BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines Unit 2 Power Plant	))))	DOCKET NO. Submitted for filing: August 7, 2000

ORIGINAL

DIRECT TESTIMONY OF JOHN B. CRISP

ON BEHALF OF FLORIDA POWER CORPORATION

ROBERT A. GLENN
Director, Regulatory Counsel Group
FLORIDA POWER CORPORATION
P.O. Box 14042
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

GARY L. SASSO
Florida Bar No. 622575
Carlton, Fields, Ward,
Emmanuel, Smith & Cutler
Post Office Box 2861
St. Petersburg, FL 33731
Telephone: (727) 821-7000
Telecopier: (727) 822-3768

IN RE: PETITION FOR DETERMINATION OF NEED
BY FLORIDA POWER CORPORATION
FPSC DOCKET NO. ________

DIRECT TESTIMONY OF JOHN B. CRISP

I. INTRODUCTION AND BACKGROUND.

Q. Please state your name and business address.

A. My name is John B. Crisp, and my business address is Florida Power Corporation, One Power Plaza, 263 13th Avenue, St. Petersburg, Florida, 33701.

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

A. I am employed by Florida Power Corporation ("FPC" or the "Company"), as the Director of Integrated Resource Planning and Load Forecasting.

Q. Please describe your duties and responsibilities with Florida Power Corporation.

A. My responsibilities include coordinating the analysis and development of load forecasts and integrated resource plans ("IRPs") for the Company on an ongoing basis. The IRP process consists of developing load forecasts and examining supply-side and demand-side resources available to the Company on its existing system and potentially available to the Company over its planning horizon to determine and recommend to the Company's management changes or additions to those resources to enable the Company to fulfill its obligation to serve. In this connection, the Planning Department prepares and presents the Company's Ten-Year Site Plan ("TYSP") documents that are filed with the Florida Public Service Commission ("PSC" or the "Commission") from time to time, in accordance with applicable statutory and regulatory requirements. In my capacity as Director of Integrated Resource Planning and Load Forecasting, I presented the Company's 1999 TYSP filing to the Commission at the planning workshop scheduled for that purpose last year, I represented the Company in Docket No. 981890-EU, addressing the aggregate electric utility reserve margins planned for Peninsular Florida, and I oversaw the completion of the Company's most recent TYSP document, filed in April 2000.

Q. Please summarize your educational background and employment experience.

A. I attended the Georgia Institute of Technology in Atlanta, Georgia. I received a Bachelor of Science degree in Industrial and Systems Engineering in 1979. As part of the requirements for my job at Oglethorpe Power Corporation, I also completed Georgia Tech's International Management Executive Program in 1990.

My power industry employment began with Oglethorpe Power Corporation in 1988, where I was involved in the management of generation planning and construction, system operations and dispatch, operations planning, load forecasting, integrated resource planning, and strategic and business planning. I also developed and implemented strategies for asset leasing and fixed price contract supply, and implemented an operations resource planning and marketing system for sales of excess generation capacity and energy.

After leaving Oglethorpe Power in 1995, I joined an independent power producer, Tenaska Inc., as its Manager of Power Services Development. In this position, I was responsible for developing and marketing capacity and energy proposals for combustion turbine and combined cycle facilities that served wholesale requirements and cogeneration functions. In February 1997, I joined Dynegy Marketing and Trade (then known as Electric Clearinghouse) in a start-up position in their Atlanta field office. In this position, I coordinated the development and implementation of power marketing strategies in the Southeast Reliability Council ("SERC") and the Florida Reliability Coordinating Council ("FRCC") regions. I was responsible for market analysis, deal identification and prioritization, capacity and energy pricing, negotiations, portfolio balance, and achievement of revenue and profit objectives. I also assisted Dynegy in the development of commercial marketing alliances, power plant and asset acquisition, merchant market evaluation, merchant plant siting, power plant marketing, and strategic asset deployment.

In May 1999, I joined FPC as its Director of Integrated Resource Planning and Load Forecasting.

II. PURPOSE AND SUMMARY OF TESTIMONY.

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

A. I am testifying on behalf of FPC, in support of its Petition for a Determination of Need, (1) to provide an overview of the "Hines 2" power plant that FPC proposes to build, (2) to discuss the Company's need for the Hines 2 plant, (3) to describe the planning process that led the Company to identify the Hines 2 plant as its next-planned, supply-side alternative, (4) to explain and describe the steps the Company has taken to seek out superior supply-side alternatives through the Request for Proposal process, (5) to discuss the Company's evaluation of competing proposals, and (6) to explain the Company's decision to proceed with the Hines 2 plant. Under separate cover, I am filing confidential testimony and exhibits discussing FPC's evaluation of two competing proposals whose sponsors have requested confidential treatment of the terms of their proposals. I will refer to these bidders in my public testimony as Bidders A and B.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to the public portion of my testimony.

JBC-1. **Florida Power Corporation's Need Study for Hines 2 (with attachments).**

JBC-2. **Florida Power Corporation's Notice of Filing Request for Proposals (dated January 26, 2000).**

III. OVERVIEW OF HINES 2 PROJECT.

Q. Please provide an overview of the Hines 2 power plant.

A. The Hines 2 power plant will be a state-of-the-art, natural gas-fired, combined cycle power plant with a nominal rating of 530 MW. FPC will build the plant at the Hines Energy Complex ("HEC") site in Polk County, Florida. The Company proposes to place the plant into commercial operation by November 30, 2003. The plant will use distillate oil as a backup fuel source. The plant will be a highly efficient unit with a projected average heat rate of 6,975 Btu/kWh. Although the Company has previously obtained Site Certification from the Florida Siting Board for the HEC in order to build the Hines 1 power plant (and for 3,000 MW of ultimate site capacity), we are seeking at this time a supplemental Site Certification for the purpose of building the Hines 2 generating unit.

The estimated total direct cost for building the unit will be $197.6 million, and our estimated transmission and interconnection costs will be $5.6 million.

We believe that the Hines 2 plant will enable the Company to meet the reliability and economic needs of our ratepayers during its 25 years of expected service and that it will provide a superior source of efficient, low-cost power to our ratepayers during that time. The Hines 2 plant will be fully committed to meeting these needs.

IV. NEED FOR THE HINES 2 POWER PLANT.

Q. Please explain FPC's need for the proposed Hines 2 power plant.

A. I am sponsoring and filing with my testimony a detailed Need Study (Exhibit JBC-1) that explains in detail how and why the Company arrived at its determination to seek approval from the Commission to build the Hines 2 plant. The information and data set forth in our Need Study have been prepared or assembled by FPC's Integrated Resource Planning and Load Forecasting Department, and provide the basis for our planning work and conclusions. As we discuss in our Need Study, the Company needs the Hines 2 power plant for several reasons.

1. First, the Company needs Hines 2 to maintain electric system reliability and integrity. FPC has recently agreed to increase its Reserve Margin planning criterion from a minimum of 15 percent to a minimum of 20 percent, effective in the summer of 2004. (Please see App. C to FPC's Need Study). The Company needs to add substantial new capacity to its system in order to meet this planning objective. Although the Company wanted to have the leeway to implement this new planning criterion as late as the summer of 2004, in our planning judgment we believe that it will be important to achieve this planning criterion by the winter of 2003/04. By putting the Hines 2 unit in service by November 30, 2003, we will meet this goal. As described more fully in the detailed Need Study (JBC-1), the Hines 2 unit will enable the Company to maintain planning reserves above the 20 percent minimum during the winter of 2003/04 and ensuing periods, and the Company should not need to build or contract for additional supply-side resources until 2005 in order to meet or exceed its 20 percent minimum Reserve Margin planning criterion.

2. Second, in order to meet its Reserve Margin planning criterion, and to comply with the directives of the Florida Energy Efficiency and Conservation

Act ("FEECA"), the Company has relied increasingly over the last decade upon dispatchable demand-side resources to reduce the "firm" load that must be protected by planning reserves. This has included placing a large number of willing customers on load-management or interruptible service in exchange for reduced tariffs. Due to the Company's experience with its Residential Energy Management program over the last two years (i.e., attrition by customers due to dissatisfaction with service interruptions), the Company believes that it is prudent (from a financial and reliability perspective) to reduce its reliance on dispatchable demand-side alternatives. Accordingly, as developed more fully in the Company's recent Demand-Side Management ("DSM") Plan filing and the TYSP, FPC has revised its Residential Energy Management program in favor of adding more supply-side generating capacity to its total reserves.

This is significant for two reasons: (a) We are facing a period of some uncertainty about how the Company's Energy Management program will be received by our residential customers, which creates the need, in our judgment, for more "insurance" in the form of additional hard generating assets in our fleet, and (b) it is our judgment, in any event, that the Company should carry more supply-side assets as part of its total reserves than it has in the past. This is the reason the Company projected in its recent TYSP filing a stepped-down reliance on demand-side reserves. (See App. D to FPC's Need Study, JBC-1, at pp. 15-20). The upshot of this is that, although FPC continues to believe that certain, specific demand-side programs provide an important and cost-effective resource, FPC will be counting more in the future on generating units to meet its customers' needs than on the willingness of customers to accept frequent curtailments in service.

To illustrate, for the winter of 2003/04, FPC's estimated firm load at time of peak load is 8,231 MW and its estimated non-firm peak load is 1,150 MW, which results in an estimated total peak load of 9,381 MW. Without the Hines 2 plant in service, FPC's firm supply-side resources (power plants on its system and firm power purchase agreements) would be 9,748 MW, or 1,517 MW greater than the estimated firm peak load. Because the Company calculates its Reserve Margin based on the relationship between only firm load and firm capacity available to serve that load, FPC's Reserve Margin (without Hines 2) would be 18 percent (based on reserves of 1,517 MW). The relationship between FPC's firm supply-side resources and its estimated total load (firm and non-firm) would be much lower, however. Specifically, FPC would have only 367 MW of firm capacity reserves in excess of estimated total peak load. This demonstrates that, in the event of weather extremes or unavailable capacity, we would have to expect a significant number of customers who participate in FPC's Energy Management program to willingly accept their non-firm service so that we could support the remaining firm load with our firm supply-side resources.

The PSC Staff on occasion has examined the relationship between (a) our firm supply-side resources and (b) the combined total of those resources and our demand-side resources. (This combined total is sometimes called "total reserves," as distinguished from our "Reserve Margin," which measures only the relationship between firm capacity and firm load.) Using this approach, in the winter of 2003/04 (without Hines 2), less than one fourth of FPC's "total reserves" would consist of firm capacity. This is simply another way of showing that, with the current resource mix, the Company has expected customers participating in the Company's Energy Management program to willingly accept their non-firm service provisions in order to be able to provide firm service to the remaining firm customers with available firm capacity. In the past, the Staff has been critical of the Company's reliance on dispatchable demand-side resources to make up a significant part of the Company's total reserves. By building Hines 2, the Company will reduce its reliance on demand-side resources. Thus, in the winter of 2003, with Hines 2 in service, the Company will be able to increase the portion of its total reserves attributable to firm capacity to almost one half (45 percent). The Company thus needs the Hines 2 plant to enhance in this manner its electric system reliability and integrity.

3. Third, the Hines 2 plant will meet the Company's need to be able to provide to its customers adequate electricity at a reasonable cost. Specifically, the Hines 2 plant will meet FPC's economic need to realize fuel savings that can be achieved through the addition of a state-of-the-art gas-fired, combined cycle unit to its fleet. FPC estimates conservatively that it will achieve fuel savings in the range of $40 million per year from the Hines 2 plant.

4. Finally, the Hines 2 unit will meet FPC's need for electric system reliability and integrity, and the Company's need for sufficient resources to provide adequate electricity at a reasonable cost, in the further sense that the plant will add diversity to the Company's supply-side mix. Taking into account the

Company's demand and energy requirements (i.e., load shape, load factors and seasonal peaking characteristics), the Company has ample baseload and peaking capacity, including purchased power resources. Baseload resources include nuclear, coal, coal-by-wire, and cogeneration contracts priced on the basis of coal units. The potential additions to FPC's fleet that generate the best value tradeoffs at this time are resources that are flexible and responsive enough to meet the challenges of intermediate service, and yet capable of shifting to baseload operations as needed if prevailing economic or operating conditions warrant the shift. Combined cycle plants are very cost effective and well suited for this service regime. The proposed Hines 2 unit is a dual-fuel capable combined cycle unit that will meet all of these operating requirements, increase the fleet's fuel diversity, and provide a cost-effective means to meet clean air compliance requirements. FPC has only two other comparable units (Hines 1 and Tiger Bay) in its fleet. The Hines 2 unit addition will serve the Company's need to maintain appropriate fuel and operating diversity in its fleet, which will thereby enhance the reliability and cost-effectiveness of the Company's generation system as a whole.

V. THE COMPANY'S INTEGRATED RESOURCE PLANNING PROCESS.

Q. Please explain FPC's Integrated Resource Planning Process.

A. FPC uses an IRP process to determine the most cost-effective mix of supply-side and demand-side alternatives that will reliably satisfy the Company's future energy needs. We have explained this process at some length in our Need Study and in our TYSP (April 2000), which we are submitting as Appendix D to FPC's Need Study (JBC-1).

For planning purposes, we begin with two basic reliability measures: (1) a minimum Reserve Margin planning criterion of 15 percent, no later than the winter of 2003/04, replaced by a minimum 20 percent Reserve Margin planning criterion, commencing no later than the summer of 2004, and (2) an assisted Loss of Load Probability ("LOLP") criterion of one day in ten years (sometimes expressed as 0.1 days per year). The Reserve Margin criterion is deterministic and provides a measure of FPC's ability to meet its forecasted seasonal peak firm load. The LOLP criterion is probabilistic, and provides a measure of FPC's ability to meet its load throughout the year taking into consideration unit failures, unit maintenance, and assistance from other utilities. Typically, we will be driven to add supply-side resources by our Reserve Margin planning criterion before our LOLP criterion would become implicated. But the LOLP criterion provides a meaningful supplemental reliability measure. Of course, we must also exercise planning judgment to take into account other facts, information, and assumptions that may not be captured fully in these planning criteria that may nonetheless have a bearing on electric system reliability and integrity, including, for example, our experience with our DSM programs and with the actual performance of our generating units.

As we discuss in the TYSP and Need Study documents, as a part of the planning process, the Company develops forecasts, including demand and energy, fuel prices, and economic assumptions. (These are addressed more fully in the Need Study and at pp. 83-85 of our recent TYSP). We then identify potential supply-side resource alternatives and collect extensive cost and operating data for the purpose of modeling these alternatives. We pre-screen the generation alternatives to isolate those generation technologies that are commercially feasible and both technologically and economically compatible with FPC's system for further, more detailed analysis.

Next, we use the proprietary PROVIEW optimization program to evaluate economic issues associated with various generation alternatives. With this optimization program, we are able to (a) evaluate a multitude of potential resource plans generated from combinations of future resource additions that meet system reliability criteria, (b) assess the relative economics (revenue requirements) of each plan, and (c) examine other system constraints such as environmental requirements (for example, SO_2 compliance). PROVIEW will rank all resource plans by system revenue requirements, with the plan with the lowest cumulative present worth revenue requirements ("CPWRR") ranked first, over the study period. Through this process, we develop the Base Optimal Supply-Side Plan. (Please see our Need Study, JBC-1, for a more detailed discussion of our supply-side screening procedure.)

Just as we evaluate potential supply-side resources, we conduct a careful screening of demand-side resources as well. Extensive analysis was performed during the DSM Goals and DSM Plan proceedings (Docket Nos. 971005-EG and 991789-EG, respectively) to assess the projected cost, performance, viability, and cost-effectiveness of a wide range of dispatchable and non-dispatchable DSM options. We use the demand-side screening model DSVIEW to conduct the cost-effectiveness evaluation.

The Base Optimal Supply-Side Plan is used to establish avoidable units for cost effectiveness screening of future demand-side resources. We then test each future demand-side alternative individually in this plan over the DSM study period to determine the benefit or detriment that the addition of the demand-side resource provides to the overall system. DSVIEW calculates the benefits and the costs for each demand-side measure evaluated and reports the appropriate benefit-to-cost ratios for the Rate Impact Measure ("RIM"), the Total Resource Cost Test ("TRC"), and the Participant Test. We then bundle together the demand-side programs that pass all three tests of cost-effectiveness to create demand-side portfolios.

In December 1999, FPC presented its proposed DSM plan and strategies, together with the results of its demand-side screening analysis, to the Commission for review and approval. We are including our DSM filing herewith as Appendix K to our Need Study, JBC-1. The Commission approved FPC's DSM filing on April 17, 2000, by Order No. PSC-00-0750-PAA-EG. We are filing that Order herewith as Appendix L to our Need Study, JBC-1.

Once we have analyzed supply-side and demand-side alternatives, we then optimize these together to formulate an Integrated Optimal Plan. To do this, we assimilate the cost effective DSM programs identified in the DSM screening process and then re-optimize the supply-side resource options that are available to meet the Company's reliability criteria over the planning period. In so doing, we identify the ten-year plan that provides the lowest revenue requirements for FPC's ratepayers while still providing reliable, efficient service.

We then test the plan that provides the lowest revenue requirements using sensitivity analyses to make sure it is the most cost-effective plan. We evaluate the economics of the plan under high and low forecast scenarios for load, fuel, and financial assumptions to ensure that the plan does not unduly burden the Company or its ratepayers in the future. A sound plan, based on our sensitivities, will be retained; an unsound one will be returned to the process to be re-evaluated. Through this process, we establish our Base Expansion Plan.

We may reach a preliminary conclusion, through this process, that the Company should make a significant resource commitment, such as building a power plant or entering into a firm power purchase arrangement. At that point, the Company analyzes more detailed cost estimates, technical, financial, corporate, and regulatory considerations to determine the best course of action to pursue.

