hyd.	NUGs	Coal	New CCs	Ext. Purch.	Gas-Stea	Oil-Steam	CTs
1	2958	658	6322	8885	938	2576	409	0
2	2958	562	5637	8874	479	2492	384	0
3	2958	539	5090	8868	129	2279	351	0
4	2958	539	4589	8867	36	2177	339	0
5	2958	539	4412	8867	27	2150	338	0
6	2958	543	5321	8870	217	2350	360	0
7	2958	590	5860	8878	723	2549	398	0
8	2958	781	7113	8887	1124	2588	437	0
9	2958	968	8443	8887	1605	2920	455	0
10	2958	1210	8952	8887	1638	4272	595	0
11	2958	1543	8976	8887	1640	5539	1492	0
12	2958	1546	8976	8887	1652	6116	2988	0
13	2958	1546	8976	8887	1655	6762	4106	48
14	2958	1546	8976	8887	1655	7288	4817	427
15	2961	1546	8976	8887	1655	7411	4998	792
16	2968	1546	8976	8887	1655	7427	5024	876
17	2968	1546	8976	8887	1655	7414	5003	809
18	2968	1546	8976	8887	1655	7299	4832	451
19	2965	1546	8976	8887	1655	6994	4430	130
20	2958	1546	8976	8887	1654	6401	3549	6
21	2958	1546	8976	8887	1650	6037	2774	0
22	2958	1537	8976	8887	1640	5413	1332	0
23	2958	1102	8873	8887	1638	3743	506	0
24	2958	846	7787	8887	1362	2639	451	0

Dec	Nuc./Hyd.	NUGs	Coal	New CCs	Ext. Purch.	Gas-Stea	Oil-Steam	CTs
1	3869	429	4446	6805	433	1489	0	0
2	3869	429	3599	6800	85	1489	0	0
3	3869	429	3252	6800	38	1489	0	0
4	3869	429	3134	6800	28	1489	0	0
5	3869	429	3481	6800	67	1489	0	0
6	3869	429	4777	6821	742	1489	0	0
7	3869	438	6803	8268	944	1491	0	0
8	3880	637	7704	9172	1028	1744	25	0
9	3880	724	8034	9217	1060	1949	78	0
10	3880	755	8141	9220	1061	2071	121	0
11	3880	766	8173	9221	1061	2113	139	0
12	3880	771	8184	9222	1061	2131	148	0
13	3880	807	8264	9226	1135	2264	215	0
14	3880	751	8127	9220	1061	2054	115	0
15	3872	790	8227	9224	1061	2199	180	0
16	3869	757	8149	9221	1061	2081	125	0
17	3877	792	8232	9224	1105	2206	184	0
18	3880	917	8403	9248	1135	2965	717	0
19	3880	922	8416	9251	1135	4120	2183	0
20	3880	918	8412	9251	1135	3395	989	0
21	3880	917	8403	9248	1135	2966	718	0
22	3880	734	8063	9218	1060	1979	87	0

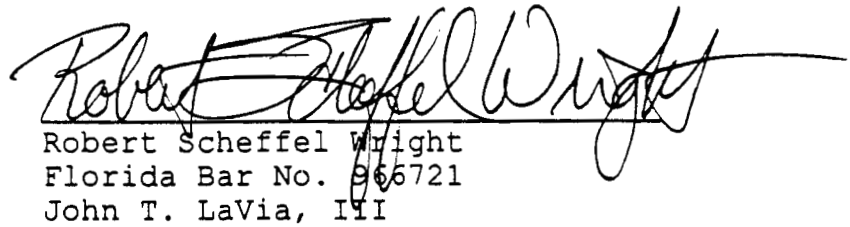
23	3873	449	6984	8461	962	1495	0	0
24	3869	429	5390	6925	905	1489	0	0

Total
22745.7
21384.3
20212.9
19506.0
19291.3
20619.7
21955.2
23888.0
26237.3
28512.1
31034.1
33122.3
34937.7
36554.2
37225.9
37359.1
37259.0
36614.3
35583.4
33976.3
32828.0
30743.0
27707.0
24929.6

Total
17469.9
16271.2
15876.8
15748.4
16134.8
18125.6
21811.7
24190.1
24940.3
25249.3
25352.3
25396.3
25790.6
25207.8
25552.2
25262.6
25620.1
27264.3
29905.6
27979.2
27266.4
25020.7

22222.6
19006.1

Respectfully submitted this 13th day of November, 2000.



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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by hand delivery (*), or U.S. Mail, on this 13th day of November, 2000, to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

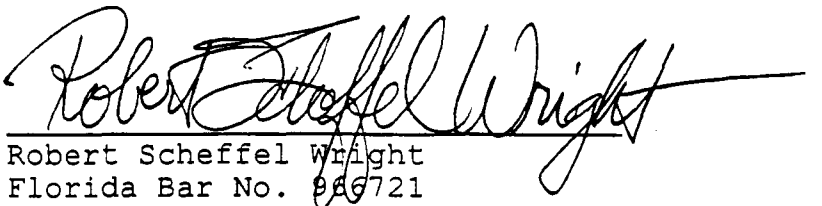
In Re: Petition for Determination of Need for an Electrical Power Plant in Polk County by Calpine Construction Finance Company, L.P.	)	DOCKET NO. 000442-EI
	)	FILED: NOVEMBER 15, 2000

CALPINE CONSTRUCTION FINANCE COMPANY'S SUPPLEMENTAL RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 16-19)

Calpine Construction Finance Company, L.P., ("Calpine"), pursuant to Uniform Rule 28-106.206, Florida Administrative Code, and the Commission's Order Establishing Procedure, as revised, hereby submits a supplemental response to Staff's First Set of Interrogatories (Nos. 16-19). The subject responses were delayed due to a prolonged electronic communications failure in Calpine's attorneys' offices. Calpine's supplemental responses are attached.

Affidavits from the individuals who assisted in the preparation of these responses will be provided to Staff counsel under separate cover.

Respectfully submitted this 15th day of November, 2000.



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Telecopier: (850) 224-5595

Attorneys for Calpine Construction
Finance Company, L.P.

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Attorney

16. **Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide the delivered prices for each fuel associated with the evaluation of the following generation alternatives for each year in the evaluation period.**

A) Combined cycle – Gas fired
B) Combined cycle – Oil fired
C) Simple cycle – Gas fired
D) Simple cycle – Oil fired
E) Steam – Coal
F) Steam – Gas
G) Steam – Nuclear
H) IGCC technology
I) Renewable energy

The assumed delivered prices in 2000 year dollars per MMBtu are shown on the Busbar.screen.xls spreadsheet, on the worksheet entitled "Detail," Lines 13 through 49, Column g. Real fuel price escalation is shown on Lines 7 through 12. No general price inflation is applicable since the values on Table 21 are based on year 2000 dollars.

Comparison of Generation Alternatives

Technology Type	Levelized Life-Cycle Cost at Assumed Capacity Factor (2000 $/MWh)		
	Peaking Operation (10% CF)	Intermediate Oper. (50% CF)	Base Load Oper. (90% CF)
Combined Cycle - Gas Fired	**$ 98 - 118**	**$ 37 - 45**	**$ 30 - 37**
Combined Cycle - Oil Fired	111 - 134	50 - 61	43 - 53
Simple Cycle - Gas Fired	85 - 116	52 - 73	45 - 68
Simple Cycle - Oil Fired	110 - 144	71 - 101	64 - 97
Steam - Coal	200 - 220	52 - 59	35 - 42
Steam - Gas	124	53	45
Steam - Nuclear	283	61	36
IGCC Technology	196 - 245	49 - 61	32 - 40
Renewable Energy	121 - 1072	67 - 240	47 - 147

COMPARISON OF GENERATION ALTERNATIVES

Line No.	Financial/Economic Assumptions	
1	Interest Rate	8.0%
2	Debt Percent	65.0%
3	Equity Rate	13.0%
4	Tax Rate	35.0%
5	General Inflation Rate	0.00%
6	Real Fuel Price Escalation	
7	Coal Price Esc.	-1.2%
8	Nat. Gas Price Esc	1.1%
9	Nuclear Price Esc	0.0%
10	Oil Price Esc.	0.6%
11	Other (Renewable, etc.)	0.0%
12	None	0.0%

Fixed Charge Rates:

Financing Period	Resource Life	Annual Rate
15 years	15	14.53%
20 Years	20	13.25%
25 Years	25	12.16%
30 years	30	11.49%
40 years	40	10.77%

Emission Allowance Costs:

NO_x	2000	$/ton
SO_2	150	$/ton

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NO_x	SO_2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M[4]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Steam - Coal																	
13	Pressurized CFB	1	379.2	1,148	7,269	0.73	1.67	coal	1.66	12.07	30.94	2.92	0.85	30	11.49%	200.42	51.65	35.12
14	Subcritical Pulverized Coal	1	397.5	1,281	9,077	4.09	3.13	coal	1.66	15.07	23.80	2.30	4.32	30	11.49%	215.11	59.00	41.65
15	Supercritical Pulverized Coal	1	401.8	1,331	8,568	1.35	1.47	coal	1.66	14.22	24.44	3.65	1.46	30	11.49%	220.14	58.20	40.20
16	Ultracritical Pulverized Coal	1	399.7	1,326	8,251	1.35	1.42	coal	1.66	13.70	24.40	2.30	1.46	30	11.49%	217.63	56.23	38.30
	Steam - Gas																	
17	Gas-fired steam tubine	3	1,726.6	671 [1]	10,310	0.17 [2]	neg. [2]	gas	2.82	29.06		2.64 [3]	0.17	30	11.49%	123.56	53.14	45.31
	Steam - Nuclear																	
18	Nuclear, Passive Adv. LWR	2	600.0	1,841	10,400	-	-	nuclear	0.46	4.78	44.85	0.53	-	40	10.77%	282.83	60.82	36.15
	IGCC Technology																	
19	Foak Oxygen Blown IGCC	1	543.2	1,471	8,522	0.21	0.48	coal	1.66	14.15	32.66	1.67	0.25	30	11.49%	244.73	60.50	40.03
20	Inter. Oxygen-Blown IGCC	1	349.2	1,407	7,513	0.18	0.13	coal	1.66	12.47	37.16	1.98	0.19	30	11.49%	240.20	58.62	38.44
21	Adv. Air-Blown IGCC	1	398.1	1,119	6,870	0.16	0.12	coal	1.66	11.40	32.80	1.67	0.17	30	11.49%	196.14	48.78	32.41
22	Adv. Oxygen-Blown IGCC	1	427.7	1,245	6,968	0.17	0.12	coal	1.66	11.57	34.22	1.88	0.18	30	11.49%	214.68	52.78	34.79
	Renewable Energy																	
23	Phosphoric Acid Fuel Cell	5	0.2	4,280	9,980	-	-	gas	2.82	28.13	344.50	0.88	-	20	13.25%	1,072.39	239.86	147.36
24	Molten Carbonate Fuel Cell	2	2.0	1,631	6,640	-	-	gas	2.82	18.72	6.79	1.48	-	30	11.49%	244.21	66.89	47.19
25	Solar Parabolic Trough	6	80.0	2,867	-	-	-	none	-	-	66.80	-	-	30	11.49%	452.33	90.47	N/A
26	Utility-Scale PV Concentrators	6	2.5	5,068	-	-	-	none	-	-	59.38	-	-	30	11.49%	732.58	146.52	N/A
27	Utility Scale Flat Plate PV	6	2.4	5,620	-	-	-	none	-	-	-	8.16	-	30	11.49%	745.28	155.59	N/A
28	Wind Energy	6	37.5	795	-	-	-	none	-	-	14.71	-	-	30	11.49%	121.10	N/A	N/A
29	Gasification-Based Biomass	6	75.0	2,006	10,000	Not Determined		other	2.50	25.00	46.02	3.84	-	30	11.49%	344.51	91.97	63.91
30	Waste to Energy-Mass Burn	5	50.0	2,610	15,500	Not Determined		other	-	-	130.49	39.15	-	30	11.49%	530.43	137.40	93.73
31	Waste to Energy-RDF unit	5	50.0	3,132	17,000	Not Determined		other	-	-	182.69	39.15	-	30	11.49%	658.48	163.01	107.96

Notes:

All dollar values expressed in year 2000 dollars.

See Page 2 of 2 for footnotes.

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COMPARISON OF GENERATION ALTERNATIVES

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NOx	SO2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M[7]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Combined Cycle - Gas Fired																	
32	GE 7EA 1x1	4	130.0	660 [4]	7,550	0.71 [5]	neg. [6]	gas	2.82	21.28	3.43 [7]	2.47 [7]	0.71	30	11.49%	117.59	45.23	37.19
33	GE 7EA 2x1	4	264.0	563 [4]	7,440	0.70 [5]	neg. [6]	gas	2.82	20.97	2.34 [7]	2.25 [7]	0.70	30	11.49%	103.14	41.88	35.07
34	Westinghouse 1x1 501 F	4	274.0	535 [4]	6,830	0.53 [5]	neg. [6]	gas	2.82	19.25	2.17 [7]	2.69 [7]	0.53	30	11.49%	97.58	39.44	32.97
35	Westinghouse 1x1 501 G	1	365.0 [8]	524	6,530 [8]	0.20 [5]	neg. [6]	gas	2.82	18.41	10.86	1.46	0.20	30	11.49%	103.49	38.61	31.40
36	GE "H" 1x1	1	400.0 [8]	510	6,320 [8]	0.19 [5]	neg. [6]	gas	2.82	17.81	10.80	1.36	0.19	30	11.49%	100.81	37.45	30.41
	Combined Cycle - Oil Fired																	
37	GE 7EA 1x1	4	134.3	660 [4]	7,210	1.83 [5]	0.39 [6]	oil	5.06	36.50	3.43 [7]	2.60 [7]	1.86	30	11.49%	133.55	61.19	53.15
38	GE 7EA 2x1	4	272.8	563 [4]	7,100	1.80 [5]	0.39 [6]	oil	5.06	35.95	2.34 [7]	2.37 [7]	1.83	30	11.49%	118.83	57.57	50.76
39	Westinghouse 1x1 501 F	4	283.1	535 [4]	6,520	0.88 [5]	0.36 [6]	oil	5.06	33.01	2.17 [7]	2.83 [7]	0.91	30	11.49%	111.37	53.22	46.76
40	Westinghouse 1x1 501 G	1	377.2 [8]	524	6,230 [8]	0.20 [5]	0.37 [6]	oil	5.06	31.54	10.86	1.53	0.23	30	11.49%	116.26	51.38	44.17
41	GE "H" 1x1	1	413.3 [8]	510	6,030 [8]	0.19 [5]	0.32 [6]	oil	5.06	30.53	10.80	1.42	0.22	30	11.49%	113.16	49.80	42.76
	Simple Cycle - Gas Fired																	
42	GE LM6000	5	85.0 [8]	519	9,030 [8]	0.91 [5]	neg. [6]	gas	2.82	25.45	5.69	7.22	0.91	30	11.49%	111.36	51.71	45.08
43	GE 7EA	5	85.0 [8]	376	11,570 [8]	1.07 [5]	neg. [6]	gas	2.82	32.61	3.47	24.60	1.07	30	11.49%	115.70	73.05	68.32
44	GE 7FA	5	172.0 [8]	288	10,460 [8]	0.28 [5]	neg. [6]	gas	2.82	29.48	2.58	10.83	0.28	30	11.49%	85.00	52.45	48.83
45	Westinghouse 501 G	5	253.0 [8]	326	10,260 [8]	0.78 [5]	neg. [6]	gas	2.82	28.92	2.22	12.12	0.78	30	11.49%	90.69	54.51	50.49
	Simple Cycle - Oil Fired																	
46	GE LM6000	5	44.0 [8]	519	8,740 [8]	1.57 [5]	0.44 [6]	oil	5.06	44.25	5.69	7.59	1.60	30	11.49%	130.60	70.95	64.32
47	GE 7EA	5	89.3 [8]	376	11,600 [8]	2.74 [5]	0.59 [6]	oil	5.06	58.73	3.47	25.82	2.79	30	11.49%	144.09	101.45	96.71
48	GE 7FA	5	180.6 [8]	288	10,490 [8]	1.30 [5]	0.53 [6]	oil	5.06	53.11	2.58	11.37	1.34	30	11.49%	109.62	77.08	73.46
49	Westinghouse 501 G	5	265.7 [8]	326	10,290 [8]	1.28 [5]	0.52 [6]	oil	5.06	52.10	2.22	12.73	1.32	30	11.49%	114.43	78.25	74.23

Sources

1. Market-Based Advanced Coal Power Systems - May 1999 (Dept. of Energy). Costs provided in 1998 dollars adjusted to 2000 dollars at rate of historical CPI.
2. Georgia Power Company 1998 Integrated Resource Plan. Costs provided in 1997 dollars adjusted to 2000 dollars at rate of historical CPI.
3. 1998 Florida Power & Light Company Form 1. Costs provided in 1998 dollars adjusted to 2000 dollars at rate of historical CPI.
4. Gas Turbine World Handbook 2000. Capacity and heat rate at ISO conditions for gas-fired operation. Heat Rate provided as LHV adjusted to HHV by factor of 1.11 for gas and 1.06 for oil. Capacity for oil operation adjusted by factor of 1.05.
5. Kissimmee Utility Authority/Florida Municipal Power Agency Need For Power Application-Cane Island Power Park Unit 3 at rate of historical CPI.
6. Renewable Energy Technology Characterizations (EPRI Topical Report No. TR-109496, December 1997). Costs provided in 1997 dollars adjusted to 2000 dollars at rate of historical CPI.

Notes

All dollar values expressed in year 2000 dollars

[1] Installed cost provided in 1981 dollars adjusted to 1998 dollars by Handy Whitman Index and further adjusted to 2000 dollars by historic CPI
[2] NOx and SO2 emissions provided in year 2000 Title V air permit for FP&L Martin plant
[3] Represents total O&M costs (fixed and variable)
[4] Installed cost provided in 1999 dollars adjusted to 2000 dollars and adjusted by factor of 1.25 to include indirect costs.
[5] NOx emissions provided in year 2000 Title V air permit from Florida in ppm adjusted to lb/MWh. Does not include SCR equipment.
[6] SO2 emissions calculated assumming .25 grains/SCF of gas and 0.05% Sulfur oil with heat contenet of 18,500. Does not include SCR equipment.
[7] Fixed and variable O&M provided from Source No. 5.
[8] Capacity and heat rate provided from Source No. 4
[9] Excludes A&G costs and property taxes

The GE 7FA performance of gas and oil for the 7EA was ratioed. GE CycleDeck only allows 65ppm NOx.
The heat rate increases with oil operation is the water injection. (WI raises kWs & raises HR)
The hhv/lhv ratio is 1.06 for oil vs 1.11 for NG

	Capacity (MW)	Installed Cost ($/kW)	Heat Rate (BTU/kWh)	NOx (lb/MWh)	SO2 (lb/MWh)
Combined Cycle - Gas Fired					
GE 7EA 1x1 [4]	130.0		7548	0.706	0.00
GE 7EA 2x1 [4]	264.0		7437	0.695	0.00
Westinghouse 1x1 501 F [4]	274.0		6827	0.528	0.00
Westinghouse 1x1 501 G [1]	365.0		6527	0.202	0.00
GE "H" 1x1 [1]	400.0		6316	0.192	0.00
Combined Cycle - Oil Fired					
GE 7EA 1x1 [4]	134.3		7448	1.830	0.39
GE 7EA 2x1 [4]	272.8		7339	1.802	0.39
Westinghouse 1x1 501 F [4]	283.1		6736	0.885	0.36
Westinghouse 1x1 501 G [1]	377.2		6441	0.202	0.37
GE "H" 1x1 [1]	413.3		6232	0.192	0.32
Combustion Turbine - Gas Fired					
GE LM6000 [5]	44.0		9030	0.906	0.00
GE 7EA [5]	85.0		11570	1.075	0.00
GE 7FA [5]	172.0		10460	0.285	0.00
Westinghouse 501 G [5]	253.0		10260	0.776	0.00
Combustion Turbine - Oil Fired					
GE LM6000 [5]	44.0		8736	1.568	0.44
GE 7EA [5]	89.3		11601	2.741	0.59
GE 7FA [5]	180.6		10488	1.304	0.53
Westinghouse 501 G [5]	265.7		10288	1.279	0.52

GE LM6000PA

	NG	Oil
Power	39450	39400
HR,lhv	9165	9285
Mx, pph	964.8	966.6
NOx, ppm	25	42
NOx, pph	36	63

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$$ppm = \frac{\text{lb-mol NOx}}{\text{10\^6 lb-mol Exh}} = \frac{\text{10\^6 * lb-mol Exh * lb NOx * lb Exh * hr}}{\text{lb Exh * lb Exh * lb-mol NOx * hr}}$$

	MW	HR, lhv	NOx rate ppmv 15%O2	Tx ıust temp	Mass flow lb/se	Mx Mass flow lb/hr	NOx, lb/hr	NOx lb/MWh	.05%Sulfur SO2 lb/hr	SO2 lb/MWh	
GE LM6000 PD	44.1	8135	25	842	280	1,008,000	40	0.91			25/42
GE Frame 7EA	85.4	10420	25	998	643	2,314,800	92	1.07			
GE Frame 7FA	171.7	9420	9	1116	952	3,427,200	49	0.28			9/42
GE Frame 7H CC	400	5687	9		1230	4,428,000	63	0.16			
W 501 FC	186.5	9130	25	1094	1014	3,650,400	145	0.78			
W 501 G (EST)	253	9241	25	1101	1241	4,467,600	177	0.70			
OIL											
GE LM6000 PD	44.1	8135	42	842	288.4	1,038,240	69	1.57	19.39	0.440	
GE Frame 7EA	89.67	10941	65	998	662.29	2,384,244	246	2.74	53.03	0.591	
GE Frame 7FA	180.285	9891	42	1116	980.56	3,530,016	235	1.30	96.39	0.535	
GE Frame 7G CC	350	5883	42		1265.87	4,557,132	304	0.87	111.30	0.318	
GE Frame 7H CC	420	5971.35	42		1266.9	4,560,840	304	0.72	135.57	0.323	
W 501 FC	196	9587	42	1094	1044.42	3,759,912	250	1.28	101.47	0.518	
W 501 G (EST)	266	9703	42	1101	1278.23	4,601,628	307	1.15	139.33	0.524	

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From Bureau of Labor Stastics Data

Consumer Price Index-All Urban Consumers

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1997	159.1	159.6	160	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3	160.5
1998	161.6	161.9	162.2	162.5	162.8	163	163.2	163.4	163.6	164	164	163.9	163
1999	164.3	164.5	165	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6
2000	168.7												

1.0603 From Jan. 97 to Jan. 00
1.0439 From Jan. 98 to Jan. 00
1.0268 From Jan. 99 to Jan. 00

17. Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide a present worth analysis for each of the following generation alternatives. For each year in the evaluation period, provide the annual and cumulative present worth values for each of the following components: capital, fixed operations and maintenance (O&M); non-fuel variable O&M; fuel; purchased power; and total costs.

A) Combined cycle – Gas fired
B) Combined cycle – Oil fired
C) Simple cycle – Gas fired
D) Simple cycle – Oil fired
E) Steam – Coal
F) Steam – Gas
G) Steam – Nuclear
H) IGCC technology
I) Renewable energy

The various operating cost components for each type generating resource are shown on the Busbar.Screen1.xls spreadsheet on worksheet entitled "Detail" (g) through (m), the capital cost component is the product of Column (m) and Column (b). The annual values of each cost component except fuel are assumed to escalate at the general inflation rate shown on Line No. 5. The annual value of the fuel component is equal to the value shown in column (h), escalated at the combined assumed general escalation rate shown on Line No. 5 and the appropriate assumed real fuel price escalation shown in Line Nos. 7 through 12.

With regard to the requirement for a present worth analysis, the annualized cost of each alternative over its life/financing period assuming 10 percent, 50 percent and 90 percent capacity factors is presented in Column (n) through (p). For a screening analysis, the annualized cost in dollars per MWh represents a more consistent and uniform methodology for screening alternatives of different sizes and economic lives. For this reason an annualized cost analysis versus a present worth analysis was prepared. The annualized cost is an annual uniform cost that has the same present worth as the actual stream of projected costs over the same number of years at the assumed discount rate. The calculation for levelizing the escalating payment was defined in the EPRI Technical Assessment Guide 1993 ("TAG"). The annualized cost of each of the alternatives in nominal dollars is summarized on the worksheet entitled "Summary".

Comparison of Generation Alternatives

Technology Type	Levelized Life-Cycle Cost at Assumed Capacity Factor (Nominal $/MWh)		
	Peaking Operation (10% CF)	Intermediate Oper. (50% CF)	Base Load Oper. (90% CF)
Combined Cycle - Gas Fired	**$ 108 - 130**	**$ 47 - 56**	**$ 39 - 48**
Combined Cycle - Oil Fired	127 - 152	64 - 78	57 - 70
Simple Cycle - Gas Fired	103 - 142	67 - 98	60 - 93
Simple Cycle - Oil Fired	138 - 181	93 - 137	86 - 132
Steam - Coal	220 - 238	60 - 69	42 - 51
Steam - Gas	137	67	59
Steam - Nuclear	309	68	41
IGCC Technology	215 - 265	56 - 69	39 - 47
Renewable Energy	128 - 1194	76 - 271	56 - 169

COMPARISON OF GENERATION ALTERNATIVES

Line No.	Financial/Economic Assumptions	
1	Interest Rate	8.0%
2	Debt Percent	65.0%
3	Equity Rate	13.0%
4	Tax Rate	35.0%
5	General Inflation Rate	3.00%
6	Real Fuel Price Escalation:	
7	Coal Price Esc	-1.2%
8	Nat. Gas Price Esc	1.1%
9	Nuclear Price Esc.	0.0%
10	Oil Price Esc	0.6%
11	Other (Renewable, etc.)	0.0%
12	None	0.0%

Fixed Charge Rates:

Financing Period	Resource Life	Annual Rate
15 years	15	14.53%
20 Years	20	13.25%
25 Years	25	12.16%
30 years	30	11.49%
40 years	40	10.77%

Emission Allowance Costs:

NO_x	2000	$/ton
SO_2	150	$/ton

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NO_x	SO_2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M [4]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Steam - Coal																	
13	Pressurized CFB	1	379.2	1,148	7,269	0.73	1.67	coal	1.66	12.07	30.94	2.92	0.85	30	11.49%	219.84	60.05	42.30
14	Subcritical Pulverized Coal	1	397.5	1,281	9,077	4.09	3.13	coal	1.66	15.07	23.80	2.30	4.32	30	11.49%	233.50	68.91	50.62
15	Supercritical Pulverized Coal	1	401.8	1,331	8,568	1.35	1.47	coal	1.66	14.22	24.44	3.65	1.46	30	11.49%	237.93	67.28	48.32
16	Ultracritical Pulverized Coal	1	399.7	1,326	8,251	1.35	1.42	coal	1.66	13.70	24.40	2.30	1.46	30	11.49%	234.70	64.61	45.71
	Steam - Gas																	
17	Gas-fired steam tubine	3	1,726.6	671 [1]	10,310	0.17 [2]	neg. [2]	gas	2.82	29.06		2.64 [3]	0.17	30	11.49%	137.42	67.00	59.18
	Steam - Nuclear																	
18	Nuclear , Passive Adv. LWR	2	600.0	1,841	10,400	-	-	nuclear	0.46	4.78	44.85	0.53	-	40	10.77%	309.44	68.14	41.33
	IGCC Technology																	
19	Foak Oxygen Blown-IGCC	1	543.2	1,471	8,522	0.21	0.48	coal	1.66	14.15	32.66	1.67	0.25	30	11.49%	264.92	69.05	47.29
20	Inter. Oxygen-Blown IGCC	1	349.2	1,407	7,513	0.18	0.13	coal	1.66	12.47	37.16	1.98	0.19	30	11.49%	261.91	67.09	45.44
21	Adv. Air-Blown IGCC	1	398.1	1,119	6,870	0.16	0.12	coal	1.66	11.40	32.80	1.67	0.17	30	11.49%	215.41	56.36	38.69
22	Adv. Oxygen-Blown IGCC	1	427.7	1,245	6,968	0.17	0.12	coal	1.66	11.57	34.22	1.88	0.18	30	11.49%	234.72	60.62	41.28
	Renewable Energy																	
23	Phosphoric Acid Fuel Cell	5	0.2	4,280	9,980	-	-	gas	2.82	28.13	344.50	0.88	-	20	13.25%	1,193.89	271.42	168.92
24	Molten Carbonate Fuel Cell	2	2.0	1,631	6,640	-	-	gas	2.82	18.72	6.79	1.48	-	30	11.49%	256.03	76.30	56.32
25	Solar Parabolic Trough	6	80.0	2,867	-	-	-	none	-	-	66.80	-	-	30	11.49%	482.08	96.42	N/A
26	Utility-Scale PV Concentrators	6	2.5	5,068	-	-	-	none	-	-	59.38	-	-	30	11.49%	759.03	151.81	N/A
27	Utility-Scale Flat-Plate PV	6	2.4	5,620	-	-	-	none	-	-	-	8.16	-	30	11.49%	748.47	158.77	N/A
28	Wind Energy	6	37.5	795	-	-	-	none	-	-	14.71	-	-	30	11.49%	127.65	N/A	N/A
29	Gasification-Based Biomass	6	75.0	2,006	10,000	Not Determined		other	2.50	25.00	46.02	3.84	-	30	11.49%	376.26	107.32	77.44
30	Waste to Energy-Mass Burn	5	50.0	2,610	15,500	Not Determined		other	-	-	130.49	39.15	-	30	11.49%	603.82	164.30	115.47
31	Waste to Energy-RDF unit	5	50.0	3,132	17,000	Not Determined		other	-	-	182.69	39.15	-	30	11.49%	755.12	194.56	132.28

Notes:

All dollar values expressed in year 2000 dollars

See Page 2 of 2 for footnotes

COMPARISON OF GENERATION ALTERNATIVES

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NOx	SO2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M [1]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Combined Cycle - Gas Fired																	
32	GE 7EA 1x1	4	130 0	660 [4]	7,550	0.71 [5]	neg. [6]	gas	2 82	21.28	3 43 [7]	2 47 [7]	0 71	30	11 49%	129.71	56.13	47 95
33	GE 7EA 2x1	4	264 0	563 [4]	7.440	0.70 [5]	neg. [6]	gas	2.82	20.97	2.34 [7]	2 25 [7]	0.70	30	11 49%	114 54	52.45	45 55
34	Westinghouse 1x1 501 F	4	274 0	535 [4]	6,830	0.53 [5]	neg. [6]	gas	2 82	19.25	2 17 [7]	2 69 [7]	0 53	30	11 49%	108 26	49 34	42 80
35	Westinghouse 1x1 501 G	1	365 0 [8]	524	6,530 [8]	0 20 [5]	neg [6]	gas	2.82	18.41	10 86	1 46	0.20	30	11.49%	117 06	48 31	40 67
36	GE "H" 1x1	1	400 0 [8]	510	6,320 [8]	0.19 [5]	neg [6]	gas	2 82	17.81	10.80	1.36	0 19	30	11 49%	114 05	46 84	39.37
	Combined Cycle - Oil Fired																	
37	GE 7EA 1x1	4	134.3	660 [4]	7,210	1.83 [5]	0.39 [6]	oil	5.06	36.50	3 43 [7]	2 60 [7]	1.86	30	11.49%	151 90	78 32	70 14
38	GE 7EA 2x1	4	272 8	563 [4]	7,100	1.80 [5]	0.39 [6]	oil	5 06	35 95	2.34 [7]	2 37 [7]	1 83	30	11 49%	136 36	74 26	67.36
39	Westinghouse 1x1 501 F	4	283.1	535 [4]	6,520	0 88 [5]	0 36 [6]	oil	5 06	33 01	2.17 [7]	2 83 [7]	0 91	30	11 49%	127 43	68 51	61 96
40	Westinghouse 1x1 501 G	1	377 2 [8]	524	6,230 [8]	0 20 [5]	0.37 [6]	oil	5 06	31 54	10 86	1 53	0 23	30	11 49%	134 81	66 06	58.42
41	GE "H" 1x1	1	413 3 [8]	510	6,030 [8]	0 19 [5]	0 32 [6]	oil	5.06	30 53	10 80	1 42	0 22	30	11 49%	131 23	64 01	56.55
	Simple Cycle - Gas Fired																	
42	GE LM6000	5	85 0 [8]	519	9,030 [8]	0.91 [5]	neg. [6]	gas	2 82	25 45	5 69	7 22	0 91	30	11 49%	128.25	66.57	59 71
43	GE 7EA	5	85.0 [8]	376	11,570 [8]	1.07 [5]	neg [6]	gas	2 82	32 61	3 47	24 60	1 07	30	11 49%	141 58	97.70	92 83
44	GE 7FA	5	172 0 [8]	288	10,460 [8]	0 28 [5]	neg [6]	gas	2 82	29 48	2 58	10 83	0 28	30	11 49%	103 43	69 96	66 25
45	Westinghouse 501 G	5	253.0 [8]	326	10,260 [8]	0 78 [5]	neg. [6]	gas	2 82	28 92	2 22	12 12	0.78	30	11 49%	109.42	72 44	68 33
	Simple Cycle - Oil Fired																	
46	GE LM6000	5	44 0 [8]	519	8,740 [8]	1.57 [5]	0.44 [6]	oil	5 06	44.25	5.69	7 59	1 60	30	11 49%	155 00	93 32	86 46
47	GE 7EA	5	89 3 [8]	376	11,600 [8]	2 74 [5]	0 59 [6]	oil	5 06	58 73	3 47	25 82	2 79	30	11 49%	181 06	137 18	132 30
48	GE 7FA	5	180 6 [8]	288	10,490 [8]	1 30 [5]	0 53 [6]	oil	5 06	53 11	2 58	11 37	1 34	30	11 49%	137 67	104 20	100 48
49	Westinghouse 501 G	5	265.7 [8]	326	10,290 [8]	1.28 [5]	0.52 [6]	oil	5.06	52.10	2 22	12 73	1.32	30	11 49%	142 42	105 44	101 33

Sources:

1 Market-Based Advanced Coal Power Systems - May 1999 (Dept. of Energy). Costs provided in 1998 dollars adjusted to 2000 dollars at rate of historical CPI.
2 Georgia Power Company 1998 Integrated Resource Plan. Costs provided in 1997 dollars adjusted to 2000 dollars at rate of historical CPI.
3 1998 Florida Power & Light Company Form 1. Costs provided in 1998 dollars adjusted to 2000 dollars at rate of historical CPI.
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5 Kissimmee Utility Authority/Florida Municipal Power Agency Need For Power Application-Cane Island Power Park Unit 3 at rate of historical CPI.
6 Renewable Energy Technology Characterizations (EPRI Topical Report No. TR-109496, December 1997). Costs provided in 1997 dollars adjusted to 2000 dollars at rate of historical CPI

Notes

All dollar values expressed in year 2000 dollars.

[1] Installed cost provided in 1981 dollars adjusted to 1998 dollars by Handy Whitman index and futher adjusted to 2000 dollars by historic CPI.
[2] NOx and SO2 emissions provided in year 2000 Title V air permit for FP&L Martin plant
[3] Represents total O&M costs (fixed and variable)
[4] Installed cost provided in 1999 dollars adjusted to 2000 dollars and adjusted by factor of 1.25 to include indirect costs.
[5] NOx emissions provided in year 2000 Title V air permit from Florida in ppm adjusted to lb/MWh. Does not include SCR equipment.
[6] SO2 emissions calculated assumming .25 grains/SCF of gas and 0.05% Sulfur oil with heat contenet of 18,500. Does not include SCR equipment.
[7] Fixed and variable O&M provided from Source No. 5.
[8] Capacity and heat rate provided from Source No. 4.
[9] Excludes A&G costs and property taxes.

The GE 7FA performance of gas and oil for the 7EA was ratioed. GE CycleDeck only allows 65ppm NOx.
The heat rate increases with oil operation is the water injection. (WI raises kWs & raises HR)
The hhv/lhv ratio is 1.06 for oil vs 1.11 for NG

	Capacity (MW)	Installed Cost ($/kW)	Heat Rate (BTU/kWh)	NOx (lb/MWh)	SO2 (lb/MWh)
Combined Cycle - Gas Fired					
GE 7EA 1x1 [4]	130.0		7548	0.706	0.00
GE 7EA 2x1 [4]	264.0		7437	0.695	0.00
Westinghouse 1x1 501 F [4]	274.0		6827	0.528	0.00
Westinghouse 1x1 501 G [1]	365.0		6527	0.202	0.00
GE "H" 1x1 [1]	400.0		6316	0.192	0.00
Combined Cycle - Oil Fired					
GE 7EA 1x1 [4]	134.3		7448	1.830	0.39
GE 7EA 2x1 [4]	272.8		7339	1.802	0.39
Westinghouse 1x1 501 F [4]	283.1		6736	0.885	0.36
Westinghouse 1x1 501 G [1]	377.2		6441	0.202	0.37
GE "H" 1x1 [1]	413.3		6232	0.192	0.32
Combustion Turbine - Gas Fired					
GE LM6000 [5]	44.0		9030	0.906	0.00
GE 7EA [5]	85.0		11570	1.075	0.00
GE 7FA [5]	172.0		10460	0.285	0.00
Westinghouse 501 G [5]	253.0		10260	0.776	0.00
Combustion Turbine - Oil Fired					
GE LM6000 [5]	44.0		8736	1.568	0.44
GE 7EA [5]	89.3		11601	2.741	0.59
GE 7FA [5]	180.6		10488	1.304	0.53
Westinghouse 501 G [5]	265.7		10288	1.279	0.52

GE LM6000PA

	NG	Oil
Power	39450	39400
HR,lhv	9165	9285
Mx, pph	964.8	966.6
NOx, ppm	25	42
NOx, pph	36	63

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$$ppm = \frac{\text{lb-mol NOx}}{\text{10^6 lb-mol Exh}} = \frac{\text{10^6 * lb-mol Exh * lb NOx * lb Exh * hr}}{\text{lb Exh * lb Exh * lb-mol NOx * hr}}$$

	MW	HR, lhv	NOx rate ppmv 15%O2	Tx ıust temp	Mass flow lb/se	Mx Mass flow lb/hr	NOx, lb/hr	NOx lb/MWh	.05%Sulfur SO2 lb/hr	SO2 lb/MWh	
GE LM6000 PD	44.1	8135	25	842	280	1,008,000	40	0.91			25/42
GE Frame 7EA	85.4	10420	25	998	643	2,314,800	92	1.07			
GE Frame 7FA	171.7	9420	9	1116	952	3,427,200	49	0.28			9/42
GE Frame 7H CC	400	5687	9		1230	4,428,000	63	0.16			
W 501 FC	186.5	9130	25	1094	1014	3,650,400	145	0.78			
W 501 G (EST)	253	9241	25	1101	1241	4,467,600	177	0.70			
OIL											
GE LM6000 PD	44.1	8135	42	842	288.4	1,038,240	69	1.57	19.39	0.440	
GE Frame 7EA	89.67	10941	65	998	662.29	2,384,244	246	2.74	53.03	0.591	
GE Frame 7FA	180.285	9891	42	1116	980.56	3,530,016	235	1.30	96.39	0.535	
GE Frame 7G CC	350	5883	42		1265.87	4,557,132	304	0.87	111.30	0.318	
GE Frame 7H CC	420	5971.35	42		1266.9	4,560,840	304	0.72	135.57	0.323	
W 501 FC	196	9587	42	1094	1044.42	3,759,912	250	1.28	101.47	0.518	
W 501 G (EST)	266	9703	42	1101	1278.23	4,601,628	307	1.15	139.33	0.524	

From Bureau of Labor Stastics Data

Consumer Price Index-All Urban Consumers

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1997	159.1	159.6	160	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3	160.5
1998	161.6	161.9	162.2	162.5	162.8	163	163.2	163.4	163.6	164	164	163.9	163
1999	164.3	164.5	165	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6
2000	168.7												

1.0603 From Jan. 97 to Jan. 00
1.0439 From Jan. 98 to Jan. 00
1.0268 From Jan. 99 to Jan. 00

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18. **Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide a present worth analysis for each of the following generation alternatives using Calpine's high natural gas price forecast. For each year in the evaluation period, provide the annual and cumulative present worth values for each of the following components: capital, fixed operations and maintenance (O&M); non-fuel variable O&M; fuel; purchased power; and total costs.**

A) Combined cycle – Gas fired
B) Combined cycle – Oil fired
C) Simple cycle – Gas fired
D) Simple cycle – Oil fired
E) Steam – Coal
F) Steam – Gas
G) Steam – Nuclear
H) IGCC technology
I) Renewable energy

The annualized cost for each of the generation alternatives is calculated assuming Calpine's high natural gas price forecast. The requested information is provided on spreadsheet Busbar.Screen2.xls on the same worksheet and columns as referenced in the response to Interrogatory No. 17. For reasons stated in the response to Interrogatory No.17, an annualized cost analysis versus a "present worth" analysis was prepared.

Comparison of Generation Alternatives

Technology Type	Levelized Life-Cycle Cost at Assumed Capacity Factor (2000 $/MWh)		
	Peaking Operation (10% CF)	Intermediate Oper. (50% CF)	Base Load Oper. (90% CF)
Combined Cycle - Gas Fired	**$ 107 - 129**	**$ 46 - 55**	**$ 38 - 47**
Combined Cycle - Oil Fired	127 - 152	64 - 78	57 - 70
Simple Cycle - Gas Fired	102 - 140	65 - 96	58 - 91
Simple Cycle - Oil Fired	138 - 181	93 - 137	86 - 132
Steam - Coal	220 - 238	60 - 69	42 - 51
Steam - Gas	136	66	58
Steam - Nuclear	309	68	41
IGCC Technology	215 - 265	56 - 69	39 - 47
Renewable Energy	128 - 1193	75 - 270	55 - 168

COMPARISON OF GENERATION ALTERNATIVES

Line No.	Financial/Economic Assumptions	
1	Interest Rate	8.0%
2	Debt Percent	65.0%
3	Equity Rate	13.0%
4	Tax Rate	35.0%
5	General Inflation Rate	3.00%
6	Real Fuel Price Escalation:	
7	Coal Price Esc	-1.2%
8	Nat. Gas Price Esc.	0.8%
9	Nuclear Price Esc	0.0%
10	Oil Price Esc	0.6%
11	Other (Renewable, etc.)	0.0%
12	None	0.0%

Fixed Charge Rates:

Financing Period	Resource Life	Annual Rate
15 years	15	14.53%
20 Years	20	13.25%
25 Years	25	12.16%
30 years	30	11.49%
40 years	40	10.77%

Emission Allowance Costs:

NO_x	2000	$/ton
SO_2	150	$/ton

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NO_x	SO_2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M [4]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Steam - Coal																	
13	Pressurized CFB	1	379.2	1,148	7,269	0.73	1.67	coal	1.66	12.07	30.94	2.92	0.85	30	11.49%	219.84	60.05	42.30
14	Subcritical Pulverized Coal	1	397.5	1,281	9,077	4.09	3.13	coal	1.66	15.07	23.80	2.30	4.32	30	11.49%	233.50	68.91	50.62
15	Supercritical Pulverized Coal	1	401.8	1,331	8,568	1.35	1.47	coal	1.66	14.22	24.44	3.65	1.46	30	11.49%	237.93	67.28	48.32
16	Ultracritical Pulverized Coal	1	399.7	1,328	8,251	1.35	1.42	coal	1.66	13.70	24.40	2.30	1.46	30	11.49%	234.70	64.61	45.71
	Steam - Gas																	
17	Gas-fired steam tubine	3	1,726.6	671 [1]	10,310	0.17 [2]	neg [2]	gas	2.82	29.06		2.64 [3]	0.17	30	11.49%	135.96	65.54	57.71
	Steam - Nuclear																	
18	Nuclear, Passive Adv. LWR	2	600.0	1,841	10,400	-	-	nuclear	0.46	4.78	44.85	0.53	-	40	10.77%	309.44	68.14	41.33
	IGCC Technology																	
19	Foak Oxygen Blown IGCC	1	543.2	1,471	8,522	0.21	0.48	coal	1.66	14.15	32.66	1.67	0.25	30	11.49%	264.92	69.05	47.29
20	Inter. Oxygen-Blown IGCC	1	349.2	1,407	7,513	0.18	0.13	coal	1.66	12.47	37.16	1.98	0.19	30	11.49%	261.91	67.09	45.44
21	Adv. Air-Blown IGCC	1	398.1	1,119	6,870	0.16	0.12	coal	1.66	11.40	32.80	1.67	0.17	30	11.49%	215.41	56.36	38.69
22	Adv. Oxygen-Blown IGCC	1	427.7	1,245	6,968	0.17	0.12	coal	1.66	11.57	34.22	1.88	0.18	30	11.49%	234.72	60.62	41.28
	Renewable Energy																	
23	Phosphoric Acid Fuel Cell	5	0.2	4,280	9,980	-	-	gas	2.82	28.13	344.50	0.88	-	20	13.25%	1,192.90	270.43	167.93
24	Molten Carbonate Fuel Cell	2	2.0	1,631	6,640	-	-	gas	2.82	18.72	6.79	1.48	-	30	11.49%	255.09	75.35	55.38
25	Solar Parabolic Trough	6	80.0	2,867	-	-	-	none	-	-	66.80	-	-	30	11.49%	482.08	96.42	N/A
26	Utility-Scale PV Concentrators	6	2.5	5,068	-	-	-	none	-	-	59.38	-	-	30	11.49%	759.03	151.81	N/A
27	Utility-Scale Flat Plate PV	6	2.4	5,620	-	-	-	none	-	-	-	8.16	-	30	11.49%	748.47	158.77	N/A
28	Wind Energy	6	37.5	795	-	-	-	none	-	-	14.71	-	-	30	11.49%	127.65	N/A	N/A
29	Gasification-Based Biomass	6	75.0	2,006	10,000	Not Determined		other	2.50	25.00	46.02	3.84	-	30	11.49%	376.26	107.32	77.44
30	Waste to Energy-Mass Burn	5	50.0	2,610	15,500	Not Determined		other	-	-	130.49	39.15	-	30	11.49%	603.82	164.30	115.47
31	Waste to Energy-RDF unit	5	50.0	3,132	17,000	Not Determined		other	-	-	182.69	39.15	-	30	11.49%	755.12	194.56	132.28

Notes:

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See Page 2 of 2 for footnotes.

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COMPARISON OF GENERATION ALTERNATIVES

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NOx	SO2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M [8][9]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Combined Cycle - Gas Fired																	
32	GE 7EA 1x1	4	130 0	660 [4]	7,550	0.71 [5]	neg [6]	gas	2 82	21.28	3 43 [7]	2 47 [7]	0 71	30	11 49%	128 64	55 06	46 88
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36	GE "H" 1x1	1	400 0 [8]	510	6,320 [8]	0 19 [5]	neg [6]	gas	2 82	17 81	10 80	1 36	0 19	30	11 49%	113 15	45 94	38 48
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[6] SO2 emissions calculated assumming .25 grains/SCF of gas and 0.05% Sulfur oil with heat contenet of 18,500. Does not include SCR equipment.
[7] Fixed and variable O&M provided from Source No. 5.
[8] Capacity and heat rate provided from Source No. 4.
[9] Excludes A&G costs and property taxes.

The GE 7FA performance of gas and oil for the 7EA was ratioed. GE CycleDeck only allows 65ppm NOx.
The heat rate increases with oil operation is the water injection. (WI raises kWs & raises HR)
The hhv/lhv ratio is 1.06 for oil vs 1.11 for NG

	Capacity (MW)	Installed Cost ($/kW)	Heat Rate (BTU/kWh)	NOx (lb/MWh)	SO2 (lb/MWh)
Combined Cycle - Gas Fired					
GE 7EA 1x1 [4]	130.0		7548	0.706	0.00
GE 7EA 2x1 [4]	264.0		7437	0.695	0.00
Westinghouse 1x1 501 F [4]	274.0		6827	0.528	0.00
Westinghouse 1x1 501 G [1]	365.0		6527	0.202	0.00
GE "H" 1x1 [1]	400.0		6316	0.192	0.00
Combined Cycle - Oil Fired					
GE 7EA 1x1 [4]	134.3		7448	1.830	0.39
GE 7EA 2x1 [4]	272.8		7339	1.802	0.39
Westinghouse 1x1 501 F [4]	283.1		6736	0.885	0.36
Westinghouse 1x1 501 G [1]	377.2		6441	0.202	0.37
GE "H" 1x1 [1]	413.3		6232	0.192	0.32
Combustion Turbine - Gas Fired					
GE LM6000 [5]	44.0		9030	0.906	0.00
GE 7EA [5]	85.0		11570	1.075	0.00
GE 7FA [5]	172.0		10460	0.285	0.00
Westinghouse 501 G [5]	253.0		10260	0.776	0.00
Combustion Turbine - Oil Fired					
GE LM6000 [5]	44.0		8736	1.568	0.44
GE 7EA [5]	89.3		11601	2.741	0.59
GE 7FA [5]	180.6		10488	1.304	0.53
Westinghouse 501 G [5]	265.7		10288	1.279	0.52

GE LM6000PA

	NG	Oil
Power	39450	39400
HR,lhv	9165	9285
Mx, pph	964.8	966.6
NOx, ppm	25	42
NOx, pph	36	63

000860

$$ppm = \frac{\text{lb-mol NOx}}{\text{10\^6 lb-mol Exh}} = \frac{\text{10\^6 * lb-mol Exh * lb NOx * lb Exh * hr}}{\text{lb Exh * lb Exh * lb-mol NOx * hr}}$$

	MW	HR, lhv	NOx rate ppmv 15%O2	Tx ıust temp	Mass flow lb/se	Mx Mass flow lb/hr	NOx, lb/hr	NOx lb/MWh	.05%Sulfur SO2 lb/hr	SO2 lb/MWh	
GE LM6000 PD	44.1	8135	25	842	280	1,008,000	40	0.91			25/42
GE Frame 7EA	85.4	10420	25	998	643	2,314,800	92	1.07			
GE Frame 7FA	171.7	9420	9	1116	952	3,427,200	49	0.28			9/42
GE Frame 7H CC	400	5687	9		1230	4,428,000	63	0.16			
W 501 FC	186.5	9130	25	1094	1014	3,650,400	145	0.78			
W 501 G (EST)	253	9241	25	1101	1241	4,467,600	177	0.70			
OIL											
GE LM6000 PD	44.1	8135	42	842	288.4	1,038,240	69	1.57	19.39	0.440	
GE Frame 7EA	89.67	10941	65	998	662.29	2,384,244	246	2.74	53.03	0.591	
GE Frame 7FA	180.285	9891	42	1116	980.56	3,530,016	235	1.30	96.39	0.535	
GE Frame 7G CC	350	5883	42		1265.87	4,557,132	304	0.87	111.30	0.318	
GE Frame 7H CC	420	5971.35	42		1266.9	4,560,840	304	0.72	135.57	0.323	
W 501 FC	196	9587	42	1094	1044.42	3,759,912	250	1.28	101.47	0.518	
W 501 G (EST)	266	9703	42	1101	1278.23	4,601,628	307	1.15	139.33	0.524	

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From Bureau of Labor Stastics Data

Consumer Price Index-All Urban Consumers

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1997	159.1	159.6	160	160.2	160.1	160.3	160.5	160.8	161.2	161.6	161.5	161.3	160.5
1998	161.6	161.9	162.2	162.5	162.8	163	163.2	163.4	163.6	164	164	163.9	163
1999	164.3	164.5	165	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6
2000	168.7												

1.0603 From Jan. 97 to Jan. 00
1.0439 From Jan. 98 to Jan. 00
1.0268 From Jan. 99 to Jan. 00

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High Natural Gas Forecast Calpine

	Summer Gas Esc.	Compound	
2000		Nominal	Real
2001	0.34%	1.0034	0.974175
2002	3.10%	1.034505	0.975121
2003	3.00%	1.065541	0.975121
2004	2.92%	1.096654	0.974363
2005	2.91%	1.128567	0.973512
2006	5.24%	1.187704	0.994683
2007	5.23%	1.249821	1.016219
2008	5.22%	1.315061	1.038122
2009	5.22%	1.383708	1.060497
2010	5.21%	1.455799	1.083251
2011	3.96%	1.513448	1.093347
2012	3.96%	1.573381	1.103538
		1.038491	1.008244

19. Refer to Table 21 on page 103 of the Exhibits to Calpine Osprey Energy Center's Petition for Determination of Need. Provide a present worth analysis for each of the following generation alternatives in which the current differential price of oil and natural gas with coal is held constant during the evaluation period. For each year in the evaluation period, provide the annual and cumulative present worth values for each of the following components: capital, fixed operations and maintenance (O&M); non-fuel variable O&M; fuel; purchased power; and total costs.

A) Combined cycle – Gas fired
B) Combined cycle – Oil fired
C) Simple cycle – Gas fired
D) Simple cycle – Oil fired
E) Steam – Coal
F) Steam – Gas
G) Steam – Nuclear
H) IGCC technology
I) Renewable energy

In response to Interrogatory No. 19, the annualized cost of each of the generation alternatives is calculated assuming the price differential between gas and oil fuel (in real terms) is held constant. These results are presented on spreadsheet Busbar.Screen3.xls on the same worksheet and columns as referred to in response to Interrogatory No. 18. For the reasons stated in response to Interrogatory No. 17, an annualized cost analysis versus a "present worth" analysis was prepared.

Comparison of Generation Alternatives

Technology Type	Levelized Life-Cycle Cost at Assumed Capacity Factor (Nominal $/MWh)		
	Peaking Operation (10% CF)	Intermediate Oper. (50% CF)	Base Load Oper. (90% CF)
Combined Cycle - Gas Fired	**$ 108 - 130**	**$ 47 - 56**	**$ 39 - 48**
Combined Cycle - Oil Fired	131 - 155	67 - 82	59 - 74
Simple Cycle - Gas Fired	103 - 142	67 - 98	60 - 93
Simple Cycle - Oil Fired	143 - 187	97 - 143	91 - 138
Steam - Coal	224 - 243	64 - 74	46 - 56
Steam - Gas	137	67	59
Steam - Nuclear	309	68	41
IGCC Technology	219 - 270	60 - 74	42 - 52
Renewable Energy	128 - 1194	76 - 271	56 - 169

COMPARISON OF GENERATION ALTERNATIVES

Line No.	Financial/Economic Assumptions	
1	Interest Rate	8.0%
2	Debt Percent	65.0%
3	Equity Rate	13.0%
4	Tax Rate	35.0%
5	General Inflation Rate	3.00%
6	Real Fuel Price Escalation:	
7	Coal Price Esc.	1.1%
8	Nat. Gas Price Esc	1.1%
9	Nuclear Price Esc	0.0%
10	Oil Price Esc.	1.1%
11	Other (Renewable, etc.)	0.0%
12	None	0.0%

Fixed Charge Rates:

Financing Period	Resource Life	Annual Rate
15 years	15	14.53%
20 Years	20	13.25%
25 Years	25	12.16%
30 years	30	11.49%
40 years	40	10.77%

Emission Allowance Costs:

NO_x	2000	$/ton
SO_2	150	$/ton

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NO_x	SO_2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M [4]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Steam - Coal																	
13	Pressurized CFB	1	379.2	1,148	7,269	0.73	1.67	coal	1.66	12.07	30.94	2.92	0.85	30	11.49%	223.87	64.08	46.33
14	Subcritical Pulverized Coal	1	397.5	1,281	9,077	4.09	3.13	coal	1.66	15.07	23.80	2.30	4.32	30	11.49%	238.53	73.94	55.65
15	Supercritical Pulverized Coal	1	401.8	1,331	8,568	1.35	1.47	coal	1.66	14.22	24.44	3.65	1.46	30	11.49%	242.68	72.03	53.07
16	Ultracritical Pulverized Coal	1	399.7	1,326	8,251	1.35	1.42	coal	1.66	13.70	24.40	2.30	1.46	30	11.49%	239.27	69.18	50.28
	Steam - Gas																	
17	Gas-fired steam tubine	3	1,726.6	671 [1]	10,310	0.17 [2]	neg [2]	gas	2.82	29.06		2.64 [3]	0.17	30	11.49%	137.42	67.00	59.18
	Steam - Nuclear																	
18	Nuclear , Passive Adv. LWR	2	600.0	1,841	10,400	-	-	nuclear	0.46	4.78	44.85	0.53	-	40	10.77%	309.44	68.14	41.33
	IGCC Technology																	
19	Foak Oxygen Blown IGCC	1	543.2	1,471	8,522	0.21	0.48	coal	1.66	14.15	32.66	1.67	0.25	30	11.49%	269.64	73.77	52.01
20	Inter. Oxygen-Blown IGCC	1	349.2	1,407	7,513	0.18	0.13	coal	1.66	12.47	37.16	1.98	0.19	30	11.49%	266.07	71.25	49.60
21	Adv. Air-Blown IGCC	1	398.1	1,119	6,870	0.16	0.12	coal	1.66	11.40	32.80	1.67	0.17	30	11.49%	219.22	60.17	42.50
22	Adv. Oxygen-Blown IGCC	1	427.7	1,245	6,968	0.17	0.12	coal	1.66	11.57	34.22	1.88	0.18	30	11.49%	238.58	64.49	45.14
	Renewable Energy																	
23	Phosphoric Acid Fuel Cell	5	0.2	4,280	9,980	-	-	gas	2.82	28.13	344.50	0.88	-	20	13.25%	1,193.89	271.42	168.92
24	Molten Carbonate Fuel Cell	2	2.0	1,631	6,640	-	-	gas	2.82	18.72	6.79	1.48	-	30	11.49%	256.03	76.30	56.32
25	Solar Parabolic Trough	6	80.0	2,867	-	-	-	none	-	-	66.80	-	-	30	11.49%	482.08	96.42	N/A
26	Utility Scale PV Concentrators	6	2.5	5,068	-	-	-	none	-	-	59.38	-	-	30	11.49%	759.03	151.81	N/A
27	Utility Scale Flat-Plate PV	6	2.4	5,620	-	-	-	none	-	-	-	8.16	-	30	11.49%	748.47	158.77	N/A
28	Wind Energy	6	37.5	795	-	-	-	none	-	-	14.71	-	-	30	11.49%	127.65	N/A	N/A
29	Gasification-Based Biomass	6	75.0	2,006	10,000	Not Determined		other	2.50	25.00	46.02	3.84	-	30	11.49%	376.26	107.32	77.44
30	Waste to Energy-Mass Burn	5	50.0	2,610	15,500	Not Determined		other	-	-	130.49	39.15	-	30	11.49%	603.82	164.30	115.47
31	Waste to Energy-RDF unit	5	50.0	3,132	17,000	Not Determined		other	-	-	182.69	39.15	-	30	11.49%	755.12	194.56	132.28

Notes:

All dollar values expressed in year 2000 dollars.

See Page 2 of 2 for footnotes.

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COMPARISON OF GENERATION ALTERNATIVES

Line No.	Type	Source	Cap.	Installed Cost	Heat Rate	NOx	SO2	Fuel Type	Fuel Cost	Fuel Cost	Fixed O&M [9]	VAR. O&M	Emission Costs	Unit Life	Carrying Charge	Annualized Cost 10%CF	50%CF	90%CF
			MW	$/kW	Btu/kWh	lb/MWh	lb/MWh		$/MMBtu	$/MWh	$/kW-yr	$/MWh	$/MWh	Years	%	$/MWh	$/MWh	$/MWh
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	Combined Cycle - Gas Fired																	
32	GE 7EA 1x1	4	130.0	660 [4]	7,550	0.71 [5]	neg. [6]	gas	2.82	21.28	3.43 [7]	2.47 [7]	0.71	30	11.49%	129.71	56.13	47.95
33	GE 7EA 2x1	4	264.0	563 [4]	7,440	0.70 [5]	neg. [6]	gas	2.82	20.97	2.34 [7]	2.25 [7]	0.70	30	11.49%	114.54	52.45	45.55
34	Westinghouse 1x1 501 F	4	274.0	535 [4]	6,830	0.53 [5]	neg. [6]	gas	2.82	19.25	2.17 [7]	2.69 [7]	0.53	30	11.49%	108.26	49.34	42.80
35	Westinghouse 1x1 501 G	1	365.0 [8]	524	6,530 [8]	0.20 [5]	neg [6]	gas	2.82	18.41	10.86	1.46	0.20	30	11.49%	117.06	48.31	40.67
36	GE "H" 1x1	1	400.0 [8]	510	6,320 [8]	0.19 [5]	neg [6]	gas	2.82	17.81	10.80	1.36	0.19	30	11.49%	114.05	46.84	39.37
	Combined Cycle - Oil Fired																	
37	GE 7EA 1x1	4	134.3	660 [4]	7,210	1.83 [5]	0.39 [6]	oil	5.06	36.50	3.43 [7]	2.60 [7]	1.86	30	11.49%	155.32	81.74	73.56
38	GE 7EA 2x1	4	272.8	563 [4]	7,100	1.80 [5]	0.39 [6]	oil	5.06	35.95	2.34 [7]	2.37 [7]	1.83	30	11.49%	139.72	77.63	70.73
39	Westinghouse 1x1 501 F	4	283.1	535 [4]	6,520	0.88 [5]	0.36 [6]	oil	5.06	33.01	2.17 [7]	2.83 [7]	0.91	30	11.49%	130.52	71.60	65.06
40	Westinghouse 1x1 501 G	1	377.2 [8]	524	6,230 [8]	0.20 [5]	0.37 [6]	oil	5.06	31.54	10.86	1.53	0.23	30	11.49%	137.77	69.02	61.38
41	GE "H" 1x1	1	413.3 [8]	510	6,030 [8]	0.19 [5]	0.32 [6]	oil	5.06	30.53	10.80	1.42	0.22	30	11.49%	134.09	66.88	59.41
	Simple Cycle - Gas Fired																	
42	GE LM6000	5	85.0 [8]	519	9,030 [8]	0.91 [5]	neg [6]	gas	2.82	25.45	5.69	7.22	0.91	30	11.49%	128.25	66.57	59.71
43	GE 7EA	5	85.0 [8]	376	11,570 [8]	1.07 [5]	neg [6]	gas	2.82	32.61	3.47	24.60	1.07	30	11.49%	141.58	97.70	92.83
44	GE 7FA	5	172.0 [8]	288	10,460 [8]	0.28 [5]	neg [6]	gas	2.82	29.48	2.58	10.83	0.28	30	11.49%	103.43	69.96	66.25
45	Westinghouse 501 G	5	253.0 [8]	326	10,260 [8]	0.78 [5]	neg [6]	gas	2.82	28.92	2.22	12.12	0.78	30	11.49%	109.42	72.44	68.33
	Simple Cycle - Oil Fired																	
46	GE LM6000	5	44.0 [8]	519	8,740 [8]	1.57 [5]	0.44 [6]	oil	5.06	44.25	5.69	7.59	1.60	30	11.49%	159.15	97.46	90.61
47	GE 7EA	5	89.3 [8]	376	11,600 [8]	2.74 [5]	0.59 [6]	oil	5.06	58.73	3.47	25.82	2.79	30	11.49%	186.56	142.68	137.80
48	GE 7FA	5	180.6 [8]	288	10,490 [8]	1.30 [5]	0.53 [6]	oil	5.06	53.11	2.58	11.37	1.34	30	11.49%	142.64	109.18	105.46
49	Westinghouse 501 G	5	265.7 [8]	326	10,290 [8]	1.28 [5]	0.52 [6]	oil	5.06	52.10	2.22	12.73	1.32	30	11.49%	147.30	110.32	106.21

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Sources

1. Market-Based Advanced Coal Power Systems - May 1999 (Dept. of Energy). Costs provided in 1998 dollars adjusted to 2000 dollars at rate of historical CPI
2. Georgia Power Company 1998 Integrated Resource Plan. Costs provided in 1997 dollars adjusted to 2000 dollars at rate of historical CPI.
3. 1998 Florida Power & Light Company Form 1. Costs provided in 1998 dollars adjusted to 2000 dollars at rate of historical CPI.
4. Gas Turbine World Handbook 2000. Capacity and heat rate at ISO conditions for gas-fired operation. Heat Rate provided as LHV adjusted to HHV by factor of 1.11 for gas and 1.06 for oil. Capacity for oil operation adjusted by factor of 1.05.
5. Kissimmee Utility Authority/Florida Municipal Power Agency Need For Power Application-Cane Island Power Park Unit 3 at rate of historical CPI.
6. Renewable Energy Technology Characteriszations (EPRI Topical Report No. TR-109496, December 1997). Costs provided in 1997 dollars adjusted to 2000 dollars at rate of historical CPI.

Notes

All dollar values expressed in year 2000 dollars.