VI. IDENTIFICATION OF HINES 2 AS THE NEXT-PLANNED GENERATING ALTERNATIVE.

Q. Please explain how the Company identified the Hines 2 power plant as its next-planned generating alternative.

A. Through the IRP process I have just described, we developed a Base Expansion Plan calling for the addition of three combustion turbine units at the Intercession City Site by December 2000 (currently in development) followed by the projected combined cycle expansion of the HEC with Units 2 through 5, which are forecast to be in service by November 2003, 2005, 2007, and 2009, respectively. These new HEC units will be state-of-the-art combined cycle units similar to HEC Unit 1 (which is currently in service). As new advances in combined cycle technologies mature, FPC will continue to examine the merits of these new alternatives to ensure the lowest possible expansion costs.

We performed sensitivity analyses on load, fuel, and financial forecasts with respect to this base plan. We concluded that the base plan was robust concerning changes in load, fuel, and financial forecasts. The low load forecast sensitivity required less combined cycle generation, and the high load forecast indicated that we would need to add more combined cycle and combustion turbine units to our system.

Our sensitivity runs did not suggest that any significant reconsideration of the base plan was necessary or appropriate. The low fuel forecast did not point to any changes to the base plan either. The high fuel forecast indicated a potential increase in benefits for future advanced technology combined cycle units (as the technologies mature) versus the current state-of-the-art combined cycle units but did not suggest a change in the next-planned unit. When we held the current differential price of oil and gas to coal constant over time, this pointed toward a slight decrease in the value for combined cycle units, but again, did not suggest a change in the next-planned unit. The variances resulting from these fuel sensitivities were not significant enough to consider departing from the Base Expansion Plan or to reconsider other alternatives to Hines 2 as the next-planned generation addition.

Subject to identifying superior opportunities by issuing a Request for Proposals, we concluded that the Hines 2 plant was our preferred next-planned generating alternative. We were able to reach this conclusion based on the modeling and other evaluation that I have already described.

VII. FPC'S REQUEST FOR PROPOSALS.

Q. Please describe FPC's efforts to solicit proposals from other supply-side providers.

A. In accordance with PSC Rule 25-22.082, FPC issued a Request for Proposals ("RFP") on January 26, 2000, soliciting proposals for other generating resources that might prove superior to Hines 2 as a supply-side alternative. (See App. P to the Need Study, JBC-1). We filed a copy of this RFP with the PSC on January 26, 2000. (See JBC-2).

I should point out that we engaged Mr. Alan Taylor of PHB Hagler Bailly – an expert in utility industry resource planning and solicitations – to consult with us concerning our RFP and evaluation process and to help us elicit and obtain superior supply-side contract opportunities. Mr. Taylor is filing testimony in this proceeding about our RFP, solicitation process, and evaluation of proposals.

In our RFP, we explained that we had identified Hines 2 as our next-planned generating unit, and we invited interested parties to make alternative proposals to the Company that may offer superior value and other attributes. We purposely set forth very few limitations in the RFP in order to encourage utilities and developers to submit creative proposals to us. We encouraged (but did not require) interested parties to provide notice to us by February 10, 2000, regarding their intent to submit a proposal, and we set up a pre-bid meeting with interested persons (also not required) on February 18, 2000, at the Tampa Airport Marriott to provide an opportunity for interested persons to ask questions and to discuss the RFP.

Thirteen companies submitted notices of intent to bid on the project, and representatives of twelve entities attended the pre-bid meeting. Also, we invited the PSC Staff to attend the pre-bid meeting, and Roland Floyd did in fact attend. At the meeting, we elaborated on the RFP and encouraged open discussion by all participants (while providing for opportunities to make confidential inquiries to the Company as well). Among other matters, we indicated in response to questions raised before and during the meeting that we would entertain proposals by bidders to build a generating unit at FPC's HEC.

In the RFP, we identified an RFP contact person (Michael D. Rib) to handle inquiries about the RFP, and we set forth his address, phone number, fax number, and email address. We provided answers to various inquiries during the time before submission of bids and circulated information that we thought might be of general interest to all bidders.

In our RFP, we indicated that proposals were due by March 27, 2000. Although many more potential bidders had expressed an intention to bid, two bidders ultimately submitted proposals for our consideration, whom I will call Bidder A and Bidder B in the public portion of my testimony. Their complete proposals and information concerning our evaluation of these proposals have been submitted in the Confidential Section of the Need Study, (Confidential) JBC-3, filed under seal with the PSC, and further discussed in the confidential portion of my testimony, in deference to their requests for confidential treatment of the terms of their proposals.

Other bidders advised us informally prior to the due date that they could not offer an alternative that could compete with Hines 2.

VIII. THE EVALUATION PROCESS.

Q. Did you evaluate the proposals you received?

A. Yes, we did.

Q. Please describe the evaluation process that you followed.

A. We began by following up with each bidder to request information that we had asked for in the RFP but that the bidders had not included in their initial proposals. In some instances, we sought clarifications of the proposals.

With the benefit of the clarifying information we received, we then conducted an analysis of the comparative economics of each proposal using both the PROSCREEN and PROSYM models, and we carefully evaluated the non-price attributes as well.

The Hines 2 alternative proved to be significantly superior to the two proposals FPC received on the basis of economic factors alone, calling for significantly lower revenue requirements over the life of the project. The results of our economic evaluations are set forth in Appendices 5 and 6 to the Confidential Section of the Need Study, (Confidential) JBC-3. Likewise, both proposals proved significantly disadvantageous in comparison to Hines 2 based on non-price attributes. The results of our analysis of the non-price attributes of each proposal are set forth in Appendices 7 and 8 to the Confidential Section of the Need Study, (Confidential) JBC-3. In fact, even if the proposals had been even with Hines 2 on economic factors (which they were not), Hines 2 would provide superior value and reliability to our ratepayers based on non-price attributes alone.

Based on this evaluation, we recommended to FPC's management that the Company proceed with the Hines 2 power plant. We promptly notified Bidders A and B that we would not be able to proceed with their projects.

IX. MOST COST-EFFECTIVE ALTERNATIVE.

Q. Is the Hines 2 power plant the Company's most cost-effective alternative for meeting its need?

A. Yes, it is. As I have described, the Company conducted a careful screening of various other supply-side alternatives as part of its IRP process before identifying Hines 2 as its next-planned generating alternative. We were able to screen out less cost-effective supply-side alternatives, identifying Hines 2 as the most cost-effective alternative available to us.

In issuing the RFP, we hoped to elicit superior, more cost-effective power purchase agreement opportunities, but we were unable to do so. The two proposals that we did receive proved to be considerably less cost-effective than Hines 2. In addition, during the RFP process, we were advised informally by would-be bidders that they were unable to offer proposals that could compete effectively on a cost basis with Hines 2. This provided further assurance that we were on the right track in selecting Hines 2 as our next-planned generating alternative.

X. CONSERVATION MEASURES.

Q. Did FPC attempt to mitigate its need for the proposed power plant by pursuing conservation measures reasonably available to it?

A. Yes, we did. In fact, as I have described, the Company has pushed the envelope in testing demand-side resources prior to adding hard generating assets to its existing fleet. For the reasons we have given, we have concluded that we have reached a practical limit, encompassing both reliability concerns and cost-effectiveness issues, on the portion of FPC's resource mix that can be satisfied with load control measures like the Energy Management program. FPC's recent modifications to the Energy Management program will help the Company achieve and maintain a more appropriate balance of supply-side and demand-side resources by limiting the overall growth of the Energy Management program as supply-side resources are added and improve overall program cost-effectiveness.

XI. BENEFIT TO THE STATE.

Q. Is the Hines 2 plant consistent with the needs of Peninsular Florida?

A. Yes, the Hines 2 power plant will assist FPC in meeting its minimum 20 percent planned Reserve Margin and will also assist Peninsular Florida in maintaining planning reserve levels above the 15 percent minimum level targeted for the FRCC region. In the (current) timeframe of this resource decision, all of the significant utilities in the FRCC appear to be moving to reinforce their system reserves, and, as a result, there have not been underutilized assets available to purchase from other utilities. The absence of other utilities offering capacity for sale, as well as the additional RFP announcements that have occurred since our RFP was announced, further reinforces the consistency of this addition with the capacity needs of Peninsular Florida.

XII. CONSEQUENCES OF DELAY.

Q. What will be the consequences of delay in implementing the Hines 2 project?

A. The most significant consequences of delaying this resource addition would be (1) the additional risk imposed on FPC's customers resulting from the overall performance of and the transition in the Company's load management programs, (2) the loss of significant fuel savings associated with Hines 2, and (3) the loss system benefits, for example, fuel and system diversity, flowing from the Hines 2 plant. FPC has estimated these delay cost impacts to range from $40-70 Million over a one to two year delay, respectively. However, this attempt to quantify the deferred revenue requirements simplistically for a delay in implementation of this facility ignores a wealth of benefits that this option offers at this time.

XIII. CONCLUSION.

Q. Please summarize the benefits of the Hines 2 power plant.

A. FPC needs the Hines 2 power plant to maintain its electric system reliability and integrity and to provide its ratepayers with adequate electricity at a reasonable cost. By building the plant, FPC will be able to meet its commitment to increase its Reserve Margins, and it will do so by improving not just the quantity, but also the quality, of its total reserves – adding more hard generating assets to the Company's overall resource mix. The plant will add diversity to FPC's fleet of generating assets in terms of fuel, technology, age, and functionality of the unit.

Having exhausted conservation measures reasonably available to the Company, FPC selected the Hines 2 plant as its most cost-effective alternative for meeting its needs. The plant will be a state-of-the art, fuel efficient, environmentally benign installation that will be located on a site substantially pre-approved for exactly this kind of power resource. We are pleased to be able to add this plant to FPC's fleet and to Peninsular Florida.

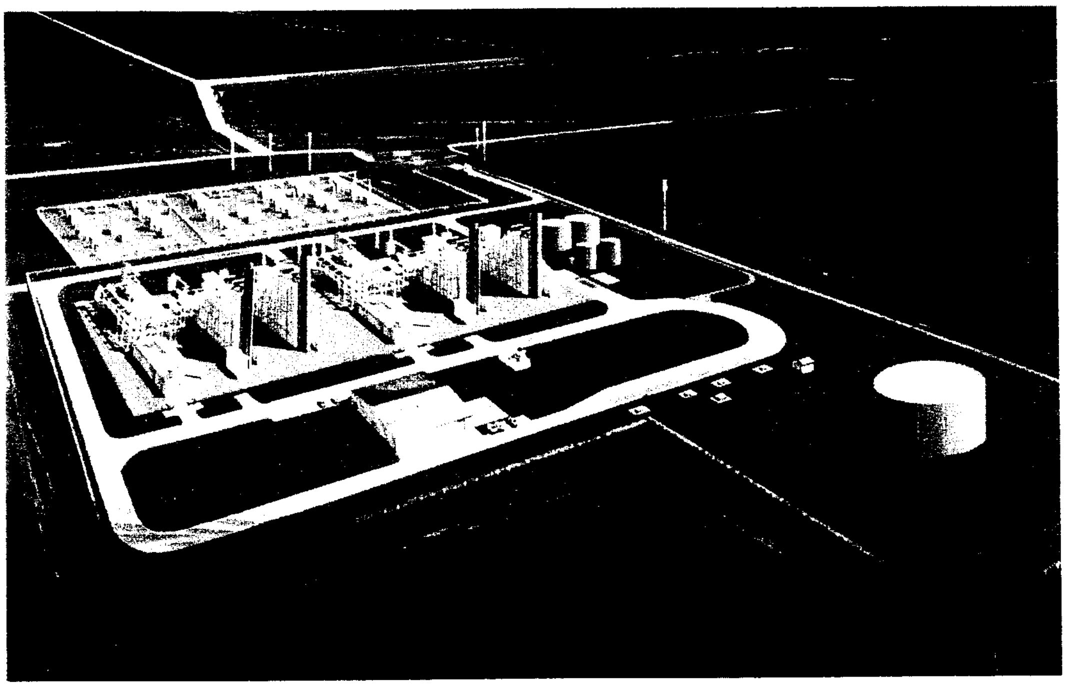
Q. Does this conclude your testimony?

A. Yes, it does.

THE NEED STUDY

In Support of

FLORIDA POWER CORPORATION'S PETITION FOR DETERMINATION OF NEED OF HINES 2 POWER PLANT



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

August 7, 2000

FLORIDA POWER CORPORATION
NEED STUDY

TABLE OF CONTENTS

THE NEED STUDY

IN SUPPORT OF
FLORIDA POWER CORPORATION'S
PETITION FOR DETERMINATION OF NEED
OF HINES UNIT 2 POWER PLANT

I. Executive Summary.

Florida Power Corporation ("FPC" or "the Company") plans to add 530 megawatts ("MW") of electrical generating resources to its system by November 30, 2003, in order to continue to provide reliable, adequate, cost-effective service to its customers. The most cost-effective way for FPC to meet this need is to construct a 530 MW state-of-the-art natural gas-fired, combined cycle power plant at FPC's existing Hines Energy Complex ("HEC") in Polk County, Florida. This unit is called "Hines 2."

The Company has come to the decision to build the Hines 2 plant as the result of the Company's ongoing Integrated Resource Planning ("IRP") process, involving an extensive analysis of supply-side and demand-side alternatives, based on feasibility, financial considerations, fuel diversity, and other relevant factors, and FPC's evaluation of its Request for Proposal ("RFP") for competitive supply-side alternatives. As a resolution of the Reserve Margin Docket No. 981890-EU, the Company committed to achieve at least a 20 percent Reserve Margin no later than the summer of 2004. Due to the significant customer attention recently experienced within the residential Energy Management program, and the Company's impending transition to new Energy Management initiatives, FPC has made the planning judgment that it needs to implement the 20 percent minimum Reserve Margin planning criterion by Winter 2003/04, adding 530 MW of hard assets at that time. FPC needs this additional generating capacity (1) to achieve and maintain system reliability and integrity; (2) to continue to provide adequate electricity at a reasonable cost; and (3) to add diversity to the Company's supply-side resource mix.

The Company has determined that the Hines 2 plant will best meet the Company's need for additional generating capacity. As a state-of-the-art gas-fired, combined cycle plant, the Hines 2 plant will provide both reliability benefits and significant fuel savings to FPC's ratepayers, in addition to assisting the Company in reducing overall emissions and meeting the requirements of the Clean Air Act.

To ensure that FPC will be pursuing the best available alternative, the Company issued an RFP to solicit supply-side alternatives to building the Hines 2 plant. The Company carefully evaluated resulting proposals based on both price- and non-price attributes. After considering relevant price- and non-price considerations, the Company ultimately concluded that the Hines 2 unit was superior to the competing alternatives offered.

The Company is filing herewith its petition for a determination of need with the Florida Public Service Commission ("PSC" or the "Commission") for approval to build the Hines 2 unit. This Need Study is being submitted in support of FPC's petition for a determination of need.

II. The Company and its Existing Resources.

A. Description of the Company.

FPC is an investor-owned public utility, regulated by the PSC, with an obligation to provide electricity to approximately 1.4 million retail customers in its service area, which covers approximately 20,000 square miles in 32 of the state's 67 counties, as shown on the map in Appendix A. FPC supplies electricity at retail to approximately 350 communities and at wholesale to about nine municipalities in the State of Florida.

FPC serves one of the faster growing areas of the country. Its forecasted annual retail customer growth is projected to be 1.6 percent over the next ten years. Retail sales growth is projected to be approximately 2.3 percent during the same period.

B. Generation Facilities.

FPC currently owns and operates one nuclear steam unit (782 MW)[1], two combined cycle units (752 MW), 12 fossil steam units (3,958 MW), and 44 combustion turbine units (2,775 MW) in the State of Florida. FPC's existing total net generating capability in the winter is 8,267 MW. In addition, FPC has utility purchased power capacity resources of 469 MW and non-utility purchased power capacity resources of 831 MW. FPC's current total existing winter capacity resource is 9,567 MW, as shown in Table 1.

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[1] This number is based on FPC's current ownership percentage of the Crystal River nuclear steam unit.

TABLE 1

FLORIDA POWER CORPORATION
TOTAL CAPACITY RESOURCE
Power Plants And Purchased Power

Plants	Number Of Units	Net Dependable Capability KW Winter
Nuclear Steam Plant		
Crystal River	1	782,000 *
Fossil Steam (FS) and Combined Cycle (CC) Plants		
Crystal River (FS)	4	2,316,000
Anclote (FS)	2	1,044,000
Paul L. Bartow (FS)	3	452,000
Suwannee River (FS)	3	146,000
Hines Energy Complex (CC)	1	529,000
Tiger Bay (CC)	1	223,000
Total FS and CC	14	4,710,000
Total Steam (Nuclear, FS and CC)	15	5,492,000
Combustion Turbines		
DeBary	10	762,000
Intercession City	11	912,000
Bayboro	4	232,000
Bartow	4	219,000
Suwannee	3	201,000
Turner	4	194,000
Higgins	4	134,000
Avon Park	2	64,000
University of Florida	1	41,000
Rio Pinar	1	16,000
Total Combustion Turbines	44	2,775,000
Total Units	59	
Total Net Generating Capability		**8,267,000**
** Adjusted for sale of 8.2% of total capacity*		
Purchased Power		
Qualifying Facilities	15	831,000
Investor Owned Utilities	2	469,000
TOTAL CAPACITY RESOURCE		**9,567,000**

FPC's non-utility purchased power contracts are listed in Table 2.