[1] Installed cost provided in 1981 dollars adjusted to 1998 dollars by Handy Whitman Index and further adjusted to 2000 dollars by historic CPI
[2] NOx and SO2 emissions provided in year 2000 Title V air permit for FP&L Martin plant
[3] Represents total O&M costs (fixed and variable).
[4] Installed cost provided in 1999 dollars adjusted to 2000 dollars and adjusted by factor of 1.25 to include indirect costs.
[5] NOx emissions provided in year 2000 Title V air permit from Florida in ppm adjusted to lb/MWh. Does not include SCR equipment.
[6] SO2 emissions calculated assumming .25 grains/SCF of gas and 0.05% Sulfur oil with heat contenet of 18,500. Does not include SCR equipment.
[7] Fixed and variable O&M provided from Source No. 5
[8] Capacity and heat rate provided from Source No. 4.
[9] Excludes A&G costs and property taxes.

The GE 7FA performance of gas and oil for the 7EA was ratioed. GE CycleDeck only allows 65ppm NOx.
The heat rate increases with oil operation is the water injection. (WI raises kWs & raises HR)
The hhv/lhv ratio is 1.06 for oil vs 1.11 for NG

	Capacity (MW)	Installed Cost ($/kW)	Heat Rate (BTU/kWh)	NOx (lb/MWh)	SO2 (lb/MWh)
Combined Cycle - Gas Fired					
GE 7EA 1x1 [4]	130.0		7548	0.706	0.00
GE 7EA 2x1 [4]	264.0		7437	0.695	0.00
Westinghouse 1x1 501 F [4]	274.0		6827	0.528	0.00
Westinghouse 1x1 501 G [1]	365.0		6527	0.202	0.00
GE "H" 1x1 [1]	400.0		6316	0.192	0.00
Combined Cycle - Oil Fired					
GE 7EA 1x1 [4]	134.3		7448	1.830	0.39
GE 7EA 2x1 [4]	272.8		7339	1.802	0.39
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Westinghouse 1x1 501 G [1]	377.2		6441	0.202	0.37
GE "H" 1x1 [1]	413.3		6232	0.192	0.32
Combustion Turbine - Gas Fired					
GE LM6000 [5]	44.0		9030	0.906	0.00
GE 7EA [5]	85.0		11570	1.075	0.00
GE 7FA [5]	172.0		10460	0.285	0.00
Westinghouse 501 G [5]	253.0		10260	0.776	0.00
Combustion Turbine - Oil Fired					
GE LM6000 [5]	44.0		8736	1.568	0.44
GE 7EA [5]	89.3		11601	2.741	0.59
GE 7FA [5]	180.6		10488	1.304	0.53
Westinghouse 501 G [5]	265.7		10288	1.279	0.52

GE LM6000PA

	NG	Oil
Power	39450	39400
HR,lhv	9165	9285
Mx, pph	964.8	966.6
NOx, ppm	25	42
NOx, pph	36	63

$$ppm = \frac{\text{lb-mol NOx}}{\text{10^6 lb-mol Exh}} = \frac{\text{10^6 * lb-mol Exh * lb NOx * lb Exh * hr}}{\text{lb Exh * lb Exh * lb-mol NOx * hr}}$$

	MW	HR, lhv	NOx rate ppmv 15%O2	Tx ıust temp	Mass flow lb/se	Mx Mass flow lb/hr	NOx, lb/hr	NOx lb/MWh	.05%Sulfur SO2 lb/hr	SO2 lb/MWh	
GE LM6000 PD	44.1	8135	25	842	280	1,008,000	40	0.91			25/42
GE Frame 7EA	85.4	10420	25	998	643	2,314,800	92	1.07			
GE Frame 7FA	171.7	9420	9	1116	952	3,427,200	49	0.28			9/42
GE Frame 7H CC	400	5687	9		1230	4,428,000	63	0.16			
W 501 FC	186.5	9130	25	1094	1014	3,650,400	145	0.78			
W 501 G (EST)	253	9241	25	1101	1241	4,467,600	177	0.70			
OIL											
GE LM6000 PD	44.1	8135	42	842	288.4	1,038,240	69	1.57	19.39	0.440	
GE Frame 7EA	89.67	10941	65	998	662.29	2,384,244	246	2.74	53.03	0.591	
GE Frame 7FA	180.285	9891	42	1116	980.56	3,530,016	235	1.30	96.39	0.535	
GE Frame 7G CC	350	5883	42		1265.87	4,557,132	304	0.87	111.30	0.318	
GE Frame 7H CC	420	5971.35	42		1266.9	4,560,840	304	0.72	135.57	0.323	
W 501 FC	196	9587	42	1094	1044.42	3,759,912	250	1.28	101.47	0.518	
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1998	161.6	161.9	162.2	162.5	162.8	163	163.2	163.4	163.6	164	164	163.9	163
1999	164.3	164.5	165	166.2	166.2	166.2	166.7	167.1	167.9	168.2	168.3	168.3	166.6
2000	168.7												

1.0603 From Jan. 97 to Jan. 00
1.0439 From Jan. 98 to Jan. 00
1.0268 From Jan. 99 to Jan. 00

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

DOCKET NO. 001748-EC

PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

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DEPOSITION OF:	**TIMOTHY R. EVES**
TAKEN AT THE INSTANCE OF:	**The Staff of the Florida Public Service Commission**
PLACE:	**Gerald L. Gunter Building Room 390A 2540 Shumard Oak Boulevard Tallahassee, Florida**
TIME:	**Commenced at 8:35 a.m. Concluded at 10:30 a.m.**
DATE:	**Friday, January 19, 2001**
REPORTED BY:	**TRICIA DeMARTE Official FPSC Reporter**

APPEARANCES:

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of Calpine Construction Finance Company, L.P.

JOSEPH A. McGLOTHLIN, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Seminole Electric Cooperative.

RACHAEL N. ISAAC and ROBERT V. ELIAS, FPSC Division of Legal Service, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

ALSO PRESENT:

JUDY HARLOW, FPSC, Division of Safety & Electric Reliability

MIKE HAFF, FPSC, Division of Safety & Electric Reliability

TODD BOHRMANN, FPSC, Division of Economic Regulation

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STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure;

that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

MS. ISAAC: We'll go ahead and take appearances.

MR. WRIGHT: Robert Scheffel Wright, law firm of Landers & Parsons, P. O. Box 271, Tallahassee 32302, on behalf of Calpine Construction Finance Company, L.P.

MR. McGLOTHLIN: Joe McGlothlin, McWhirter, Reeves, 117 South Gadsden, on behalf of Seminole Electric Cooperative.

MR. ELIAS: Bob Elias, Commission Staff, this address, on behalf of the Commission Staff.

MS. ISAAC: Rachael Isaac on behalf of Commission Staff. Okay. Do all the parties agree to the normal stipulations?

MR. McGLOTHLIN: I see no reason not to.

MR. WRIGHT: Yes. We will read and sign.

MS. ISAAC: Will the court reporter please swear in the witness.

TIMOTHY R. EVES

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MS. ISAAC:

Q Good morning, Mr. Eves. I'm Rachael Isaac with the Florida Public Service Commission. I'm taking your deposition on behalf of the Commission Staff in

Docket 001748-EC. If you need me to restate the question or do not understand the question, please let me know, and I'll restate it or rephrase it. I also ask that you answer with a "yes" or "no" first before you explain your answer.

Please state your full name for the record.

A Timothy Richard Eves.

Q By whom are you employed?

A Calpine Eastern Corporation.

Q What is your position with your employer?

A Director of business development.

Q What does your position entail?

A I'm responsible for development activities of our power generation portfolio in Florida.

Q On whose behalf are you testifying in this proceeding?

A Calpine.

Q Did you file any testimony in this docket?

A Yes.

Q Direct or rebuttal?

A Direct testimony.

Q Did you also file any exhibits?

A Yes.

Q Will you please list those.

A May I look?

Q Yes.

A I know it's in here somewhere. Let's see. Attached to my testimony I have -- do you want the names of them or just numbers or --

Q The numbers are fine.

A Okay. I have TRE-1, TRE-2, TRE-3, TRE-4, and TRE-5. And in Volume 2 of our amended exhibits to the petition, I am sponsoring figures Roman Numeral II-1 and II-2, Tables II-1, II-13, II-19, and II-20.

Q And what is the purpose of the testimony that you have given in your prefiled testimony?

A The purpose of my testimony is to support the joint petition of Calpine and Seminole to request an affirmative determination of need from the Public Service Commission.

Q Okay. First, we're going to ask some questions on the specifics of the power purchase -- or the purchased power agreement.

A Okay.

Q According to your testimony, the contract with Seminole begins in June 2004; correct?

A No, I would say that's not correct. Our -- the contract with Seminole begins on the commercial operation of the unit or June 2004, whichever is later. I'm sorry. Is that correct? I think --

MR. WRIGHT: Do you want to look at the contract?

THE WITNESS: Yeah, let me take a look at that.

MS. ISAAC: Let's go off the record for a moment.

(Discussion off the record.)

A I would say the contract became effective when it was executed by Seminole on December 14th of 2000.

Q And the expected in-service date of the Osprey unit is when?

A I would say the early in-service date that we would expect would be June 2003.

Q Is Calpine still on schedule to meet this expected in-service date?

A Yes. I would say we'll need, I would say, a couple breaks to meet the June 2003 in-service date, which would include a bench vote from the Public Service Commission.

Q What are Calpine's plans for the capacity and energy of the plant prior to June 2004 with Seminole?

A Our contract with Seminole commits all the power from this power plant through May of 2020 under pricing in terms of -- that already have been put in place. I would say for the period prior to June 2004, that power is committed to Seminole. Seminole has negotiated with us a

flexible arrangement where they could call on that capacity and energy.

Q In your opinion, how does this year prior to the firm commitment with Seminole mesh with the Supreme Court's requirement in Duke that capacity be fully committed to retail-serving entities?

A Well, I would say my understanding, my interpretation of our contract is that that output is committed to Seminole from as soon as that plant goes commercial.

Q Isn't that only if you haven't sold it to someone else already?

A We have -- in our contract with Seminole, we have negotiated terms and conditions and pricing for the reserve -- for their reserve options, which is for all the power other than the firm capacity they have committed. We also have the ability to sell that power under long-term contracts to others if Seminole has not already exercised their option to take that power.

Q Could you explain in further detail Seminole's rights to the capacity and energy prior to the contract date -- or the -- prior to June 2004?

A They have a firm option so that all the terms and pricing have already been negotiated. So if we get it up and running and they need the power, they can call on

the power, and the terms, everything has already been negotiated. They have a notice provision to take that power as well.

Q Before when you referred to the breaks that Calpine will need to meet the June 2003 in-service date, what other breaks are you referring to?

A We are scheduled to go in front of the certification -- our certification hearing is scheduled for mid April. As long as -- if we get a bench decision by I guess that will be February 16th would be the end of the week that our hearing is scheduled for and we can meet the statutory time limits and get in front of the certification hearing by our scheduled April date, we'll have to get it to the administrative law judge and to the Power Plant Citing Board, and as long as we can stay on the statutory dates, we should be able to meet an in-service date of June '03. If we miss the bench vote, then that will -- that, most likely, will delay the rest of the hearings.

Q Does Seminole have a first right of refusal option on the capacity prior to the June 2004 date?

A No. What they have is a notice provision. And if they -- they give us notice. Once they have given us notice, then we cannot sell that capacity to somebody else.

Q Does this contract provision give Seminole some sort of special status above any other utility wishing to buy firm capacity from Calpine's proposed unit?

A I would say yes in that as long as -- if we haven't sold the power by the time they give us notice, then they have a call on that power. But what Seminole gets out of it is that the terms and conditions and pricing are already in place, which is a status far above anybody else. So when Seminole calls for the power, it's just a mere notice that they want to take the power, because all the terms, everything is already negotiated. So I would say that puts them in a special position.

Q After the June 2004 date, Seminole has the rights to 350 megawatts on a firm basis; correct?

A Yes.

Q And the plant has a capacity of 529 megawatts; correct?

A That's correct.

Q Could you describe Seminole's rights to the remaining capacity of the plant from 2004 to 2009?

A It's very similar to their rights to the capacity prior to the June 2004 date. All the terms are negotiated. Pricing is put together. They have notice -- a notice period that they will need to give us if they want to call on that power.

Q Are prices set for the additional megawatts also?

A Yes.

Q Does this contract provision give Seminole some sort of special status above any other utility wishing to buy firm capacity from Calpine's proposed unit?

A I would give you the same answer that I gave before. Yes, it gives them special status.

Q Would you characterize Seminole's right to the remaining capacity as a first right of refusal?

A No.

Q In your opinion, does the contract for 350-megawatt firm out of the 529-megawatt total capacity of the plant meet the requirements of the Supreme Court decision in the Duke case?

MR. WRIGHT: I'm going to object just to the extent that you're asking him for a legal conclusion. He can answer in context as long as we're understanding that he's not giving a legal opinion. Okay?

MS. ISAAC: Okay.

A Rachael, I would say our contract with Seminole meets the intent of -- my opinion is or my thoughts on that or whatever is the right way to say it is that I think our contract with Seminole meets the intent of the Supreme Court. We have committed the output to Seminole.

We have given them flexibility to fit into their planning horizon. Now, whether they actually call on that output, I would say the 350 firm for five years is just part of the overall contract. So I would say, you know, the overall contract that commits all the output to Seminole is what meets the intent of the Supreme Court.

Q After May 2009, the contract provides for Calpine to continue providing 350-megawatts firm to Seminole through May 31st, 2020. Could you explain the contract language that allows either party to opt out of the contract on a five-year basis?

A That's one I'm going to have to look at.

MS. ISAAC: Let's go off the record.

(Discussion off the record.)

A I got it here.

Q Go ahead.

A Can you ask the question again, please.

Q Oh, sure. After May 2009, the contract provides for Calpine to continue providing 350-megawatts firm to Seminole through May 31st, 2020. Could you explain the contract language that allows either party to opt out of the contract on a five-year basis?

A The contract language says that we will need to execute a continuation by July 2005 in order to extend the contract after 2009, and it gives both parties the free

right to terminate the agreement based on their sole judgment.

Q What action would it take to terminate the contract?

A This is Section 16 of the contract, and the contract continues in force unless an affirmative action has been taken by one of the parties, which would be noticed to the other party, that they wish to either renegotiate the terms or to terminate the contract.

Q Is that a four-year notice to terminate?

A Yes.

Q Do these contractual reopeners technically allow Seminole or Calpine to walk away from the contract in 2009?

A Yes.

Q How does this right for either party to opt out of the contract after May 2009 mesh with the Supreme Court requirement that the capacity be fully committed?

MR. WRIGHT: Same objection as before. He's free to answer, but he's not giving a legal opinion.

MS. ISAAC: Okay.

A I would say as utilities plan for their capacity needs, the market changes, things change. I think what Seminole has negotiated here is a very flexible arrangement where they can meet their needs continuing out

to May 2020. I think it would be very difficult for Seminole to make a decision to buy firm capacity out for 20 years in light of the changing market. So what they have done is entered into a deal here that gives them flexibility to provide the best benefits to their customers.

And in line with the Supreme Court decision, I would say because of the way the contract is put together, the power is committed to Seminole. It's Seminole's option whether they take it or not, and that power is committed all the way out through 2020.

Q What is your opinion of the term "fully committed"?

A I think if you look back over what other utilities have done is, they have gone through need determination cases. You'll see that as they have come through the need determination, they have put together a forecast of how are they going to grow into this unit. They, for example, wouldn't come in here -- they would not wait until they had all of the capacity from -- until they required all of the capacity from a plant before they came in and asked to build that plant.

As their demand grew, they would come in and ask for a determination to build a plant larger than what they need that would give them time to grow into that capacity.

I would say fully committed, you need to take a look at how is the demand growing both with Seminole and within the State, and is this plant going to be required to meet the demand of the State just as you've reviewed other power plants since you've been doing need determination hearings. So I would say fully committed is based on a need of -- the need and the demand growth of Seminole and the demand growth of the State.

Q Are you aware that the contract term for purchases from plants such as Hardee, Cedar Bay, and Indiantown are for longer than five years?

A I'm not aware of that.

Q What rights does Seminole have to the capacity over 350 megawatts from the period May 2009 to May 2020?

A They have full rights to that capacity. And again all the terms and conditions, pricing is all put together. They do have the option to renegotiate those provisions, but they have -- they do have the right to that capacity. And Calpine has, subject to the terms of the contract, committed that capacity to Seminole.

Q Is this true even if they opt out?

A No. If they opt out, then the contract would be terminated.

MS. ISAAC: Let's go off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q Mr. Eves, can you explain the provisions of the termination further? For example, does opting out result in termination of the contract?

A No. What the contract provides for is renegotiation of the terms as we get into extending the periods. We have negotiated a contract with Seminole that provides Seminole with a good-priced power and some flexibility options. In the event that something changes in the market that would cause prices to go up or to go down, Seminole and Calpine would get together, and what the contract provides for is to renegotiate those pricing provisions for the extension.

Q This next question has to do with the scope of the need order if it's issued by the Public Service Commission. Do you believe that the need order Seminole and Calpine are requesting as co-applicants is specific to the Osprey Energy Center? And if not, what happens to the need order after the contract has expired? Does Seminole then have a need order for the capacity?

A Can we just chat for a little bit?

Q Yes.

MS. ISAAC: We're off the record.

(Discussion off the record.)

A Do you want to ask that question again, please.

Q Sure. Do you believe that the need order Seminole and Calpine are requesting as co-applicants is specific to the Osprey Energy Center? If not, what happens to the need order after the contract has expired? Does Seminole then have a need order for the capacity?

A To the first part of that question I would say yes, that Calpine and Seminole are jointly petitioning this Commission to enter an order for an affirmative determination of need for the Osprey Energy Center.

Q And what about that second two parts?

A I think the first part you asked, do I think that that's specific to the Osprey Energy Center, and I said yes, and I think you went on to say, and if not, then the other question.

Q That's right.

A So I think that what we're asking for is a determination of need specific to the Osprey Energy Center.

Q Okay. Thanks. Okay. On the status of the certification process at DEP, on Page 20 of your testimony, you state that the site certification application was sufficient at the Department of Environmental Protection; correct?

A That's correct.

Q How were the sufficiency concerns raised by the

Southwest Florida Water Management District resolved?

A We received sufficiency -- and I can give you the exact date -- on December 11th of last year. There were a couple questions from the Southwest Water -- Southwest Florida Water Management District that we're in the process of resolving. They have issued us a couple more questions and -- let me ask a question for a minute.

MS. ISAAC: Off the record.

(Discussion off the record.)

A Okay. The Southwest Florida Water Management District submitted to us proposed conditions. We have reviewed the conditions and are in full agreement of the conditions. And we'll go in front of the Board of the Water Management District on the 30th of this month.

Q Can you discuss the status of the certification process at DEP? Has it changed since you filed your testimony?

A No. I would say the certification process hasn't changed since we filed the testimony.

Q Is the certification process still on schedule at DEP to allow the expected in-service date of the plant?

A Yes. My understanding of the process is, once they have issued their determination of sufficiency, we're done with the process at DEP until we get to the certification hearing, which would be following the need

determination and the final approval on the land use.

Q Okay. The next two questions have to deal with the transmission upgrades for this plant. On Page 20 of your testimony, you discuss the expected transmission upgrade cost to interconnect the Osprey Energy Center to the TECO system. Under TECO's transmission tariff, does Calpine pay all costs for the transmission upgrades?

A Yes. Calpine will pay all the costs for the transmission upgrades required -- or yes, we'll pay for all the transmission upgrades required to transmit our power across their system.

Q What is the estimated completion date for the necessary transmission upgrades?

A Rachael, I'm afraid I don't know the answer to that question. I would say it's prior -- that's one I will have to look into.

Q Has TECO agreed to build these upgrades?

A Yes.

Q On Page 21 of your testimony -- okay. To get back to the question on the completion date for the necessary transmission upgrades, we would like a late-filed exhibit or response to that or have someone else respond to that question.

MR. WRIGHT: Would you state the question again, please.

MS. ISAAC: What is the estimated completion date for the necessary transmission upgrades?

MR. WRIGHT: We're going -- I believe we'll have to do that via a late-filed exhibit because the only other witness that you're deposing is Ken Slater, and he's not going to know.

MS. ISAAC: That's fine.

MR. WRIGHT: Okay. So why don't we go ahead and identify that as Late-Filed Deposition Exhibit Number 1.

MS. ISAAC: Okay.

THE WITNESS: Could we just go off the record for a minute?

MR. WRIGHT: Sure.

(Discussion off the record.)

A It's clear they are going to have that done way in time to meet our in-service date, but is it going to be June of '02, is it going to be January of '02, I don't know exactly what the date is, but it will be sufficiently in time for start-up and activity and all that.

MR. HAFF: That's a question we might get from a Commissioner, though.

THE WITNESS: So I can make a phone call and get that answer.

MR. HAFF: Okay. Let's do that instead.

BY MS. ISAAC:

Q Okay. On Page 21 of your testimony, you state that the expected completion date of the unit is June 1, 2003. Have you estimated the impact or the harm on Calpine if the in-service date is delayed until 2004?

A Yes. The impact would really be in our ability to meet the contract with Seminole. When you bring a power plant into commercial operation, usually you need a period of time to run the power plant so that you don't have -- you're sure that, you know, you can run it at the full output and get over any kind of start-up issues that you come up with.

So if we were to delay the commercial operation of this plant until June of 2004, we would be very uncomfortable that that plant would be fully operational to meet the commitments that we have with Seminole.

Q How long will you need to test the plant?

A I would say what would make us most comfortable is to have a good six months to run that plant in commercial operation prior to having to meet our contract dates with Seminole.

Q Would the output of the plant during this breaking period be sold as nonfirm to the grid?

A If Seminole didn't take it, it could be sold as nonfirm to the grid. Seminole has the right to call on that power under our contract.

Q On Page 32 of your testimony, you discuss the benefits of the project due to lower costs of ancillary services. Please explain why the project is expected to lower ancillary service costs.

A Well, the project is expected to lower costs because of its efficiency and -- I mean, what we're building here is a state-of-the-art, efficient power plant. And due to the efficiency and the fuel choice, it will provide lower costs of services.

Q Can you please be more specific on how this is going to lower costs of the ancillary services. On Line 18 on Page 32 is where you state it.

A I would say that this fact that there's a -- that this is an additional power plant providing more supply will just overall suppress the price of the ancillary services.

Q Mr. Eves, can you explain more of how that will work?

A Okay. I would say the ancillary services that are going to be impacted by this power plant are: Scheduling system control and dispatch services, reactive supply and voltage control from additional generation sources, regulation and frequency response services, energy and balance services, operating reserve, spinning reserve services, and operating reserve supplemental

reserve services.

I would say all of these services will be positively impacted by this power plant because we're adding more power to the grid and it's efficient and a low cost alternative to the market.

Q Has Calpine estimated the monetary value of these savings?

A No, we have not.

Q On Page 34 of your testimony, you state that the plant is expected to operate between 7,500 and 8,500 hours per year. Do you have an estimate of the number of hours the plant must be dispatched to break even?

MR. WRIGHT: Objection to form. The question is vague. Can you explain what you mean by "break even"?

MS. ISAAC: So that the -- that the costs -- to recover Calpine's costs.

A I think your question was, have we performed an analysis to figure out how many hours we need to run to break even. I would say no, we have not performed that analysis.

Q Will the contract with Seminole pay off Calpine's debt service in or by 2009?

A This power plant is being built by Calpine at the risk of our investors and shareholders, and will not be borne by the -- the financial risks of the construction

or operation of this power plant won't be borne by Florida ratepayers. And as we've entered into the contract with Seminole, we've looked at the financial risks we'll take in building that power plant.

MR. WRIGHT: Off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q To clarify that last question, will the capacity payments Calpine receives from Seminole through 2009 pay off the capital costs of the plant?

A No.

Q These next group of questions has to do with Calpine's status as an electric utility. Does Calpine currently own generation assets within Florida?

A Yes.

Q Does Calpine currently own or expect to own transmission assets within Florida?

A Let me go off the record for just a minute.

MS. ISAAC: Off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q I'll repeat the question. Does Calpine currently own or expect to own transmission assets within Florida?

A I'm not sure what the definition of transmission

assets are, but we will own interconnections between our power plants and the substations where we'll interconnect into the grid.

Q Do you believe this makes Calpine an electric utility under Chapter 366, Florida Statutes, and therefore subject to the Ten-Year Site Plan and Grid Bill requirements?

MR. WRIGHT: Objection. It calls for a legal conclusion which is not appropriate to testimony.

Q Do you believe that under specified emergency power conditions, the Governor of Florida has the legal authority to issue an order requiring the Osprey Energy Unit to run?

MR. WRIGHT: Objection. It calls for a legal conclusion which is not appropriate to testimony. You can ask him what Calpine would do if they were subject to such an order or if such an order were to be issued, but you're asking him to interpret the statute, and that's not appropriate to testimony.

BY MS. ISAAC:

Q Okay. What would Calpine do under emergency power conditions if the Governor of Florida -- would the Governor of Florida -- if the Governor of Florida was to issue an order requiring the Osprey Energy Unit to run?

A Well, we're coming into this State to build

power plants, and we expect to be subject to all the rules that apply to other people who run power plants in this State. So we are fully expecting to come here and play by all the rules that apply to the other folks here as well. So if the Governor was to give us an emergency order, we would abide by that and keep our power in the State.

Q In your opinion, do you believe that Calpine's owning of generation assets and transmission assets in Florida makes Calpine an electric utility under Chapter 366 and therefore subject to the Ten-Year Site Plan and Grid Bill requirements?

MR. WRIGHT: Same objection. It calls for a legal conclusion. You can ask him if we filed the Ten-Year Site Plan.

BY MS. ISAAC:

Q Did you file a Ten-Year Site Plan?

A Yes, we did file a Ten-Year Site Plan. And with regard to your question regarding the Grid Bill, I would say the same answer applies as the Governor's emergency order. We expect to participate in the energy system here in Florida subject to the same rules as everybody else. So whether or not we're classified as a utility or whatever, we expect to play by the same rules.

Q The next group of questions has to do with the Section 403 requirement of need for power. What is your

understanding of the meaning of "need for power" as stated in Section 403.519, Florida Statutes?

A I would say the need for power is the demand in the State, the forecasted demand in the State. I guess that would be my -- and the forecasted demand in the State.

MR. WRIGHT: Do you have a copy of the statute that the witness could refer to?

MS. ISAAC: Yes. Hold on. Let's go off the record.

(Brief recess.)

BY MS. ISAAC:

Q What is your understanding of the meaning of "need for power" as stated in Section 403.519, Florida Statutes?

A I believe that when the Commission makes a decision whether to grant need, they should look at the need for electric system reliability and integrity, the need for adequate electricity, and that electricity at a reasonable cost, whether it's the most cost-effective alternative available to serving an identified need, and I would say in reviewing our joint application that the need for this power plant really is based on Seminole's forecast demand.

Q In your opinion, is Seminole or any other

load-serving entity in this State subject to this criterion?

A As I understand, Seminole is not required to go through a need determination process. Is it? Okay. Oh, right. I'm sorry. That's correct. What I meant was, they are not required to go through an RFP process. Sorry.

Q In your opinion, do you think that Calpine's proposed generating unit, independent of Seminole, is subject to this criterion?

A Could you repeat that again, please.

Q Sure. In your opinion, do you think that Calpine's proposed generating unit, independent of Seminole, is subject to this criterion, the need for power criterion?

MR. WRIGHT: I'm going to object to the form because I think the question is confusing, but he can answer it if he can answer.

BY MS. ISAAC:

Q Okay. I'll point out specifically in your testimony. On Page 5, Lines 12 through 14, you state that Calpine's need for the project to meet its obligations to Seminole -- do you think that this meets the criterion of need for power under Section 403.519, Florida Statutes?

A Yes, I do.

Q Do you think Calpine is subject for the need for power mandate of this statute?

A I think that in order to build the Osprey Energy Center there has to be a need for the power, and I think the joint application of Calpine and Seminole meets this need.

Q Do you know if there are any retail customers who will buy power from the proposed generating unit directly from Calpine?

A Yes, I do know the answer to that, and that is, no retail customers will buy power from this power plant.

Q In your opinion, does Calpine have an obligation to serve like that of Florida's retail-serving utilities?

A It's my understanding that the obligation to serve is tied to the retail customers. Seeing that we don't serve retail customers, I would say we do not have an obligation to serve.

Q Okay. The next set of questions goes to the cost-effective alternative criteria. What is your understanding of the meaning of "cost-effective alternatives" as stated in Section 403.519, Florida Statutes?

A My interpretation of cost-effective is to look at what's the demand and what is the most economic way of meeting that demand considering all the different factors

and technologies that are available.

Q Is this criterion applicable to Seminole or to Calpine?

A I would say that that criterion is applicable to both Calpine and Seminole.

Q Do you think that Calpine's proposed generating unit, independent of Seminole, is subject to this criterion?

A I would say yes.

Q At Page 33, Part 2, Lines 9 through 18 of your direct testimony, why do you make a point to discuss how the proposed unit is cost-effective to Calpine when this is not the criteria stated in Section 403.519, Florida Statutes?

A Could you give me the cite again of those lines?

Q Page 33, Section 2, Roman Numeral II, Lines 9 through 18 -- oh, no, no, Roman Number II.

A Okay. Your previous question -- go ahead.

MR. WRIGHT: I'm going to object to the form on the grounds the question is vague, particularly in regard to your statement to the effect that it's not the criterion -- (inaudible). I'm interposing an objection as to form on the grounds that the question is vague because I don't understand what Ms. Isaac meant when she said that cost-effective alternative criterion is not the criterion

in Section 403.519. So I would ask that she clarify that so that the witness can have a full understanding of the question before answering.

MS. ISAAC: Can we go off the record?

(Discussion off the record.)

BY MS. ISAAC:

Q At Page 33, Lines 9 through 18 of your direct testimony, why do you make a point to discuss how the proposed unit is cost-effective to Calpine?

A What we have discussed in our -- what I have discussed in my testimony is that Calpine has looked at a number of generation technologies available, and have determined that the gas-fired, combined cycle generation technology provides the lowest total cost of the technology we evaluated.

Now we have worked with Seminole. Seminole has determined that the power that we're selling them is the most cost-effective alternative available to Seminole to obtain intermediate and base load power to meet the needs of their customers.

Q The next set of questions has to do with the emissions from the plant. At Page 24, Lines 19 through 24 of your direct testimony, you discuss how the proposed Calpine generating unit is expected to reduce Peninsular Florida's total sulfur dioxide and nitrogen oxide

emissions by 8,000 to 23,000 tons per year. In calculating this estimate, did Calpine assume that its unit would displace existing generation in the State?

A Yes.

Q How much generation was assumed to be displaced?

A Those calculations are based on operating this 529-megawatt power plant for the capacity factors that we have identified in here of somewhere in the order of 86 to 93 percent. So that the power that it would offset from the more inefficient power plants would be equal to the power that would come out of a 529-megawatt plant at those capacity factors, which is roughly 4,000 gigawatt hours per year.

Q Did Calpine assume that the 350 megawatts of generation it sells to Seminole will replace Seminole's existing partial requirements purchases from older, less efficient units owned by other Peninsular Florida utilities?

A I would say I don't know that, and I would suggest that would be a good question to ask Mr. Woodbury.

MS. ISAAC: Off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q Did Calpine assume that the 350 megawatts of generation it sells to Seminole will replace Seminole's

existing partial requirements purchases from older, less efficient units owned by other Peninsular Florida utilities?

A In calculating the reduction in emissions that's in my testimony, we looked at the entire supply stack of generation capacity in Florida and compared that to the demand, and based on that, by the addition -- what we calculated was the addition of one new 529-megawatt power plant to meet that demand of the State, which included the 350 megawatts from Seminole.

Q At Page 29, Lines 6 through 9 of your direct testimony, you mention that Calpine may use the project to sell to other load-serving entities in Peninsular Florida. If Seminole does not contract for the excess capacity of the proposed unit, do you believe that Calpine will sell to the other utilities if it can?

A Yes.

Q If Seminole does not contract for the excess capacity from the proposed unit, do you believe that Calpine's proposed unit is fully committed as defined in the Florida Supreme Court's order in the Duke Smyrna Beach case?

A Yes.

Q If Seminole or Calpine opt not to extend the contract beyond the initial five-year term, do you believe

that Calpine's proposed unit fully committed as defined in the Florida -- excuse me -- do you believe that Calpine's proposed unit is fully committed as defined in the Florida Supreme Court's order in the Duke case?