TABLE 2

FLORIDA POWER CORPORATION
QUALIFYING FACILITY GENERATION CONTRACTS
AS OF DECEMBER 31, 1999

FACILITY NAME	FIRM CAPACITY (MW)
BAY COUNTY RES. RECOV.	11
CARGILL	15
CFR-BIOGEN	74
DADE COUNTY RES. RECOV.	43
EL DORADO	114
LAKE COGEN	110
LAKE COUNTY RES. RECOV.	13
LFC JEFFERSON	8
LFC MADISON	8
MULBERRY	79
ORLANDO COGEN	79
PASCO COGEN	109
PASCO COUNTY RES. RECOV.	23
PINELLAS COUNTY RES. RECOV. 1	40
PINELLAS COUNTY RES. RECOV. 2	15
RIDGE GENERATING STATION	40
ROYSTER	31
TIMBER ENERGY 1	13
US AGRICHEM	6
TOTAL	**831**

C. Transmission and Distribution Facilities.

FPC owns approximately 4,700 miles of transmission lines and over 80 transmission substations. FPC's distribution system includes over 25,000 circuit miles and over 270 distribution substations. FPC has 54 points of interconnection with other utilities within its transmission system, and it is part of a nationwide interconnected power network. The existing FPC system in the State of Florida, including generating plants, substations, transmission lines and service area, is shown on the system map in Appendix B.

III. FPC's Resource Planning Process: Its Criteria, Forecasts, and Assumptions.

A. Introduction.

FPC employs a planning process known as Integrated Resource Planning ("IRP") to assess the Company's resource needs. This involves updating key planning forecasts and assumptions, identifying a wide range of resource alternatives, assessing the alternatives in the context of the Company's continuing operations, and ultimately selecting resource additions required to meet the needs of its customers. IRP is well established in the electric utility industry, has long been used by FPC and other electric utilities located within and outside the State of Florida, and is consistent with the requirements of the Energy Policy Act of 1992.

Integrated Resource Plans are forward-looking studies that (i) determine if there is a need for new electric capacity resources at a particular future time that cannot be mitigated by existing or additional cost-effective Demand Side Management ("DSM") programs and, if there is such a need, (ii) identifies the combination or portfolio of resources available to meet that need that is the most cost-effective for FPC's customers. FPC's determination to seek approval to build Hines 2 in this proceeding is an outgrowth of the Company's ongoing IRP process as well as FPC's specific assessment of market options and financial and strategic considerations.

B. Dual Reliability Criteria: Reserve Margin and Loss of Load Probability.

FPC plans its resources in a manner consistent with utility industry planning practices, utilizing a dual reliability criteria: a minimum Reserve Margin planning criterion and a maximum Loss of Load Probability ("LOLP") criterion. The Reserve Margin planning criterion is deterministic and measures FPC's ability to meet its forecasted seasonal peak load with firm capacity. LOLP is a probabilistic criterion that measures FPC's ability to meet its load throughout the year, taking into account unit failures, unit maintenance, and assistance from other utilities. The standard LOLP reliability threshold value in the electric utility industry, and the criterion used by FPC, is a maximum of 0.1 days per year.

By using both the Reserve Margin and LOLP planning criteria, FPC's overall system is designed to have sufficient capacity for peak load conditions, and the generating units are selected to provide reliable service under all load conditions. FPC has based its planning on the use of a dual reliability criteria since the early 1990s, a practice that has been accepted by the PSC over time. Using the dual criteria, FPC has found that resource additions are typically triggered to meet Reserve Margin thresholds before LOLP becomes a factor, as is the case with FPC's next-planned capacity addition for the winter of 2003/04. However, FPC still considers LOLP a meaningful supplemental reliability measure.

FPC's current minimum Reserve Margin threshold is 15 percent. The PSC recently approved a joint proposal from the investor-owned utilities in peninsular Florida – FPC, Florida Power & Light Company, and Tampa Electric Company – to increase minimum planning Reserve Margin levels to at least 20 percent by the summer of 2004 (Order No. PSC-99-2507-S-EU, Docket No. 981890-EU, attached as Appendix C to this Need Study). FPC proposed to increase its minimum Reserve Margin criterion from 15 percent to 20 percent to improve the quality and depth of its reserves and to help allay concerns raised by PSC Staff in the Generic Reserve Margin docket. By constructing the Hines 2 plant, FPC will meet its commitment to increase its planning reserves.

C. Key Planning Forecasts and Assumptions.

As the Company moves forward along its planning horizon, the Company seeks to make significant resource selection decisions based on the best information available to the Company at the time. Accordingly, the Company updates key factors and assumptions in the course of evaluating its overall resource plan. These factors are addressed in the ensuing sections of this report covering energy sales, customer demand, fuel prices, economic and financial assumptions, a summary of the existing supply-side and demand-side resources currently available, and an assessment of cost and performance of new resource alternatives available to the Company.

1. Demand and Energy Forecast.

Economic and Demographic Assumptions and Forecast Methodologies. The IRP process and ensuing supplemental analyses use many inputs and assumptions that are ultimately taken into account to develop FPC's most cost-effective capacity resource or optimal supply-side plan. The inputs and assumptions result from a number of parallel activities conducted for the IRP process. One such activity is energy and demand forecasting. FPC's long-term forecast of customers, energy sales, and seasonal peak demands are vital inputs in the IRP process.

FPC's forecasts used in the IRP process are called "long-term" forecasts because they attempt to capture the long-term trends in FPC's customer, energy sales, and peak demand growth over the next ten years. FPC's forecasts are reported annually for the next ten-year forecast horizon, in this case, the period 2000 through 2009. Because the forecasts are "long-term," they do not project economic business cycles beyond the first few years of the forecast. Rather, they identify a trend that cuts through the middle of any future business cycle fluctuations, thus reducing the risk that the forecasts will vary widely from actual economic conditions in the future.

With respect to this forecasting activity, there are a number of assumptions that serve as inputs to the forecasts based on economic and demographic factors, such as weather conditions, population growth trends, economic growth trends, and the regulatory environment. The assumptions underlying FPC's energy load and sales forecasts used in the IRP process are discussed in detail in FPC's Ten Year Site Plan ("TYSP") filed with the PSC in April 2000. See Appendix D, pp. 27-35. The assumptions are based not only on the work of experts within FPC but also the research efforts of a number of external, independent, and respected sources such as the Bureau of Economic and Business Research ("BEBR") at the University of Florida, Data Resources Incorporated ("DRI"), and *Blue Chip Economic Indicators*. They provide relevant information concerning the outlook for the Florida economy in general and certain sectors comprising large sales, such as the phosphate mining industry, in particular. A summary of the assumptions used in FPC's forecasts, as well as additional detail concerning FPC's forecast system inputs and results, is included in Appendix E to this Need Study.

The following table further summarizes key economic and demographic assumptions associated with FPC's customers, energy sales, and peak demand forecasts. Table 3 contains a summary of key economic and demographic assumptions like changes in Gross Domestic Product ("GDP"), Florida Personal Income, Industrial Production index, inflation, service area population, and employment.

TABLE 3
ECONOMIC & DEMOGRAPHIC SUMMARY
(1999 – 2009)
AVERAGE ANNUAL GROWTH RATE

Real GDP	2.3%
Fl. Employment	2.1%
Fl. Personal Income	5.6%
FPC Service Area Population	1.6%

FPC uses several statistical models in developing its long-term forecasts. The models incorporate multiple forecasting techniques, such as time-series analysis, ordinary least squares regression analysis, and highly detailed end-use models, that are well accepted and widely used in the electric utility industry. The long-term forecasting model used by FPC is called the System for Hourly and Annual Peak and Energy Simulation ("SHAPES-PC"), a recognized industry standard in end-use forecasting, which is owned and maintained by New Energy Associates, LLC. With such accepted, long-term forecasting techniques, relationships between FPC's historical customer, energy, and peak demand data, which impact electrical demand, and other variables like population, weather, economic conditions, saturation of electric end-use appliances, and the price of electricity, can be identified and explained.

FPC also uses short-term econometric models typically used in the utility industry for projections over a shorter planning horizon. Output from the short-term econometric models, therefore, is used to develop projections for the first five years of FPC's forecast. Output from the SHAPES-PC model is used for the remaining years of the forecast. FPC's use of these modeling methodologies in FPC's IRP process is described below and in the chart in Appendix F to this Need Study. FPC's modeling methodologies are also discussed in greater detail in the Company's TYSP filed with the PSC in April 2000 (Appendix D to this Need Study).

Customer Load Forecasts. Population projections for each of the 32 Florida counties served by FPC drive the forecasts of FPC's residential and commercial customers, who together comprise 98 percent of FPC's total customers. Population increases in FPC's service area translate directly into a greater number of residential electric customers and, as a further consequence, a greater number of commercial establishments to serve them. FPC relies on the BEBR at the University of Florida for population estimates and projections in its service area. The BEBR relies primarily on a cohort component computer model that uses demographic data to develop high, low, and medium cases for its population projections. FPC uses the BEBR medium case as the basis for its residential and commercial class customer forecasts. FPC then uses time-series models to project industrial, street and highway lighting, and public authority customers because they follow relatively stable historical growth trends and make up only two percent of FPC's total customers on its system. A more complete discussion of the customer load forecasts and the methodologies behind them can be found in FPC's 2000 TYSP. See Appendix D, Chapter 2.

Schedules 2.1 and 2.2 attached as Appendix G to this Need Study contain FPC's history and forecasts of customer load for rural and residential, commercial, industrial, street and highway lighting, and other public customers. The forecast horizon spans the ten-year period from 2000 to 2009.

Sales Forecasts. FPC forecasts energy (i.e., megawatt-hour) sales using a dual modeling approach that incorporates both short-term and long-term forecast models. Short-term models are used because they are flexible enough to capture expected fluctuations in the next business cycle. In the short-term, monthly econometric models are used for each customer class (e.g., residential, commercial, etc.). They are premised on a statistical relationship between a significant "driver" – or a variable that explains electrical use in a customer class, such as income and weather (among others) for the residential customer class. In selecting significant "drivers" for the models, FPC chooses variables that are statistically proven to affect energy use in a particular customer class historically. With econometric models, it is assumed that future energy use is driven by the same variables that determined past energy use. The results of the monthly econometric models provide energy use projections for each customer class for the next five years. Specifications for each of the monthly econometric models used by FPC can be found in Appendix F to this Need Study.

Long-term energy use by residential, commercial, and industrial customers is projected using individual modules of the SHAPES-PC model. In the SHAPES-PC model, customer forecasts are combined with projections of certain key economic parameters, "end-use" (i.e., electrical appliances) consumption estimates, and patterns of electricity use to produce projections of annual energy consumption by customer class.

Residential energy consumption is premised in the model on the concept that all residential energy needs are met through the operation of certain typical electrical appliances, or "end-uses." Seventeen appliances found in most residential households are used in the model, which takes into account the sum of the energy requirements and saturation levels for each appliance, and produces a forecast of total residential energy consumption. A list of the appliances used in the model is in Appendix F to this Need Study.

The industrial sector end-use model is designed to project energy consumption levels associated with selected manufacturing industries. The variables that affect energy consumption in this sector are the real price of electricity, the level of economic activity within each industry, and the relative intensity of energy use in each industry. Because energy requirements for a given measure of economic activity vary from one industry to another, the model separates the industrial sector into eleven two-digit Standard Industrial Code ("SIC") categories. That way, the model captures changes in energy consumption due to changes in the industrial mix. The annual energy consumption in each of the eleven industrial use categories is calculated by multiplying the projected level of economic activity – expressed in employment level – by the projected energy intensity – expressed as kilowatt-hours per employee adjusted for changes in the electric price. The SIC categories are listed in Appendix F to this Need Study.

One significant industrial sector is modeled separately, outside the end-use model. That industry is the phosphate mining industry, which comprises five large customers who consume a significant share of the energy used by FPC's industrial class. Individual projections of energy use are made based on direct contact with each of the five customers to discuss operating schedules, market conditions for fertilizer products, mine-out projections, and self-service cogeneration possibilities in order to develop projections of energy sales to these customers. The phosphate and non-phosphate industrial forecasts are combined to make up the total industrial class energy forecast.

The commercial sector includes the non-manufacturing and non-governmental businesses. The level of energy consumption by this sector is determined by electric energy requirements for nine individual commercial building types and three separate end-uses: base use, heating, and cooling. First, the intensity of energy use by building type is determined by normalizing kWh use per square foot of floor space relative to the end-uses (i.e., weather sensitivity and base use). Next, projections for energy use by floor space for each building type are developed based on building type, employment projections, and trends in floor space requirements per employee. The two are combined in the next step along with changes in energy use due to electric price impacts to come up with annual energy forecasts by end-use and building type. The individual building types used in the model are listed in Appendix F to this Need Study.

Energy sales to the governmental ("Public Authority") and street and highway lighting users are also projected. An econometric approach is used for public authority energy sales to account for population growth and the state of the economy, which together impact the level of local governmental service, and thus the level of governmental energy consumption. Historically, government employment has been the best single indicator of increases or decreases in local government service due to changes in the population and economy. The model, accordingly, uses local government employment, weather impacts on governmental energy use, and variations in energy use when school is in and out of session, to develop the public authority energy sales projections.

Energy sales for street and highway lighting is also projected to increase with population increases in FPC's service area. FPC has found that residential customer growth best captures trends in historic and future growth in street and highway lighting energy sales. Accordingly, a linear regression model based on the number of residential customers is used to forecast energy sales for the street and highway lighting class.

Finally, FPC forecasts sales to its wholesale customers, which include municipalities and rural electric authorities. FPC supplies capacity and energy service to wholesale customers on a "full," "partial," and "supplemental" requirements basis. Full requirements customer demand and energy is assumed to grow at rates determined by projected levels of population and economic activity. Future partial requirements sales are based on current MW demand declarations nominated each year per contract. FPC's projections of supplemental service to Seminole Electric Cooperative, Inc. ("SECI") is based on a contractual arrangement to provide supplemental service over and above a level SECI has arranged to supply itself through other means.

A more complete discussion of FPC's energy sales forecasts and the methodologies behind them can be found in FPC's TYSP filed with the PSC in April 2000. See Appendix D, Chapter 2. Schedules 2.1 and 2.2 in Appendix G to this Need Study contain FPC's history and forecast of energy sales for each customer class. Schedule 2.3 in Appendix H to this Need Study contains FPC's history and forecast of its total number of customers and net energy for load.

The forecast horizon spans the ten-year period from 2000 to 2009.

Peak Demand Forecasts. Seasonal peak hour demand is the final component in FPC's forecast. FPC separates its peak demand forecast into winter and summer peaks. In each season, FPC disaggregates and projects the following components of total system peak demand: potential firm retail load, interruptible demand, company-use demand, wholesale demand, and dispatchable and non-dispatchable DSM program capability.

Potential firm retail load refers to the projected retail hourly seasonal peak demand, excluding interruptible, curtailable, and standby service, before the effect of conservation or load management programs is taken into account. Determining FPC's retail load without the impact of utility-induced conservation or load control enables FPC to observe and correlate the underlying trend in retail peak demand in the service area to total system customer levels and coincident weather conditions without the year-to-year variations caused by conservation or the need to activate load control. Potential firm retail peaks are projected using historical seasonal peak data, regardless of which month the seasonal peak occurred. Coincident weather conditions and retail customer levels are what drive the forecasts.

The interruptible load is developed from historic trends on FPC's interruptible, curtailable, and standby tariffs, as well as direct information obtained from FPC's largest customers using the interruptible tariff. FPC "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon.

Wholesale demand, as noted above, comprises supplemental, partial, and full requirements service. Supplemental load is based on sales to SECI, FPC's supplemental requirements customer. Demand for partial requirements services is based on historical ratios of coincident-to-contract levels of demand to future contract levels stated in annual nomination letters, which extend out five years. Beyond the initial five-year time horizon, demand requirements are based on the MW level declared in the final year of the contract. Peak demand projections for each full requirements municipal customer is performed by econometrically modeling seasonal peaks and determining the relationship between weather and economic impacts specific to each locale. The seasonal (winter and summer) projections become the January and August peak values, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month relative to the winter peak, and each summer month relative to the summer peak demand.

Each of the peak demand components described above is a positive value. The DSM program capability is not. DSM program impacts represent a reduction in peak demand; therefore they are assigned a negative value. DSM program projections are applied to the forecast at levels that achieve the goals set by the PSC after passing tests for cost-effectiveness. Projections of non-dispatchable DSM (e.g., insulation, duct repair, etc.) MW impacts are cumulative and are subtracted from the projection of potential firm retail demand. Dispatchable DSM program (e.g., load management) MW reductions reflect direct load control capability at normal peaking temperatures and likewise produce a reduction in total potential retail demand. Total system peak demand, therefore, is calculated as the arithmetic sum of the four positive and one negative components. A more complete discussion of the peak demand forecasts and the methodologies behind them can be found in FPC's TYSP filed with the PSC in April 2000. See TYSP, Appendix D, Chapter 2.

Schedules 3.1.1, 3.1.2, and 3.1.3 attached as Appendix I to this Need Study contain

FPC's summer peak demand forecasts, and schedules 3.2.1, 3.2.2, and 3.2.3 attached as Appendix J to this Need Study contain FPC's winter peak demand forecasts. The forecast horizon spans the ten-year period from 2000 to 2009.

Both the summer and winter peak demand forecasts contain a base case and high and low load forecast. The base case represents the most likely scenario, and therefore it was developed using both the short-term and long-term models with a 50/50 probability of an outcome falling either above or below the base case forecast. The high and low cases both have a 90/10 probability of occurrence, such that there is an 80 percent probability of an outcome falling between the high and low cases.

2. FPC's Fuels Forecast.

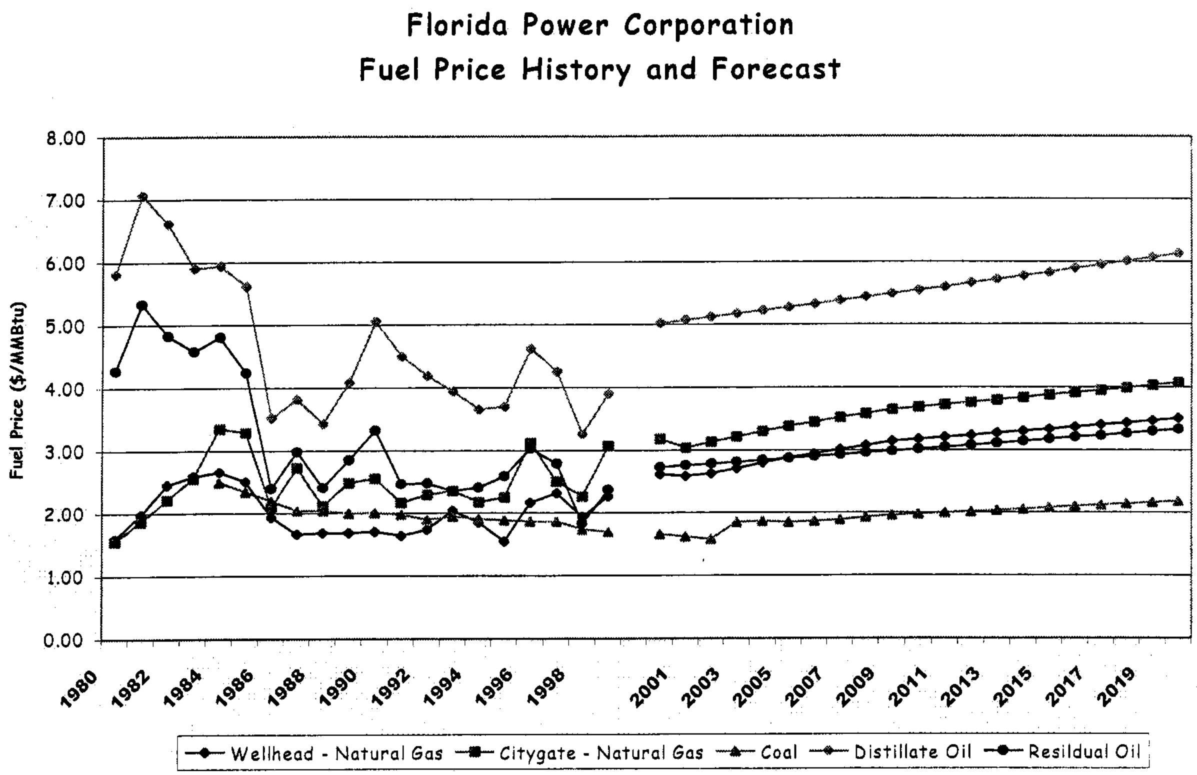
FPC's fuels forecast consists of several discrete forecasts of prices by fuel type, depending on the fuels used or most likely to be used by FPC at its existing and future generation plants. Prices are projected for the following fuels: natural gas, coal, and oil. Where different grades of fuel are available, for example, in the case of coal and oil, FPC also forecasts prices for several different grades or types. Specifically, FPC forecasts fuel prices for the grades or types of coal that can be burned at FPC's Crystal River Units 1, 2, 4, and 5; 2.5 percent sulfur, 1.5 percent sulfur, and 1.0 percent sulfur residual fuel, and No. 2 fuel oil; and natural gas. For the natural gas part of FPC's fuels forecast, FPC's contracts for natural gas transportation capacity and estimates of interruptible natural gas supplies are also included in the forecast.

FPC's natural gas forecast was derived from price estimates for the Gulf Coast market area, specifically the Henry Hub and Mobile Bay. FPC also uses Petroleum Industry Research Associates as a forecasting consultant service. In addition, FPC contacts suppliers who are willing to enter into long-term contracts for gas supplies, and quotes by these companies are used as an additional input in developing FPC's natural gas price forecast. Data from public agencies such as the Energy Information Administration are also considered as a reference source by FPC in developing its natural gas price forecast. The final natural gas price forecast is an estimate based upon all these inputs, as well as transportation costs for natural gas. Transportation costs, including fixed and variable components, were estimated based upon the prevailing tariff rate for service on the Florida Gas Transmission ("FGT") pipeline system and the expected rates available from the various proposed new pipelines into peninsular Florida.

FPC develops a bandwidth of probable prices for each fuel, first considering a "base," or expected fuels price case, for each fuel FPC has identified. Price estimates are based on expected price trends over the next five to ten years using FPC's historical experience with fuel prices and relying on an analysis of widely recognized and generally accepted third party sources of information relevant to the projected supply and price of each fuel. FPC also develops a high and low fuels price case, reflecting FPC's planning judgment on the extent of the deviation upward or downward from its base case if either event occurred. Developing base, high, and low bandwidth cases is consistent with FPC's historical practice of preparing fuels forecasts and standard practice in the electric utility industry.

FPC's fuels price forecasts are continually evaluated against various, standard third party fuels price forecasts in the industry and developments and trends with respect to each fuel type to verify that FPC was and is reasonable in developing its fuel price forecasts. When and if necessary, FPC will adjust its fuels forecast to take into account changes in the fuels markets. The development of FPC's base, high, and low fuels price forecasts is described further in FPC's TYSP filed with the PSC in April 2000 (Appendix D to FPC's Need Study). Table 4 in this Need Study contains FPC's current long-term fuels forecast.

TABLE 4



3. Economic and Financial Assumptions.

FPC's evaluation of its supply-side generation alternatives takes into account those economic and financial factors that affect the decision to select the most economical generation expansion plan. FPC prepares and incorporates forecasts for such key economic and financial factors as the general inflation rate, construction cost escalation rate, and interest rates into its PROVIEW model for the analysis of generation alternatives. These forecasts are based on FPC's annual assessment of regional and national economic factors, and represent what FPC anticipates in support of FPC's financial management process.

FPC's forecast of what it believes in its planning judgment to be the critical economic and financial factors, and what it uniformly uses to evaluate the supply-side generation alternatives reasonably available to FPC, is contained in Table 5 of this Need Study.

TABLE 5

FINANCIAL ASSUMPTIONS FOR 2000 Ten-Year Site Plan and IRP
BASE CASE VALUES

Base year 2000

	10-Year Site Plan Values	
DISCOUNT RATE	8.53%	
REAL DISCOUNT RATE	5.53%	
FED INC. TAX RATE	38.58%	
INFLATION RATE	3.00%	
AFUDC RATE	8.53%	
CAPITALIZED INT. DEBT RATE	7.0%	
DEBT STRUCTURE BOOK	45.00%	
DEBT STRUCTURE FOR TAX	100.00%	
DESIRED RETURN ON RATE BASE	9.75%	
ITC RATE	0.0%	
LONG TERM DEBT INT. RATE	7.0%	
COST OF CAP. ESC. RATE (Coal)	2.5%	
COST OF CAP. ESC. RATE (C.T.)	2.5%	
COST OF CAP. ESC. RATE (C.C.)	2.5%	
COST OF CAP. ESC. RATE (Transm & Substa)	2.5%	
COST OF CAP. ESC. RATE (Distrib)	2.5%	
FUEL COST ESCALATION (Coal)	1.0%	(after 2009)
FUEL COST ESCALATION (Oil)	1.0%	(after 2009)
FUEL COST ESCALATION (Gas)	1.0%	(after 2009)
FIXED COST ESCALATION	2.5%	
VARIABLE COST ESCALATION	3.0%	
REVENUE DISCOUNT RATE	8.53%	
WEIGHTED COST OF CAPITAL	9.75%	
CONSTRUCTION ESCALATION (Coal)	2.5%	
CONSTRUCTION ESCALATION (C.T.)	2.5%	
CONSTRUCTION ESCALATION (C.C.)	2.5%	
LEVELIZED CHARGE RATE (Coal)	13.77%	
LEVELIZED CHARGE RATE (C.T.)	13.88%	
LEVELIZED CHARGE RATE (C.C.)	14.35%	
CUSTOMER COST ESCALATION	3.0%	
DSM EXPENSE ESCALATION	3.0%	
GENERAL INFLATION (CPI)	3.0%	
GDP PRICE Index	2.5%	

Base Case Cap Structure

Long Term Debt	45.00%	7.00%	3.15%
Preferred Stock	0.00%	8.00%	0.00%
Common Stock	55.00%	12.00%	6.60%
Composite			9.750%
Debt Tax Deductible			1.22%
After-Tax Discount Rate			8.53%

Federal Income Tax Rate	35.00%
State Income Tax Rate	5.50%

4. Existing Supply-Side Resources.

As an integral part of the planning process, the Company must update the performance characteristics of its existing resources, incorporating any changes that have been or are forecasted to have a material impact on performance. FPC's current total supply-side capacity resource is 9,567 MW, as shown in Table 1 in this Need Study. This capacity includes 469 MW of utility purchased power, 831 MW of non-utility purchased power, 2,775 MW of combustion turbine power, 782 MW of nuclear power, 3,958 MW of fossil steam power, and 752 MW of combined cycle power. For the winter of 2003/04, FPC forecasts that it will have total firm capacity resources of 9,748 MW to meet an expected peak firm load of 8,231 MW (based on an estimated peak non-firm load of 1,150 MW).

5. Existing and Planned Demand-Side Resources.

To comply with the directives of the Florida Energy Efficiency and Conservation Act ("FEECA"), FPC must file with the PSC its DSM plan to meet the conservation goals established by the PSC pursuant to FEECA. Most recently, the PSC established new conservation goals for FPC that span the ten-year period from 2000 through 2009 in Order No. PSC-99-1942-FOF-EG issued October 1, 1999 in Docket No. 971007-EG. Consistent with these new conservation goals established by the PSC, FPC filed its DSM plan on December 29, 1999. A copy of FPC's DSM plan is in Appendix K to this Need Study. FPC's DSM plan was approved by the PSC in Order No. PSC-00-0750-PAA-EG, Docket No. 991789-EG, issued on April 17, 2000. A copy of that Order is in Appendix L to this Need Study.

With the approval of its most recent DSM plan by the PSC, FPC will offer five (5) residential programs, eight (8) commercial and industrial programs, and one (1) research and development program. These DSM programs include both dispatchable and non-dispatchable

DSM resources. They are described in detail in FPC's DSM Plan previously filed with the PSC in Docket No. 991789-EG (Appendix K to this Need Study).

FPC's DSM programs have been successful in the past. Significant numbers of customers have chosen DSM programs offering direct load control in exchange for reduced tariffs. As a result of its Energy Management,[2] interruptible service, and other DSM programs, FPC has met and exceeded past conservation goals set by the PSC.

With the success of FPC's DSM programs, the Company has in recent years relied increasingly on demand-side resources to reduce the "firm" load that must be protected by planning reserves. In the last two years, however, FPC experienced attrition by customers from the Energy Management program because of their dissatisfaction with that level of service. During the process of developing and establishing its DSM Goals and Plans, FPC determined that it was no longer cost-effective to add new participants to the existing Energy Management program and that it needed to revise the program. FPC was forced to re-evaluate its reliance on DSM programs to offset peak load and, in its planning judgment, chose to reduce its reliance on dispatchable demand-side alternatives in favor of adding more generating assets to its total reserves.

FPC's reduced reliance on dispatchable demand-side alternatives to satisfy peak demand growth is reflected in the revised Energy Management program in FPC's DSM Plan as approved by the PSC in Order No. PSC-00-0750-PAA-EG (Appendix L to this Need Study). Under its revised Energy Management program, FPC will move from a year-round load control program to a winter-only program. The current year-round Energy Management program is closed to new customers and will be gradually reduced or phased out beginning in April 2001.

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[2] FPC's residential and commercial load management programs are referred to as the "Energy Management" program by the Company.

As evidenced by its continued and significant investment in DSM programs, FPC continues to believe that demand-side resources are an important and cost-effective resource to meet its customers' electricity needs. But recent experience has demonstrated to FPC that there can be drawbacks to increased reliance on demand-side resources to meet such needs. As FPC has learned, when interruptions in service increase in frequency, customers are less willing to accept such service for lower rates. For this reason, FPC plans in the future to rely more on additional generating resources to meet its customers' needs for electrical power than on the consent of customers to interruptions in service for reduced tariffs.

FPC's recent experience further cautions against overly optimistic expectations from its revised Energy Management program. In its planning judgment, FPC has, therefore, taken a conservative view of the effects of the revised program until it has developed the operating experience required to gauge more accurately customer tolerance and participation impacts. As a result, during the transition period, FPC has planned for higher reserves (25% in 2004, 23% in 2005), which will be met by additional supply-side resources. This plan is consistent with FPC's commitment to carry more supply-side assets as part of its total reserves than it has in the recent past.

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1, containing FPC's history and base-case forecasts of summer and winter peak demand respectively, in Appendices I and J to this Need Study. The schedules show the historical achievements in reduced demand from FPC's DSM programs, the effects of attrition from the Energy Management program in 1998 and 1999, and the desired reductions in peak demand from the Energy Management program approved by the PSC.

6. Cost and Performance Projections for New Resource Alternatives.

FPC includes conventional, advanced, and renewable energy resources as potential capacity addition alternatives in its overall IRP process. These resource alternatives are periodically reassessed and the performance characteristics updated to ensure that projections for new resource additions capture new and emerging technologies over the planning horizon. This analysis involves a preliminary screening of the generation resource alternatives based on cost, commercial viability, and technical feasibility. The cost and performance projections were updated with the assistance of specialists at Black & Veatch who have access to information on a wide spectrum of energy projects and emerging technologies worldwide.

FPC examined the commercial viability of each technology for use in utility-scale applications. In order for a particular technology to be considered commercially viable, the technology must be built and operating on an appropriate commercial scale in continuous service by or for an electric utility. Although many of the technologies evaluated are not currently commercially viable, they were still assessed based on the other two criteria, technical feasibility and cost. Reasonable levels of detail for emerging technologies were developed to allow FPC to screen the technology options and to stay abreast of potential economic benefits as they mature.

Technical feasibility for commercially viable technologies was satisfied if the technology met FPC's particular generation requirements in that (i) it was likely to be cost effective for FPC, given current economic projections, and (ii) the alternative would integrate well into FPC's system. Evaluation of technical feasibility included the size, fuel type, and construction requirements of the particular technology and the ability to match the technology to the service it would be required to perform on FPC's system, e.g., baseload, intermediate, cycling, or peaking.

Finally, for each alternative, an estimate of the levelized cost of energy production, accounting for capital, fuel, and O&M costs over the typical life expectancy of the unit, was developed. Where costs were dependent on site specific or other information that might have been unavailable in the pre-screening phase of planning, a typical range of performance and cost factors were selected to ensure that the technology was evaluated in a consistent manner with all other alternatives. For most technologies, the performance and costs are based on a specified size. In addition, overall levelized cost ranges for the general technology types are provided.

Categories of capacity addition alternatives that were reviewed and characterized include: Renewable Technologies, Waste Technologies, Advanced Technologies, Energy Storage Systems, Nuclear Technology, and Conventional Alternatives.

D. The Integrated Resource Planning Process.

1. Introduction.

The IRP process used by FPC incorporates sophisticated resource optimization computer models to evaluate future generation alternatives and cost-effective demand-side resources on a consistent and integrated basis. This process requires significant manpower and computer resources, and it involves input from a wide range of departments within the Company to support the updates of key planning forecasts and assumptions. The IRP process helps FPC combine existing and new generation resources, cost-effective DSM programs, purchased power contracts, and interruptible load in a portfolio that will provide reliable electrical service at the lowest overall cost to FPC's customers over the planning horizon. Within the process, FPC develops these resource options over a ten-year planning period with consideration for long-term economic impacts. A diagram of FPC's IRP process is included in Appendix M to this Need Study.

The IRP process begins with the development of a forecast of system load growth during the next ten years. This forecast draws on the collection of certain input data, such as population growth, fuel prices, interest rates, and inflation, and the development of economic and demographic assumptions from that information that impact future energy sales and customer demand. Base forecasts reflecting FPC's view of the most likely future scenarios for such key factors as fuel prices and interest rates are developed, along with high and low forecasts that reflect alternative future scenarios. The computer models used in the IRP process are then brought up to date with that data, along with updated information on the operating parameters and maintenance schedules for FPC's existing generation units, to provide the basis for further analysis in the IRP process.

Next, FPC takes into account its future supply of capacity from purchased power contracts and existing and committed generation units that will be in service during the study period. FPC evaluates the relationship of demand and supply on FPC's system in the future against FPC's reliability criteria to determine if additional capacity is needed on FPC's system during the planning period.

If a need for additional capacity during the planning period is identified, FPC examines alternative generation expansion scenarios. Supply-side resources are screened to determine those that are the most cost-effective. FPC begins with a wide range of options, identified from various industry sources and FPC's experience, and pre-screens those that do not warrant more detailed cost-effectiveness analysis. The screening criteria include costs, fuel sources and availability, technological maturity, environmental impacts, and overall resource feasibility within the Company's system.

Generation alternatives that pass the initial screening are considered viable capacity alternatives and are included in the next step of the planning process. That step involves an economic evaluation of generation alternatives in PROVIEW, a module of New Energy Association's proprietary computer model, called PROSCREEN. The primary output of PROVIEW is a Cumulative Present Worth Revenue Requirements ("CPWRR") comparison of all of the viable resource combinations that will satisfy FPC's reliability requirements. The most cost-effective supply-side resource plans (or combinations) are evaluated on FPC's system, resulting in a ranking of the various generation plans by system revenue requirements. Each of these resource combinations is ranked based on cost performance over both the "study period" (40 years) and the "planning period" (10 years). Generally, the generation plan with the lowest CPWRR over the study period is chosen as the Base Generation Plan. In this Plan, the next uncommitted generation addition is designated the "next planned unit."

The next step consists of planning and developing a group of cost-effective DSM programs. As part of Docket No. 991789-EG: Approval of Demand-Side Management Plan of Florida Power Corporation, FPC identified a set of DSM programs and used the DSVIEW module of PROSCREEN, which is an accepted and widely used model in the utility industry, to evaluate the cost-effectiveness of each program. All of the cost-effective DSM programs that the Company plans to implement are then included in the Company's system models. Because DSM programs reduce the peak demand and/or energy consumption on FPC's system, the expected reductions from the DSM programs are factored in as adjustments to FPC's peak demand and energy sales forecasts.