A Yes. And again I would say this is a joint petition for determination of need for the Osprey Energy Center.

Q At Page 30, Lines 7 through 9 of your testimony, you state that it is unlikely that any significant amount of the project's output would be sold outside Peninsular Florida under any scenario. This implies that, while unlikely, Calpine could, in fact, sell outside of Peninsular Florida under certain conditions. What would those conditions be?

A Well, let me give you a little bit longer answer than just your question. As we have modeled this plant and looked at, does it make sense for us to build a plant here in Florida, all of our modeling, all of our transmission analysis was based solely on the Florida market. We also have plants in construction in Alabama, Mississippi, Tennessee, and we're looking at some plants in Georgia. So our philosophy is to build plants in the markets that we intend to serve.

Now, your question was, what scenario would make it -- would give us the ability to sell power outside of

the state of Florida. And there are certain, but very limited, times during the year when there will be weather conditions that would have -- cause Georgia to have a higher demand or Alabama to have a higher demand than Florida, and there would be excess capacity here in the State. And at that time, I could see us selling power outside the State, right along with Florida Power & Light, and Florida Power Corp, and TECO, and anybody else who has generating facilities here in the State.

Q Would wholesale power prices have to reach a certain height before Calpine would consider selling out of state?

A I would say that's more a function of the buyer. To sell power out of state is very expensive because you have to pay transmission on every system that you cross. So the buyer would pay those transmission prices. If we have excess capacity in this State and there's a buyer in another state who is in a situation where he needs to pay the higher price to get the power there, then of course we would sell it to him.

Q Has Calpine performed any studies which indicate the likelihood of out-of-state sales from the proposed unit?

A No, we have not done any studies like that. We have made this decision solely based on factors from the

Florida market.

Q At Page 32, Lines 14 through 16 of your direct testimony, you discuss how the proposed unit would displace more costly generation on the order of 150 million per year. How was this value determined?

A That value was determined very much the way we calculated the economic, or I'm sorry, the environmental or the emissions, the reduction in emissions. We took the entire generation stack of the State. We took the forecast demand over the ten-year period beginning in 2003 on an hourly basis. We compared the two with and without the addition of the Osprey Energy Center. And by putting the Osprey Energy Center into the mix, the cost of wholesale generation in the State was on the order of $150-million-a-year savings.

Q Does this value include any cost savings achieved by Seminole by terminating its partial requirements contracts?

A No. That number is strictly a cost of generation in the State.

Q Does Exhibit TRE-3 to your direct testimony contain the Federal Energy Regulatory Commission's acceptance letter of Calpine's market-based rate tariff?

A If you said "Calpine Construction Finance Corporation," the answer is yes.

Q In which states, ISOs, or power pools does this tariff apply?

A That tariff applies to wherever -- hang on just a minute.

It's my understanding that the letter from the Federal Energy Regulatory Commission grants Calpine Construction Finance Corporation the authority to sell wholesale power at market-based rates wherever they have a power plant.

Q Is Peninsular Florida in any one of these regions?

A Yes. CCFC will be building the Osprey Energy Center, so they have been granted -- my understanding is, they have been granted market-based rates for the sale of wholesale power.

My understanding of this letter is, that second paragraph I think is what you're asking the question about, is that that is strictly -- where it talks about California ISO, New England Power Pool, is strictly dealing with ancillary services.

Q Can you please --

MR. WRIGHT: This may be our call.

MS. ISAAC: Can we go off the record?

(Discussion off the record.)

BY MS. ISAAC:

Q I'll restate the question. Is Peninsular Florida in any one of these regions?

A The letter from FERC is granting Calpine Construction Finance Company the authority to bid market-based rates into the existing ISOs and power pools that are already established. As Florida does not have a power pool established, we did not or could not request authority to bid market-based rates into the existing Florida power pool because there is no power pool. So the authority granted in this letter is authority granted to participate in the power pools where they exist.

Q The response to Staff's first set of interrogatories, Numbers 6 through 8, indicate a working relationship with Gulfstream, Buccaneer, and FGT. Explain Calpine's progress with Buccaneer as to contract negotiations and whether they are favorable as they were with Gulfstream.

A Well, first of all, Buccaneer was the pipeline that was owned by Duke Williams. All of our contract negotiations have been with Gulfstream. Duke Williams recently bought the Gulfstream pipeline from ANR Coastal and discontinued any kind of development of the Buccaneer pipeline. We have very close -- we have enjoyed and continue to enjoy very close relationships with Gulfstream. And now with the new owners, Duke Williams,

we have been working also very closely with them, and there have been no impact on any type of contractual arrangements that we had with Gulfstream prior to the takeover.

Q Does Calpine have a signed contract with Buccaneer or any pipeline?

A We don't have a signed contract with Buccaneer. We never expected to have a signed contract with Buccaneer. We never negotiated with Buccaneer, but we do have a signed precedent agreement with Gulfstream.

Q In response to Interrogatory Number 6, it is stated that FGT would construct an approximate four-mile lateral from its existing system, and Buccaneer would construct an approximate two-mile lateral from its proposed route. Which is the better deal, in your opinion? And is the proposed route of Buccaneer the original route or the route of the newly acquired Gulfstream?

A Could we go off the record just for a minute?

Q Yes.

(Discussion off the record.)

BY MS. ISAAC:

Q In response to Interrogatory Number 6, it is stated that FGT would construct an approximate four-mile lateral from its existing system, and Buccaneer would

construct an approximate two-mile lateral from its proposed route. Which is the better deal, in your opinion? And is the proposed route of Buccaneer the original route or the route of the newly acquired Gulfstream?

A There's a few parts to that question. I would first like to say, Gulfstream -- the Gulfstream pipeline is going to be the primary source of fuel to this power plant. We have every confidence that that pipeline will be constructed and put into service as scheduled by Gulfstream by June of 2002.

The discussions that we had with Buccaneer and with FGT were to provide us an alternate supply of fuel. The Buccaneer pipeline that's referred to in this response to the interrogatory no longer exists. When Duke Williams, the owner of Buccaneer, bought the Gulfstream pipeline, they bought the route of the Gulfstream pipeline, and they ceased development of any type of Buccaneer pipeline.

We do continue -- so to answer your question, which is a better deal, FGT or Buccaneer as a secondary or alternate source of fuel supply, the FGT option makes much more sense as an alternate supply.

Q Okay. And I'm going to go back and reask a question we talked about earlier dealing with transmission

upgrades. What is the estimated completion date of the necessary transmission upgrades for the Osprey Energy Center?

A Tampa Electric Company is required by contract to have those upgrades completed by December 2002.

MS. ISAAC: That was the last question. Thank you.

MR. WRIGHT: I have, I think, about three questions on redirect.

CROSS EXAMINATION

BY MR. WRIGHT:

Q Mr. Eves, in a series of questions asked by Ms. Isaac, you were asked about the commitment of the Osprey Project to Seminole, and in that context you responded that the project is committed by Calpine to Seminole, and that Seminole has some flexibility. My question for you along those lines is: Does Seminole get some additional benefits by being able to buy 350 megawatts of firm capacity out of a 530-megawatt or 529-megawatt power plant? And if so, could you describe those briefly?

A Yes. Seminole does get quite a benefit from buying 350 megawatts out of a 529-megawatt power plant because the price -- the cost to build a larger power plant is less on a per unit basis. So in our contract

with Seminole, we are pricing the power to Seminole by -- from a power plant that is generating on the basis of 529 megawatts instead of 350 megawatts. So Seminole, in essence, is getting the power price, the beneficial power price of power from a 529-megawatt power plant for 350 megawatts.

Q Could Seminole build a 350-megawatt power plant itself and get the same cost of power?

A My opinion would be no.

Q Could Calpine build a 350-megawatt power plant and provide power -- provide that 350 megawatts to Seminole at the same pricing that it's able to provide with a 529-megawatt power plant?

A No.

Q You were asked a question regarding the amount of time it would -- Calpine would prefer to have the project in service for testing before beginning delivering firm committed capacity to Seminole, and you responded you'd like to have about six months. My question as a follow-up to that is: During that time, the testing period, would you expect the capacity and energy output of the Osprey Energy Center to be available to serve Florida at, more or less, near full capacity?

A First of all, there will be a testing period before we go into commercial operation. I would say that

six-month period is not properly characterized as a testing period but strictly a period where we can run a commercial operation to make sure that that power plant is operating properly. And I would say yes. During that period after commercial operation, that power would be available to serve Florida retail-serving utilities.

Q So in practical terms, if Calpine is successful at bringing the plant into commercial operation on June 1st, 2003, would the project's output be available to serve in Florida for the summer of 2003?

A Yes.

Q Ms. Isaac prefaced a few of her questions regarding the need for the power plant with a qualification as to whether the need was independent of Seminole. My question as a follow-up for you is: In this case, is Calpine seeking a need independent of Seminole's, or is Calpine seeking a determination of need for the Osprey Energy Center as a joint applicant with Seminole?

A Calpine is seeking a determination of need as a joint applicant with Seminole.

MR. WRIGHT: Off the record for one minute.

(Discussion off the record.)

BY MR. WRIGHT:

Q You were asked some questions regarding the commitment of the project's output to Seminole. In

particular, you were asked some questions regarding whether Seminole has a right of first refusal with respect to the output, and you responded, no, but they have an option to the output.

My question for you is: As of today, can Seminole Electric Cooperative exercise its option to buy the full output of the project for the five-year committed capacity period of June 1, 2004 through May 31, 2009?

A I would say the answer to that question is yes, but as of today, Seminole has the option to take all the power from that plant when it goes commercial.

MR. WRIGHT: Okay. Thanks. That's all.

MS. ISAAC: Okay. Thank you.

(Deposition concluded at 10:30 a.m.)

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ERRATA SHEET

DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 001748-EC
NAME: TIMOTHY R. EVES
DATE: JANUARY 19, 2001

Page	Line	Change

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

DATE:_____ _____

TIMOTHY R. EVES

FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that TIMOTHY R. EVES personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 23rd day of January, 2001.

Tricia DeMarte

TRICIA DeMARTE
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition of TIMOTHY R. EVES.

I FURTHER CERTIFY that this transcript, consisting of 45 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 23rd day of January, 2001.

Tricia DeMarte

TRICIA DeMARTE
Official FPSC Reporter
(850) 413-6736

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 001748-EC

In the Matter of

PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

_____/

ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE A CONVENIENCE COPY ONLY AND ARE NOT THE OFFICIAL TRANSCRIPT OF THE HEARING AND DO NOT INCLUDE PREFILED TESTIMONY.

DEPOSITION OF:	**KENNETH J. SLATER**
TAKEN AT THE INSTANCE OF:	**The Staff of the Florida Public Service Commission**
PLACE:	**Gerald L. Gunter Building 2540 Shumard Oak Boulevard Room 362 Tallahassee, Florida**
TIME:	**Commenced at 9:10 a.m. Concluded at 10:10 a.m.**
DATE:	**Tuesday, January 23, 2001**
REPORTED BY:	**KORETTA E. STANFORD, RPR Official FPSC Reporter**

APPEARANCES:

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of Calpine Construction Finance Company, L.P.

JOSEPH A. McGLOTHLIN, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Seminole Electric Cooperative.

RACHEL N. ISAAC, FPSC Division of Legal Service, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

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PROCEEDINGS

MS. ISAAC: We'll go ahead and start this deposition, and we'll take appearances right now.

MR. WRIGHT: Robert Scheffel Wright, law firm of Landers & Parsons, 310 West College Avenue, Tallahassee, 32301, appearing on behalf of Calpine Construction Finance Company, L.P.

MR. McGLOTHLIN: I'm Joe McGlothlin, 117 South Gadsden Street, Tallahassee, appearing for Seminole Electric Cooperative, Inc.

MS. ISAAC: Rachel Isaac appearing on behalf of the Commission Staff.

Do all the parties agree to the regular stipulations?

MR. McGLOTHLIN: Seminole agrees.

MR. WRIGHT: We do, too. We'll read and sign.

MS. ISAAC: Can the court reporter please swear in the witness?

KENNETH J. SLATER

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MS. ISAAC:

Q Mr. Slater, I'm Rachel Isaac --

A Good morning.

Q -- with the Public Service Commission. I'm taking your deposition on behalf of the Commission Staff in docket number 001748-EC.

If you need me to restate the question or do not understand a question, let me know, and I'll either restate it or try to rephrase it for you. I also ask that you answer with a yes or no first before explaining your answer.

Please state your full name, for the record.

A Kenneth John Slater.

Q By whom are you employed?

A I'm the President of Slater Consulting.

Q What is your position -- well, you're the president. What does the position entail?

A Running a small consulting organization, nine people, and working in that consulting practice.

Q On whose behalf are you testifying in this proceeding?

A On Calpine's behalf.

Q Did you file any testimony in docket number 001748-EC?

A Yes.

Q Direct or rebuttal?

A Direct.

Q Did you also file any exhibits?

A The exhibits are contained in the same body.

Q Could you list those exhibits? You can list the number.

A Exhibit KJS-1 is my resume.

Exhibit 2 is a two-page exhibit on some fuel price assumptions.

Exhibit 3 is, basically, the dispatched cost-effectiveness of each generating unit in Peninsular Florida. It's 8 pages long.

And then, Exhibit 5 is a summary of existing capacity, just in numbers. They go up, capacity.

Exhibit 6 is the FRCC's projected summer and winter firm peak months.

And Exhibit 7 is the FRCC's projection of net energy for load and number of customers.

Exhibit 8 is just an annual summary of how the Osprey project would operate 2003 to 2012.

And Exhibit 9 is the same thing, but for the higher gas price sensitivity that we did.

Exhibit 10 shows the results of the load growth sensitivities, low load growth, high load growth comparison of those, just annual summary of Osprey operation.

Exhibit 11 is just some examples of the dispatch on the Peninsular Florida system on an hour-by-hour basis

for a typical January day in a typical June -- sorry -- June to December days in 2005 with and without the Osprey project so that one can see the impact on the other generation in Peninsular Florida.

12 is an excerpt from Public Utilities Fortnightly showing electric retail rates in the various NERC regions of the country. They're basically in the last few years, '97 through '99, the date it comes from.

13 is looking at the whole of Peninsular Florida, what is the average heat rate of power production with and without Osprey and what the improvement is when you add the Osprey project.

Number 14 is fuel consumptions, primary fuel consumptions, in Peninsular Florida with and without Osprey. 14 expressed the change in the fuel consumption expressed in MM BTU and exhibit -- and the second page of the Exhibit 14 shows, basically, the same information in gigawatt hours generated by fuel type.

Exhibit 15 is a table for the base case run showing the suppression of wholesale energy prices by the presence of Osprey.

And Exhibit 16 is the same thing for the high gas price sensitivity.

And 17, the same thing for the low load growth case.

And 18, same thing for the high load growth case.

And Exhibit 19 is a comparison of planned and proposed generating units. There's just a listing of them comparing their capacities and peak rates and alleged capacity factors from the 10-year site plan information that's being filed, direct construction costs if they were reported, but they're not always reported.

The Exhibit 20 shows a comparison of the load and capacity, just a reserve -- ends up with a reserve margin, does it with and without the Osprey project for the years 2000 through 2009.

Exhibit 21 does the winter peak load and capacity comparison.

And, finally, Exhibit 22 shows the impact of the Osprey Energy Center on SO-2 and NOX emissions in Peninsular Florida for the generation that supplies Peninsular Florida. Why I say that is because we've included things like Sherer in that, emissions by Sherer accounted in this.

Q Okay. What is the purpose of your testimony that you filed in your prefiled testimony?

A The basic purpose of the testimony is to show the impact on Peninsular Florida of the advent of the Osprey project beginning in 2003, impact on wholesale

energy prices and on reserves and on emissions.

Q Okay.

A And fuel consumption, primary fuel consumption, and the efficiency of the fuel conversion for electricity; all of those things, all the good things that happen when you put the Osprey project in.

Q Did you prepare or supervise the preparation of any analysis of the Osprey Energy Center in which the assumption was made that some of the power was sold outside of Peninsular Florida?

A Our assumption was that all the power was going to Peninsular Florida.

Q On Page 6 of your testimony, you state that your analysis was completed without assuming duct-firing and power augmentation. Do you have an estimate of the plant's capacity if duct-firing and power augmentation is included?

A The addition of duct-firing, as long as you've got the additional capability in the steam turbine and the generator for this type of unit, would at least get you 50 megawatts, probably more; depends how they do it, how much they have, but other installations that I've modeled would get you at least another 10% capacity. The heat rate for that additional piece is usually somewhere around about 9,000, just the incremental heat rate for the incremental

generation from that duct-firing.

Q In general, how would including duct-firing and power augmentation have effected the results of your analysis?

A It would have provided, basically, additional impacts on the wholesale energy prices. They would have come down a little further. The fuel conversion efficiency in the state would probably not have changed very much, because we're dealing with the addition of about 9,000 -- as I say, about somewhere in that 9,000 BTUs per kilowatt hour conversion range.

So, it wouldn't have had much impact on the statewide heat rate; maybe a little bit, because we may have reduced generation on some of the less efficient combustion turbines. So, if anything, there would be an improvement, but not as big an improvement as you see by adding the Osprey project itself.

Emissions, you'd probably see an improvement in NOX emissions by using Osprey for doing a little peaking rather than using some smaller gas turbine.

Q On Page 14 of your testimony, you state that the Osprey project will be slightly more cost-effective than merely all the other planned gas-fired combined cycle units in the region. What are the primary reasons for why the Osprey unit is more cost-effective?

A A very good heat rate, as good a heat rate as just about anything that's there that's being proposed, except for the H-technology machines that Florida Power & Light is looking at. They have a better efficiency, better heat rate. The capital cost that Calpine has assured me, I think, is better than most others, because of their bulk buying. They ordered quite a number of combined cycle units, and they get a good price for those.

I think, we had an interrogatory to this effect. Yeah, there was an Interrogatory Number 23, and it's sort of quoting this fact that Calpine is going to own a lot of these things. They get a better price for them in the first place, plus, their cost of running them is going to be better.

Q Do other utilities use bulk buying of CTs?

A Nobody seems to have bought quite as many as Calpine. They've bought -- I think, they've got the biggest list of anybody in the country of units that they've put on order. This is not just for Florida, this is for all over the country that they're buying these for.

Q Okay. On Page 19 of your testimony you discuss the fuel price forecast used as an input in your models. Do you feel that these forecasts are still appropriate given the recent increase in natural gas prices?

A Yes. The recent increase in natural gas prices,

I believe, is the sort of thing that happens when we've had the coldest November and December combination judged for the whole country on record since they began keeping records, and that was 1896.

So, if you looked at the nationwide degree days for heating load for gas, you would find it extraordinarily high up to that point. November and December in the process, we're seeing in December and in January a reflection really of how much gas has had to come out of storage.

You have the gas supply to the northern states, et cetera, relies quite a bit on some kind of storage to the gas storages and the market, day by day gas market, if you'd like, looks very closely at how much gas is still in storage.

And this cold November and very cold December has stripped a lot of that storage out of there, and the prices have just gone through the roof. But that's a tempered thing for this sort of season, and I expect the prices to come back down again once we've had a period of normal or even mild weather allow the storages to be refilled next summer. Next winter may be entirely different.

Q Do you feel that the increase in demand by the electric industry has also impacted the price of gas?

A Well, it has, and that's been built into the forecasts that are around. The price is not going to be as low as it was a couple of years ago. Some of those low prices, they're not going to be repeated, but everybody's forward forecasts does have -- not everybody's, most people's forward forecasts have increase in gas prices because of the increase in demand. Most long-term forecasts where there's a supply-demand balance underlying it are showing increases into the future years, and I'm fairly happy with those forecasts.

You'll have to also realize that there's more supply coming on-line, and some of that supply is coming in in very useful locations. If we look at where the Sable Island gas from Nova Scotia off the coast of Nova Scotia where that's coming in, it's coming up in the northeast, which is very nice, and then there's the Hibernian field off the New Finland coast, which they haven't yet decided yet to start bringing on-line, but it's likely that it'll come in behind the Sable Island gas, the same route, into New England, as well as Canada, of course. It'll come into Nova Scotia and then it'll continue on by pipeline into New England.

Q How did you select the higher natural gas prices used in your sensitivity case?

A Well, the higher prices are those that were

produced by the Energy Information Administration's own forecasting process which, over the years, has always appeared to be high and often proven to be high compared with other forecasts.

I think, we answered an interrogatory on this, that it was the RDI forecast for the gas that we followed in the base case. The Energy Information Administration, in their energy outlook, annually publishes their own forecast, along with about three other forecasts from nationally-recognized forecasting groups.

And generally, the gas price forecast of the EIA's own forecasting model shows, in the long term, higher gas prices than the others do. And so, for the base case, I chose, basically, the second highest gas price out of that group; I think, it was the second highest, EIA's being the highest. So, then, for the high gas price sensitivity I used the EIA's net forecast.

Q Do you believe that your higher gas price sensitivity is still appropriate given the recent escalation in natural gas prices?

A Yes. It's higher than the others in the longer term. So, it's got very little to do with current conditions, that long-term forecast. It's got to do with supply-demand conditions in the 2005, 2010, 2015 time frame.

Q How do your base case and high case gas prices compare for 2004 through 2009?

A I think, you'll find them, I think, in one of the exhibits. Yes, if you look at Exhibits 1 and 2, you can see the way the gas prices change between those two. And you'll find it's only the gas prices that change. It's just a higher gas sensitivity, it's not a higher fuel price. If you look at those, you will see that 2000 and 2001 are precisely the same, and they start to depart in 2002, such that by the time you get out to 2009 -- I think, that's the year you mentioned --

Q Yes.

A 2009 the high gas price sensitivity is about 10% higher. Let me look at that. Yeah, about 10%. And it keeps on getting a little bit more in the last few years.

Q On Page 21 of your testimony, you discuss your adjustment to the FRCC's net energy for load projections --

A Sorry. Could you start that again? I was thinking this.

Q Sure, sure. On Page 21 of your testimony, you discuss your adjustment to the FRCC's net energy for load projections due to energy use from interruptible and load management customers. How does your assumption of energy use from interruptible and load management customers

compare to the utility's estimates?

A For most of the utilities, they are the utility's estimates. For one of them, I think, it was only one, but I have in the back of my mind that there might have been a problem with one of the other ones, but, I think, it was mainly one of them.

Their forecast use of load management and interruptions was at the maximum level. That's what they forecast. Yet, their history didn't show them using it at maximum. So, you had a disconnect from their historic net energy flow to their forecast net energy load, and that wouldn't be right. What we're trying to do here is forecast what is likely to happen rather than what could, if that utility had a perfect knowledge of the future and a desire to interrupt the limit of its ability all the time.

To do that you would have to have a real good crystal ball to know what's going to happen for the rest of the summer, things like that. But what we chose to do was to exercise that interruptibility and load management to the same degree that they had in the past.

Q Which utility did you adjust?

A I think -- I can't swear to this because the stack of papers are back in the office, I think, it was Florida Power Corp.

Q How did you develop --

A I'm not certain, though. If somebody wants to know, I can, in fact, look it up.

Q How did your assumption for energy use from interruptible and load management customers impact your results compared to using the FRCC estimate?

A In all, very little, okay? Assuming that -- put it this way: We were trying to balance the energy to the NERC ES&D forecast. The NERC ES&D, of course, does not produce month-by-month forecasts. The only month-by-month forecasts we had -- and we need to break out the annual forecast into months for the model, for the purposes of the model. The only month-by-month ones we had existed in the 10-year site plans. There's a couple of years of month-by-month numbers.

So, to get that, we have to use the 10-year site plans, but we did want our energy forecast to add up to the NERC ES&D published FRCC fad use. So, that was where we made our adjustment on that interruptibility and load management for that one company. If we hadn't made it there, we would have made it somewhere else to get the sum of the site plan forecasts to add up to the FRCC's peninsular total. So, in essence, very little impact of us, assuming that it was net load management that was the problem.

Q What does ES&D stand for?

A Energy supply and demand. There used to be -- I suppose, in theory, there still is -- a FERC form -- no, sorry, DOE 411, IE 411, and the NERC ES&D now is filed in lieu of, or as well as, for some of the regions, the IE 411 information. And that's what it contains, the IE 411 stuff.

Q You assume that transmission was costless for all transactions, correct?

A Yes.

Q Is this a typical assumption for this type of analysis?

A For this type of analysis, yes.

Q On Page 22, you state that altering this transmission assumption would likely have very little impact on the actual dispatch of the Osprey project. Do you have any analysis to back up this statement?

A Only our experiences elsewhere, you know, on other systems.

Q On Page 25 of your testimony, you discuss your assumption that sales from the project outside Peninsular Florida are highly unlikely, because Florida's generation resources are high cost.

Isn't it true that Florida's utilities currently make sales outside of Peninsular Florida?

A I haven't looked, but I don't think they make any appreciable sales, not like some states do. I'm sure that on occasion, on a particular day when southern company might have a few outages and might be having some difficulties, there might be some sales, or an adjacent system in the southeast having a bad day, Florida might be able to sell something, if it's having a good day. But I'd rather not rely on that sort of thing for the economics of the project.

Q How do costs for the Osprey unit compare to costs outside Peninsular Florida?

A For the Osprey unit, the costs for it are fairly good, because gas is not awfully expensive in Florida, but its similar prices or better prices just to the north of Peninsular Florida. So, the generation costs may be a little higher from the Osprey project than from similar units.

However, the combined cycle units are so much better than conventional gas-fired units that the Osprey prices look pretty good or the Osprey costs look pretty good.

Q Then, why do you feel it is highly unlikely the power will not be sold outside the region?

A Because it can be well used inside the region. There's plenty of higher-cost generation in Peninsular

Florida to displace. That's the point. It's not based on the Osprey project itself. It's the overall costs in Peninsular Florida that are high.

Q Your model provides estimates of the expected fuel savings for Peninsular Florida. How will these results be impacted by the contract with Seminole? That is, how will your fuel savings results be impacted if Seminole decides not to build its next planned combined cycle unit?

A If they decide not to build the next combined cycle unit, then, the benefits that were put forward in this -- in our analysis, would be a bit higher. We have assumed that Seminole was going to build that combined cycle, and then Osprey would come along as well. So, what Osprey can displace is not quite as good as it would be if Seminole doesn't build that extra combined cycle.

Q On Page 28, you state that dispatch decisions are based on total variable costs. Are you stating that dispatch decisions are based on incremental O&M or total variable O&M costs?

A Variable O&M costs. And why I've said total variables is that I've also included emission costs; in other words, the value of emission allowances consumed by the generation as a cost, as well as fuel, of course.

Q How did you determine your estimate for variable

O&M costs for coal units?

A Coal units, what we've used there is our knowledge of what variable O&Ms other companies use in areas where it's been traditional to dispatch whole pools and where units all have variable O&M costs associated with them. And our experience in that area shows us what is typical for a unit of a certain age, size, and fuel, and that's what we've used. We've translated from other areas of the country, whether we have utility's own data for things like that.

Q On Page 30, you state that the Osprey unit's dispatch cost of $32.57 per megawatt hour is lower than the dispatch cost of 38,000 megawatts of Peninsular Florida's capacity.

A Where is that?

Q On Page 30.

MR. McGLOTHLIN: Did you say the 38,000?

MS. ISAAC: 38,000 megawatts.

MR. WRIGHT: I think, it's on Page 31 of his testimony.

BY MS. ISAAC:

Q On Page 31.

A Yes. I think, we have Exhibit 4 that's all stacked up. Exhibit 4, this was 2008, okay. If you look at all of the prices, we've developed the annual average

dispatch costs for the units, and total up all of the capacity that's more costly than Osprey, you get to that number. That's exactly how we did it, just adding it up from that Exhibit 4.

Q This dispatch cost translates into power supply cost savings between 627 million and 1.12 billion in the first 10 years. Did your analysis assume that the Osprey unit will be dispatched at cost?

A Yes. The whole analysis was based upon dispatching generating units, all generating units at cost.

Q Calpine has market pricing authority from FERC, correct?

A Don't understand that question. It's not --

MR. WRIGHT: Want to go off the record for a second?

MS. ISAAC: Sure, let's go off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q Do you know if Calpine has market pricing authority from FERC?

A I am told it does.

Q Assuming that is the case, Calpine's capacity and energy won't necessarily be sold at cost, but at whatever price the market will bear, correct?

A It might be, but what we've assumed in the analysis is that the marginal generation from the Osprey project will actually be sold at cost and that if Calpine wants to sell all of its capability to produce energy in that -- in Peninsular Florida, it'll end up dispatching at least the marginal generation at cost, if it's selling into a market.

If it fails to do that, if it dispatches at some other cost, there will be some loss of profit to Calpine, as well as some loss to the wholesale market. So, what our normal assumption on these analyses is, is that people will end up dispatching marginally at cost, because they sacrifice profit if they don't.

Q Given that the power will be priced based on market prices rather than cost, can we expect this to reduce the expected power supply benefits when we look at these benefits from the point of view of ratepayers in the region?

MR. WRIGHT: To clarify, when you ask about reducing the benefits, do you mean reduce them from the value shown in these tables?

MS. ISAAC: Yes.

A I don't expect that, because as long as the Osprey project gets dispatched at something like the level that we have assumed it will dispatch at, and the model,

doesn't matter what price the power is sold for, there will still be an impact on the wholesale energy prices in the state as measured by the hour-by-hour marginal costs of production. As long as Osprey is dispatched, the units that set that margin will still be setting that margin and setting it at a different level with and without the Osprey project.

BY MS. ISAAC:

Q How can we expect your power supply cost reduction estimates to translate into rates for the region's ratepayers?

A If, in fact, everybody in the state operates just as the state is operating now and enters into every single transaction that is economic on the broker, it will drive down to what we have modeled with the statewide dispatch. Therefore, those wholesale energy prices on which energy is traded around the state will drop.

Sorry. I should have finished that by saying that as long as there's fuel clauses in the rates, these things end up passing through.

Q Did you use the broker system in your analysis?

A No. What was used in the analysis was the assumption that all possible transactions would take -- all economic transactions would take place, whether it was by the broker or whether it was by an ISO or RTO-run

wholesale market; doesn't matter, the economics are still the economics.

Q You state that the Calpine unit has significantly lower direct construction costs than most of the proposed combined cycle capacity for the region. Do you have a feel for the primary reasons for this?

A I just think it's volume; the more you do, the more you buy, the cheaper it becomes. You economize on corporate overheads, because you're doing the same thing repeatedly, you get a better price from the suppliers, you only do the engineering several times, rather than once for every installation you put it in. There is a saving.

Q On Page 36, you discuss the developments which could cause the proposed plant to be noncost-effective. You cite failure of the project to become operational or dramatic technological changes.

Do you believe that there is any increase in natural gas prices high enough to cause the proposed plant to be noncost-effective?

A I don't know the answer to that, because gas is on the margin in Florida quite a lot of the time. And oil is very often related to gas in price, because there's so many units in north America that can fuel switch that it's very hard for gas and oil to get that far apart long term.

If gas gets too expensive, more oil gets burned,

less gas gets burned. If the other happens, it goes the other way. Therefore, I don't believe they can get all that far apart.

Now, given that, most of the time in Peninsular Florida, the gas and oil would be on the margin of the electric generation. And therefore, wholesale prices would rise if gas rises, and rising to an extent that may even benefit a project like Osprey because of its better efficiency compared with the units that would be setting the marginal price. For that reason, Osprey won't even profit from an increase in gas prices.

I think, if you look at our sensitivity, the change that we've -- the overall change in wholesale energy prices with and without Osprey, that saving that I've put forward, it varies very little between the high gas price sensitivity and the base case, very little change in that number, and that's what I expect to hold, even if the wholesale -- even if the price of gas goes somewhat higher. But whether there's some breaking point out there, there may be, but not in the range that anybody is reasonably looking at, anyway.

Q You stated that the Osprey project will increase Peninsular Florida's reserve margins by 1.1 to 1.3%. Does this calculation include Seminole's next planned combined cycle unit or is the unit excluded?

A It does include their next unit. So, this is just a simple piece of arithmetic of what difference does the addition of Osprey make to the reserve margin in Peninsular Florida. If it exactly displaces another unit of the same size, then, there'll be no impact on the reserve margin in Peninsular Florida.

Q On Exhibit KJS-7, the load factors begin to increase significantly in 2001. Why are the load factor estimates increasing?

MR. McGLOTHLIN: What year did you say in your question?