In the resource integration step of the IRP process, the Company seeks to optimize its supply-side options into a final, integrated optimal plan. After the addition of the cost-effective

DSM programs, the generation plan is re-optimized to establish the most cost-effective overall plan, which becomes the Company's Integrated Optimal Plan. The PROVIEW program considers all future combinations of supply-side alternatives that meet the Company's reliability criteria in each year over the ten-year planning period. The long-term economic performance of each of these combinations is then assessed over the entire study period. PROVIEW will consider many tens or hundreds of thousands of combinations and rank those options that provide the lowest overall costs over the study period.

The plan providing the lowest customer revenue requirements is further tested using sensitivity analyses. The economics of the plan are evaluated under high and low forecast scenarios for such key factors as load growth, interest and inflation rates, and fuel costs, to ensure that the plan does not unduly burden the Company or its ratepayers if the future unfolds in a way very different from the Company's base forecast. If the plan is judged robust under these sensitivity analyses, it becomes the final Base Expansion Plan for the Company.

The IRP results provide FPC with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply-side and the demand-side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, long-term power purchase), the Company will move forward with directional guidance from the IRP and delve into much more specific levels of examination. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations, and the most current dynamics of the business and regulatory environments.

FPC's present Determination of Need Petition, its 2000 TYSP, its Commission established DSM Goals, and its Commission-approved DSM Plan are all consistent with the

Company's IRP process, as described herein.

2. Supply-Side Screening of Generation Alternatives.

In the first step of developing generation expansion alternatives, as discussed above, FPC screened a wide range of generation technologies including:

- Renewable Technologies (wind energy conversion, solar thermal systems, photovoltaic cells, wood chip combustion, geothermal power, and hydroelectric power);
- Waste Technologies (refuse-to-energy conversion, sewage sludge-to-energy conversion, and used tire-to-energy conversion);
- Advanced Technologies (Brayton cycles, advanced coal technologies, magnetohydrodynamics, fuel cells, fusion, ocean wave energy, ocean tidal energy, and ocean thermal energy);
- Energy Storage Systems (pumped storage, battery storage, compressed air energy storage, fly wheel energy storage, and super conducting magnetic energy storage);
- Nuclear Technology; and
- Conventional Technologies (simple cycle combustion turbine, combined cycle, pulverized coal, fluidized bed, repowering, integrated gasification combined cycle (IGCC)).

With the assistance of specialists at Black & Veatch, FPC assessed the cost, commercial viability, and technical feasibility of known generation expansion alternatives available to electric utilities. As a result of this initial screening process, all but the conventional technologies were eliminated from further consideration by FPC, as discussed below.

Within the Renewable Technologies category of generation alternatives, which tend to offer low capacity factors, the wind energy, solar thermal, and photovoltaics options were eliminated because their capital costs exceeded (by several times) the capital costs for combined cycle units. Similarly, wood chip-fired generation on a utility scale was eliminated because of high capital costs, as well as environmental emission problems and a lack of readily available raw materials in Florida. Finally, geothermal and hydroelectric generating alternatives were eliminated because they require natural resources that are simply unavailable in Florida.

Waste Energy Technologies likewise were eliminated from further consideration because of their high capital costs and the lack of readily and consistently available fuel supplies in the State of Florida in sufficient quantities to support utility scale commercial operation of a power plant. Of the Advanced Technologies evaluated, only fuel cell and supercritical coal technologies were commercially available. These technologies require prohibitive capital and operating costs, and accordingly they were eliminated from consideration. While some of the Energy Storage System Technologies are potentially commercially available, they offer low operating capacity factors with high capital and operating costs. Therefore, pursuit of such technologies to fulfill FPC's capacity needs could not be economically justified. Finally, high capital costs, as well as high operating cost and time intensive and uncertain licensing requirements, led FPC to forego further evaluation of Nuclear Technology as a viable means of satisfying FPC's capacity needs beginning in 2003.

More detailed information on the cost and operational factors of these non-conventional generation technologies is provided in Appendix N to this Need Study. The evaluation of each of the generation technologies available in the electric utility industry on commercial viability, technical feasibility, and cost grounds, as discussed above, has been summarized in Table 6 in this Need Study.

TABLE 6

SCREENING EVALUATION OF GENERATION TECHNOLOGIES				
Technology	**Cost**	**Commercial Viability**	**Technical Feasibility**	**Retain for Economic Screening**
Renewable Technologies				
Wind Energy Conversion	High	Yes	No	No
Solar	High	Yes	No	No
Photovoltaics	High	Yes	No	No
Wood Chip	High	Yes	No	No
Geothermal	High	Yes	No	No
Hydroelectric	High	Yes	No	No
Waste Technologies				
Refuse to Energy	High	Yes	No	No
Landfill Gas	High	Yes	No	No
Sewage Sludge to Energy	High	Yes	No	No
Used Tire to Energy	High	Yes	No	No
Advanced Technologies				
Humid Air Turbine	Low	No	Yes	No
Kalina Cycle	High	No	Yes	No
Cheng Cycle	High	No	Yes	No
Supercritical Pulverized Coal	High	Yes	Yes	No
Pressurized Fluidized Bed	High	No	Yes	No
Magnetohydrodynamics	High	No	Yes	No
Fuel Cells	High	Yes	No	No
Fusion	High	No	No	No
Ocean Tidal Energy	High	No	No	No
Ocean Thermal Energy	High	No	No	No
	High	Yes	No	No
Battery Energy Storage	High	Yes	No	No
Compressed Air Storage	High	Yes	No	No
Nuclear Power				
Fission	High	Yes	Yes	No

SCREENING EVALUATION OF GENERATION TECHNOLOGIES				
Technology	**Cost**	**Commercial Viability**	**Technical Feasibility**	**Retain for Economic Screening**
Renewable Technologies	Low	Yes	Yes	Yes
501G Combined Cycle	Low	Yes	Yes	Yes
7EA CT – Gas	Low	Yes	Yes	Yes
7EA CT – Oil	Low	Yes	Yes	Yes
7FA CT – Gas	Low	Yes	Yes	Yes
7FA CT – Oil	Low	Yes	Yes	Yes
Bartow Repower - #1 & 2	Low	Yes	Yes	Yes
Bartow Repower - #3	Low	Yes	Yes	Yes
Small Steam Repowering	Low	Yes	Yes	Yes
Pulverized Coal	Medium	Yes	Yes	Yes
Fluidized Bed	Medium	Yes	Yes	Yes
IGCC	Medium	Yes	Yes	Yes

Of the generation technologies screened, only the conventional technologies – simple cycle combustion turbine, combined cycle, repowering, pulverized coal, fluidized bed, and IGCC technologies – were retained for the more detailed economic screening phase of the evaluation.

FPC performed economic evaluations of a wide range of potential expansion plans based on the conventional generation alternatives using the PROVIEW optimization program. FPC compiled more detailed planning estimates of initial cost, performance, and O&M requirements for each of the conventional generation alternatives to show expected trends in cost performance within a given technology as well as among technologies. FPC selected the block size of the generation alternative evaluated based on the Company's need for capacity and economies of scale associated with the particular generation technology being considered. The cost estimates and performance factors for these conventional generation technology alternatives are listed below in Tables 7 and 8 in this Need Study.

TABLE 7

SUPPLY-SIDE ALTERNATIVES

SUMMARY OF ESTIMATED COST AND PERFORMANCE FOR CONVENTIONAL GENERATION ALTERNATIVES

(Year 2000 $)

ALTERNATIVE	NOMINAL CAPACITY (MW)	CAPITAL COST		O&M COST		HEAT RATE BTU/ KWH	FORCED OUTAGE %	FUEL TYPE
		$1,000	$/KW	$/KW-YR	$/ MWH			
Combustion Turbine - "EA"	89	26,667	301	1.4	4.4	11,814	3.0	NG/Dist.
Advanced Combustion Turbine - "F"	165	44,808	272	2.9	3.8	10,614	3.0	NG/Dist.
Combined Cycle - HEC #2	531	165,830	312	2.5	2.1	6,800	3.7	NG/Dist.
Combined Cycle - Market	531	186,430	351	2.5	2.1	6,800	3.7	NG/Dist.
Advanced Combined Cycle - "G"	344	160,680	467	2.4	2.0	6,787	3.7	NG/Dist.
Integrated Gasification Combined Cycle - "IGCC"	536	718,940	1,343	33.4	0.7	8,555	8.0	HS Coal
Pulverized Coal Plant	790	707,610	896	22.0	1.3	9,874	7.0	HS Coal
Fluidized Bed Coal Plant	500	491,310	983	20.3	4.6	10,300	7.0	HS Coal
Bartow Repower (net CC MW / incremental new MW)	539/316	194,155	360/614	9.9	1.3	7,045	5.0	NG/Dist.
Higgins Repower	367	173,040	472	5.9	2.0	8,060	5.0	NG/Dist.

TABLE 8

SUPPLY-SIDE ALTERNATIVES

SUMMARY OF ESTIMATED CAPITAL COST RANGE FOR CONVENTIONAL GENERATION ALTERNATIVES

(Year 2000 $)

ALTERNATIVE	NOMINAL CAPACITY (MW)	CAPITAL COST		CAPITAL COST RANGE				FUEL TYPE
		$1,000	$/KW	LOW $1,000	HIGH $1,000	LOW $/KW	HIGH $/KW	
Combustion Turbine - "EA"	89	26,667	301	25,333	33,333	286	377	NG/Dist.
Advanced Combustion Turbine - "F"	165	44,808	272	42,568	56,011	259	340	NG/Dist.
Combined Cycle - HEC #2	531	165,830	312	157,539	182,413	297	344	NG/Dist.
Combined Cycle - Market	531	186,430	351	177,109	233,038	334	439	NG/Dist.
Advanced Combined Cycle - "G"	344	160,680	467	155,015	176,645	451	514	NG/Dist.
Integrated Gasification Combined Cycle - "IGCC"	536	718,940	1,343	579,684	745,308	1,083	1,392	HS Coal
Pulverized Coal Plant	790	707,610	896	638,600	778,680	808	986	HS Coal
Fluidized Bed Coal Plant	500	491,310	983	437,750	527,875	876	1,056	HS Coal
Bartow Repower (net CC MW / incremental new MW)	539/316	194,155	360/614	159,653	210,831	296/505	391/667	NG/Dist.
Higgins Repower	367	173,040	472	157,578	191,506	430	523	NG/Dist.

Each generation alternative being evaluated was entered as a separate resource option available to PROVIEW with which it develops ten-year expansion plan alternatives to supplement FPC's existing system. The model assesses FPC's seasonal reserve margins and automatically adds resources, in a wide array of combinations, to meet the prescribed minimum reserve margin requirements. Then the model screens the expansion plan alternatives it creates and ranks them based on the revenue requirements (CPWRR) over the duration of the study period. Most often, the top three or four ranked plans are very close to each other in terms of overall revenue requirements (e.g., less than 0.1% difference). FPC assesses this low cost cluster of expansion plan alternatives to determine which plan offers the best balance of cost, timing, constructability, system compatibility, and strategic benefits. This plan becomes FPC's Base Optimal Supply-Side Plan, which is also available for use as a basis for screening and cost-effectiveness assessments of DSM programs.

3. Demand-Side Screening.

Extensive analysis was conducted during the DSM Goals and DSM Plan proceedings (Docket Nos. 971005-EG and 991789-EG respectively) to assess the projected cost, performance, viability, and cost-effectiveness of a wide range of dispatchable and non-dispatchable DSM program options. Based on this analysis, the Company identified a set of DSM programs that were cost-effective and met Commission established goals. The DSVIEW module of PROSCREEN was used to screen potential DSM program options under each of the three Commission approved tests of cost-effectiveness: The Participant Test, the Rate Impact Measure ("RIM") Test, and the Total Resource Cost ("TRC") Test. The Base Optimal Supply-Side Plan was used as the basis for this screening process.

The future supply-side alternatives that are selected for the Base Optimal Supply-Side Plan represent a stream of potentially avoidable units that the DSM alternatives are screened against. Each DSM program option is individually added to the Base Optimal Supply-Side Plan and the system is redispatched over the ten-year planning period. DSVIEW compares the results of this DSM program case with the Base Optimal Supply-Side Plan to determine the benefits and costs of adding the DSM resource. DSVIEW calculates the appropriate benefits and costs for each of the three cost-effectiveness tests (Participant, RIM, TRC). DSM programs that pass all three tests are then bundled together into portfolios and included in the resource integration phase of the IRP process.

4. Resource Integration.

Once the range of supply-side and demand-side alternatives have been screened, an integration assessment is conducted to determine the optimum supply-side expansion plan coupled with the portfolio of cost-effective DSM programs. To accomplish this, the DSM program portfolio is assimilated into the Company's system models and the overall supply-side resource optimization is then repeated.

In this phase, FPC screened thousands of expansion plan alternatives encompassing the conventional generation technologies using PROVIEW. The combined cycle and combustion turbine generation technologies consistently surfaced in all of the top ranked plan alternatives as the first units being constructed. In the results of the economic screening in PROVIEW, the combination of combined cycle units (Hines 2, 3, and 4), came up in the top ten plans, with some variations in timing and combinations with additional combustion turbines and/or combined cycle units. In the top ranked plan, Hines 2 was shown in service in late 2003, followed by Hines 3, 4, and 5 spaced two years apart, respectively. This plan was chosen by FPC as the

Integrated Optimal Plan and was also published as the Base Expansion Plan in the Company's 2000 TYSP filed with the PSC on April 1, 2000. This is included in Table 9 in this Need Study, which contains a summary of the top five generation expansion plans from PROVIEW.

TABLE 9

FLORIDA POWER CORPORATION
PROVIEW LEAST COST OPTIMIZATION RESULTS
1999/2000 IRP UPDATE

YEAR*	PLAN 1	PLAN 2	PLAN 3	PLAN 4	PLAN 5
2004	HINES 2	HINES 2	HINES 2	HINES 2	HINES 2
2005					
2006	HINES 3	HINES 3	HINES 3	HINES 3	"F" PEAKERS (1)
2007					HINES 3
2008	HINES 4	HINES 4	HINES 4	HINES 4	HINES 4
2009					
2010	HINES 5	"E" PEAKER (3) "F" PEAKER (1)	"F" PEAKER (3)	"G" CC(1) "F" PEAKER (1)	HINES 5
* UNITS ARE TYPICALLY SCHEDULED TO BE ON-LINE IN NOVEMBER OF THE YEAR PRIOR TO THE YEAR DEPICTED IN THIS TABLE					

5. Sensitivity Analyses.

In the process of evaluating and selecting the Integrated Optimal Plan, FPC tests the planning results under different sensitivity scenarios to identify variances, if any, that would warrant reconsideration of any of the basic plan assumptions. These "sensitivities" are run with the PROVIEW model using high, medium (base), or low forecast ranges for demand and energy, fuel prices, and critical economic and financial assumptions. High, medium, and low forecasts are developed based on FPC's experience and its ongoing review and analysis of industry trends and forecasts in the key areas underlying each of these Company forecasts. In addition, FPC reviews a special fuel sensitivity where the differential between oil/gas and coal is maintained constant over time.

Load Forecast. The high load forecast, which included increased retail demand and higher wholesale customer retention, indicated that additional combined cycles and combustion turbines would potentially be required over the planning period to ensure that reserve margins are maintained. While the low load forecast sensitivity indicated a need for fewer combined cycle units over the planning period, Hines 2 was still required to meet FPC's energy and capacity needs.

Fuels Forecast. The fuels forecast sensitivities indicated that the Base Expansion Plan – with Hines 2 in the winter of 2003/04 – was sound. The low fuels forecast did not suggest any changes in the Base Expansion Plan. The high fuels forecast indicated an increase in savings for the future advanced technology combined cycle units (as the technologies mature) toward the end of the planning period, but did not suggest any changes in the Hines 2 addition. The sensitivity holding the differential price of oil and gas to coal constant over time indicated reduced benefits for combined cycle units, but the variances resulting from this fuel sensitivity were not significant enough to suggest a change in the Base Expansion Plan.

Financial Forecast. When the financial forecast sensitivities were run, there were no substantive changes in the ranking of the expansion plan alternatives. This result confirmed that the Base Expansion Plan was quite robust.

As expected, all of the high sensitivity cases indicated an increase in total revenue requirements while the low sensitivities indicated lower total revenue requirements. The results of these sensitivity studies confirm that a robust plan had been chosen for further consideration and that there would be no need to depart from the base assumptions used in this assessment.

IV. FPC's Need for Additional Generating Capacity in 2003/04.

A. Introduction.

The IRP process that we have described is an ongoing dynamic process that constantly evolves as new developments occur. This planning process gives the Company flexibility to re-evaluate resources as the time approaches for making significant commitments for construction or implementation, and to evaluate the addition of new resources not previously examined, on an ongoing basis. In the Company's resource plans over the course of several previous years, the Hines 2 addition has been targeted for November 2004. In the fall of 1999, through a continuing and thorough examination of FPC's combined cycle options, energy and capacity requirements, and transition issues concerning FPC's new Energy Management program, the Company concluded that it would be in the best interests of the Company and its ratepayers to move the combined cycle addition up one year to November 2003. It was concluded that this adjustment would provide significant economic benefits and help the Company move forward with necessary improvements in reserve quality while providing a hedge against exposure to demand-side program attrition and program transition uncertainty. These conclusions were initially tested using specific targeted financial assessments, followed with further scrutiny and verification in the Company's 1999/2000 Integrated Resource Plan Update, which serves as the basis for the Company's 2000 TYSP (April 2000).

In summary, FPC's need for additional supply-side resources in November 2003 comes from expected growth in demand, FPC's decision to increase its minimum Reserve Margin planning criterion from 15 percent to 20 percent at that time, and, based on recent experience, a more realistic perspective on FPC's reliance on dispatchable DSM programs to meet energy demands during peak demand periods. We discuss these factors in more detail below.

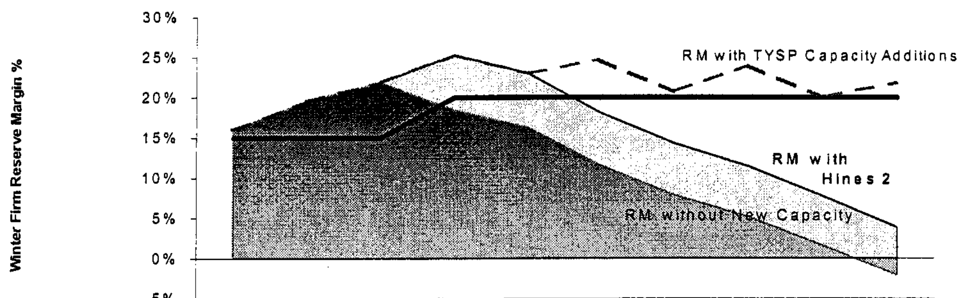
B. Electric System Reliability and Integrity.

The Company needs 530 MW of electrical generation resources in November 2003 to maintain electric system reliability and integrity. As discussed, FPC agreed to increase its Reserve Margin planning criterion from a minimum of 15 percent to a minimum of 20 percent, effective in the summer of 2004. Over the planning horizon, FPC will need to obtain significant new capacity resources in order to achieve this objective. The agreement provides the latitude to move to 20 percent as late as the summer of 2004, but FPC has concluded, in its planning judgement, that it is necessary, feasible, and cost-effective to implement this planning criterion by the Winter of 2003/04. This shift should help alleviate reliability concerns that the Company has had and mitigate concerns that the PSC and the PSC Staff have expressed in the past several years about the quantity and quality of planned reserves, recurring capacity advisories, changes to unit ratings, and volatility in weather and consumption patterns. Hines 2 will enable the Company to maintain its firm Reserve Margin above the 20 percent minimum during the winter of 2003/04 and beyond. (See Appendix O to this Need Study for a more detailed listing of FPC's load and resources). Based on current projections, the Company should not need to build or contract for additional supply-side resources beyond Hines 2 until November 2005 to satisfy its 20 percent minimum planning criterion. FPC's reliability need is graphically demonstrated in Table 10 to this Need Study.

TABLE 10

FPC Winter Firm Reserve Margin (RM) %

Impact of Hines 2 on Reserve Margin



	WTR 00/01	WTR 01/02	WTR 02/03	WTR 03/04	WTR 04/05	WTR 05/06	WTR 06/07	WTR 07/08	WTR 08/09	WTR 09/10
RM with Hines 2 Addition	16%	20%	22%	25%	23%	18%	14%	11%	8%	4%
RM without New Capacity	16%	20%	22%	18%	16%	12%	8%	5%	2%	-2%
Minimum RM Requirement	15%	15%	15%	20%	20%	20%	20%	20%	20%	20%
RM with TYSP Capacity	16%	20%	22%	25%	23%	25%	21%	24%	20%	22%

In order to meet its Reserve Margin planning criterion, and to comply with the directives of the FEECA, the Company has relied increasingly over the last decade upon dispatchable demand-side resources to reduce the "firm" load that must be protected by planning reserves. This has included placing a large number of willing customers on load management or interruptible service in exchange for reduced tariffs. Due to the Company's experience with its Energy Management program over the last two years, the Company believes that it is appropriate to reduce its reliance on certain demand-side alternatives and transition its existing participants to more cost-effective programs as turnover is experienced. This decision was driven by the fact that it is no longer cost-effective to continue to add new participants to the Company's original Energy Management program, as well as a recent attrition of customers from the program due to dissatisfaction with that type of service. Accordingly, as developed more fully in FPC's DSM Plan that was filed and approved by the Commission (Docket No. 971005-EG: Approval of

DSM Plan of Florida Power Corporation), FPC has revised its Energy Management program in a manner that will improve its cost-effectiveness, but also reduce its size and scope.

This is significant for two reasons: (a) FPC is facing a period of uncertainty about how implementation and utilization of the Company's Energy Management program (both existing and new) will affect program participation and be accepted by its retail customers, which creates the need, in FPC's judgment, for additional hard generating assets in the Company's fleet, and (b) it is FPC's judgment, in any event, that the Company should carry more supply-side assets as part of its total reserves than it has in the past. This is the reason the Company projected a stepped-down reliance on dispatchable demand-side reserves in its recent TYSP filing. See FPC's 2000 TYSP. (Appendix D to this Need Study). Although FPC continues to believe that its dispatchable demand-side resources provide important and cost-effective resources when appropriately utilized, FPC will be counting more in the future on generating units to meet its customers' needs than on the willingness of customers to accept frequent curtailments in service.

To illustrate, for the winter of 2003/04, FPC's estimated firm load at time of peak load is 8,231 MW, its estimated non-firm load at the time of peak is 1,150 MW, which results in an estimated total peak load (without load control) of 9,381 MW. (See Table 11 below.) Without the Hines 2 plant in service, FPC's firm supply-side resources (power plants on its system and firm power purchase agreements) would be 9,748 MW, which is 1,517 MW greater than the estimated firm peak load. Because the Company calculates its Reserve Margin based on the relationship between firm load and firm capacity available to serve that load, FPC's Reserve Margin (without Hines 2) would be 18 percent, based on reserves of 1,517 MW. However, the relationship between FPC's firm supply-side resources and its estimated <u>total</u> load (firm and non-firm) would be much lower. Specifically, FPC would have only 367 MW of firm supply-side capacity reserves in excess of estimated total load.

TABLE 11

Reserve Levels With and Without Hines 2
Winter 2003/2004

	Without Hines 2	Including Hines 2
Normal Weather Peak Demand (Before DLC)	9,381	9,381
DLC Capability	1,150	1,150
Firm Demand (After All DLC)	8,231	8,231
Total Available Capacity	9,748	1,0315
Supply Reserves (Before DLC)	367	934
Total Reserves (Including DLC)	1,517	2,084
Firm Reserve Margin	18%	25%
Supply % of Total Reserves	24%	45%

Without Hines 2, in the event of extreme weather or unavailable capacity, FPC would have to expect a significant number of customers participating in FPC's Energy Management program to willingly accept their non-firm service so that FPC could support the remaining firm load with its firm supply-side resources. Non-firm load is available as a resource if needed, and it is paid for at comparable rates, but it is not really a comparable substitute for generation since it cannot be used as often or for extended periods like generation could be used without eventually affecting customer participation levels.

The PSC Staff, on occasion, has examined the relationship between (a) FPC's firm supply-side resources and (b) the combined total of those resources and FPC's dispatchable demand-side resources. (This combined total is sometimes called "total reserves," as distinguished from FPC's "Reserve Margin," which measures only the relationship between firm capacity and firm load.) Using this approach, in the winter of 2003/04, without Hines 2, less than one fourth of FPC's total reserves would consist of firm capacity. This is simply another way of showing that, with the current resource mix, the Company has expected customers who participate in the Energy Management program to willingly accept their non-firm service provisions in order to be able to provide firm service to the remaining firm customers with available firm capacity. In the past, the PSC Staff has been critical of the Company's reliance on demand-side resources that have made up a significant part of the Company's total reserves. By building Hines 2, the Company will take a significant step in reducing its reliance on demand-side resources. Thus, in the winter of 2003/04, with Hines 2 in service, the Company will be able to increase the portion of its total reserves attributable to firm capacity to almost one half (45 percent). The Company thus needs the Hines 2 plant to enhance in this manner its electric system reliability and integrity.

C. Provide Adequate Electricity at a Reasonable Cost.

The Hines 2 plant will meet the Company's need to be able to provide to its customers adequate electricity at a reasonable cost. Specifically, the Hines 2 plant will meet FPC's economic need to realize fuel savings that can be achieved through the addition of a state-of-the-art gas-fired combined cycle unit to its fleet. FPC estimates conservatively that the addition of the Hines 2 unit to the existing fleet would provide fuel savings in the range of $40 million per year at the same time that the goal of system capacity reinforcement is being addressed. In addition, the projected installed cost for Hines 2 is well below the current market estimates for equivalent units because of previously negotiated favorable equipment option terms.

D. Add Diversity to the Company's Supply-Side Resource Mix.

Finally, Hines 2 adds diversity to the Company's supply-side mix. Taking into account the Company's demand and energy requirements (i.e. load shape, load factors, and seasonal peak characteristics), the Company has ample baseload and peaking capacity, including purchased power resources. FPC's baseload coverage is provided by a combination of nuclear, coal, coal-by-wire, and cogeneration contracts priced on the basis of coal units. Combined-cycle unit additions to FPC's fleet generate the best value trade-offs at this time because they are flexible and responsive enough to meet the challenges of intermediate service when needed and yet capable of shifting to baseload operations when prevailing economic or operating conditions warrant the shift. Combined cycle plants are very cost-effective and well suited for this service regime. The proposed Hines 2 unit is a gas-fired, combined cycle unit that will meet all of these operating requirements, increase the fleet's fuel diversity, and provide a cost-effective means to meet clean air compliance requirements. FPC has only two other comparable combined cycle units (Hines 1 and Tiger Bay) in its fleet. The Hines 2 unit addition will serve the Company's need to maintain appropriate fuel and operating diversity in its fleet, which will thereby enhance the reliability and cost-effectiveness of the Company's generation system as a whole.

V. Strategic and Financial Assessment of the Next-Planned Unit.

A. Introduction.

Before the Company finalized the selection of Hines 2 as its next-planned unit in its Base Expansion Plan, FPC evaluated the unit on several occasions to confirm that it "fit" FPC from both a strategic and system standpoint. This evaluation is essential to ensure that the generation expansion alternative does not lead to unstable future rates or to other instabilities on FPC's system in the event that one of FPC's input assumptions proves to be inaccurate. Only when this evaluation is completed without any significant concerns is the generation expansion alternative recommended to FPC's management, and subsequently to the PSC, as the next-planned unit in FPC's Base Expansion Plan. The following areas of consideration were addressed in FPC's review.

B. Hines 2 Contract Advantages.

While any significant new generation resource will draw on FPC's financial resources, the construction and financing of Hines 2 to meet FPC's future capacity needs offers a critical advantage over any other generation alternative. Because of the length of the planning process for Hines 2, and the Company's preservation of previously negotiated, favorable contract equipment terms, FPC obtained and now has the opportunity to take advantage of substantial price and other contract benefits from its combined cycle technology supplier. These contract benefits represent somewhere between a $20 to $40 million advantage to FPC's ratepayers over current market prices for the exact same combined cycle technology. As a result, Hines 2 is extremely cost-effective.

C. Adequacy of Supply and Transportation of Fuels.

FPC also looked at the Hines 2 unit in terms of whether a secure, reliable primary fuel supply existed and could be expected to exist in the future for the plant. Natural gas is an attractive fuel source because, compared to coal and oil, it is a clean burning fuel. As a result, it can reduce FPC's overall sulfur emissions, thereby assisting FPC in complying with the Clean Air Act. For the same reason, natural gas fuel has a favorable impact on the capital cost of constructing generating facilities capable of complying with current and future environmental regulations like the Clean Air Act. The Clean Air Act will continue in the future to cause lower sulfur fuels like natural gas to be more in demand than higher sulfur fuels. Natural gas, therefore, will continue to be an attractive primary fuel source for FPC.

Natural gas is a readily available fuel source. There currently are vast domestic natural gas reserves, compared to the daily quantity of gas required to operate a plant like Hines 2, available for the production and supply of natural gas as a fuel source. The natural gas exploration and production industry, in this country and in Canada, is also engaged in aggressive efforts to maintain and expand the North American natural gas reserve base, spurred by both greater demand for gas and higher, short-term gas prices. There is a substantial amount of exploration and development activity going forward in the deeper waters of the Gulf of Mexico, where large new gas reserves are located, which will be a geographically close source of supply for gas-fired generation plants located in Florida. Further, and as demonstrated by the proposed Cypress pipeline project, liquefied natural gas ("LNG") can and will be added to the mix of gas supply available to gas consumers in the United States. Taken together, there is abundant evidence that adequate supplies of natural gas will be available to fuel a gas-fired plant like Hines 2 for the entire useful life of that plant.

Florida is also an attractive market for the developers and operators of natural gas resources to market their gas. The state is situated close to (a) significant existing and potential onshore gas reserves in Louisiana, Mississippi, and Alabama, (b) the existing and potential offshore Gulf Coast gas producing regions, and (c) some of the nation's largest deposits of coalbed methane. These supply sources have and will have easy access to the existing Florida Gas Transmission ("FGT") gas pipeline and any new underwater gas pipeline connecting the Florida gas markets to the huge existing and potential gas reserves of the Gulf Coast and adjacent Outer Continental Shelf. Consequently, transportation distances for natural gas into Florida are now relatively short and will become shorter, resulting in lower transportation costs for gas sold for consumption in Florida, making it inevitable that natural gas will be aggressively and competitively marketed in the State of Florida.

Natural gas is also expected to be a competitively priced fuel source in the future, based on the forecast of natural gas price trends compared to oil and coal price trends. While natural gas prices have recently escalated due to a tight short-term market, they are expected to fall and level out over the long term. Short-term hikes in gas prices have in large part resulted from low natural gas prices that prevailed in the market over the past two to three years. Relatively low gas prices discouraged additional exploration and development of new and existing gas reserves and caused the demand for natural gas as a fuel source to increase faster than the ability of natural gas resource operators to make the gas available for delivery. With increased natural gas prices, however, additional exploration and development, and the expansion of natural gas reserves and the delivery of natural gas, will be encouraged, which, in turn, will put downward pressure on the price for natural gas. Accordingly, FPC expects that natural gas prices will come down from the current levels, as reflected in FPC's fuels forecasts.

Sufficient and reliable firm gas transportation service for Florida natural gas customers can also be expected. FPC has subscribed firm capacity for its existing gas-fired generation fleet from FGT's Phase IV expansion, which FGT is currently constructing. FGT is also developing Phase V and Phase VI to further expand its existing pipeline to add additional capacity to transport gas into the State of Florida. There are also two new pipeline projects, the Gulfstream Natural Gas System ("Gulfstream") project and the Buccaneer Gas Pipeline Company ("Buccaneer") project, that have received preliminary authorization from the Federal Energy Regulatory Commission ("FERC") to construct interstate gas pipelines under the Gulf of Mexico to serve Florida's gas markets. Further, El Paso Energy Corporation has proposed a pipeline project, the Cypress pipeline, to transport gasified LNG from its Elba Island LNG terminal to an interconnection with FGT in north Florida. With these projects currently in development, it is expected that adequate gas transportation service will be available for gas customers in the State of Florida, including FPC.

D. Environmental and Site Benefits.

FPC places a strong emphasis on environmental quality in its planning process. While two resource alternatives may be economically competitive, their effects on the environment may be quite different, and FPC prefers not only the most cost-effective resource but also one that satisfies FPC's concerns for the quality of the environment. Accordingly, the fuel for a preferred generation alternative should be a relatively clean source. It must not only comply with current Clean Air Act provisions, but must also provide substantial flexibility in the event of changes in this Act or other environmental rules. Second, the generation technology should have a high efficiency (low heat rate). Efficient plants use less fuel per unit of electric service delivered and therefore create smaller environmental impacts per unit of service. Combined with the use of a clean fuel, efficient plants reduce the exposure of FPC to new environmental rules, constraints, or taxes.

The Hines 2 plant satisfies all of these concerns. Its primary fuel is natural gas, which is a clean, low cost fuel source. The new unit will help reduce overall sulfur dioxide ("SO_2") emissions for FPC's fleet, which reduces FPC's reliance on the market for purchasing SO_2 emission credits to meet FPC's overall emissions targets. Additionally, Hines 2 is an efficient state-of-the-art combined cycle unit with a low heat rate. Thus, from an environmental viewpoint, Hines 2 is an attractive generation alternative to meet FPC's capacity needs.

Hines 2 will be located at the Hines Energy Complex ("HEC"), an existing power plant site in Polk County, Florida. The HEC site was approved by the Florida Siting Board on January 25, 1994 for up to 3,000 MW of generating capacity. The HEC is an 8,200 acre site located on land used formerly for a phosphate mining operation. FPC specifically selected the HEC as a power plant site because of its minimal environmental impact. Because of the site's history, there were and are no major environmental limitations. Indeed, most if not all of the environmental issues associated with the site were resolved when the site was certified for Hines 1 and ultimately for 3,000 MW. Accordingly, Hines 2 presents FPC with a supplemental permitting process that will invariably require less time, and therefore less cost, in obtaining the necessary approval over conventional certification requirements. FPC has filed its Supplemental Site Certification Application for the Hines 2 project with the Florida Department of Environmental Protection ("DEP") pursuant to the requirements of the Florida Electrical Power Plant Siting Act ("PPSA") and Chapter 62-17, F.A.C.

The proposed new unit will be located adjacent to the Hines 1 unit. The existing infrastructure – including extensive site development (excavation, fill, access roads), a 722 acre cooling pond, a fully sized natural gas lateral pipeline, as well as all common facilities and manpower requirements needed to support two-unit operations at the site – provides Hines 2 with significant site-development and construction-cost advantages over any other generation alternative available to FPC.

E. Fuel Savings and Fuel Diversity.

The Hines 2 unit provides FPC's customers significant fuel saving potential. As discussed in prior sections of this report, FPC estimates conservatively that it will achieve fuel savings in the range of $40 million per year from Hines 2. The new unit will also help reinforce fuel diversity and provide operating flexibility that is needed on the system.