MS. ISAAC: 2001.

A I think, you'd have to ask the utilities this. That's the function of their load forecast. And it is the sort of thing that you'd have to look -- well, from 2001 on, this is weather normalized peak load compared with net energy for load.

And the actuals always vary from the forecast, but it would look as if, you know, if you average those, the history, they would average out lower than the forecast. And I understand that, and it's something that when you're not doing the load forecasts for them, you don't have a whole lot of control over them. Maybe their peak loads are actually a bit higher than that, but their forecasts might be a little on the low side.

Q Are the load factor estimates consistent with the FRCC estimates?

A These are the FRCC estimates.

Q Okay.

A That's what these are. They come out of those little half-inch thick volumes from the FRCC.

MS. ISAAC: Okay. Well, thank you.

MR. WRIGHT: That's it?

MS. ISAAC: Yes.

MR. WRIGHT: Good. A few questions on redirect.

CROSS EXAMINATION

BY MR. WRIGHT:

Q You were asked a question -- well, actually, in summarizing your exhibits you made a reference to the data reprinted from the Public Utilities Fortnightly. I think, you described that as retail rates. Are you sure whether that's retail rates or is it something else?

A Let me look. I'll read it carefully. The print's a bit small on this.

Well, it's two things. It's both the retail rate and the production cost. I was only reading the bottom line, the retail rate line, which doesn't exactly follow the production costs, but somewhat does.

So, you'll find the lowest retail rates, generally, where you have lowest production cost, but not

always. There are exceptions to that, but it's just a general, general trend thing.

Q Thank you.

In response to a question by Ms. Isaac, you confirmed that you assumed that transmission was costless per your analyses.

A Yes.

Q Would it make any difference if you assumed that transmission costs the same for all transactions within the region being studied?

A It would make no difference.

Q You were asked a series of questions regarding prices that Calpine might receive for its power and cost of production and cost reductions. I wanted to ask you a couple of follow-ups on that.

What, if any, price do your analyses assume that Calpine will get paid?

A It doesn't assume any price that Calpine gets paid. It only assumes that if you end up being dispatched, at least marginally, on its cost.

Q Okay. Your Exhibits KJS-15 through KJS-18 summarize estimated savings from the Osprey project. What is that measuring?

A It is simply measuring the downward shift in the average hourly module energy cost on the system on an

annual basis. And those numbers are in the third column from the right-hand side, dollars per megawatt hour wholesale price suppression. That is multiplied by the total net energy for load to come up with the nominal dollar savings in the second column from the right, and then they just present valued at 10% in the right-hand column.

Q So, does your model calculate in one run an hourly production cost for dilute in that hour without the Osprey project and then do a comparable run calculating the cost to serve the same load in the same hour with the Osprey project in operation?

A Well, it could do that, but that's not what this number is.

Q Okay. And what does that number do?

A This number is the marginal energy cost, which is where the -- how do you call it in Florida? The as-available energy cost, put it that way, where that would end up --

Q Okay.

A -- averaged over the year. That's what that number is. If it was a competitive generation market, that would be the average of the energy prices for all hours of the year that would be applied to all of the generation in the state. If you assume that everybody got

paid on clearing prices, this would be the average of the hourly clearing prices. Those are in the third and fourth columns from the left, those two numbers. And the difference between them is the suppression. But the program does, in fact, calculate that marginal energy cost hour by hour.

Q Okay. Could Calpine get a price greater than the lower wholesale price after its entry?

A Well, it does get a little higher. Even dispatching totally at cost it would get a price a little higher than the lower one, because there are some hours of the year when the Osprey project doesn't run. Those hours -- this is by economic dispatch. And those hours would be the lowest energy prices in the year that are averaged into these numbers.

So, if you skip some of the lowest ones, the average that you get is a little better than the average for the whole system. But it doesn't matter what their generation was sold at as long as their dispatch looks like the dispatch you would get if you dispatched at cost, at least marginally, then, you'd get this same suppression.

Because as long as that generation is there and the wholesale price, if you'd like, or the as-available energy cost on the system is set by the marginal units,

which are not Osprey, generally not Osprey, then, you'll get the same sort of suppression just by Osprey being dispatched by the amount that it would be dispatched, if it was dispatched -- or at least marginally dispatched.

Q I think, what the Staff's line of questioning was interested in is how, if at all, those wholesale price suppression effects would translate into changes in rates to customers. Can you explain that?

A Well, if it was -- let's start at the back end of this. If it was a competitive wholesale market where each one of the entities serving load was buying off that wholesale market and paying the clearing price, this is exactly what would happen.

Given that the present set-up is probably not quite as efficient as that, you may not get all these savings passed to the customers, but if you have efficient fuel clauses, and if there is trading all around the place, the aggregate benefit to the customers should be the same amount, if they're awfully efficient at their brokering.

Q Okay. You were asked a question regarding your statement in your testimony that the Osprey project has lower direct construction costs than the majority of new gas combined cycle. You responded that you think that's because of volume and certain overhead savings.

How does the -- as a follow-up question, I would ask you how does the direct construction cost of the Osprey project compare to the cost of repowering combined cycle projects that are being constructed in Florida?

A It appears to be better which, in some ways, is surprising and in some ways not, repowering with combined cycles, new ones, because it's dealing with the more expensive part of it, the combustion turbine, and a lot of that part that has to be replaced in both cases and the heat recovery units, the repowering is often not as good as putting in a brand new one.

Q Okay.

A In the general sense, they are very competitive for an owner, but if you've got some advantage in the new construction, you'll beat them.

MR. WRIGHT: Thank you. Anything else?

MS. ISAAC: No.

MR. WRIGHT: Jim?

MR. McGLOTHLIN: Nothing from me.

MS. ISAAC: That's the end of the deposition.

(Deposition concluded at 10:10 a.m.)

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ERRATA SHEET

DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 001748-EC
NAME: KENNETH J. SLATER
DATE: JANUARY 23, 2001

Page	Line	Change

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

DATE

KENNETH J. SLATER

FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that KENNETH J. SLATER personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 29th day of January, 2001.

Koretta E. Stanford
MY COMMISSION # CC916954 EXPIRES
March 8, 2004
BONDED THRU TROY FAIN INSURANCE, INC.

Koretta E. Stanford

KORETTA E. STANFORD
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, KORETTA E. STANFORD, RPR, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition of KENNETH J. SLATER.

I FURTHER CERTIFY that this transcript, consisting of 36 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 29th day of January, 2001.

Koretta E. Stanford

KORETTA E. STANFORD, RPR
Official FPSC Reporter
(850) 413-6734

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 001748-EC

In the Matter of

PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE A CONVENIENCE COPY ONLY AND ARE NOT THE OFFICIAL TRANSCRIPT OF THE HEARING AND DO NOT INCLUDE PREFILED TESTIMONY.

DEPOSITION OF:	GARL S. ZIMMERMAN
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Gerald L. Gunter Building Room 362 2540 Shumard Oak Boulevard Tallahassee, Florida
TIME:	Commenced at 9:00 a.m. Concluded at 10:05 a.m.
DATE:	Thursday, January 25, 2001
REPORTED BY:	TRICIA DeMARTE Official FPSC Reporter

APPEARANCES:

JOHN R. LaVIA, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of Calpine Construction Finance Company, L.P.

JOSEPH A. McGLOTHLIN, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Seminole Electric Cooperative, Inc.

RACHAEL N. ISAAC, FPSC Division of Legal Service, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

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STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure;

that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

MS. ISAAC: Okay. We'll go ahead and start, and take appearances now.

MR. McGLOTHLIN: I'm Joe McGlothlin, appearing for Seminole Electric Cooperative, Inc.

MR. LaVIA: Jay LaVia, appearing for Calpine.

MS. ISAAC: Rachael Isaac, appearing on behalf of the Commission. Do all the parties agree to the usual stipulations?

MR. McGLOTHLIN: Seminole will want to read and sign the transcript; other than that, we agree.

MR. LaVIA: We agree too.

MS. ISAAC: Would the court reporter please swear in the witness.

GARL S. ZIMMERMAN

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MS. ISAAC:

Q Good morning, Mr. Zimmerman. I'm Rachael Isaac for the Public Service Commission. I'm taking your deposition on behalf of the Commission Staff for Docket 001748-EC. If you need me to restate the question or do not understand a question, please let me know, and I'll either restate the question or try to rephrase it for you.

I also ask that you answer with a "yes" or "no" first before explaining your answer.

Please state your full name for the record.

A My full name is Garl S. Zimmerman.

Q By whom are you employed?

A I'm employed by Seminole Electric Cooperative, Incorporated.

Q What is your position with your employer?

A I am the manager of system planning.

Q What does this position entail?

A The system planning section is responsible for determining all future needs for resources and also for new transmission facilities.

Q On whose behalf are you testifying in this proceeding?

A On behalf of Seminole Electric Cooperative.

Q Did you file any testimony in this docket?

A Yes, I did.

Q Direct or rebuttal?

A Direct.

Q Did you also file any exhibits?

A Yes, ma'am, I did.

Q Will you please list those exhibits.

A Yes. The exhibits: GSZ-1, "Summer Reserve Margin." GSZ-2, "Mills/Kilowatt-Hour Versus Capacity

Factor." GSZ-3 is the Seminole RFP. GSZ-4, "Ranking of Peaking Capacity Bids," and GSZ-5, the Calpine Osprey Savings Present Value of Revenue Requirements.

Q What is the purpose of your testimony that you have given in your prefiled testimony?

A The purpose of my testimony is to give an overview of the Seminole planning process, how we determined what our future requirements were, and how we evaluated the responses to our request for proposals.

Q Okay. Mr. Zimmerman, on Page 4 of your testimony, you state that occasionally Seminole's share of operating reserves allocated by the FRCC requires Seminole to maintain total reserves which exceed 15 percent. Could you explain this statement?

A Yes. Seminole calculates operating -- in Seminole's calculation of operating reserves, we include the -- our entitlement to the Hardee Power Station units. Those units have certain restrictions on their use. They are not always available to Seminole for operating reserves, particularly within the ten-minute time frame. If units are not operating, they are not available within the ten-minute requirement of operating reserves.

So when we calculate our operating reserve requirement as specified by the FRCC, we look at the other types -- the other resources available, and sometimes the

total reserve requirement is greater than 15 percent.

Q On Page 11 of your testimony, you discuss comparing the Calpine contract with your partial requirements contract with Florida Power Corporation. How is the partial requirements contract with FPC priced?

A The partial requirements pricing with FPC is -- has a stratified pricing arrangement. It's broken into peaking, intermediate, and base load capacity pricing. At our current capacity commitment level within FPC, we normally are only buying peaking type of partial requirements capacity. So it looks more like a typical peaking capacity unit. FPC has certain units classified in the peaking category, and so it is priced like peaking capacity.

Q Was the FPC contract included in the initial reliability round to determine Seminole's reserve margin in 2004?

A No. Our partial requirements are not included in either our calculation of reserves or EUE because our partial requirements are 100 percent available. It's not a dispatchable resource, and FPC has the requirement to supply that capacity and carry the reserves for it.

Q Could you describe the process Seminole used to compare the FPC partial requirements contract with the Calpine contract?

A The -- well, let me clarify. Partial requirements were not compared to the Calpine contract. They were compared to peaking -- responses to our RFP for peaking capacity where Calpine is an intermediate type of unit. We looked at the pricing that was quoted in the RFP for peaking capacity, compared that to what we're paying FPC for peaking capacity, and determined that it was more economical to keep the FPC peaking capacity at the current level.

Q Did you make any comparison based on the intermediate base load pricing of the PR contract?

A No. We did not do a detailed evaluation, although the pricing of the Calpine Osprey offering was less than the FPC intermediate capacity pricing.

Q On Page 14, you discussed the assumption made in the self-build option that fuel and fuel transportation costs are the same as for the Calpine facility. Why do you feel this is a reasonable assumption?

A I'm sorry, would you restate the question? I was turning to the reference as you were talking.

MR. McGLOTHLIN: What page number did you say?

Q On Page 14, Lines 19 through 20, you discuss the assumption made in the self-build option that fuel and fuel transportation costs are the same as for the Calpine facility. Why do you feel this is a reasonable

assumption?

A For each intermediate type of capacity or unit that we have, for example, our Payne Creek unit, which is under construction, fuel transportation is firmed up based on expected load factors or capacity factors of those units. It's a rather detailed optimization that's required, and we would do the same thing if we were to build our own unit instead of the Calpine Osprey purchase. We would -- without doing a detailed analysis, it's a reasonable assumption that we would have transportation costs similar to what are in our Calpine Osprey purchased power agreement.

Q Is the Seminole site for the self-build option in close proximity to the Calpine site?

A The -- we did not specifically designate a -- or pick a site for the self-build option. It most probably would have been built on the Payne Creek site, which is in the same general area of the State. The Payne Creek facility is right near the Polk-Hardee County line, and the Osprey unit is in Polk County.

Q On Page 15, Lines 17 through 20, you state that the Calpine contract is more cost-effective than the self-build option on a five-year basis. What are the primary reasons that the contract compares favorably to the self-build option?

A The savings listed in my testimony were based strictly on capacity costs and the Seminole cost of financing versus the capacity cost for the Calpine. We assumed that fuel would be, again, the same for either facility because they would be identical-type facilities.

Q In Exhibit Number GSZ-1, is the FPC partial requirements contract included in the reserve margin calculation?

A No, it is not.

Q Could you explain in general why the contract with Calpine is for 350 megawatts when Seminole's need in 2004 is for 201 megawatts?

A The need really is -- was determined to be 350 megawatts. We had a 200-megawatt need for the purpose of meeting load growth and expiring contracts, and an additional 150 megawatts was determined to be an economic replacement of an existing contract.

Q How were the capacity factors reconciled when the least expensive peaking proposal was compared to the combined cycle proposals available to Seminole?

MR. McGLOTHLIN: Would you repeat that? I don't think I followed the whole question.

MS. ISAAC: Sure.

BY MS. ISAAC:

Q How were the capacity factors reconciled with

the least expensive peaking proposal -- I'm sorry, let me repeat it. How were the capacity factors reconciled when the least expensive peaking proposal was compared to the combined cycle proposals available to Seminole?

MR. McGLOTHLIN: I'm not clear on which capacity factors you have in find. Capacity factors of competing proposals?

MS. ISAAC: Let's go off the record.

(Discussion off the record.)

MS. ISAAC: We're going to strike the last question.

BY MS. ISAAC:

Q Calpine has testified that the Osprey unit will have a capacity factor of 94 percent. Given this high capacity factor, can you explain why coal would not make -- would not be a cost-effective choice for Seminole's capacity needs?

A Yes. Calpine's calculated capacity factor includes more than just Seminole's requirement. The Seminole need for its own native load results in a capacity factor for the 350-megawatt portion that ranges from around 40 percent in the early part of the contract to near 50 percent in the -- toward the end of the first five years of the contract. The higher capacity factor is based on certain off-system sales.

Q According to Volume 1 of the exhibits on Page 23, Seminole used production software to simulate its system over the time period 2004 to 2008 in its evaluation of the capacity offers from the RFP. Why have you characterized this time period as Seminole's preferred contract term?

A A number of the offers that we received in response to our RFP were for five-year terms. Also, the Calpine Osprey offer has a reopener at the end of five years -- the first initial five-year term where the pricing would be adjusted to market. Without having firm pricing beyond 2008, it's difficult to do an analysis that would give us an accurate present worth of revenue requirements.

Q The next group of questions goes to the need for power requirement. Are you sponsoring Table 3 on Page 14 of the revised need study?

A Yes.

Q Do Seminole's production costs simulation models determine the amount of capacity needed by type?

MR. McGLOTHLIN: Please repeat the question.

Q Do Seminole's production costs simulation models determine the amount of capacity needed by type? For example, peaking, intermediate, or base load.

A The models themselves -- well, the PROMOD

production costing model does not determine the type of capacity. It evaluates various types of capacity against each other. We do have another model also licensed from NewEnergy that will determine the capacity by type.

Q Can you explain briefly how this analysis is performed?

A The -- are you asking about the production costing analysis?

Q Yes.

A The production costing software uses as inputs the characteristics of various types of units, combined cycle units, peaking units. And for each of these types of units, we put in the heat rate curves, we have fuel types with fuel costs and so forth that the software will dispatch the appropriate unit based on the cost, the incremental cost, of the next unit to serve the load.

Also, we -- another input is the load model. We have to have a load model included, and it will calculate on either from an hourly basis to an annual basis the revenue requirements for the energy costs. It does not take into account fixed costs. That's done in a financial model that's associated with the production costing model.

Q From the simulated dispatch, is there a level of megawatts for each capacity type that is determined?

A Not directly from the production costing model.

The analysis -- a separate analysis was done to determine the break points in capacity factor for various types of capacity, the break point between base and intermediate, and the break point between intermediate and peaking capacity. And that was done external to the model, and then we modeled the type of capacity in the production costing model based on -- and the production costing model will give us the capacity factor, and so we modeled the type of unit that's appropriate for the capacity factor that we get.

Q Are you sponsoring Table 4 on Page 16 of the revised need study?

A Yes, I am.

Q Is the Calpine Project replacing the first unknown combined cycle in this table, the one with June 2004 in-service date?

A Yes, the Calpine unit will replace the first combined cycle and a portion of the following combustion turbine.

Q Are you sponsoring Tables 5 and 6 on Pages 17 and 18 of the revised need study?

A Yes, ma'am, I am.

Q The reserve margin percentages contained in these two tables appear to be inconsistent with how the reserve margin is normally calculated. Explain how

Seminole calculates percentage reserve margin.

A The Seminole reserve margin is calculated from this table that there are items that are not included in Seminole's calculation of reserve margins because it is capacity that is 100 percent available, and Seminole is not required to carry reserves for that capacity.

For example, partial requirements and full requirements are just what they -- what the names imply, and they are the responsibility of the supplying utility to make that capacity available 100 percent of the time. And so we don't carry reserves for that.

We also have some purchases from Florida Power Corporation for some intermediate and peaking capacity that are also 100 percent available, and so we don't plan reserves for those. So we don't plan the loads served by those -- by that capacity or that capacity in our calculation of reserve margin.

MS. ISAAC: Can we go off the record?

(Discussion off the record.)

BY MS. ISAAC:

Q Are any of Seminole's partial requirements purchases embedded in another number in this table, in the Table 5 on Page 18 (sic) of the revised need study?

A The partial requirements are shown as a separate line item and are also included in the system firm winter

peak, but are not included in the system firm obligation.

Q Which number are they included in?

A The partial requirements are included in system firm winter peak demand, but not included in system firm winter obligation.

Q In the year 2000 on Table 5, which numbers on that row give you the 26.4 reserve margin percentage?

A The reserve margin before maintenance, which is 492 megawatts, is the numerator. The denominator is the firm summer obligation, the 2,319 minus the FPC capacity, which is fully reserved, which in the year 2000 was 155 megawatts of peaking and 150 megawatts of intermediate.

Q Can you please repeat that last number. How much intermediate did you say?

A 150 megawatts of intermediate.

Q Thank you. Do you have a copy of Mr. Woodbury's testimony?

A Yes, I do.

Q Please turn to Exhibit TSW-2 of his testimony. Are any of the resources in this table embedded in another number in Table 5 on Page 17 of the revised need study?

A Yes. All of this capacity would be included in Table 5 in various columns.

Q Please explain the differences between the

capacity and demand values in Table 5, Page 17 of the revised need study, and Table 2, Page 13 of the revised need study.

MR. McGLOTHLIN: Could you repeat the two references, please.

MS. ISAAC: Sure. Table 5, Page 17, and Table 2, Page 13 of the revised need study.

A The calculations in Table 5 include all of the capacity shown in our self-build back-stop plan, which is Table 4 on Page 16. The tables on Page 13 show what our reserve margins would be if we added no additional capacity in the year 2004 and beyond.

Q Why isn't the demand the same in both tables? It appears to differ by exactly 150 megawatts in each year, and I was just wanting to know why.

A Table 1 and Table 2 assume that -- also a determination of the FPC intermediate capacity.

Q Okay.

A I'm sorry.

Q Go ahead.

A It's the other way around. It assumed that the capacity -- that the intermediate capacity was there serving the demand and was 100 percent reserved, so we didn't include that in our calculation, where Table 5 includes all of our resources and obligations.

Q Can you please repeat what was included and what wasn't included in Table 1 and Table 2.

A Table 1 and Table 2 assumed that we still had the FPC intermediate capacity, and we did not -- and that it was 100 percent reserved, so we did not include that in the demand number that was used to calculate reserves. Wherein, in Table 5, it is shown in the firm summer peak demand number.

Q The next group of questions goes to the cost-effectiveness requirement. How does Seminole evaluate the cost-effectiveness of supply-side additions to its system?

A Since Seminole is a not-for-profit organization, generally the option with the lowest present worth of revenue requirements is the most cost-effective option to Seminole.

Q How many years does the present worth revenue requirements analysis cover?

A In this -- in our present analysis, we only used a five-year period because several of the proposals were for five-year terms. And also, as I mentioned previously, the Osprey offering has a reopener at the end of five years where we would negotiate the price beyond that period of term. So we just used the five-year term in the contract.

Q How long was the present worth revenue requirements analysis on the past Ten-Year Site Plans?

A I'm trying to remember where in the Ten-Year Site Plan we --

MS. ISAAC: Okay. Let's go off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q What planning horizon is used for the Ten-Year Site Plan expansion plans?

A It's a ten-year planning horizon starting with the present year.

Q Why is it different from the one used in this case?

A The planning horizon used in this case is in actuality not all that much different, because in the Ten-Year Site Plan, the current year is the first year of the plan, where Calpine or our need does not start until 2004, and it's five years beyond that period. So the ending period of the planning horizon is very close.

Q Was Seminole's self-build option evaluated in accordance with this criterion, with the present worth revenue requirements criterion?

A Yes, it was, although the only portion of that present worth of revenue requirements that was evaluated was the fixed cost, because we assumed, again, that fuel

would be the same as it would be for the Calpine Osprey unit.

Q Did Seminole evaluate the RFP respondents in the Calpine project in accordance with this criterion?

A Yes, we did.

Q At Page 15, Lines 17 through 18 of your testimony, you state that Calpine was the most cost-effective proposal when viewed on a five-year basis. Isn't it customary for utilities to evaluate revenue requirement impacts over a longer term such as 20 or 30 years?

A Yes, historically that was true. However, in the current environment, the -- many utilities, including Seminole, are looking at much shorter planning horizons and evaluating options that give us more flexibility than you would have with a 20- or 30-year long-range plan.

Q Table 11 at Page 29 of the revised need study contains the PWRR savings of the Calpine Project compared to other bidders and the Seminole self-build option. Did Seminole perform an annual PWRR analysis of these projects broken out by capital, O&M, and fuel costs?

MR. McGLOTHLIN: What was your page reference again?

MS. ISAAC: Page 29, Table 11 of the revised need study.

A Yes, we did.

Q Is this analysis considered to be confidential?

A Yes, it is.

Q We would like to ask for you to file this as a late-filed deposition exhibit entitled, "Present Worth Revenue Requirements Analysis of Self-Build Option and Alternatives."

A We'll be glad to do that.

Q Thank you.

MR. McGLOTHLIN: And we will assert the confidentiality at the time we provide it.

(Late-Filed Deposition Exhibit 1 identified.)

MS. ISAAC: Okay. When can you get this to us?

MR. McGLOTHLIN: When can we get that to them?

THE WITNESS: Probably -- I was going to say tomorrow, but I better say Monday.

MS. ISAAC: Okay.

MR. LaVIA: What was the title of the exhibit going to be?

MS. ISAAC: Late-Filed Exhibit, "Present Worth Revenue Requirements Analysis of Self-Build Option and Alternatives."

THE WITNESS: Yeah, I can -- we will provide that no later than Monday.

MS. ISAAC: Sure.

BY MS. ISAAC:

Q Okay. The note just below Table 11 on Page 29 states that the above self-build cost assumes that the capacity not needed by Seminole could be sold for the time period not needed. What does this mean, and how does it impact the cost-effectiveness of the Calpine Project?

A To be able to compare the self-build option on a megawatt-for-megawatt basis, we assume that the capacity over and above the 350 megawatts in the self-build would be sold so that we would not have to pay the carrying costs on that addition capacity because that would penalize the self-build option when compared to the short-term offerings of the other bidders.

Q On Page 10 of your direct testimony, you stated that Seminole received 14 responses to its RFP. How many responses did not include natural gas as the primary fuel for the given technology?

A Okay. The 14 proposals included both the peaking and intermediate. The intermediate capacity proposals were all gas-fired, and I believe that the majority of the peaking proposals were gas-fired, although I believe one was a system purchase which did not specify.

Q On Page 34 of Volume 1 of Seminole's exhibits to its amended need petition, Seminole has forecasted natural gas prices to rise from $2.573 in 2004 to $2.898 in 2009.

How high would forecasted natural gas prices need to rise before Seminole chose an option other than the purchased power agreement with Calpine?

A Since all of the offerings in the RFP were natural gas-fired, the -- an increase in gas prices, no matter how high, would not change the decision as far as either one of the other proposals or the self-build option.

The only thing that might -- there would be a crossover between gas prices and coal at some point, but coal is not an option because -- coal or nuclear or any other type of base load unit would not be an option because of a much longer lead time to build a large base load unit. Those units still require seven-plus years to permit, engineer, construct, and build, and start-up.

MS. ISAAC: Thank you.

THE WITNESS: Thank you.

MR. McGLOTHLIN: Jay, do you have any questions?

MR. LaVIA: No questions.

MR. McGLOTHLIN: I may have a very few.

MS. ISAAC: Okay.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Zimmerman, in response to some of Staff's questions, you refer to some of Seminole's load as being

"fully reserved" by the supplier. Would you elaborate on what you meant by that term?

A Yes. "Fully reserved" means that the capacity is 100 percent available to Seminole, and therefore, Seminole does not need to carry its own reserves for that capacity.

Q Would it be either reasonable or appropriate for Seminole to supply reserves for that same capacity?

A No, it would not. To carry our own reserves would be to carry additional reserves that are not required.

Q You were asked to explain why it was reasonable on your part to assume that fuel costs and transportation of fuel costs for the self-build option would be the same as Calpine's, and I believe you referred to the fact that the self-build option is a gas-fired, combined cycle unit. Is that a consideration that bears on the reasonableness of your assumption?

A Yes, yes.

Q Can you explain why?

A The self-build gas-fired, combined cycle units would have a very similar fuel and fuel transportation requirement to the Calpine offering. That's why we considered fuel and fuel transportation to be a wash between the two options.

Q Compared to the Calpine unit, what size unit would you select as a self-build option?

A It would be almost an identical unit, the same -- nominally the same megawatt size.

Q And what about the relative efficiency or acute rate?

A It would be identical.

Q Would that also bear on the reasonableness of the assumption that the costs would be the same?

A Yes, it would.

Q In response to another question, you indicated that Seminole and other utilities are beginning to look at flexibility and shorter term options because of what you refer to as the current environment. What did you mean when you said "current environment"?

A The -- by the term "current environment," I meant the uncertainty in the future of the regulation of electric utilities pending deregulation of the wholesale market, the fact that there has been a reluctance for sometime to build additional capacity. We've had very tight times, particularly during the summer periods, of available capacity within the State. Also, with the RTO that's being formed, there are certain ICE requirements, installed capacity and energy requirements, that have some level of uncertainty as far as the capacity that's going

to be required in the future. And all of these lead us to want to have some options available in the near term.

Q Are suppliers also beginning to formulate their proposals and their offers in terms of periods of time that are shorter than traditionally --

A That's very true. We had more short-term proposals than we had long-term. The majority of our proposals were five-year terms. I think we had one that was a ten-year term. We didn't have any proposals for longer than ten years.

Q If you are evaluating a contract that has a reopener provision that gives each party the right to renegotiate, is it feasible to perform present worth revenue requirements analysis that extends beyond that reopener?

A The -- I would say no, because you have to make certain assumptions on what the market will be. And so the present worth of revenue requirements beyond the reopener simply are our best guess of what market conditions will be. And that would be the same numbers that would be in the base case that we would compare it to. And so the present worth of revenue requirements for our comparison case and for the case with -- beyond the reopener would have zero difference in present worth of revenues requirements.

Q You were asked whether there is a price at which Seminole would look at an option other than the Calpine unit, and you referred to the longer lead times associated with a coal unit, I believe you said seven years. When does Seminole require additional capacity to maintain reliability?

A We require the additional capacity to meet our reliability criteria beginning in the summer of 2004.

Q That being the case, is a coal unit an option for Seminole?

A No, it's not, not for this need.

Q And my last question is simply a clarification. You were asked to explain the calculation of a reserve margin, and you identified certain values as a numerator, and then you proceeded to talk about others, but I don't think you ever used the word "denominator." Would you --

A The denominator was the other number that I referred to that included the firm obligation minus the FPC capacity that is fully reserved.

MR. McGLOTHLIN: Those are all of our questions.

MS. ISAAC: Can I ask one more question?

MR. McGLOTHLIN: Certainly.

REDIRECT EXAMINATION

BY MS. ISAAC:

Q This leads into one of your cross questions.

Not including the lead time for a coal unit, what would the price of gas need to be in order for a coal unit to be cost-effective?

A I don't have that number right in front of me, but I can provide that.

Q Can you give us an estimate?

MR. McGLOTHLIN: Let's go off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q Regarding the last question, can you provide a late-filed exhibit on what you believe the price of gas would need to be in order for a coal unit to be cost-effective?

A Yes, I can.

MS. ISAAC: Thank you.

(Late-Filed Deposition Exhibit 2 identified.)

MR. McGLOTHLIN: I'd like to say for the record that Seminole will provide the late-filed exhibit, but we want to note a couple of caveats. One being that Seminole has determined that the cogen isn't optional -- not an option because of the lead time and the fact that Seminole requires a capacity in 2004. The other being that Seminole has based its evaluation on its in-house professional fuel forecasts, and those forecasts indicate to Seminole that over the longer term, the price of gas

will trim back toward the underlying fundamentals. With those caveats, we will provide the information.

MS. ISAAC: Thank you.

(Deposition concluded at 10:05 a.m.)

- - - - -

ERRATA SHEET

DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 001748-EC
NAME: GARL S. ZIMMERMAN
DATE: JANUARY 25, 2001

Page	Line	Change

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

DATE:_____ _____
GARL S. ZIMMERMAN

FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that GARL S. ZIMMERMAN personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 29th day of January, 2001.

Tricia DeMarte

TRICIA DeMARTE
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition of GARL S. ZIMMERMAN.

I FURTHER CERTIFY that this transcript, consisting of 30 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 29th day of January, 2001.

Tricia DeMarte

TRICIA DeMARTE
Official FPSC Reporter
(850) 413-6736

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 001748-EC

In the Matter of

PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

_____/

ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE A CONVENIENCE COPY ONLY AND ARE NOT THE OFFICIAL TRANSCRIPT OF THE HEARING AND DO NOT INCLUDE PREFILED TESTIMONY.

DEPOSITION OF:	**TIMOTHY S. WOODBURY**
TAKEN AT THE INSTANCE OF:	**The Staff of the Florida Public Service Commission**
PLACE:	**Gerald L. Gunter Building Room 362 2540 Shumard Oak Boulevard Tallahassee, Florida**
TIME:	**Commenced at 10:10 a.m. Concluded at 11:45 a.m.**
DATE:	**Thursday, January 25, 2001**
REPORTED BY:	**TRICIA DEMARTE Official FPSC Reporter**

APPEARANCES:

JOHN R. LaVIA, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of Calpine Construction Finance Company, L.P.

JOSEPH A. McGLOTHLIN, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Seminole Electric Cooperative, Inc.

RACHAEL N. ISAAC, FPSC Division of Legal Service, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Commission Staff.

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STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure;

that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

MS. ISAAC: Before we take appearances, I want to go on the record and excuse Robert Woodall from the deposition.

Okay. We'll go ahead and start this deposition. We'll now take appearances.

MR. McGLOTHLIN: Joe McGlothlin for Seminole Electric Cooperative, Inc.

MR. LaVIA: Jay LaVia for Calpine.

MS. ISAAC: Rachael Isaac for Commission Staff. Do all the parties agree to the regular stipulations?

MR. McGLOTHLIN: Mr. Woodbury will read and sign his deposition; otherwise, we'll stipulate.

MR. LaVIA: We stipulate.

MS. ISAAC: Could the court reporter please swear in the witness at this time.