F. Conclusion: Hines 2 is the Next-Planned Unit.

As explained above, the Hines 2 power plant option offers FPC a number of benefits that FPC cannot obtain with any other generation alternative. These benefits include the proven technology and high efficiency of an advanced combined cycle unit at below market cost, environmental and site benefits associated with an existing site, dual-fuel flexibility, and enhanced diversity in FPC's fuel supply. Taking all these factors into account, FPC found Hines 2 to be the most cost-effective option to meet its ratepayers future capacity needs. As a result, Hines 2 was confirmed as FPC's next-planned generation alternative.

VI. FPC's Request for Proposals.

A. Introduction

Having selected the Hines 2 power plant as its next-planned generating alternative, FPC solicited competitive proposals from third parties to meet the Company's need, pursuant to Rule 25-22.082, F.A.C. FPC issued a Request for Proposals ("RFP") on January 26, 2000 to solicit competitive proposals for supply-side alternatives to its planning and bid evaluation benchmark, Hines 2. FPC also filed its RFP with the PSC on January 26, 2000, as required in the rule. A copy of FPC's RFP is included in Appendix P to this Need Study.

B. Development and Distribution of the RFP.

In its RFP, FPC endeavored to attract all proposals that might offer lower cost supply-side resources or provide more economic value to FPC and its ratepayers. In the RFP, the only real limitations on potential proposals were that the capacity offered to FPC in a proposal had to be dedicated solely to FPC's use and subject to economic dispatch by FPC. FPC sought proposals that might offer FPC superior value and other attributes from anyone interested in responding to the RFP.

FPC sent its RFP to more than 50 independent power producers and electric utilities, published the RFP on the Company's internet website, and published notice of the RFP in several national and local newspapers and in various widely disseminated trade journals. FPC requested notification from potential bidders by February 10, 2000, expressing their interest in submitting a proposal in response to the RFP, called a Notice of Intent to Bid ("NOI"). FPC set up a pre-bid meeting for interested parties on February 18, 2000, to provide an opportunity for any interested person to ask questions about the RFP or to discuss the RFP.

Thirteen companies submitted NOIs on the project, and representatives of twelve entities attended the optional pre-bid meeting. A member of the PSC Staff also attended the pre-bid meeting. At that meeting, and in response to questions raised before the meeting, FPC said that it would entertain proposals by bidders to build their power plants at the HEC. FPC also identified a contact person to handle all questions about the RFP.

Before the time for submissions of bids arrived, FPC provided answers to various inquiries from potential bidders. Questions of general interest – and FPC's answers – were circulated to all potential bidders that had submitted an NOI. FPC also posted a transcript of the pre-bid meeting and the answers to the potential bidder's questions on its website.

In its RFP, FPC had set March 27, 2000 as the deadline for bids. Although numerous potential bidders had expressed an intention to bid, two bidders in fact submitted proposals for FPC's consideration. Both bidders requested that the terms of their proposals be treated as confidential. Accordingly, FPC discusses the bidders' proposals and FPC's evaluation of the proposals in the Confidential Section of its Need Study, which is being filed contemporaneously with this Need Study but separately and on a confidential basis. Copies of the proposals from these two bidders are included with the Confidential Section of this Need Study and are filed with the PSC on a confidential basis.

C. Conclusion and Resource Selection.

After a thorough analysis of the two bids, which is explained in the Confidential Section of this Need Study, FPC concluded that the Hines 2 plant was the most cost-effective supply-side alternative available to FPC to meet its need for power.

VII. The Proposed Plant: Hines 2.

A. Introduction.

The Hines 2 unit is a state-of-the-art, highly efficient, 530 MW (net) combined cycle unit. Its beneficial heat rate, availability, and responsiveness, among other attributes, provide the Company with a low-cost, highly flexible source of power. Upon construction and operation, Hines 2 will be the most efficient unit on the Company's system. This section outlines the characteristics and requirements for the proposed new facility.

B. The Hines Energy Complex.

The HEC is an 8,200 acre site located on a reclaimed phosphate mine in an industrial section of southwest Polk County, Florida. It is approximately 40 miles east of Tampa, 7 miles south of Bartow, and approximately 3.5 miles northwest of Fort Meade. The HEC site currently contains the Hines 1 power plant and its associated facilities. The site offers a multitude of attributes for power plant development, many of which have been discussed in prior sections of this report.

C. Hines Unit 2 Description.

Hines 2 is a 2-on-1 combined cycle unit. The basic power generation cycle for Hines 2 consists of two nominal 170 MW Westinghouse 501 F combustion turbines, two unfired heat recovery steam generators ("HRSGs"), one nominal 190 MW steam turbine, and a closed-cycle cooling water system. The Hines 2 combustion turbines will be dual-fuel units capable of operating on natural gas or distillate oil. Natural gas will be the primary fuel. Low sulfur (0.05 percent) distillate oil is planned as the backup fuel.

D. Projected Unit Performance.

The proposed unit is a high efficiency combined cycle unit with an equivalent availability factor of approximately 94 percent and average net operating heat rate of 6,975 Btu/kWh. Its heat rate approaches the lowest for generation units in operation today, meaning that it will generate more energy per unit of gas than existing generating plants. Its design also allows for greater flexibility in matching FPC's system operating requirements. For example, a highly efficient, technologically advanced combined cycle unit like Hines 2 can be operated as a baseload or intermediate unit on FPC's system depending on the needs of the system and the prevailing economic conditions. Hines 2 is expected to operate in a capacity factor range of roughly 55 percent to 65 percent. For this reason, and others, modern combined cycle power plants, like Hines 2, are the most efficient power cycles available today. Hines 2 provides FPC with greater flexibility in the overall operation of its system at a low cost and at industry leading efficiency.

E. Fuel Transportation and Supply.

Hines 2 will run on natural gas transported by pipeline to the HEC. On average Hines 2 will require approximately 65,000 million British thermal units ("MMBtu's") per day of transportation service (80,000 MMBtu's a day at peak operation).

Currently, there is only one gas pipeline in the Florida peninsula, the FGT pipeline. The HEC is currently served by a connection to FGT and FPC has reserved firm gas transportation on FGT to serve Hines 1. FGT does not currently have surplus firm transportation capacity sufficient to serve Hines 2 available at the HEC. There are planned expansions of the FGT pipeline and several additional gas pipelines proposed for service into Florida in various stages of development. One or more of the proposed pipelines or pipeline expansions can reasonably be expected to be completed and capable of providing natural gas transportation service to FPC for Hines 2 in the next two to three years.

FPC intends to negotiate with FGT and the sponsors of the new pipeline projects for firm transportation capacity for Hines 2. Because of the competitive environment created by the competing pipeline expansions and proposed pipeline projects, FPC anticipates that the rates it will pay for firm gas transportation service for Hines 2 will be no higher than, and in all likelihood lower than, the rates for such service currently charged by FGT under its current FERC natural gas tariff. FPC expects to be able to arrange for all of the firm gas transportation service it will require for Hines 2 at attractive rates in time to meet the expected in-service date for the unit in late 2003.

FPC plans to contract for its gas supply closer to the in-service date for the Hines 2 plant. Based on FPC's fuels forecast and gas procurement experience, the Company expects the cost of the natural gas supply for Hines 2 to be lower if the gas supply contracts are obtained at some time closer to the commercial operation of Hines 2 because most gas suppliers would impose significant "up front" payments and/or "stand by" payments on FPC in return for the advance commitment of their reserves to Hines 2. The cost of such payments made in advance of gas delivery should exceed any potential increase in gas prices leading up to the Hines 2 in-service date. Further, current gas prices are relatively high due to a tight, short-term natural gas market, but they are expected to come down significantly and increase at a more gradual pace over the long term. For these reasons, in FPC's planning judgment, the cost of gas supply for Hines 2 will be lower if the contracts for such supply are entered into closer to the Hines 2 in-service date. It therefore is premature, potentially costly, and unnecessary for FPC to enter into contracts for either short- or long-term gas supplies long before the plant's in-service date and before the Company has received regulatory authorization for Hines 2.

FPC anticipates no difficulty in obtaining contracts for gas supply adequate for Hines 2 at the right time on competitive terms and conditions and at market-based prices. FPC has developed and will maintain gas supply relationships with a number of gas producers and gas marketers for this reason. FPC expects that, in all likelihood, it will enter into a "portfolio" of gas supply contracts of varying terms to meet the fuel requirements for the Hines 2 unit, in order to achieve the lowest cost of fuel consistent with reliable availability.

Distillate oil will serve as the backup fuel for Hines 2. It will be delivered to the HEC by truck and stored in existing tanks at the site. Similar backup fuel transportation service is being provided now to the HEC for Hines 1. The addition of Hines 2 to the HEC is not expected to increase significantly the truck transportation of distillate oil to the HEC. Hines 2, like Hines 1, will operate primarily on natural gas. The existing oil tank at the HEC is adequate to provide backup fuel to both units, Hines 1 and 2, for approximately four days of continuous operation at full load.

F. Transmission Requirements.

With the addition of the proposed Hines 2 unit at the HEC in November 2003, the projected total net generation at the HEC with the Hines 1 and 2 units will be 977 MW in the summer and 1,096 MW in the winter. There are three existing 230kv transmission circuits from the HEC that were installed to connect the Hines 1 unit to the transmission grid, two circuits to FPC's Fort Meade substation, and a single circuit constructed on double circuit structures to FPC's Barcola substation. Transmission facility upgrades and additions at an estimated total cost of $5.6 million will be required for the connection of the Hines 2 unit to the FPC transmission system and the operation of Hines 2 at the HEC (and for other, future generation additions in the same area by other utilities). These facility upgrades and additions will include the substation interconnection requirements (busswork, breakers, controls) and upgrade work on two of the circuits.

With the proposed addition of Hines 2 in November 2003, a forced outage of the existing Hines-Barcola 230kv circuit 1 (3.1 miles) could thermally overload the existing FPC Fort Meade-West Lake Wales 230kv line under certain operating conditions in violation of FPC's transmission planning criteria. Hence, the second circuit to the Hines-Barcola 230kv line is needed to alleviate this potential contingency overload situation with the addition of the Hines 2 unit. FPC proposes installing this second circuit on the existing steel pole structures using bundled 954 kcm ACSR conductor per phase, which was already approved by the Florida Siting Board on January 25, 1994.

Also included in the $5.6 million transmission facility additions and upgrades in connection with Hines 2 is an upgrade of the existing single circuit, 3.97 mile, 230kv transmission interconnection between FPC's Barcola substation and Tampa Electric Company's ("TECO") Pebbledale substation. The loading on this existing single circuit is affected by the generation additions at FPC's HEC, SECI's Payne Creek Plant, and TECO's Polk Plant. All three utilities are planning to add generation at the above sites in the 2000-2004 timeframe. In FPC's planning studies, by the winter of 2003/04, a forced outage of the existing Fort Meade-West Lake Wales 230kv (19.87 mile) circuit will overload the Barcola-Pebbledale 230kv interconnection in violation of FPC's transmission planning criteria. To avoid this potential contingency overload situation, FPC plans to replace the existing single circuit structures with new double circuit steel pole structures and upgrade the conductor on the existing circuit from single 954 kcm ACSR conductor to bundled 954 kcm ACSR conductor per phase. FPC and TECO will be negotiating the upgrade of this interconnection in 2000, with the final scope and responsibility for the work on this upgrade finalized by a Transmission Interconnection and Operating Agreement between FPC and TECO.

G. Environmental Considerations.

Both natural gas and distillate oil are low sulfur, low ash fuels. Flue gas is the only byproduct of the combustion process, whether burning natural gas or distillate oil, which leaves the HEC. The manufacturer guarantees full load nitrogen oxide ("NOx") emission levels of 6 ppm for Hines 2 while burning natural gas. This will require the installation of selective catalytic reduction ("SCR") technology to control NOx emission levels. While firing distillate oil as a backup fuel, water injection along with SCR will be used to limit NOx levels. The cost of the SCR is accounted for in the Total Installed Cost for Hines 2.

For air emissions, Hines 2 will be considered a major stationary emission source and will be subject to Prevention of Significant Deterioration ("PSD") permitting requirements. Hines 2 will be considered a minor stationary emission source with respect to sulfur dioxide ("SO_2") and particulate matter emissions and will be permitted under a federally enforceable annual SO_2 emission limit of 40 tons per year. No other air pollution techniques are required, although as noted above, water injection will be required when burning oil. Airborne emissions are limited because the Hines 2 unit will burn a relatively clean fuel with good combustion practices to ensure complete combustion and will use appropriate emission control technologies.

The HEC is a zero surface water discharge facility with respect to the National Pollution Discharge Elimination System program for industrial wastewaters. Process wastewater streams are treated on-site and are used as makeup for the cooling pond. Water consumption and loss occur primarily through evaporation from the cooling pond. Accordingly, a key feature of the HEC design for zero surface water discharge is the existing 722 acre cooling pond, which will serve not only as the heat dissipation device but also as a water storage device. Hines 2 will use treated effluent and storm water for cooling with no discharge offsite.

FPC is required, under its existing Site Certification, to obtain alternative sources of water to groundwater for makeup cooling water for the Hines 2 plant. Reclaimed water from the City of Bartow, on-site storm water runoff and water cropping (use of on-site rainfall collection basins), and re-use of process water will be used to provide the makeup water to the cooling pond during the operation of Hines 1 and 2. An existing detention pond serves as the site storm water management system with overflow to the on-site cooling pond. This system is adequate for Hines 1 and 2.

In sum, the Hines 2 unit will have a low environmental impact. Combined cycle units operating on natural gas, like the Hines 2 unit, are one of the cleanest sources of fossil generation. Additionally, the vast majority of any remaining environmental issues were addressed and resolved, as noted above, in the 1994 Site Certification for the Hines 1 unit and an additional 3,000 MW at the HEC.

H. Hines 2 Costs.

1. Project Cost.

The capital cost estimate for Hines 2 was developed on the basis of the original Polk Combined Cycle Project Specifications (with minimal revisions) and Option Contracts originally negotiated in 1996. Indirect capital costs include the typical items of engineering, construction management, general indirect costs, and contingency. Total project cost is the summation of direct and indirect capital costs for commercial operation in 2003.

The total project cost for Hines 2 (stated in actual dollars) is estimated to be $198 million. The total project cost reflects significant savings (somewhere between $20 and $40 million) compared with the current generation market. The savings are possible because the Company was able to negotiate and preserve beneficial equipment pricing options and other favorable contract terms and conditions, such as performance guarantees and liquidated damages provisions, from its major equipment suppliers.

The total project capital cost estimate also reflects savings associated with the sharing of common site utilities and equipment, including buildings and other associated facilities. These site utilities and facilities include the site access road, cooling pond, effluent supply pipeline, water treatment and wastewater disposal, gas lateral, transmission facilities, and buildings located at the HEC. Location of the Hines 2 unit at the HEC will save the Company greenfield site development costs the Company otherwise would have incurred. As a result, the Company and its ratepayers will save additional engineering and construction costs by locating a new combined cycle unit at the HEC.

2. O&M Costs.

The estimated annual fixed Operation and Maintenance ("O&M") is $2.2 million (in 2003 dollars), and the estimated variable O&M is $1.11/MWh (also in 2003 dollars). For the fixed O&M analysis, it was assumed that fixed costs will remain constant in real dollars over the life of the plant. Fixed O&M costs are those independent of plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Variable O&M costs include consumables, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation.

3. Associated Facilities.

No additional associated facilities are required for Hines 2. The existing gas lateral at the HEC is sufficient to supply the Hines 2 unit. The Hines 1 distillate oil storage tank and the four truck unloading stations will also be used for Hines 2 without adding tank capacity or unloading stations.

4. Transmission Interconnection Facilities.

Transmission facility additions and upgrades required in connection with Hines 2 will cost an estimated $5.6 million. That cost includes the expansion of the Hines Energy substation by one more 230kv substation bay to accommodate two additional substation terminations, the connection of the Hines 2 combined cycle unit, and a second Hines-Barcola 230kv transmission circuit, all to connect Hines 2 to the transmission grid. This additional transmission capacity, which the Siting Board certified in 1994, will be required when both Hines 1 and 2 are on line.

VIII. Consequences of Delay of Hines 2.

If the Hines 2 plant is delayed, FPC would not be able to satisfy its desired minimum 20 percent Reserve Margin planning criterion by the winter of 2003/04. This would expose FPC's customers to a risk of interruption of service in the event of unanticipated forced outages or other exigencies for which FPC maintains reserves. Delay would further subject FPC's customers to the risk resulting from the overall performance of, and the transition to, the Company's new Energy Management program.

Furthermore, and certainly not insignificantly for FPC and its ratepayers, a delay in the Hines 2 unit would defer or possibly eliminate the estimated fuel savings from the plant and may also impact the Company's ability to preserve its below market pricing for the Hines 2 unit. Estimates of these cost impacts of a one to two year delay, absent the potential reliability impacts, range from \$40 - \$70 Million (CPWRR). This attempt to quantify the deferred revenue requirements simplistically for a delay in implementation of this facility ignores a wealth of benefits that this option offers. As a result, FPC is very motivated to keep this project on schedule to ensure that the ratepayer benefits are preserved.

IX. Conclusion.

The Hines 2 power plant will be a state-of-the-art, highly efficient, environmentally benign unit, and it will be built at a site that is well-suited to accommodate the planned expansion of FPC's generation system. The plant is the most cost-effective alternative available to FPC. It will provide needed diversity, efficiency, and cost-effectiveness to FPC, enabling FPC to achieve substantial fuel savings for its ratepayers over the life of the plant.

For all the reasons provided above, FPC seeks an affirmative determination of need for the Hines 2 power plant to meet FPC's needs for electric system reliability and integrity and to enable FPC to continue to provide adequate electricity to its ratepayers at a reasonable cost. FPC determined to seek this approval only after conducting a rigorous internal review of supply-side and demand-side options, and after soliciting and evaluating competing proposals submitted by interested third party suppliers. FPC has attempted to avoid or defer constructing the unit by considering and pursuing cost-effective demand-side options reasonably available to it, but FPC has nonetheless concluded that it cannot avoid or defer its need to build the unit.