TIMOTHY S. WOODBURY

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MS. ISAAC:

Q Good morning, Mr. Woodbury. I'm Rachael Isaac with the Florida Public Service Commission. I'm taking your deposition on behalf of the Commission Staff in Docket Number 001748-EC. If you need me to restate a

question or you don't understand a question, please let me know, and I'll either restate the question or try to rephrase it for you. I also ask that you answer with a "yes" or a "no" before you explain your answer.

Please state your full name for the record.

A Timothy S. Woodbury.

Q By whom are you employed?

A Seminole Electric Cooperative, Inc.

Q What is your position with your employer?

A Vice president of strategic services.

Q What does the position entail?

A I'm responsible for rate design development, strategic planning, power marketing, load forecasting, acquisition, and administration of purchased power and transmission contracts.

Q On whose behalf are you testifying in this proceeding?

A Seminole Electric's.

Q Did you file any testimony in Docket Number 001748?

A Yes, I did.

Q Was it direct or rebuttal?

A Direct.

Q Did you also file any exhibits?

A Yes, I did.

Q Could you please list those exhibits.

A Exhibit Number TSW-1 is Seminole Member Distribution Cooperatives. It's essentially a map of our Member systems service territories.

Exhibit Number TSW-2, revised, is Seminole year-round purchased power resources and Seminole seasonal purchased power resources.

Q What is the purpose of your testimony that you have given in your prefiled testimony?

A First, my testimony is to give an overview of Seminole, to discuss the Calpine contract, to describe its strategic advantages all in support of our joint application to receive a favorable determination of need on the Osprey Project.

Q Calpine has testified that the expected in-service date of the Osprey unit is June 2003. Could you describe Seminole's rights to the capacity and energy from the Osprey unit from the in-service date until June 2004?

A Yes. Seminole's rights under the contract will be to -- we could, if we decided to, call on that output, the full output of the unit, up to the full output of the unit, during that calendar year under terms -- under that not calendar year, but under that 12-month period during -- under the terms that are described in the

agreement.

Q Would the pricing during this time be the same as after the June 2004 date?

A Yes.

Q Does Seminole have a first right of refusal option on the capacity prior to the June 2004 contract date for firm capacity and energy?

A So that we're making sure that we're talking to each other properly, I want to make sure, the right of first refusal, I just want to make sure I understand what you're saying when you say it.

Q The right of first refusal, I'm saying that before Calpine can sell it to somebody else, they have to ask Seminole, and you have to refuse it.

A They do not have to offer to us anything that they might be offering to somebody else to sell the output during that period of time.

Q In your opinion, how does this year prior to Calpine's firm commitment with Seminole mesh with the Supreme Court's requirement in the Duke case that capacity be fully committed to retail-serving entities?

MR. McGLOTHLIN: I'll object to the extent that calls for a legal conduction. To the extent that Mr. Woodbury as a layperson involved in the industry can describe how what he does interfaces with that, he can

answer.

MS. ISAAC: Okay.

A With that caveat, my view is, is that the output of the plant being available to us under the option that we have under the agreement just provides us with significant flexibility in an uncertain period of time. So our general conclusion is, is that the Supreme Court was not attempting to prevent such optionality in those kinds of contracts, and we've established a firm need starting in the year 2004.

The fact that the unit is going to go in service or hopefully will go in service before that period of time does not in our way -- is not in our way -- in our view inconsistent with the Supreme Court's decision.

Q After the June 2004 contract date, Seminole has rights to 350 megawatts on a firm basis; correct?

A That's correct.

Q And the capacity of the plant is 529 megawatts; correct?

A That's correct. Let me -- just before I correct -- agree with that too quickly.

Q Okay.

A I believe the summer rating on that unit is more in the neighborhood of 480-something megawatts, and the winter rating was closer to the number that you mentioned.

Q Okay. Can you describe Seminole's rights to the remaining capacity of the plant from 2004 to 2009?

A Seminole's rights to the remaining output of the plant are provided for in the agreement under --

MR. McGLOTHLIN: Before we answer, the remaining output, are you referring to the difference between the 350 and the total maximum?

MS. ISAAC: Yes.

A -- provided in Section 16 of the contract. And essentially what Seminole can do with a six months' notice under that section is to notify Calpine that it wishes to acquire the additional amount of output from the unit that's available to it if Calpine has not otherwise already sold that capacity to another party.

Q Calpine's Witness Eves testified that Seminole can purchase the remaining output of Calpine's proposed unit above 350 megawatts to the extent that this additional capacity has not been firmly committed to other Florida load-serving utilities. Does this contract provision give Seminole some sort of special status above any other utility wishing to buy firm capacity from Calpine's proposed unit?

A There's a provision in this contract that I think has been already -- has been identified as being as part of the confidential provisions, and that in order for

me to answer that question, I probably would have to just address that provision.

MR. McGLOTHLIN: Let's go off the record a second.

MS. ISAAC: Okay.

(Discussion off the record.)

BY MS. ISAAC:

Q I'm going to repeat the question regarding the purchase of the remaining output of Calpine's proposed unit above 350 megawatts. Does the contract provision regarding this give Seminole some sort of special status above any other utility wishing to buy firm capacity from Calpine's proposed unit?

A Yes. By special status we can say that it does in the sense that the contract terms have already been negotiated, that the pricing is already in place, and that Seminole has the right to simply call on the output at those defined terms and conditions and prices in one-year block extensions.

Q Does Seminole currently plan to purchase any of this remaining capacity?

A We, at this point, haven't decided that definitively, but my personal expectation is, is that there is a very good likelihood that Seminole will be leaning in that direction. It's a very attractive

arrangement, and we will consider it as being one of our superior options.

Q When you say "superior," are you saying that there are benefits to Seminole of having this capacity available?

A I think the pricing that we've got is extremely favorable, and the optionality that we got in the contract provides us with significant strategic advantages.

Q Would Seminole be taking the extra capacity from Calpine to reduce what they are receiving from FPC's partial requirements contract?

A Not necessarily. We may be doing it, retaining the FPC intermediate, as well as acquiring the additional amounts. We are looking at our reserve margin requirements that we think that there's enough room to accommodate both.

Q In your opinion, if Seminole does not contract for the excess capacity from the proposed unit, do you believe that Calpine's proposed unit is fully committed as defined in the Florida Supreme Court's Duke case?

MR. McGLOTHLIN: Same objection as earlier and same caveat.

A Yes, I do. It seems to me that if we didn't have the Calpine arrangement, Seminole would be here before you with a 500-megawatt vintage, combined cycle

unit to meet our needs. There is no need to rely on some unspecified third party for some unspecified need to justify this 500-megawatt project.

Seminole's need, even though we have only contracted initially for 350 megawatts, you can see our capacity needs grow rather quickly. And that if we didn't have Calpine making this offer, we would likely be here with a 500-megawatt, combined cycle unit at the same time. So this is why I believe that this project is completely consistent with the Supreme Court's order -- decision.

Q After May of 2009, the contract provides for Calpine to continue providing 350-megawatts firm to Seminole through May 31st, 2020. Can you explain the contract language that allows either party to opt out of the contract on a five-year basis?

A I want to be careful on the opting out of the contract. I think we're, again, referring to the reopener provision in Section 16. That provision obligates both parties to negotiate in good faith to reach an accommodation to attempt to effectively rebenchmark this contract back to market to the extent it needs any rebenching -- rebenchmarking.

Now, Seminole -- from Seminole's perspective, it does have the right to decide that it doesn't want to move forward with the contract, but this provision seems to

provide us with a prudent amount of flexibility to be able to react to changes in a marketplace that is extremely dynamic right now. So at this juncture, that option having that flexibility is a strategic advantage to us.

Q On Page 31, Section 16 of the purchased power agreement, it discusses the contract reopener. The contract states that if a continuation is not executed by July 31st, 2005, each party has 60 days from the written notice of the seller to terminate the contract as of May 31st, 2009; correct?

A That's correct.

Q If neither party chooses to terminate the contract and it continues beyond May 2009, will the terms and conditions of the contract, in particular the pricing and capacity terms, remain the same as currently written?

A If neither party chooses to terminate, will it continue in effect under those terms? The answer would be yes.

Q Under the reopener provision, if both parties choose not to terminate the contract, must the contract continue in five-year increments, or could the parties continue beyond 2009 for less than five years?

A I think the contract contemplates that it would be extended in five-year increments, but the parties would be free, I think, to negotiate any modification to that

that they would decide would be in their best interest at that juncture, but I believe that the contract does contemplate that we would attempt to do this every five years.

Q In your opinion, if Seminole or Calpine opt not to extend the contract beyond the initial five-year term, do you believe that Calpine's proposed unit is fully committed as defined in the Florida Supreme Court's Duke New Smyrna Beach case?

MR. McGLOTHLIN: Same objection, same caveat. I would like to have the question read again, please.

MS. ISAAC: Sure.

BY MS. ISAAC:

Q In your opinion, if Seminole or Calpine opt not to extend the contract beyond the initial five-year term, do you believe that Calpine's proposed unit is fully committed as defined in the Florida Supreme Court's order in the Duke New Smyrna Beach case?

A Yes. I don't see anything in that Supreme Court decision that suggests anything with regard to the term of the arrangement that might be entered into. At the time we are seeking the need, this unit will be fully committed to Seminole.

Q What rights does Seminole have to the capacity over 350 megawatts from the period of May 2009 to

May 2020?

A From May 31st, 2009 through 2020. Basically, again, those rights are provided for in Section 16, the reopener, which provides that the parties will sit down and attempt to negotiate any modifications to the agreement that either party deems necessary for continuance of the agreement that will be done in five-year increments.

Q To clarify what I was asking, are the rights from 2009, May 2009 to May 2020 the same as the rights Seminole has to the capacity from May 2004 to 2009?

MR. McGLOTHLIN: If I understand correctly, in essence, you're asking, what are Seminole's rights to capacity presently under the terms and conditions that exist now?

MS. ISAAC: Presently for that period.

MR. McGLOTHLIN: Okay.

A Well, I'm trying to best figure out how to answer that. For that period of time, you know, in advance of May 2009 by July 31st of 2005, the parties are going to negotiate the terms for the extended period, and that could involve pricing, or it could involve other changes to the contract provisions as they are currently identified. So at this point, I can't tell you definitively what the terms and conditions will be for the

extended period.

MR. McGLOTHLIN: Let's go off the record a second.

(Discussion off the record.)

BY MS. ISAAC:

Q If the terms and conditions remain the same as the terms and conditions are stated in the contract currently, what rights does Seminole have to the capacity over 350 for the period after 2009?

A The rights would remain equivalent to those that exist prior to 2009, and that is that Seminole could upon six months' notice call on the full amount of the capability of the unit in one-year increments.

Q Would you characterize Seminole's right to the capacity over 350 megawatts from the period of May 2009 to May 2020 as a first right of refusal?

A Using that definition that you articulated earlier, the answer would be no for the same reason that I gave you earlier.

Q Do you believe that the need order Seminole and Calpine are requesting as co-applicants is specific to the Osprey Energy Center?

A Yes, I do.

Q How would Seminole be affected if the in-service date of the Osprey unit is delayed?

A Delayed beyond what period?

Q It's delayed beyond the -- delayed beyond May 2004 when the capacity is supposed to be coming --

MR. LaVIA: Can you repeat the question?

Q How would Seminole be affected if the in-service date of the Osprey unit is delayed beyond May 2004.

MR. LaVIA: That may call for a response that gets into some of the confidential parts of the PPA, but if you can answer it without --

MR. McGLOTHLIN: Let's go off the record for a second.

(Discussion off the record.)

BY MS. ISAAC:

Q Let me repeat the question. How would Seminole be affected if the in-service date of the Osprey unit is delayed beyond May 2004?

A If the in-service date is delayed beyond that period, it would have an adverse effect on Seminole's reserve requirements and could have an adverse effect on our Member systems reliability.

Q Has Seminole estimated the financial impact of a delay in the in-service date?

MR. McGLOTHLIN: Let's go off the record.

(Discussion off the record.)

BY MS. ISAAC:

Q To repeat and get a clarification on this question, has Seminole estimated the financial impact of a delay in the in-service date -- or the date, May 2004?

A The contract that we have with Calpine provides, from Seminole's perspective, adequate financial protection for any reasonable delay. Although, there could be -- you know, there could be, obviously as I indicated, I think, earlier, in my earlier answer, that there could be adverse reliability impacts to the organization for any delay in in-service date.

Q Would Seminole be affected if the in-service date of the Osprey unit is delayed beyond June 2003?

A Not financially, not from a reliability perspective that based on the current conditions, but if conditions change, which they inevitably do, we would much rather see that unit in service earlier rather than later.

Q On Page 4 of your testimony, Lines 7 through 9, you state that the wholesale power contracts between Seminole and its Members expire in May 2020. If these contracts are not continued beyond May 2020, is Seminole then a free agent?

A What do you mean by "free agent"?

Q Can they go out and -- do they have to still supply their Members?

A The Member systems' obligations to serve their

consumers would not be impacted by Seminole's contract with the Members. What would happen, to the extent that the Member systems did not extend Seminole's contract would mean that the Member systems, who are the owners of Seminole, would have control of whatever assets were in place at that time and would be able to dispose of them or utilize them as they wish without the Seminole organization.

And I'm not a lawyer, and I don't know all the ramifications of how they would have to deal with that, but that's my layperson's response.

Q Do you expect these contracts to be continued beyond May 2020?

MR. McGLOTHLIN: Which contracts?

MS. ISAAC: The contracts between Seminole and its Members.

A I can't say at this point.

Q In your opinion, do you believe that the fact that the contracts with Seminole's Members expire in 2020 has any bearing on the requirement in the Supreme Court's Duke order that the capacity be fully committed?

A No.

Q On Page 6 of your testimony, you discuss Seminole -- the Seminole Board of Trustees. Do the terms of the Board members also expire in 2020?

A The contracts with Seminole's Members, the arrangements with Seminole's Members provide that each Member is going to have representation on Seminole's Board. Each Member essentially has two voting trustees and one nonvoting trustee. That will -- the terms of the individual people that serve on our Board is really a function, I believe, of our -- each Member system has a different rotation policy. So the individuals themselves, it's really a function of the Member systems' policies.

The representation on our Board that each Member has will stay the same throughout the term of our contract unless our bylaws are otherwise changed pursuant to the manner in which those bylaws can be changed.

Q Seminole is not currently a FEECA utility; correct?

A That's correct.

Q In your opinion, does this have any bearing on Seminole's ability to obtain a need determination under the Supreme Court decision in the Duke case?

MR. McGLOTHLIN: Same objection as earlier, but you can answer.

A No.

Q Why not?

A Well, as I indicated earlier, the Member systems are owned by their retail consumers, and Seminole is owned

by its Member systems. So as I see it, the retail needs when Seminole is here before you seeking a need, we are effectively representing the retail consumers throughout the State who are purchasing their power from the organizations that they own are Member distribution cooperatives.

Q On Page 9 of your testimony, you discuss Seminole's contract with Tampa Electric Company for 295 megawatts on a first call basis from the Hardee Power Station. How much of this capacity has Seminole taken on a historical basis?

A This is on Page 9, Lines 6 where I say, "Under this contract, Seminole has first call on 295-megawatts of capacity from Hardee," is that the question?

Q Yes.

MR. McGLOTHLIN: I have a clarification request. When you say "how much is taken," are you talking in terms of the frequency or the number of megawatts or both?

MS. ISAAC: The number of megawatts.

A I was going to answer that on capacity because that's easier for me to answer. We have always taken the capacity. In other words, the capacity is there and available to us. I couldn't answer without having to check some other records as to how much energy we have taken out of the facility.

Q Can you give a rough estimate?

A Of the amount of energy?

Q Of the capacity.

A The capacity is the 295, and that's available to us all the time.

Q Of the energy.

A No, but we can easily provide that information to you.

MR. McGLOTHLIN: Let's go off the record for a second.

(Discussion off the record.)

BY MS. ISAAC:

Q To repeat the question or to clarify, can you give me an estimate of how much energy Seminole has taken on a historical basis from the Hardee Power Station?

A Yes, I do have available the amount of megawatt hours we purchased from Hardee Power Partners for the year 2000. And for the combined cycle component, which is 220 megawatts of that 295, we took roughly 180,000-megawatt hours. For the peaker, which is roughly 75 megawatts, we took roughly 20,000-megawatt hours.

Q On Page 11 of your testimony, you discuss the strategic advantages of the contract with Calpine. You state on Lines 16 through 19 that the reopener provision of the contract offers Seminole a valuable advantage over

a self-build option. Would you please elaborate on this advantage.

A Well, the advantage that a reopener provision provides to you as compared to a self-build option is that the self-build option is effectively a 30-year commitment to a particular asset, and that commitment entails being obligated to provide for the fixed costs associated with that asset for the life of the facility.

What purchased power contracts with reopener provisions such as the Calpine contract provides us is the flexibility to not have to make that kind of a long-term commitment to a particular asset in a changing world. So from that perspective, it provides us with strategic advantages.

Q On Page 12 of your testimony, you state that under the contract with Calpine, Seminole may resell energy from the Osprey Project. Are there any limitations according to the contract on the amount of energy which may be purchased by Seminole for the purpose of resale?

A As to the amounts that we have contracted -- for the 350, there is no restriction on our ability to resell. And to the extent we acquire any of the reserve firm capacity, there would be no restrictions on our ability to resell the additional amounts we might acquire.

Q And the next group of questions goes to the

RFPs. How much were bidders charged to submit a project in response to Seminole's request for proposal?

MR. LaVIA: Can we go off the record a second?

MS. ISAAC: Yes.

(Discussion off the record.)

A Seminole required each bidder to pay a nonrefundable application fee of $500.

Q In your experience, is this amount in line with the RFP fees charged by other Florida utilities in the recent past?

A I've really not undertaken any analysis of what others charge.

Q Did each respondent's RFP fee cover the entire cost for Seminole to evaluate the bid?

A I would say no.

Q On average, what was Seminole's cost to evaluate a bid response to the RFP?

A I have not done any study to analyze what it cost us to evaluate the RFPs, if that was the question.

I should just say that our objective is to not -- this is not a profit center for the company, and we're simply trying to make some nominal requirement that discourages people from making completely frivolous proposals, but our objective is not to make it even a cost recovery mechanism. My guess, if I had to make one is, is

that others probably charge more.

Q What was charged per bid when the first Hardee plant was built?

A I don't have that information available. We could provide it to you.

Q That's all right. When did Seminole issue its RFP?

A July 6th of 2000.

Q Was the Calpine offer received in response to Seminole's RFP?

A I believe Calpine -- we were already in negotiations with Calpine prior to the issuance of the RFP. But I should clarify that we indicated that to the prospective bidders that anybody that we were involved in negotiations would not have to resubmit a bid, but that it would be deemed as having been a response to the bid.

Q When did negotiations begin with Calpine relative to the RFP issue date?

A I'd have to check my files on that to give you a definitive answer.

MS. ISAAC: Okay. That was my last question. Thank you.

MR. McGLOTHLIN: Jay?

MR. LaVIA: I don't have any questions.

MS. ISAAC: One more question, I'm sorry, or a

request. Can we please, as a late-filed, have the correspondence between Calpine and Seminole before the RFP issue date.

MR. McGLOTHLIN: Clarification, is that all correspondence or correspondence on a particular subject?

MS. ISAAC: Any correspondence that dealt with the development of this contract.

THE WITNESS: The one thing I want a clarification on is this: If there were correspondence, they likely involve exchanges of negotiating material. In other words, the parties were already negotiating a contract. I don't know at what level we were at in the Memorandum of Understanding at that point in time. I would assume that both parties would consider any exchanges of memorandum drafts as being confidential. So the cover letters associated with, you know, exchanges to show that there was an action going on, if that's sufficient.

MS. ISAAC: You can file a request of confidentiality with that, and we'll -- we just want to look at it, and we may not even have to rule on the confidentiality. We could return it to you.

MR. McGLOTHLIN: Okay. And just for the record, we will assert the claim of confidentiality at this point to the extent we find it applies when we review the

correspondence and submit it accordingly.

MS. ISAAC: Okay.

MR. LaVIA: Just another point of clarification. All correspondence back and forth, so you're asking for Calpine's correspondence too?

MS. ISAAC: Yes, please.

MR. LaVIA: He may not have everything. I don't know if he kept -- he might have kept copies of everything he sent, I assume.

MS. ISAAC: Do you have copies of what you sent and what you received?

THE WITNESS: I wouldn't ever say that it was everything, but I'll show you what we've got.

MS. ISAAC: Okay. That's fine.

MR. LaVIA: So we have no obligation to supplement at this point.

MS. ISAAC: No. That's fine.

MR. McGLOTHLIN: And this is prior to the issuance of the RFP?

MS. ISAAC: Correct.

MR. McGLOTHLIN: Okay.

(Late-Filed Deposition Exhibit 1 identified.)

MS. ISAAC: Thank you.

CROSS EXAMINATION

BY MR. McGLOTHLIN:

Q Mr. Woodbury, in response to a question from Staff Counsel, you said that Seminole would have -- under the PPA, Seminole would have rights to the capacity from Osprey that exceeds the 350 firm capacity to the extent that Calpine hasn't already sold it to another party. Is it just any sale to another party that would overrule Seminole's rights to that capacity or on certain kinds of sales?

A It would be firm sales to another party.

Q You also said in response to another question that if it were not for Calpine, the availability of Calpine's Osprey Project, Seminole would be here at the PSC with a similar 500-megawatt plant. Would you explain further what you meant by that statement?

A Yes. Seminole's needs initially start out at the 350-megawatt level that we have talked about. You can see from some of the exhibits that Mr. Zimmerman has submitted that those needs grow quickly, and that within a few short years, we're looking at the full capability in terms of needs.

If Seminole were to -- didn't have Calpine as an option, we would not be coming in here for a 350-megawatt, combined cycle unit. These units are not -- you can't split them up into convenient megawatt quantities to fit your exact needs each year. We would be coming in with a

500-megawatt vintage type of combined cycle unit, and we would be looking to sell the excess capability to the extent we decided it was in our Members' best interest to do that until the need grew. So that's the clarification.

Q All right. Assuming that your need is 350 megawatts, would it be even possible to construct a combined cycle unit of precisely 350 megawatts?

A No.

Q Would it be a smart thing to do? Given the dynamics over time, would it be a smart thing to do even if it were possible?

A No. I think the economies of scale would suggest that you are better served by putting in the 500-megawatt unit, selling the extra power in the marketplace, and growing into the facility. Now, I would say that if I were coming in for a 30-megawatt need, I would not be proposing a 500-megawatt facility to meet that need, but a 350-megawatt need, I would be quite reasonable in looking for a 500-megawatt unit.

Q Staff asked if Seminole has a right of first refusal with respect to the balance of the capacity above 350. In your view, is it necessary for Seminole to have a right of first refusal in order to enjoy the benefits of the commitment of that capacity under the contract?

A No.

Q You were asked about the period of time prior to the date in 2004 when Seminole needs the firm capacity for reliability. Assume that the Osprey unit comes on-line in June of 2003. At that point, under the terms of the PPA, how much of the capacity and energy of that unit by contract is available to Seminole?

A Up to the full amount.

Q Do you think that fact bears on whether the unit is being committed to Seminole?

A I believe it's consistent with the notion that it is committed to Seminole.

Q You were asked some questions regarding Seminole's ability to buy from the Osprey Project and to resell to customers other than its Members. If Seminole were to exercise that right under the contract, how will those off-system sales affect your customers, your Member customers?

A Being that Seminole is a nonprofit organization, it would serve to lower their overall revenue requirement, and it would lower their power cost.

Q Would that make their cost of electricity more reasonable than would otherwise be the case?

A We believe they are already reasonable, but more reasonable, yes.

Q There was a question and answer during which you referred to the provisions in the contract as they relate to the pricing of the firm capacity and the optional capacity, and I believe during a conversation off the record you indicated that you misspoke. Did you intend to address the specifics of the pricing provisions as they relate to the firm and nonfirm capacity or simply the existance of a contract of terms that address that?

A I was intending to say that the terms and conditions relative to those -- the firm piece as well as the reserve firm piece are already established and defined in the contracts. And I should clarify that with the limited exception that there is a distinction on the dollar per kW charge as between the two. All other terms and conditions, I believe, are consistent with each other.

MR. McGLOTHLIN: Those are all the questions I have.

MR. LaVIA: No follow-up.

MS. ISAAC: Thank you.

(Discussion off the record.)

MS. ISAAC: To clarify the request before for the correspondence leading up to the MOU -- or no, the RFP, before the RFP, we want the correspondence between Seminole and Calpine, but you can redact that correspondence to omit any confidential information.

MR. McGLOTHLIN: All right. And is that the first exhibit that was requested of Mr. Woodbury? Do you want to number them?

MS. ISAAC: That was the first.

MR. McGLOTHLIN: Okay. That will be Late-Filed Number 1.

MS. ISAAC: Yes.

MR. McGLOTHLIN: Okay.

MS. ISAAC: Thank you.

(Deposition concluded at 11:45 a.m.)

- - - - -

ERRATA SHEET

DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 001748-EC
NAME: TIMOTHY S. WOODBURY
DATE: JANUARY 25, 2001

Page	Line	Change

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

DATE:_____ _____

TIMOTHY S. WOODBURY

FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that TIMOTHY S. WOODBURY personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 29th day of January, 2001.

Tricia DeMarte

TRICIA DeMARTE
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition of TIMOTHY S. WOODBURY.

I FURTHER CERTIFY that this transcript, consisting of 33 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 29th day of January, 2001.

Tricia DeMarte

TRICIA DeMARTE
Official FPSC Reporter
(850) 413-6736

CONFIDENTIAL

FPSC Docket No. 1748-EC
Deposition of Garl Zimmerman
Late Filed Exhibit 1 - Page 1 of 2

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Data Detail for Table 11 "Calpine Osprey: Savings (PVRR) when compared to:"
($ X 1000)

	TOTAL	2004	2005	2006	2007	2008
STUDY #1 Calpine (350 MW)						
Fixed Costs	$	$	$	$	$	
Variable Cos	$	$	$	$	$	
********* Total Costs	$	$	$	$	$	
Bidder 2						
Fixed Costs	$	$	$	$	$	
Variable Cos	$	$	$	$	$	
********* Total Costs	$	$	$	$	$	
Difference						
Fixed Costs	$	$	$	$	$	
Variable Cos	$	$	$	$	$	
Total Costs	$	$	$	$	$	
$ x 100	$	$	$	$	$	
STUDY #2 Calpine (100 MW)						
Fixed Costs	$	$	$	$	$	
Variable Cos	$	$	$	$	$	
********* Total Costs	$	$	$	$	$	
Bidder 3						
Fixed Costs	$	$	$	$	$	
Variable Cos	$	$	$	$	$	
********* Total Costs	$	$	$	$	$	
Difference						
Fixed Costs	$	$	$	$	$	
Variable Cos	$	$	$	$	$	
FOR Total Costs	$	$	$	$	$	
350 MW						

		$ x 100	$	$	$	$
$	$					
	Bidder 4					
	Fixed Costs	$	$	$	$	$
$						
	Variable Cos	$	$	$	$	$
*********						
	Total Costs	$	$	$	$	$
*********						
	Difference					
	Fixed Costs	$	$	$	$	$
$						
	Variable Cos	$	$	$	$	$
$	FOR					
	Total Costs	$	$	$	$	$
$	350 MW					
	$ x 100	$	$	$	$	$
$	$					

STUDY #3 Self-build (350 MW)

Fixed Costs	$	$	$	$	$
$					
Variable Cos	$	$	$	$	$
*********					
Total Costs	$	$	$	$	$
*********					
Difference	$	$	$	$	$
$					
$ x 100	$	$	$	$	$
$					

Notes: Fixed costs
Variable costs
Discount rate
Outlined values correspond to Table 11 values.
The self-build option is compared to Calpine's costs in Study #1.

Florida Public Service Commission
Docket No. 001748-EC
Late-Filed Exhibit 2
To the Deposition of Garl Zimmerman

BREAKEVEN ANALYSIS - GAS vs. COAL

Assumptions:

1. New pulverized coal unit installed cost $1500.00/kW

2. Fixed Charge Rate for 17 year financing 11.61%

3. Pulverized coal O & M $1.92/kW/Mo based on Seminole Plant

4. Heat rates PC 10,000 BTU/kWh, Combined Cycle Heat Rate (Representative Value)

5. Breakeven analysis performed for capacity factor typical of Intermediate Operation.

6. High band coal forecast of $1.80/mmbtu

7. Combined Cycle cost from range of RFP process.

Total breakeven gas price, based on foregoing assumption:

$7.80/mmbtu

Important Notes:

1. While Seminole has performed the calculation requested by Staff during Mr. Zimmerman's deposition, a pulverized coal unit is not an option for Seminole. Seminole must add capacity by 2004 in order to maintain its minimum criterion of reliability; the lead time for a pulverized coal unit is seven years.

2. Based on its projection of fuel prices, Seminole's view is that the current very high prices for natural gas will return to the trend dictated by long term fundamentals by 2004. Accordingly, the hypothetical price generated by this breakpoint calculation is not meaningful to a determination of the most cost-effective option available to Seminole.

3. Movements in the price of one fuel affect the prices of alternative fuels. It would be

inappropriate to hypothesize extremely high prices for natural gas without taking those high prices into account when deciding which coal price to use in the analysis. For purposes of this exercise, Seminole used the high coal price scenario from its fuel forecast.

4. The value shown for the installed cost of a pulverized coal unit is an engineering estimate; detailed costing analyses were not performed for this calculation.

ADDITIONAL SCENARIO:BREAKEVEN GAS PRICE FOR GASIFIER

Assumptions:

1. Assumptions 2, 4, 5, 6, and 7 above are same.

2. Gasifier only installed costs: $1200.00/kW = $11.61/kW/Mo.

Analysis:

1. Additional gas fuel cost to equal gasifier fixed costs:

$11.61/Hours typical of Intermediate operation = ($/mmbtu)(Representative heat rate of combined cycle)

Using this methodology, and employing assumptions and values identical to those used in the calculation of the breakeven price of gas for a pulverized coal unit, the corresponding breakeven total cost of gas for a combined cycle unit with a gasifier would be

$7.56/mmbtu

Important Note: The caveats that Seminole noted on the calculation of the breakeven price of gas for a pulverized coal unit apply here. However, even if the price of gas were to rise to such levels, this calculation indicates that it would be more cost-effective to construct a combined cycle plant now and add a gasifier in that event than to build a pulverized coal unit.

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January 23, 2001

VIA HAND DELIVERY

Rachel Isaac
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No.: 001748- EC

Dear Rachel:

I am enclosing the information regarding recent gas price forecasts that Staff asked Seminole witness Bob Woodall to provide on an informal basis. His explanation of the material is attached with the forecast information.

I hope this meets Staff's needs. Please call me if you would like to discuss it further.

Sincerely,

Joseph A. McGlothlin

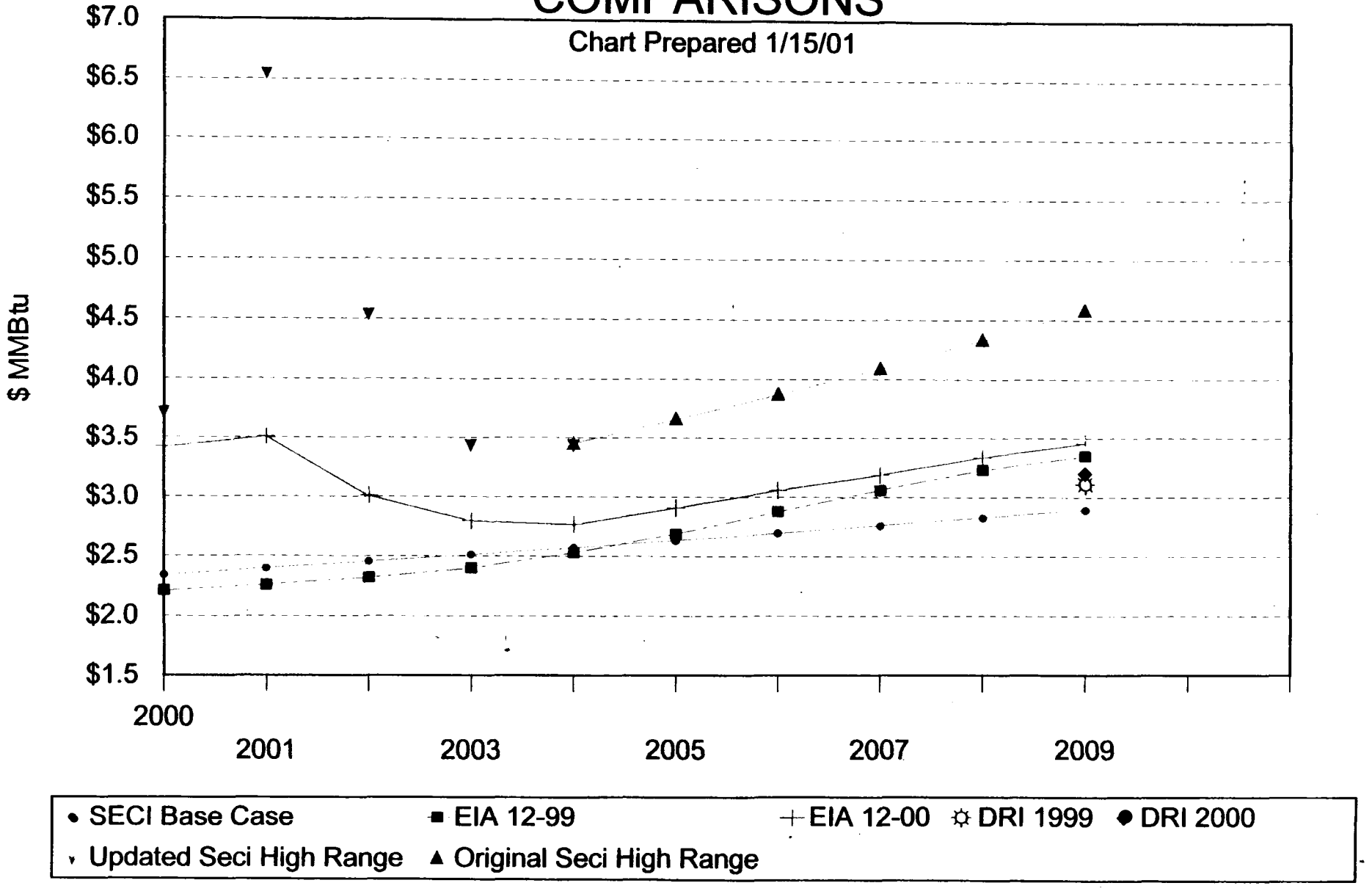
JAM/kmr
Enclosure
cc: Judy Harlow
Schef Wright
Bob Woodall
Tim Woodbury

Re: Docket No. 001748-EC-informal information request from Staff

At Staff's request, Bob Woodall plotted on a copy of his Exhibit __(RLW-3) the projected gas prices that appear on the most recent forecasts available from DRI and EIA. In addition, Mr. Woodall very recently prepared for Seminole a short-term revision of its high gas price scenario. That sensitivity is also shown on the overlay, which is attached.

The additional information shown on the attached graph does not alter Mr. Woodall's or Seminole's opinion regarding either the appropriateness of the forecasts that he prepared for use in evaluating generation alternatives or the conclusion that the Osprey project represents the most advantageous choice available to Seminole. Rather, the additional forecast information from EIA and DRI reinforces his view that the current high prices reflect a short-term excursion from the norm, and that over the longer term the fundamental trends reflected in his forecast will reestablish themselves.

WELLHEAD NATURAL GAS PRICE FORECAST COMPARISONS



CONFIDENTIAL

POWER PURCHASE AGREEMENT

By and Between

CALPINE ENERGY SERVICES L.P.

and

SEMINOLE ELECTRIC COOPERATIVE, INC.

Dated as of December 14, 2000

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INTRODUCTION

THIS POWER PURCHASE AGREEMENT (the "Agreement") is entered into as of December 14, 2000 (the "Agreement Date"), by and between CALPINE ENERGY SERVICES, L.P., a Delaware limited partnership ("Seller"), and SEMINOLE ELECTRIC COOPERATIVE, INC. ("Buyer"), a Florida corporation. Buyer and Seller may be individually referred to herein as a "Party" and, collectively, as the "Parties."

RECITALS

WHEREAS, Buyer is a cooperative corporation organized and existing pursuant to the laws of the State of Florida; and

WHEREAS, Buyer provides wholesale electric capacity and energy to its distribution cooperative members' electric utility systems, which in turn provide that electric capacity and energy to their retail member-consumers within Florida; and

WHEREAS, Seller is a Delaware limited partnership engaged in the business of marketing wholesale electric capacity and energy in the United States; and

WHEREAS, Calpine Construction Finance Company, L.P. or its successor ("CCFC"), an affiliate of Seller, is presently developing the Osprey Energy Center, a natural gas fired, combined cycle power plant in Auburndale, Polk County, Florida (the "Plant"), which through a contractual arrangement Seller provides fuel to and receives all of the electric capacity and energy from the Plant for sale at wholesale in Florida; and

WHEREAS, Buyer needs additional firm generating capacity and energy resources to meet the future needs of its distribution cooperative members' electric utility systems; and

WHEREAS, pursuant to this Agreement the full output of the Plant will be committed on a firm (i.e., unit contingent) basis, as provided herein, to Buyer for the benefit of Buyer, Buyer's member systems, and the retail member-consumers of Buyer's member systems.

NOW, THEREFORE, in view of the foregoing premises and in consideration of the mutual benefits to be gained by Buyer and Seller, the Parties hereby agree to the following:

Section 1. Definitions

In addition to terms defined in the Introduction and Recitals, the following terms shall have the meanings set forth below.

"Affiliate" means any Person that directly or indirectly Controls or is Controlled by or is under common Control with, the Person in question.

"Agreement" has the meaning set forth in the Introduction.

"Agreement Date" has the meaning set forth in the Introduction.

"Alternate Delivery Point" means a point of delivery for Requested Energy, which has been mutually agreed to by the Parties, other than the Delivery

"Ancillary Services" means those services necessary to support the transmission of Energy from resources to loads as defined in Tampa Electric Company's or its successor's open access transmission tariff, as amended from time to time.

"Applicable Law" has the meaning set forth in the Section 14.

"Attributable Start" has the meaning set for in Section 4.4.

"Breaching Party" has the meaning set forth in Subsection 21.3.

"Business Day or "Business Daily" means any day which is not a Saturday, Sunday or a day which is a NERC holiday .

"Buyer" has the meaning set forth in the Introduction.

"Buyer's Natural Gas Transportation Entitlement" means the firm transportation allotment to which Buyer is entitled on the applicable Interstate Pipeline as defined by the following formula:

[Firm Capacity/534]

"Capacity Charge" has the meaning set forth in Subsection 4.1.

"CCFC" has the meaning set forth in the Recitals.

"Claims" means all claims or actions threatened or filed by a person other than a Party, and whether groundless, false or fraudulent, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorney's fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

"Commencement Date" has the meaning set forth in Subsection 3.1.

"Commercial Operation Date" means the date on which Seller provides notice to Buyer

that the Plant, in accordance with Good Utility Practice, is capable of providing Firm Capacity and Energy for sale to Buyer at the Delivery Point pursuant to the terms and conditions of this Agreement, which date shall be no earlier than the date on which the Plant successfully completes the Commercial Operation Tests.

"Commercial Operation Tests" means: a twenty-four (24) hour demonstration test during which the Plant must operate during each hour at an output of a minimum of 350 MW at ISO Conditions. The output of the Plant shall be corrected to ISO Conditions through the utilization of the OEMs' standard performance correction curves, and by measuring the ambient conditions of temperature, relative humidity and atmospheric pressure at the Plant site. Such test shall not be deemed successful unless the twenty-four (24) hour demonstration test shows that the Plant can operate meeting all Permit requirements. Seller shall provide Buyer ten (10) Business Days prior written notification of the Commercial Operation Test, and Buyer shall have the right to be present at such testing. Buyer shall pay its avoided cost for test Energy produced during the demonstration and performance tests, if after reasonable notice by Seller to Buyer, Buyer agrees to take and purchase the test Energy from Seller. Otherwise, Seller may at its own discretion sell all of such test Energy to a third party.

"Confidential Information" has the meaning set forth in Section 11.

"Continuation" has the meaning set forth in Section 16.

"Contract Price" means collectively, the Capacity Charges, Requested Energy Charges, and Start-Up Charges, as set forth in Section 4.

"Contract Year" means (i) for the first Contract Year, the period commencing on the Commencement Date and ending on May 31, 2005, and (ii) for each 12-month period thereafter through the Termination Date, the Contract Year shall be each 12-month period ending May 31, unless the Termination Date is prior to a May 31, in which case the last Contract Year shall end on such Termination Date.

"Controls or Controlled" means the possession, directly or indirectly, through one or more intermediaries, of the following: (a) in the case of a corporation, 50% or more of the outstanding voting securities thereof; (b) in the case of a limited liability company, partnership, limited partnership or venture, the right to 50% or more of the distributions therefrom (including liquidating distributions); (c) in the case of a trust or estate, 50% or more of the beneficial interest therein; (d) in the case of any other entity, 50% or more of the economic or beneficial interest therein; or (e) in the case of any entity, the power or authority, through the ownership of voting securities, by contract or otherwise, to direct the management, activities or policies of the entity.

"Costs" means, with respect to a Party, brokerage fees, commissions and other similar transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or in entering into new arrangements which replace this Agreement and attorneys' fees, if any, incurred in connection with enforcing its rights under this Agreement.

"CPI-U" means the U.S. Consumer Price Index for All Urban Consumers published by the Bureau of Labor Statistics of the U.S. Department of Labor, or any successor

"Defaulting Party" has the meaning set forth in Subsection 21.1.

"Delivered Energy" means, pursuant to a Request for Energy, the amount of (i) metered Requested Energy expressed in MWh produced at the Plant and delivered at the Delivery Point, and (ii) Requested Energy provided as Substitute Energy and Replacement Energy pursuant to Subsections 3.3 and 3.4, respectively. Delivered Energy in any hour shall not exceed the Request for Energy for such hour. Seller shall be responsible for all costs related to generation scheduling imbalances related to the provision of Delivered Energy.

"Delivery Point" means the high side of the transformer at the interconnection between the Plant and Tampa Electric Company's or its successor's transmission system.

"Designated Network Resources" means those generating resources designated by the Buyer and accepted by the transmission provider as eligible to provide Energy to serve Buyer's load.

"Early Termination Date" means any date earlier than May 31, 2020 on which either Party, pursuant to the terms of this Agreement, terminates this Agreement.

"Eastern Standard Time" means the time prevailing in the Eastern United States time zone.

"Energy" means electric energy having characteristics commonly known as three phase alternating current, with a nominal frequency of sixty (60) Hertz, a nominal voltage equivalent to that of Tampa Electric Company's or its successor's transmission system, and measured in KWh or MWh.

"Event of Default" has the meaning set forth in Subsection 21.1.

"FERC" means the Federal Energy Regulatory Commission or its successor.

"Firm Capacity" has the meaning set forth in Subsection 3.1 as may be adjusted pursuant to Subsection 3.5.

"First Call Priority" means (i) as to system purchases, a priority equivalent to native load, and (ii) as to unit contingent purchases, a priority equal to all other firm customers sharing the unit (e.g., deratings will be accomplished on a pro-rata basis between or among all firm customers).

"Force Majeure" has the meaning set forth in Section 13.

"Fuel Charge" has the meaning set forth in Subsection 4.2.

"Fuel Index Price" has the meaning set forth in Subsection 4.5.

"Fuel Transportation Charge" has the meaning set forth in Subsection 4.1.

"Fuel Transportation Price" means

"GAAP" means generally accepted accounting principles.

"Gains" means,

"Gas Day" means the 24 hour period of time as defined in the applicable Interstate Pipeline's FERC approved transportation tariff as a "day."

"Good Utility Practice" means, at a particular time, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry prior to such time, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result(s) at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts expected to accomplish the desired results, having due regard for, among other things, manufacturers' warranties, Applicable Law, Permits, NERC guides, and applicable safety and maintenance codes.

"High Demand Season" has the meaning set forth in Subsection 7.1.

"Impaired Capacity" has the meaning set forth in Subsection 3.4.

"Initial Firm Capacity" has the meaning set forth in Subsection 4.1.

"Interstate Pipeline" means Gulfstream Natural Gas System, L.L.C. or such other interstate pipeline which Seller utilizes to transport natural gas to the Plant. or its successor pipeline.

"ISO Conditions" means the standard temperature, atmospheric pressure and relative humidity conditions of 59° F, atmospheric pressure at sea level, and 60% relative humidity, as established by International Standards Organization.

"kW" means kilowatt.

"kWh" means kilowatt-hour.

"Late Payment Rate" means a per annum rate of interest equal to the Prime Rate plus two percent (2%); provided, the Late Payment Rate shall never exceed the maximum lawful rate permitted by applicable law.

"Losses" shall mean,

"Low Demand Season" has the meaning set forth in Subsection 7.1.

"Minor Maintenance Days" has the meaning set forth in Subsection 6.2.

"MMBtu" means one million British thermal units.

"MW" means a megawatt. One MW is equal to 1,000 kW.

"MWh" means a megawatt-hour. One MWh is equal to 1,000 kWh.

"Negotiation Period" has the meaning set forth in Section 9.

"NERC" means the North American Electric Reliability Council, or its successor.

"Non-Defaulting Party" has the meaning set forth in Subsection 21.1.

"Non-Performing Party" has the meaning set forth in Section 13(A).

"OEM" means the original manufacturer of the Plant's equipment or components thereof.

"Outage" has the meaning set forth in Section 6.

"Party" has the meaning set forth in the Introduction.

"Permit" or "Permits" means the specific governmental permits applicable to the operation of the Plant.

"Person" means an individual, partnership, corporation, limited liability company, association, trust, unincorporated organization, or a government authority or agency or political subdivision thereof.

"Plant" has the meaning set forth in the Recitals, and as further described in Attachment 5.

"Prime Rate" means the prime lending rate as may from time to time be published in the *Wall Street Journal* under "money rates" or a successor heading, provided that if more than one rate is published under such heading, the Prime Rate shall be the average of such rates so published.

"Projection Period" has the meaning set forth in Section 5.

"Replacement Power" has the meaning set forth in Subsection 3.4.

"Request for Energy" means the request by Buyer for the delivery of Energy, including changes thereto, in accordance with the applicable provisions of Section 5.

"Requested Energy" has the meaning set forth in Subsection 3.2.

"Requested Energy Charge" has the meaning set forth in Subsection 4.2.

"Requested Energy Notice Requirements" means the advance notice requirements required to issue a Request for Energy specified in Table A-1 under Subsection 4.1 and Section 5.

"Reserved Firm Capacity" has the meaning set forth in Subsection 3.5.

"RUS" means the Rural Utilities Service.

"Sales Price" has the meaning set forth in Subsection 7.2.

"SCA" has the meaning set forth in Section 9.

"Scheduled Outage" means any reduction or outage of the Plant or a major component thereof, which is necessary, as commercially reasonably determined by Seller, to maintain or repair the Plant in accordance with Good Utility Practice and which has been scheduled in accordance with Subsection 6.2; provided, however, that Scheduled Outage excludes any outage of the Plant as a result of any Unscheduled Outage.

"Seasonal On-Peak Hours" has the meaning set forth in Subsection 7.1.

"Seller" has the meaning set forth in the Introduction.

"Security Coordinator" means the applicable security coordinator authorized by and under the Florida Reliability Coordinating Council or its successor for the Plant.

"Start-Up Charge" means the aggregate of the Start-Up Maintenance Charge and Start-Up Fuel Charge.

"Start-Up Fuel Charge" has the meaning set forth in Subsection 4.4.

"Start-Up Maintenance Charge" has the meaning set forth in Subsection 4.4.

"Substitute Energy" has the meaning set forth in Subsection 3.3.

"Term" has the meaning set forth in Section 2.

"Termination Date" means May 31, 2020, unless this Agreement is terminated earlier in accordance with the provisions of this Agreement, in which case the Termination Date means such earlier date on which this Agreement is terminated.

"Unscheduled Energy" has the meaning set forth in Subsection 3.6.

"Unscheduled Outage" means any reduction or outage of the Plant or a major component thereof, which is necessary, as commercially reasonably determined by Seller, to (i) maintain or repair the Plant in accordance with Good Utility Practice and was not reasonably foreseeable by Seller in time to perform as scheduled or routine maintenance, (ii) prevent significant harm or damage to the Plant, (iii) prevent harm or damage to life or property of others, or (iv) respond to any Force Majeure event; provided, however, that Unscheduled Outage excludes any outage of the Plant as a result of any scheduled or routine maintenance.

"Variable O&M Charge" has the meaning set forth in the in Subsection 4.2.

Section 2. Duration

This Agreement shall become effective as of the Agreement Date, upon signing by both Parties. This Agreement shall continue in effect through May 31, 2020, unless terminated early pursuant to the terms hereof (the "Term").

Section 3. Scope

Subsection 3.1 Firm Capacity

Beginning with the later of the Commercial Operation Date of the Plant and June 1, 2004 ("Commencement Date"), for the remainder of the Term, Seller shall provide and Buyer shall purchase the firm (i.e., unit contingent) electric capacity from the Plant at the Delivery Point, in the amounts identified in the monthly firm capacity schedule attached hereto as Attachment 1. Such amounts, as may be increased in accordance with Subsection 3.5, shall be defined as "Firm Capacity"

Subsection 3.2 Requested Energy

For the period between the Commencement Date and the end of the Term, Seller shall be obligated to sell and deliver at the Delivery Point, and Buyer shall be obligated to purchase and receive, the amount of Energy for each hour, requested by Buyer under a Request for Energy, up to the number of MWh that corresponds to the MW of Firm Capacity, subject to a minimum take by Buyer of enough MWs, in combination with Seller's use of its share of the Plant, so that the Plant is not going to operate at less than 250 MW per hour ("Requested Energy").

Subsection 3.3 Substitute Energy

Subsection 3.4 Replacement Power

Subsection 3.5 Reserved Firm Capacity

In addition to the Firm Capacity specified in Subsection 3.1 above, for the period between the Commercial Operation Date and the end of the Term, Seller shall provide Buyer, on a reserved firm capacity option basis, the right to call upon, up to the difference between (i) Buyer's then committed Firm Capacity amount and (ii) the then-full MW capability of the Plant as adjusted for seasonal variability and projected degradation (such seasonal variability and projected degradation of the then-full MW capability of the Plant to be provided by Seller to Buyer upon written request) (said difference hereinafter being defined as "Reserved Firm Capacity");

If Buyer calls upon all or a portion of the Reserved Firm Capacity as provided for above, such called upon portion of Reserved Firm Capacity shall be considered Firm Capacity.

Subsection 3.6 Exclusivity

For the period between the Commencement Date and the end of the Term, the Plant shall be dedicated to providing Firm Capacity and Requested Energy as described herein to Buyer, except during those periods when Seller is performing testing and operational maintenance as

provided herein. Buyer is not obligated to pay the Start-Up Charges associated with the Plant during such testing or maintenance. For the period between the Commencement Date and the end of the Term,

Subsection 3.7 Title. Risk of Loss and Indemnity with Respect to Requested Energy

As between the Parties, Seller shall be deemed to be in exclusive control (and responsible for any damages or injury caused thereby) of the Requested Energy up to the Delivery Point or Alternate Delivery Point, and Buyer shall be deemed to be in exclusive control (and responsible for any damages or injury caused thereby) of the Requested Energy from the Delivery Point or Alternate Delivery Point. Seller warrants that the Requested Energy delivered by Seller shall be free and clear of all liens, claims and encumbrances at the Delivery Point or Alternate Delivery Point. Title to and risk of loss related to the Requested Energy shall transfer from Seller to Buyer upon delivery of the Requested Energy at the Delivery Point or Alternate Delivery Point.

Section 4. Price

Subsection 4.1 Capacity Charge.

The monthly capacity charge ("Capacity Charge") shall be :

The Capacity Charge shall be applied to the Firm Capacity for the then applicable month for the purpose of invoicing.

Subsection 4.2 Requested Energy Charge

The monthly Requested Energy charge shall be comprised of a fuel charge and a variable O&M charge component ("Requested Energy Charge"). The fuel charge shall be calculated by multiplying the Delivered Energy (MWh) during the applicable billing month by a $/MWh rate, which rate shall be calculated by

The variable O&M charge shall be calculated by applying a monthly Variable O&M Price per MWh ($/MWh) to all Delivered Energy purchased

Subsection 4.3 Firm Capacity and Requested Energy

Six months prior to the end of each calendar year of the Term, Buyer

Subsection 4.4 Start-Up Charges

If Seller, in response to a Request for Energy is required to start either of the two (2) combustion turbines at the Plant, such start shall be considered a start attributable to Buyer on a whole basis and if Seller, in response to a Request for Energy is required to start either of the two (2) combustion turbines at the Plant, such start shall be considered a start attributable to Buyer

Subsection 4.5 Fuel Index Price Procedure

Section 5. Scheduling

(a) Seller shall provide to Buyer through electronic telemetering equipment the allowable operating limits for the Plant. These operating limits will be established through the utilization of the OEMs' standard performance test curves for the ambient conditions existing at the Plant. Buyer shall pay for such telemetering equipment and the installation thereof. Buyer shall pay for a dedicated telephone line capable of supporting said telemetering equipment, the installation thereof and any phone charges associated therewith. The installation of the telemetering equipment and the phone line shall be subject to the review and approval of Seller. Seller shall, at its expense, provide the necessary interconnection to its Plant control system and operate and maintain its Plant control system in a manner consistent with such telemetering.

(b) Seller shall provide Buyer the upper and lower operating limits, maximum allowable ramp rate and real and reactive power output for the Plant via an electronic interface made available to Buyer at the common point of interface in the Plant switchyard. The upper and lower operating limits for the Plant will be established in accordance with the OEMs' performance correction curves by measuring the ambient temperature, barometric pressure and humidity at the Plant. This information will be calculated at a minimum of once every five minutes and telemetered to the dispatcher.

(c) Seller shall provide Buyer an advance projection of expected capacity available and expected operation of the Plant if any, for each hour of the twenty-four (24) hour period for the next Gas Day ("Projection Period") (If the next Gas Day is a weekend or a holiday, such projection shall include the applicable weekend and holiday days). The advance projection shall be communicated on a Business Daily basis before 7:00 a.m. Eastern Prevailing Time, by telephone and confirmed in writing. In addition, if Buyer, on or before 8:00 am Eastern Prevailing Time, requests an advance projection of expected capacity available : s, for each hour of the twenty-four (24) hour period for the next Gas Day, Seller shall provide Buyer such information along with any scheduling flexibility limitations by 9:00 am Eastern Prevailing Time by telephone and confirmed in writing on the date of such request.

(d) Seller shall be entitled to make changes to such before 7:00 a.m. Eastern Prevailing Time advance projection, communicated per Subsection 5(c) above, after 7:00 a.m. Eastern Prevailing Time, subject to Good Utility Practice, the technical limits (Seller shall not use the technical limits as an excuse to not provide Requested Energy between the loads of 250 MW to the Firm Capacity), applicable laws and applicable Permits. Seller shall advise Buyer promptly of any change in condition that materially alters Seller's expectation as to the availability of Firm Capacity from the Plant.

(e) Seller's advance projection of capacity and changes thereto (including telephone requests and written confirmations) shall clearly specify

(f) Requests for Energy scheduled shall be communicated by telephone and confirmed by Buyer in writing on a Business Daily basis before 10:00 a.m. Eastern Prevailing Time one Gas Day ahead for each hour of the twenty-four (24) hour period for the next Gas Dav.

(i) For Attributable Starts of the Plant, and for increases or reductions in Requested Energy, Buyer shall be required to, pursuant to its Request for Energy, schedule as Requested Energy the Energy produced to ramp the Plant up or down to the ultimate Requested Energy level.

Section 6. Outages

Subsection 6.1 Outages

An "Outage" of the Plant shall mean the unavailability of the Plant, either in whole or in part, caused by either a Scheduled Outage or an Unscheduled Outage.

Subsection 6.2 Scheduled Outages

At least sixty (60) days before the beginning of each calendar year, Seller shall provide Buyer with a proposed schedule of Scheduled Outages of the Plant for the next calendar year. Such schedule shall be based on Good Utility Practice and OEMs' recommendations. Seller shall make good faith efforts to coordinate Scheduled Outages with Buyer so as to take account of scheduled outages of one or more of Buyer's generating units. If Buyer reasonably objects to

the Scheduled Outage schedule proposed by Seller, Buyer shall notify Seller thereof within thirty (30) days after receipt of Seller's proposed schedule, stating in detail the reasons for its objection and a proposed alternative Scheduled Outage schedule. Seller shall consider Buyer's objections and proposed alternative schedule reasonably and in good faith, and shall develop a revised Scheduled Outage schedule. Seller may revise the Scheduled Outage schedule during a calendar year, subject to Buyer's approval, such approval to not be unreasonably withheld taking into consideration Good Utility Practice, OEMs' recommendations, and scheduled outages of one or more of Buyer's generating units. Under no circumstances, however, may a Scheduled Outage take place during the On Peak Hours during the months of except, however, Buyer shall provide, with ten (10) Business Days notice to Seller, two (2) consecutive days in each quarter of each calendar year for the purpose of Seller performing minor maintenance ("Minor Maintenance Days"), and said Minor Maintenance Days shall not be deemed as having violated the aforementioned On-Peak Scheduled Outage restriction. During each Scheduled Outage, Seller shall keep Buyer apprised of the status of the Plant and the expected duration of the Scheduled Outage.

Subsection 6.3 Unscheduled Outages

Seller shall provide Buyer with a good faith oral best estimate (followed by written confirmation) of the cause, duration and scope of each Unscheduled Outage as soon as practical after the occurrence thereof.

Section 7. Failure To Provide or Receive Requested Energy

Subsection 7.1 Failure of Seller To Provide Requested Energy

(a) Unless excused by Buyer's failure to perform, Seller shall in the months of ("High Demand Season") during the Term maintain an Equivalent Availability Factor of

(b) Unless excused by Buyer's failure to perform, Seller shall in the months of ("Low Demand Season") during the Term maintain an Equivalent Availability Factor of

Subsection 7.2 Failure of Buyer To Receive Requested Energy

If pursuant to a Request for Energy, Seller has incurred an obligation to take and pay for gas supply under this Agreement, unless excused by Force Majeure or Seller's failure to perform, and Buyer fails to receive or otherwise take the Requested Energy, then

Section 8. Commercial Operation Date Delay

Subsection 8.1 Commercial Operation Date Delay

In the event that the Commercial Operation Date of the Plant shall occur later than the expected in-service date of June 1, 2004, for reasons other than Force Majeure

Section 9. Termination for Convenience/Conditions Subsequent

Subsection 9.1 Conditions Subsequent

If any of the following conditions subsequent are not satisfied, Buyer may terminate this Agreement for its convenience by written notice to Seller:

Section 10. Dispute Resolution

The dispute resolution procedures set forth in this Section 10 shall govern the resolution of any dispute, controversy or claim arising out of, under, or relating to this Agreement (a "Dispute") unless mutually agreed to by the Parties. The Parties agree to first negotiate in good faith to attempt to resolve any Dispute that arises under this Agreement. In the event that the Parties are unsuccessful in resolving a Dispute through such negotiations, the controversy may be submitted to binding arbitration as provided below.

(A) Good-Faith Negotiations.

The process of "good-faith negotiations" requires that each Party set out in writing to the other its reason(s) for adopting a specific conclusion or for selecting a particular course of action, together with the sequence of subordinate facts leading to the conclusion or course of action. The Parties shall attempt to agree on a mutually agreeable resolution of the Dispute. Upon request, each Party shall promptly make available to the other such information, including existing studies and raw data, to the extent related to the Dispute. The related information to be made available must include both studies and raw data that support the position advocated and existing studies and raw data that are related to, but do not support, the position advocated. A Party shall not be required as part of these negotiations to provide any information which is confidential or proprietary in nature unless it is satisfied in its discretion that the other Party will maintain the confidentiality of and will not misuse such information or any information subject to attorney-client or other privilege under applicable law regarding discovery and production of documents.

Additionally, where one Party possesses the exclusive capability of collecting additional raw data or making additional studies related to the Dispute, it shall accommodate reasonable requests from the other Party requesting such data or studies, subject to limitations on disclosure

of confidential, proprietary or privileged information. The Party requesting such data shall reimburse the other Party for the cost incurred to provide the data. The negotiation process shall include at least two meetings to discuss any Dispute prior to invoking arbitration rights. Unless otherwise mutually agreed, the first meeting shall take place within ten (10) Business Days after either Party has received notice from the other of the desire to commence formal negotiations concerning the Dispute. Unless otherwise mutually agreed, the second meeting shall take place no more than ten (10) Business Days later. In the event a Party refuses to attend a negotiation meeting, either Party may proceed immediately to binding arbitration concerning the Dispute.

(B) Binding Arbitration.

Binding arbitration may be initiated at any time by either Party following Good Faith Negotiations (the "Binding Arbitration Notice"). The Binding Arbitration Notice shall specify the issue(s) to be submitted to binding arbitration, including a summary of the complaining Party's position with respect thereto and a proposed resolution. The Party receiving the Binding Arbitration Notice shall have the right to rebut the issue(s) set forth in the Binding Arbitration Notice. The Parties shall by mutual agreement appoint an arbitrator within thirty (30) days after receipt of the Binding Arbitration Notice giving preferred consideration to former US Circuit Court Judges with training or experience to address the issue in controversy. In the event the Parties are unable to agree upon an arbitrator within such time frame, either Party may request the American Arbitration Association to designate three potential arbitrators, each of whom (1) shall have agreed to arbitrate the Dispute, (2) shall have never been affiliated with either Party or its affiliate(s), (3) shall be qualified by training or experience to address the issue in controversy and (4) shall be available to fulfill the responsibilities of binding arbitration in a timely manner. Each Party shall be provided relevant information related to each potential arbitrator, including applicable fees; and each shall designate its first, second and third choices among the potential arbitrator, with the designated choice receiving four, three and one point(s), respectively. In the event a Party fails to designate an order of choice, each potential arbitrator shall receive one point. The potential arbitrator receiving the most points shall be the arbitrator. Unless otherwise mutually agreed, binding arbitration shall commence two (2) weeks after the selection of the arbitrator. The arbitration shall proceed in accordance with the rules for commercial arbitration established by the American Arbitration Association absent the contrary agreement of the Parties. Any recommendation or decision by the arbitrator shall be binding on the Parties. The fees and expenses of the arbitrator shall be shared equally by the Parties, and each Party shall bear its own costs.

(C) Confidentiality and Non-Admissibility of Statements Made in, and Evidence Specifically Prepared for, Good Faith Negotiations and Binding Arbitration.

Each Party hereby agrees that all statements made in the course of good faith negotiations, as contemplated in Section 10(A), and in binding arbitration, as contemplated in Section 10(B), shall be confidential, and shall not be disclosed to or shared with any third parties (other than the arbitrator, potential arbitrators or any other person whose presence is necessary to facilitate the negotiation and/or binding arbitration process). Furthermore, each Party agrees that any documents or data specifically prepared for use in good faith negotiations and/or binding arbitration shall not be disclosed to any third party, except those parties whose presence is necessary to facilitate the binding arbitration process. Each Party agrees and acknowledges that no statements made in or evidence specifically prepared for good faith negotiations, under

Section 10(A) shall be admissible for any purpose in any subsequent binding arbitration.

Section 11. Confidentiality of Shared Information

Neither Party shall disclose or otherwise make available to any other party any information of a technical, commercial or business nature regarding the Plant or this Agreement ("Confidential Information") without the prior written consent of the other Party, except that Seller may provide Confidential Information to its lenders. Confidential Information shall not include information which (i) the receiving Party can demonstrate was known to it prior to its disclosure by the other Party, (ii) is, or later becomes, public knowledge without breach of this Agreement by the receiving Party, (iii) was received by the receiving Party from a third party without obligation of confidentiality, or (iv) is developed by the receiving Party independently from Confidential Information received from the other Party, as evidenced by appropriate documentation. In the event that disclosure is required by court order or a Governmental Body, the Party subject to such requirement may disclose Confidential Information to the extent so required, but shall promptly notify the other Party and shall use reasonable efforts to obtain protective orders or similar restraints with respect to such disclosure. Notwithstanding the above, either Party may disclose information required pursuant to regulation by a Governmental Body, on a non-confidential basis if necessary, but only to such extent necessary, in connection with a regulatory filing contemplated hereunder or as otherwise required pursuant to this Agreement.

Section 12. Buyer's Support for Need Determination of the Plant

Buyer shall provide such support for the petition for determination of need for Seller's Plant as the Parties mutually agree is necessary to facilitate and expedite the permitting and construction of the Plant. Buyer's support shall include becoming a co-applicant for the requisite determination of need for the Plant.

Section 13. Force Majeure

(A) Force Majeure Excuse. Neither Party shall be responsible or liable for or deemed in breach of this Agreement for any delay or failure in the performance of its respective obligations under this Agreement to the extent such delay or failure is due to circumstances beyond the reasonable control of the Party experiencing such delay or failure (such Party referred to herein as the "Non-Performing Party"), and such circumstances are limited to: (i) types of events such as acts of God, drought, flood, landslide, earthquake, hurricane, tornado, storm, or other such unusually severe weather conditions, fire, lightning, epidemic, war, blockade, riot, civil disturbance, famine, sabotage, explosions, theft, embargo, and injunction, (ii) labor strikes or slowdowns of the Non-Performing Party's employees to the extent that such strikes or slowdowns also affect employers in addition to the Non-Performing Party___

In the event of Force Majeure:

1. the Non-Performing Party shall give the other Party notice within forty-eight (48) hours (or as soon as practicable) after learning of the Force Majeure, with details further describing the particulars of the occurrence to be supplied within ten (10) Business Days after learning of the Force Majeure; if such notice is given within the required time period, the Non-Performing Party shall be relieved of its obligations from the commencement of the Force Majeure; if such notice is given later than the required time period, the Non-Performing Party shall be relieved of its obligations from the time of giving such notice; if no notice is given, then the obligations of the Parties shall continue without regard to the Force Majeure event;

2. the suspension of performance shall be of no greater scope and of no longer duration than is reasonably attributable to the Force Majeure;

3. the Non-Performing Party shall use its reasonable commercial efforts to remedy its inability to perform;

4. when the Non-Performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party notice to that effect; and

(B) Non-Force Majeure Examples. Examples of circumstances which the term Force Majeure does not include are as follows: (1) changes in market conditions that affect the cost of a Party's supply of fuel or any alternate supplies of fuel, (2) any negligent or intentional acts, errors or omissions, or failure to comply with any Applicable Law, or any breach of or default under this Agreement, or any other agreement, by the Non-Performing Party or its contractors, (3) the inability to obtain any Permits required to construct and operate the Plant, (4) changes in market conditions that affect the cost of producing or making available Requested Energy or Firm Capacity or any necessary wheeling or transmission arrangements, (5) any damage to or failure of necessary equipment comprising the Plant caused by a defect in design, manufacturing or construction of the Plant or any component thereof, (6) any damage to or failure of the Plant or any component thereof caused by normal wear and tear, and (7) inability of Seller to enter into a firm gas transportation agreement with an Interstate Pipeline. These examples are not intended to be exclusive or exhaustive.

Section 14. Applicable Law

This Agreement shall be made under and shall be governed by and construed in accordance with the laws of the State of Florida, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction ("Applicable Law"). The Parties agree to submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Middle District of Florida, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Circuit Court of the State of Florida sitting in Hillsborough County, Florida, and the Parties further agree to waive any right they may have to a jury trial with respect thereto.

Section 15.

Section 16. Reopener

The Parties will engage in good faith negotiations concerning the price, terms and conditions under which this Agreement will continue beyond May 31, 2009 ("Continuation"). If the Continuation is not executed by July 31, 2005, then Seller shall promptly thereafter notify Buyer in writing that unless either Party within sixty (60) days of such written notice from Seller elects to terminate this Agreement for its convenience as of May 31, 2009, that this Agreement shall be deemed continued as written for another sixty (60) month increment, with the exception that all references to "May 31, 2009" in this Section shall be modified to reflect the date sixty (60) months thereafter and all references to "July 31, 2005" in this Section shall be modified to reflect the date forty-six (46) months prior to such sixty (60) months thereafter date. Within sixty (60) days of such notice from Seller, either Party, based on its sole judgment, will be free to terminate this Agreement as of May 31, 2009 for its convenience.

If the Continuation is not executed by July 31, 2005, and neither Party, within sixty (60) days of such notice from Seller terminates this Agreement for its convenience, pursuant to the preceding sentence, then this Agreement shall be deemed continued consistent with the terms hereof. The Parties agree that, unless otherwise agreed to by the Parties, Continuations to this Agreement's term shall be in sixty (60) month increments and that similar reopener provisions to that contained herein shall be part of any such Continuation.

Section 17. Ancillary Services

Section 18. Metering

Subsection 18.1 Meter Reading

The Parties will cause meters to be read monthly at times agreed upon. Metering records shall be available at all reasonable times to authorized representatives and employees of the Parties.

Subsection 18.2 Billing, Meters and Associated Transformers

Seller will, own, operate, and maintain the billing meters and associated transformers at the Delivery Point. Seller's records of data collected from such meters shall be available at all reasonable times to the duly authorized representatives of Buyer.

Subsection 18.3 Meter Tests

Each meter used hereunder shall, by comparison with accuracy standards as provided for in Subsection 18.4, be tested and calibrated by Seller or its agent at approximate intervals of twelve (12) months or as otherwise agreed to by both Parties. If a meter is found not registering accurately, it shall be restored to an accurate condition or it shall be replaced by an accurate meter. Seller shall provide Buyer prior written notification of any such testing and calibration, and Buyer shall have the right to be present at such testing and calibration.

Subsection 18.4 Meter Accuracy

Each Party shall have the right to request that a special test of metering equipment be made at any time. If any test made at Buyer's request discloses that the metering equipment tested is registering within one-half percent (+ or - 0.5%) accuracy, Buyer shall bear the expense of the test. The expense of all other such tests shall be borne by Seller.

Subsection 18.5 Meter Adjustments

The results of all meter tests and calibrations shall be open to examination by Buyer. Any meter tested and found to be within one-half percent (+ or - 0.5%) accuracy shall be considered to be accurate. If, as a result of any test, any meter is found to register not within plus or minus one-half percent accuracy, the readings of such meter previously taken shall be corrected according to the percentage of inaccuracy so found for the most recent one-half of the time period since the date the meter was last tested, and the applicable invoices shall be adjusted to reflect such corrected meter readings; provided, however, that the time period for which the meter readings are adjusted shall not exceed six months. If any metering equipment fails to register, or if the meter registration is erratic, the Energy delivered shall be determined first by

reference to backup meters, if any. If no backup meters exist, or if the backup meters are not accurate, the Energy delivered shall be determined by mutual agreement of the Parties.

Section 19. Representation and Warranties

Subsection 19.1 Representations and Warranties

As a material inducement to entering into this Agreement, each Party, with respect to itself, hereby represents and warrants to the other Party as of the Agreement Date as follows:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation and is qualified to conduct its business in those jurisdictions necessary to perform this Agreement;

(b) it has all regulatory authorizations necessary for it to legally perform its obligations under this Agreement, except for those which Seller is to obtain as conditions subsequent pursuant to Subsection 9.1 and except for the regulatory approval from the Administrator of the RUS pursuant to Subsection 9.1;

(c) the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms or conditions in its governing documents or any contract to which it is a party or any law, rule, regulation, order, writ, judgment, decree or other legal or regulatory determination applicable to it;

(d) this Agreement constitutes a legal, valid and binding obligation of such Party enforceable against it in accordance with its terms, subject to bankruptcy, insolvency, reorganization and other laws affecting creditor's rights generally, and with regard to equitable remedies, to the discretion of the court before which proceedings to obtain same may be pending;

(e) there are no bankruptcy, insolvency, reorganization, receivership or other arrangement proceedings pending or being contemplated by it, or to its knowledge threatened against it; and

(f) there are no suits, proceedings, judgments, rulings or orders by or before any court or any governmental authority that could reasonably be expected to materially adversely affect its ability to perform this Agreement.

Subsection 19.2 No Other Representations and Warranties

Each Party acknowledges that it has entered into this Agreement based solely upon the express representations and warranties set forth in this Agreement.

Section 20. Additional Covenants

Subsection 20.1 Remaking of Representations and Warranties

Each Party covenants that it will cause its respective representations and warranties in Subsection 19.1, except for suits and proceedings under Subsection 19.1(f), to remain true and correct throughout the Term.

Subsection 20.2 Financial Information

Each Party shall cause to be delivered to the other Party such financial information as is reasonably requested by the other Party, including annual audited financial statements

Section 21. Events of Default and Remedies

Subsection 21.1 Event of Default

An "Event of Default" shall mean, with respect to a Party alleged to have taken or been affected by any of the actions set forth below in this Subsection 21.1 (the "Defaulting Party"):

(a) the failure of the Defaulting Party to make, when due, any payment required under this Agreement if such failure is not remedied within ten (10) Business Days after written notice of such failure is given to the Defaulting Party by the other Party ("Non-Defaulting Party") and *provided* the payment is not the subject of a good faith dispute as described in the billing and payment provisions under Subsection 22.1; or

(b) any representation or warranty made by the Defaulting Party in this Agreement shall prove to have been false or misleading in any material respect when made, or ceases to remain true and not cured within thirty (30) days of receipt of written notice from the other Party that such representation or warranty has ceased to be true, during the Term, except for suits and proceedings under Subsection 19.1(f); or

(c) the failure by the Defaulting Party to perform any material covenant set forth in this Agreement (other than the events that are otherwise specifically covered in this Subsection 21.1 as a separate Event of Default or its obligations to deliver or receive Requested Energy, a remedy for good faith failure of which is provided in Subsections 7.1 and 7.2), and such failure is not excused by Force Majeure or cured within ten (10) Business Days after written notice thereof to the Defaulting Party or if the breach or default is not of the type that can be reasonably cured by the payment of money within ten (10) Business Days, within a reasonable period not longer than thirty (30) days so long as (i) the Defaulting Party has commenced to cure the breach or default within such ten (10) Business Day period and thereafter diligently pursues such cure to

completion, (ii) the Defaulting Party continues to perform all other obligations under this Agreement; or

(d) the Defaulting Party shall:

(i) make an assignment or any general arrangement for the benefit of creditors;

(ii) file a petition or otherwise commence, authorize or acquiesce in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or have such petition filed against it and such petition is not withdrawn or dismissed for thirty (30) days after such filing;

(iii) otherwise become bankrupt or insolvent (however evidenced); or

(iv) be unable to pay its debts as they fall due.

Subsection 21.2 Remedies Upon an Event of Default

Subsection 21.3 Effects of Regulation

In the event that either Party is regulated by a federal, state or local regulatory body, and such body shall disallow all or any portion of any costs incurred or yet to be incurred by such regulated Party under any provision of this Agreement, such action shall not operate to excuse such regulated Party from performance of any obligation, nor shall such action give rise to any right of such regulated Party to any refund or retroactive adjustment of the Contract Price. Notwithstanding the foregoing, if a Party's activities hereunder become subject to regulation of any kind whatsoever under any law to a greater or different extent than that existing on the Agreement Date and such regulation either (a) renders this Agreement illegal or unenforceable or (b) materially adversely affects the business of a Party, with respect to its financial position or otherwise, then in the case of (a) above, either Party, and in the case of (b) above, only the Party affected (the "Breaching Party"), shall at such time have the right to

Section 22. Billing and Payment

Subsection 22.1 Billing and Payment

Seller shall render to Buyer (by regular mail, facsimile or other acceptable means pursuant to Subsection 27.8) for each calendar month during the Term a statement setting forth the total Capacity Charges for the month, the Requested Energy Charges for that month, Start-Up Charges for that month, and any other charges due Seller or Buyer. On or before fifteen (15) Business Days after receipt of Seller's statement, Buyer or Seller, as the case may be, shall pay, by wire transfer, the amount set forth on such statement. to the other Party. Wire transfers to Seller shall be to Seller's account as Seller directs on its statement. Any payment determined to be due to Buyer by Seller under this Agreement shall be rendered by Seller to Buyer by wire transfer to Buyer's account as specified by Buyer in a notice to Seller. Overdue payments shall accrue interest from, and including, the due date to, but excluding, the date of payment at the Late Payment Rate. If either Party, in good faith, disputes a statement, such Party shall provide a written explanation specifying in detail the basis for the dispute and pay the portion of such statement conceded to be correct no later than the due date. If any amount disputed by such Party is determined to be due to the other Party, it shall be paid within fifteen (15) Business Days of such determination, along with interest accrued at the Late Payment Rate until the date paid.

Subsection 22.2 Netting

If Buyer and Seller are each required to pay an amount in the same month, then such amounts with respect to each Party may be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount shall pay to the other Party the difference between the amounts owed. Each Party reserves to itself all rights, counterclaims and other remedies and defenses consistent with this Section 22 (to the extent not expressly herein waived or denied) which such Party has or may be entitled to arising from or out of this Agreement.

Subsection 22.3 Audit

Each Party (and its representatives) has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If requested, a Party shall provide to the other Party statements evidencing the quantities of Requested Energy delivered at the Delivery Point or mutually agreed to alternate delivery point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be promptly made and shall bear interest calculated at the Late Payment Rate from the date the overpayment or underpayment was made until paid; *provided, however*, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of from the end of the year in which the statement was rendered; and *provided further* that this Subsection 22.3 will survive any termination of this Agreement for a period of from the date of such termination for the purpose of such statement and payment objections.

Section 23. Assignment

Subsection 23.1 Assignment

Neither Party shall assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, either Party may, without the need for consent from the other Party (and without relieving itself from liability hereunder), (a) transfer, sell, mortgage, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements directly related to the construction of the Plant, including lease back arrangements relating to the Plant; (b) transfer or assign this Agreement to an Affiliate of such Party; or (c) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets of such Party; *provided, however*, that in each such case any such assignee shall agree in writing to be bound by the terms and conditions hereof. Notwithstanding the above, Buyer's interest in this Agreement may be assigned, transferred, mortgaged or pledged by Buyer without Seller's consent for the purpose of creating a security interest for the benefit of the United States of America, acting through the RUS (and thereafter the RUS, without the approval of Seller or its Lenders, may cause the RUS's interest in this Agreement to be sold, assigned transferred or otherwise disposed of to a third party.). To the extent this Agreement is transferred, sold, mortgaged, pledged, encumbered or

assigned in connection with any financing or other financial arrangements related to the construction of the Plant or to the RUS, the non-assigning Party shall cooperate with the assigning Party by providing reasonably requested documentation (i.e., consents and acknowledgements).

Subsection 23.2 Binding Effect

This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns. No assignment or transfer permitted hereunder shall relieve Seller or Buyer of any of its respective obligations under this Agreement, except those assignments permitted hereunder or consented to by the non-assigning Party.

Section 24. Indemnification, Limitation of Liability and Insurance

Subsection 24.1 Seller Indemnification

Seller hereby agrees to indemnify, defend and hold harmless Buyer, its agents, servants, partners, officers, directors, trustees, affiliates, and employees of each (collectively, "Buyer's Indemnitees"), from and against any and all losses, claims, damages and liabilities to third parties

arising out of the fraud, negligence or willful misconduct of Seller relating to power delivered under this Agreement before or at such time as the power has been delivered to Buyer at the Delivery Point or mutually agreed to alternative delivery point including, without limitation, the loss or claims for loss or damage to property, except to the extent caused by the fraud, negligence or the willful misconduct or breach of obligation under this Agreement of Buyer's Indemnitees and provided that Seller shall be promptly notified in writing of any such claim or suit brought against any such Buyer Indemnitee and shall be permitted to manage at its cost and expense reasonably acceptable to Buyer a defense against or negotiate a settlement (other than any settlement involving criminal liability or admission of guilt or responsibility by such Buyer Indemnitee) of such claim or suit through counsel. The foregoing notwithstanding, Seller's obligations under this Agreement towards any Buyer Indemnitee are conditioned upon such Buyer Indemnitee providing at Seller's expense such cooperation as Seller may reasonably request in connection with its defense or settlement of the claim or suit against such Buyer Indemnitee.

Subsection 24.2 Buyer's Indemnification

Buyer hereby agrees to indemnify, defend and hold harmless Seller, its agents, servants, partners, officers, directors, trustees, affiliates and employees of each (collectively, "Seller's Indemnitees"), from and against any and all losses, claims, damages or liabilities to third parties

arising out of the fraud, negligence or willful misconduct of Buyer relating to power delivered under this Agreement after such power has been delivered to Seller at the Delivery Point or mutually agreed to alternative delivery point, including, without limitation, the loss or

claims for loss or damage to property, except to the extent caused by the fraud, negligence or the willful misconduct or breach of obligation under this Agreement of Seller's Indemnitees and provided that Buyer shall be promptly notified in writing of any such claim or suit brought against any such Seller Indemnitee and shall be permitted to manage at its cost and expense reasonably acceptable to Seller a defense against or negotiate a settlement (other than any settlement involving criminal liability or admission of guilt or responsibility by such Seller Indemnitee) of such claim or suit through counsel. The foregoing notwithstanding, Buyer's obligations under this Agreement towards any Seller Indemnitee are conditioned upon such Seller Indemnitee providing at Buyer's expense such cooperation as Buyer may reasonably request in connection with its defense or settlement of the claim or suit against such Seller Indemnitee.

Subsection 24.3

Subsection 24.4 Duty To Mitigate

Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

Subsection 24.5 Florida Uniform Commercial Code

Except as otherwise provided for in this Agreement, the provisions of the Florida Uniform Commercial Code shall govern this Agreement and shall be deemed to apply to this

Agreement. Requested Energy shall be deemed to be a "good" for purposes of the Florida Uniform Commercial Code.

Subsection 24.6 Insurance

Within thirty (30) days after execution of this Agreement, each Party shall provide the other Party certificates of insurance demonstrating that it has adequate liability insurance pursuant to its corporate policies for any liability arising out of its activities undertaken pursuant to this Agreement. Each Party agrees to provide at least thirty (30) days' notice to the other Party prior to cancellation of its liability insurance policy.

Section 25. Taxes

Subsection 25.1 General

Buyer and Seller shall each use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with their intent to minimize taxes, so long as neither Party is materially adversely affected by such efforts. Either Party, upon written request of the other, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if either Party is exempt from taxes, and shall use reasonable efforts to obtain and cooperate with obtaining any exemption from or reduction of tax. Either Party with knowledge of a tax on the purchase or sale of the capacity or Energy, that may be applicable to the Firm Capacity or Requested Energy sold hereunder, shall notify the other Party, in advance, of the applicability of such tax and shall also notify the other Party of any proposal to implement a new tax or apply an existing tax to the purchase, sale, delivery, or receipt of Firm Capacity or Requested Energy hereunder.

Subsection 25.2 Applicable Taxes

Seller shall be responsible for all existing and any new sales, use, excise, ad valorem, and any other similar taxes, imposed or levied by any federal, state or local governmental agency on the Requested Energy to be sold and delivered hereunder prior to the transfer of title. Buyer shall be responsible for all existing and any new sales, use, excise, ad valorem, and any other similar taxes, imposed or levied by any federal, state or local governmental agency on the Capacity sold hereunder, the Requested Energy sold and delivered hereunder and imposed or levied on the Delivered Energy after transfer of title thereto. If either Party is required to pay any tax that under the provisions hereof is the responsibility of the other Party, the paying Party shall be reimbursed by the other Party. Neither Party is required to pay, or cause to be paid, any taxes measured by the income of the other Party. Each Party shall indemnify (to the extent permitted by law), release, defend and hold harmless the other Party from and against any and all liability for (i) taxes measured by the income of the other Party and (ii) taxes imposed or assessed by any taxing authority with respect to the Firm Capacity and Requested Energy sold, delivered and received hereunder that are not the responsibility of such other Party pursuant to this Subsection 25.2.

Section 26. Construction Schedule and Access Rights

Seller shall submit an integrated project schedule to Buyer within ninety (90) days from the execution of this Agreement. This schedule shall identify key licensing, permitting, construction, performance testing and operating milestone dates and activities. Seller shall notify Buyer of any material changes in such schedule within ten (10) Business Days after such changes are determined. Seller shall provide monthly progress reports to Buyer, which shall report in detail on the status of the Plant, and in addition will report promptly any adverse events that are reasonably likely to delay the achievement of milestone dates.

Seller shall arrange through its affiliate CCFC to provide Buyer and its authorized experts, representatives and/or agents with access to the Plant upon reasonable prior notice (in light of the circumstances) and subject to CCFC's safety and operating rules and regulations of general applicability, in connection with the design, construction and operation of the Plant. Such access shall include access to CCFC's maintenance records during normal business hours upon at least thirty (30) Business Days' prior notice to Seller by Buyer. Any information provided to Buyer by Seller or by CCFC on behalf of Seller in accordance with this Section shall constitute confidential information and be treated by Buyer in accordance with Section 11. Buyer's access shall not interfere with Seller's or CCFC's normal business operations.

Section 27. Miscellaneous

Subsection 27.1 Entirety

This Agreement and its Attachments, which are incorporated by reference, constitute the entire agreement between the Parties. There are no prior or contemporaneous agreements or representations affecting the same subject matter other than those herein expressed. Except for any matters that, in accordance with the express provisions of this Agreement, may be resolved

by verbal agreement between the Parties, no amendment, modification or change herein shall be enforceable unless reduced to writing and executed by both Parties.

Subsection 27.2 Non-Waiver

No waiver by any Party of any one or more defaults by the other Party in the performance of any of the provisions of this Agreement shall be construed as a waiver of any other default or defaults whether of a like kind or different nature.

Subsection 27.3 Severability

Except as otherwise stated herein, any provision or article declared or rendered unlawful by a court of law or regulatory agency having jurisdiction over the Parties, or deemed unlawful because of a statutory change, will not otherwise affect the lawful obligations that arise under this Agreement.

Subsection 27.4 Headings: Attachments

The headings used for the sections and subsections herein are for convenience and reference purposes only and shall in no way affect the meaning or interpretation of the provisions of this Agreement. References in this Agreement to sections and subsections shall be deemed a reference to this Agreement, unless otherwise indicated. Any and all Attachments referred to in this Agreement are, by such reference, incorporated herein and made a part hereof for all purposes.

Subsection 27.5 Winding Up Arrangements

All indemnity, limitation of liability and audit rights shall survive the termination of this Agreement. All obligations provided in this Agreement shall remain in effect for the purpose of complying herewith.

Subsection 27.6 No Third Party Beneficiaries

Nothing in this Agreement shall provide any benefit to any third party or entitle any third party to any claim, cause of action, remedy or right of any kind, it being the intent of the Parties that this Agreement shall not be construed as a third party beneficiary contract.

Subsection 27.7 Counterparts

This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument.

Subsection 27.8 Notices

All notices, requests, or statements shall be made as follows. Notices required to be in writing shall be delivered by letter, facsimile or other documentary form. Notice by facsimile or hand delivery shall be deemed to have been received by the close of the Business Day on which it was transmitted or hand delivered (unless transmitted or hand delivered after close in which case it shall be deemed received at the close of the next Business Day). Notice by overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent. A Party may change its address by providing notice of same in accordance herewith.

If to Buyer: Seminole Electric Cooperative, Inc.
Attention: Director of Pricing and Bulk Power Contracts
16313 North Dale Mabry Highway
Tampa, FL 33618
Phone: (813) 963-0994
Fax: (813) 264-7906

If to Seller: Calpine Energy Services, L.P.
Attention: Director, Contracts and Administration
The Pilot House, Second Floor
Lewis Wharf
Boston, MA 02110
Phone:
Fax:

Each Party shall have the right to change the place to which notices shall be sent or delivered or to specify one additional address to which copies of notices may be sent, in either case by similar notice sent or delivered in like manner to the other Party.

EXECUTION

By the signatures of their authorized representatives below, Buyer and Seller enter into this Agreement. This Agreement may be executed in any number of counterparts, such counterparts may be transmitted by either Party to the other Party by facsimile transmission, and each executed counterpart or facsimile transmission thereof shall have the same force and effect as an original instrument.

CALPINE ENERGY SERVICES, L.P.
a Delaware limited partnership

By: Robert K. Alff
Name: Robert K. Alff
Title: Senior Vice President

SEMINOLE ELECTRIC COOPERATIVE, INC.
a Florida corporation

By: _____
Name: Richard J. Midulla
Title: Executive Vice President and General Manager

ATTACHMENT 1
MONTHLY FIRM CAPACITY SCHEDULE

Month	Firm Capacity
January	360
February	360
March	354
April	350
May	346
June	341
July	340
August	340
September	342
October	347
November	355
December	360

ATTACHMENT 2

ATTACHMENT 3
DEGRADATION

Contract Year	Degradation Factor	Heat Rate for Compensation (MMBTU/MWhr-HHV)
1		
2		
3		
4		
5		

ATTACHMENT 4
START-UP FUEL

Startup Energy, Hot Start	
Startup Energy, Cold Start	

ATTACHMENT 5
PLANT DESCRIPTION

The Osprey Energy Center is located in Auburndale, Florida. The Plant will tie into a number of existing facilities, including potable water, reclaimed water and wastewater pipelines, a paved road, and Tampa Electric Company's Recker Substation, which has 230-kV transmission lines adjacent to the Plant.

The Plant will consist of a nominal 534-MW combined-cycle power plant and associated facilities. The Plant will include two nominal 170-MW Westinghouse "F" Class combustion turbines (CTs) and associated triple pressure heat recovery steam generators (HSRGs). The CTs will be equipped with dry low-nitrogen oxides combustors to reduce NOx emissions from the CTs. The HRSGs will be equipped with Selective Catalytic Reduction systems to further reduce NOx emissions. The CT units will have a combined generating capacity of nominally 340-MW (net), when operating under average ambient conditions (74^0 F), excluding power augmentation. The HRSGs will supply steam to a steam turbine electric generator, which will have a nominal generating capacity of 200-MW under average ambient conditions, excluding duct firing. The Plant will have a total generating capacity of nominally 534-MW (average ambient). The Plant will be fired exclusively with natural gas and is expected to be operated in a combined-cycle mode.

Electric energy from the Plant will have characteristics commonly known as three-phase alternating current, with a nominal frequency of sixty (60) Hertz, a nominal voltage equivalent to that of the transmission system into which the energy is delivered.

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No .....

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Sandra Beeler, who on oath says that she is the Inside Sales Supervisor of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

Public Notice

in the matter of Public Service Commission

in the

Court, was published in said newspaper in the issues of

12-17-2000

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed Sandra Beeler
Sandra Beeler
Inside Sales Supervisor
Who is personally known to me.

ADM Exhibit 5

Sworn to and subscribed before me this 20TH day of December A.D. 20 00

Patricia Ann Rouse
Notary Public
PATRICIA ANN ROUSE

(Seal)

PATRICIA ANN ROUSE
MY COMMISSION # CC 978018
EXPIRES: October 17, 2004
Bonded Thru Notary Public Underwriters

My Commission Expires.....

268430 E870

Attach Notice Here

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
NOTICE OF NEED DETERMINATION HEARING AND PREHEARING CONFERENCE ON
PROPOSED ELECTRICAL POWER PLANT
TO
SEMINOLE ELECTRIC COOPERATIVE, INC.,
CALPINE CONSTRUCTION FINANCE COMPANY, L.P.
AND
ALL OTHER INTERESTED PERSONS
DOCKET NO. 001748-EC

IN RE: PETITION FOR DETERMINATION OF NEED FOR THE OSPREY ENERGY CENTER IN POLK COUNTY BY SEMINOLE ELECTRIC COOPERATIVE AND CALPINE CONSTRUCTION FINANCE COMPANY, L.P.

ISSUED: December 12, 2000

NOTICE is hereby given that the Florida Public Service Commission will hold a hearing in the above docket at the time and place listed below.

9:30 a.m., Monday, February 12, 2001
4075 Esplanade Way
Room 148 - Betty Easley Conference Center
Tallahassee, Florida

Tuesday, February 13, 2001, has also been reserved for continuation of the hearing, if necessary. All persons who wish to be heard are urged to be present at the beginning of the hearing on February 12, 2001. The starting time of the next day's session will be announced at the conclusion of the prior day's hearing may be adjourned early if all testimony is concluded.

Any person requiring some accommodation at the hearing or the prehearing conference because of a physical impairment should call the Division of Records and Reporting at (850) 413-6770 at least 48 hours prior to the hearing or prehearing conference. Any person who is hearing or speech impaired should contact the Florida Public Service Commission by using the Florida Relay Services, which can be reached at 1-800-955-8771 (TDD).

PURPOSE AND PROCEDURE

The purpose of this hearing will be for the Commission to take final action to determine the need, pursuant to Sections 403.501-.519, Florida Statutes (1999), for the construction of a power plant and related facilities in Polk County, Florida. This proceeding shall allow Seminole Electric Cooperative, Inc. and Calpine Construction Finance Company, L.P. to present evidence and testimony in support of their petition for a determination of need for its proposed plant and related facilities in Polk County, Florida; to permit any intervenors to present testimony and exhibits concerning this matter; to permit members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and for such other purposes as the Commission may deem appropriate. All witnesses shall be subject to cross-examination at the conclusion of their testimony.

The proceedings will be governed by the provisions of Chapter 120, Florida Statutes, Section 403.519, Florida Statutes, and Chapters 25-22 and 28-106, Florida Administrative Code.

Under Section 403.519, the Commission is the sole forum for the determination of need for the electrical power plant and associated facilities. In making its determination, the Commission must take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available. The Commission must also expressly consider the conservation measures taken by or reasonably available to the applicants or its members which might mitigate the need for the proposed plant and other matters within the jurisdiction which it deems relevant. The Commission's determination of need for the Polk County facility shall create a presumption of public need and necessity and shall create a presumption of public need and necessity and shall serve as the Commission's report required by Subsection 403.507(2) (a) (2), Florida Statutes. An order entered by the Commission pursuant to this hearing shall constitute final agency action.

Only issues relating to the need for the power plant will be heard at the February 12 and 13, 2001 hearing. Separate public hearings will be held, before the Division of Administrative Hearings at a later date to consider environmental and other impacts of the proposed plant and associated facilities.

Members of the public who are not parties to the need determination proceeding will have an opportunity to present testimony regarding the need for the proposed plant and associated facilities. All members of the public who wish to offer testimony should be present at the beginning of the hearing. All witnesses will be sworn in and will be subject to cross-examination at the conclusion of their testimony.

Written comments regarding the need for the proposed plant and associated facilities may be sent to the Commission at the following address:

Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0870
Re: Docket No. 001748-EC

Anyone wishing to become a party to the need determination proceeding should file an appropriate petition pursuant to Rule 25-22.039, Florida Administrative Code with the Director of the Commission's Division of Records and Reporting at the address listed above. Copies of the petition should be sent by mail to all parties. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be a qualified representative pursuant to Chapter 120, Florida Statutes, and Rule 28-106.106, Florida Administrative Code. Petitions for leave to intervene must be filed at least five (5) days before the final hearing, must conform with Rule 28-106.201 (2), Florida Administrative Code, and must include allegations sufficient to demonstrate that the intervenor is entitled to participate in the proceeding as a matter of constitutional or statutory right or pursuant to Commission rule, or that the substantial interests of the intervenor are subject to determination or will be affected through the hearing.

GENERAL LOCATION AND PROJECT DESCRIPTION

The proposed electrical power plant is estimated to produce 529 MW of net generating capacity. The proposed plant is to be located in the City of Auburndale, Polk County, Florida. The Project site is located approximately 1.5 miles southwest of downtown Auburndale and approximately 37 miles east of Tampa Bay. The proposed unit consists of two combustion turbine generators, two matched heat recovery steam generators, and one steam turbine generator. The proposed plant is estimated to commence commercial operation in the second quarter of 2003.

PREHEARING CONFERENCE

The prehearing conference is scheduled for:

1:30 p.m., Tuesday, January 30, 2001
Commission Hearing Room 182
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

The purpose of this prehearing conference will be for: (1) simplify the issues; (2) identify the positions of the parties on the issues; (3) consider the possibility of obtaining admissions of fact and of documents whichwill avoid unnecessary proof; (4) identify exhibits; (5) establish an order of witnesses; and (6) consider such other matters as may aid in the disposition of the action.

JURISDICTION

Jurisdiction over this matter is vested in the Commission by Sections 403.519, Florida Statutes.

APPLICATION

A copy of the Petition for Determination of Need and supporting exhibits is available for public inspection during normal business hours at the following location:

Florida Public Service Commission
Division of Records and Reporting
4075 Esplanade Way
Room 110 - Betty Easley Conference Center
Tallahassee, Florida

BY DIRECTION of the Florida Public Service Commission this 12th day of December, 2000.

(SEAL)

BLANCA S. BAYO, Director
Division of Records and Reporting

E-870 - 12-17; 2000

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