THE NEED STUDY

IN SUPPORT OF
FLORIDA POWER CORPORATION'S
PETITION FOR DETERMINATION OF NEED
OF HINES UNIT 2 POWER PLANT

LIST OF APPENDIX ITEMS.

A. Florida Power Corporation's ("FPC's") Service Area Map.

B. FPC's Electric System Map.

C. PSC Order No. 99-2507-S-EU, Docket No. 981890-EU, issued December 22, 1999.

D. FPC's April 2000 Ten-Year Site Plan ("TYSP").

E. FPC's Forecasting Methods and Procedures.

F. FPC's Load Forecast Model Documentation.

G. FPC's History and Forecast of Energy Consumption and Number of Customers by Customer Class.

H. FPC's History and Forecast of Energy Sales.

I. FPC's History and Forecast of Summer Peak Demand (Base, High, and Low Forecasts).

J. FPC's History and Forecast of Winter Peak Demand (Base, High, and Low Forecasts).

K. FPC's Demand-Side Management Plan, December 29, 1999.

L. PSC Order No. 00-0750-PAA-EG, Docket No. 991789-EG, issued April 17, 2000.

M. FPC's Integrated Resource Planning ("IRP") Process Overview Diagram.

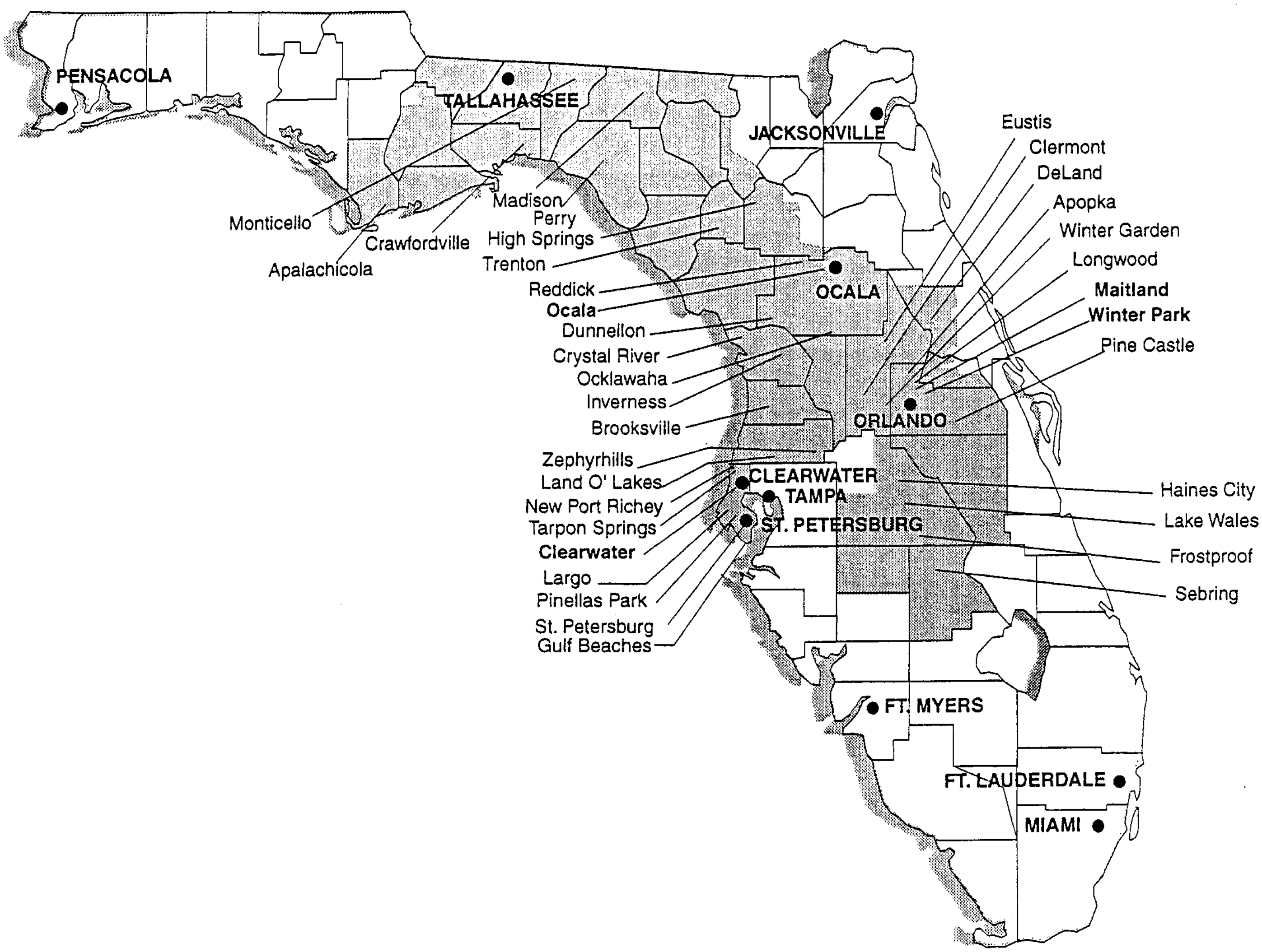
N. Cost and Operational Factors for Non-Conventional Generation Technologies.

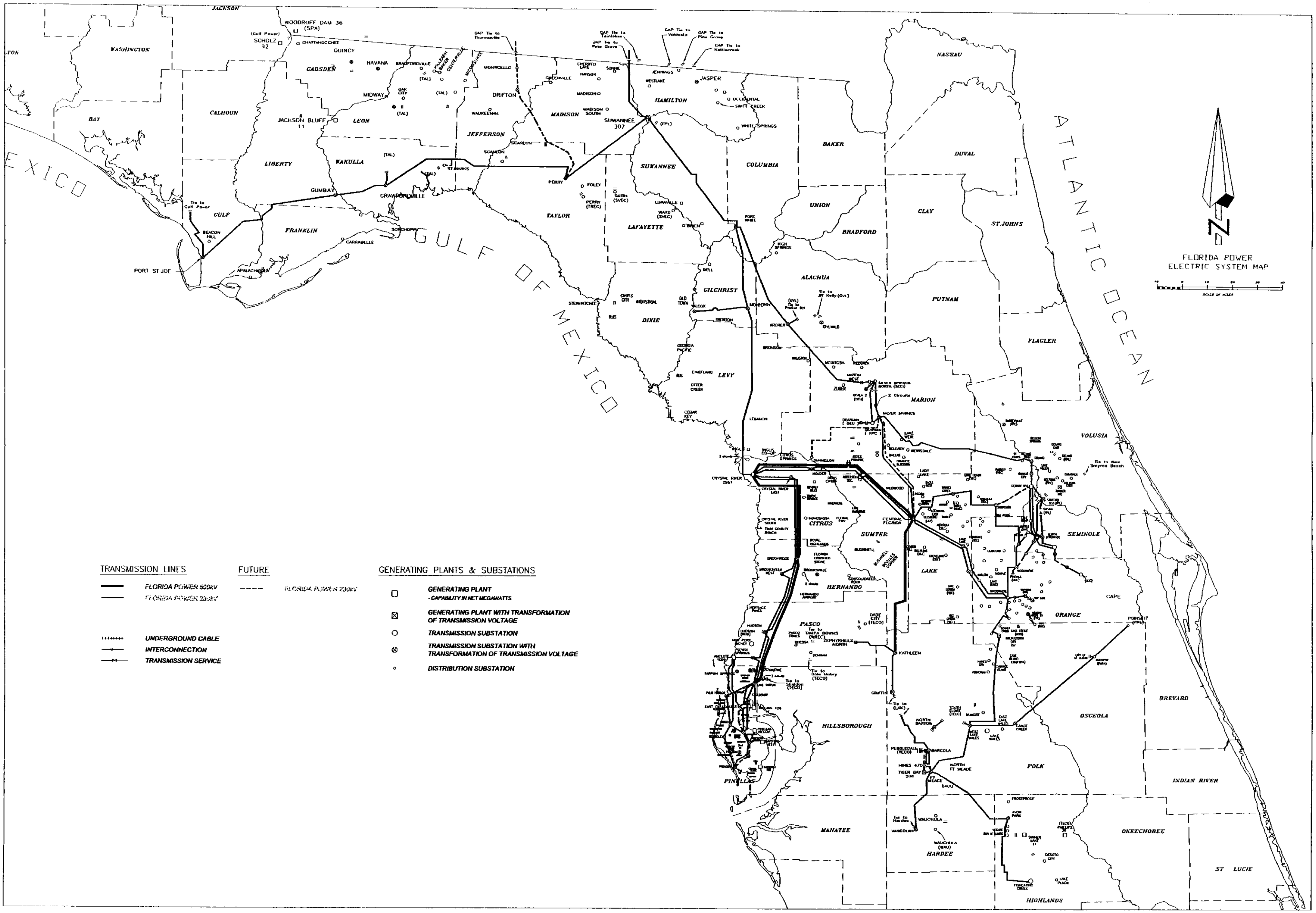
O. FPC's 2000 TYSP Analysis With and Without Capacity Additions.

P. FPC's Request For Proposals ("RFP"), dated January 26, 2000.

Florida Power CORPORATION

Florida Power Corporation • Area of Service





FLORIDA POWER
ELECTRIC SYSTEM MAP
ATLANTIC OCEAN
GULF OF MEXICO
TRANSMISSION LINES
FLORIDA POWER 500kV
FLORIDA POWER 230kV
FUTURE
FLORIDA POWER 230kV
UNDERGROUND CABLE
INTERCONNECTION
TRANSMISSION SERVICE
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT
- CAPABILITY IN NET MEGAWATTS
GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION
TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
DISTRIBUTION SUBSTATION
JACKSON
WASHINGTON
CALHOUN
BAY
GULF
LIBERTY
FRANKLIN
GADSDEN
LEON
WAKULLA
JEFFERSON
MADISON
TAYLOR
HAMILTON
SUWANNEE
LAFAYETTE
COLUMBIA
BAKER
NASSAU
DUVAL
UNION
BRADFORD
CLAY
ST.JOHNS
ALACHUA
GILCHRIST
DIXIE
LEVY
PUTNAM
FLAGLER
MARION
VOLUSIA
CITRUS
SUMTER
LAKE
SEMINOLE
HERNANDO
PASCO
ORANGE
HILLSBOROUGH
PINELLAS
POLK
OSCEOLA
BREVARD
MANATEE
HARDEE
HIGHLANDS
OKEECHOBEE
INDIAN RIVER
ST LUCIE
WOODRUFF DAM 36 (SPA)
SCHOLZ 32
QUINCY
HAVANA
MIDWAY
JACKSON BLUFF 11
DRIFTON
PERRY
SUWANNEE 307
JASPER
GUMBAY
CRAWFORDVILLE
PORT ST JOE
CRYSTAL RIVER 2961
CENTRAL FLORIDA
KATHLEEN
NORTH BARTOW
BARCOLA
HINES 470
TIGER BAY 208
NORTH FT MEADE
PEBBLEDALE (TECO)
WAUCHULA
ZEPHYRHILLS NORTH
DADE CITY (TECO)
POINSETT
CAPE
SILVER SPRINGS
LEBANON

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.	DOCKET NO. 981890-EU ORDER NO. PSC-99-2507-S-EU ISSUED: December 22, 1999

The following Commissioners participated in the disposition of this matter:

JOE GARCIA, Chairman
J. TERRY DEASON
SUSAN F. CLARK
E. LEON JACOBS, JR.

APPEARANCES:

JAMES D. BEASLEY and LEE WILLIS, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302, appearing on behalf of Tampa Electric Company.

JOSEPH A. McGLOTHLIN, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of Reliant Energy Power Generation.

VICKI GORDON KAUFMAN and JOHN MCWHIRTER, McWhirter, Reeves, McGlothlin, Davidson, Dekker, Kaufman, Arnold & Steen, 117 South Gadsden Street, Tallahassee, Florida 32301, appearing on behalf of the Florida Industrial Power Users Group.

GARY L. SASSO, Carlton, Fields, Ward, Emmanuel, Smith & Cutler, P.A., Post Office Box 2861, St. Petersburg, Florida 33731, appearing on behalf of Florida Power Corporation.

MATTHEW M. CHILDS, Steel, Hector & Davis, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301, appearing on behalf of Florida Power & Light Company.

DEBRA SWIM, Legal Environmental Assistance Foundation, 1115 North Gadsden Street Tallahassee, Florida 32301, appearing on behalf of Legal Environmental Assistance Foundation (LEAF).

ROY YOUNG, Young, van Assenderp and Varnadoe, P. A., P. O. Box 1833, Tallahassee, Florida 32302-1833, appearing on behalf of the City of Lakeland and Kissimmee Utility Authority.

PAUL SEXTON, Thornton Williams & Associates, 215 South Monroe Street, Suite 600-A, Tallahassee, Florida 32301, appearing on behalf of the Florida Reliability Coordinating Council, Inc.

JON C. MOYLE, JR. Moyle, Flanigan, Katz, Kolins, Raymond & Sheehan, 210 South Monroe Street, Tallahassee, Florida 32301, appearing on behalf of PG&E Generating Company.

ROBERT SCHEFFEL WRIGHT, Landers & Parsons, 310 West College Avenue, Tallahassee, Florida 32302, appearing on behalf of Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P.

FREDERICK M. BRYANT, General Counsel, Florida Municipal Power Agency, 2010 Delta Boulevard, Tallahassee, Florida 32315, appearing on behalf of Florida Municipal Power Agency.

THOMAS J. MAIDA, III, Foley & Lardner, Post Office Box 508, Tallahassee, Florida 32302, appearing on behalf of Seminole Electric Cooperative.

KENNETH A. HOFFMAN, Rutledge, Ecenia, Underwood, Purnell and Hoffman, P. O. Box 511, 215 South Monroe Street, Suite 420, Tallahassee, Florida 32302-0551, appearing on behalf of the City of Tallahassee.

MICHAEL B. WEDNER, Office of General Counsel, 117 West Duval Street, Suite 480, Jacksonville, Florida 32202, appearing on behalf of Jacksonville Electric Authority.

ROBERT V. ELIAS, GRACE JAYE and COCHRAN KEATING, FPSC Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission Staff.

ORDER APPROVING STIPULATION

BY THE COMMISSION:

During our reviews of the Ten Year Site Plans filed in 1997 and 1998, we expressed concerns about the adequacy of the reserve margins planned for Peninsular Florida. At the December 15, 1998, Internal Affairs meeting, we directed staff to open this docket to consider the reserve margins planned for Peninsular Florida electric utilities.

By Order No. PSC-99-1274-PCO-EI, nineteen issues were identified for consideration in this proceeding. The investor-owned utilities, the cooperative utilities, several municipal utilities, the various intervenors, and Commission staff filed testimony concerning these issues. The hearing was scheduled for November 2nd and 3rd, 1999.

At the outset of the hearing, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO), presented a proposal designed to settle the case; addressing what they believe are the Commission's major concerns. By the proposal, these three utilities stipulated to voluntarily adopting a twenty percent reserve margin planning criterion. Each of these three utilities would achieve the twenty percent level by the summer of 2004. Further, pursuant to the proposal, no decisions would be made concerning the specifically enumerated issues, and the docket would be closed. FPL, FPC, and TECO would be the only utilities adopting the twenty percent criteria.

Other parties argued in support of and against the proposal. The Florida Industrial Power Users Group (FIPUG) requested additional time to present a counter-proposal. The hearing was continued until November 30, 1999, and the parties were directed to attempt to reach a negotiated settlement. FIPUG offered a counter-proposal on November 17, 1999. No settlement was reached.

At the continued hearing, we considered both proposals. After discussion, FPL, FPC, and TECO agreed to further modifications to their proposal. A document incorporating these agreed-upon changes was filed on December 15, 1999. A copy of this document (hereinafter the "Stipulation") is included in this Order as Attachment A and is incorporated herein by reference. FPL, FPC, and TECO have each agreed to achieve a planned twenty percent reserve margin by the summer of 2004. In response to concerns expressed by some of the other parties, each utility has agreed to make a good faith effort to notify the Commission if it opts to modify the twenty percent criterion. The three utilities signing the Stipulation further acknowledge in paragraph 9 at page 4 that

> the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

We approve the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company. It addresses the basic concern about the adequacy of planned reserve margins for Peninsular Florida. Collectively, these three utilities plan for approximately 80 percent of the Peninsular Florida load. Thus, a twenty percent planning criterion adopted by these three utilities is a significant increase over the fifteen percent criterion currently employed.

Further, we will convene a workshop to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs. In addition, we will convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate reserve margin.

Based on the foregoing, it is therefore

ORDERED by the Florida Public Service Commission that the Stipulation agreed to by Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company, which is included in this Order as Attachment A and is incorporated by reference herein, is approved. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 22nd day of December, 1999.

BLANCA S. BAYÓ, Director
Division of Records and Reporting

(S E A L)

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of Records and reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT A
(page 1 of 5)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida
_______________________________/

Docket No. 981890-EU

STIPULATION

WHEREAS, the Florida Public Service Commission initiated this proceeding regarding reserve margins of Peninsular Florida utilities in December 1998; and

WHEREAS, subsequent to that date Staff and parties identified certain issues to be addressed and procedures to be followed; and

WHEREAS, Florida Power & Light Company (FPL), Florida Power Corporation (FPC), and Tampa Electric Company (TECO) (collectively, the IOUs) have asserted, and continue to assert, that the scope of the proceeding has been expanded beyond the intent of the Commission, and that the procedural posture of this proceeding is such that the Commission cannot lawfully take formal action that would affect their substantial interests at this time; and

WHEREAS, in Orders No. PSC-99-1274-PCO-EU and No. PSC-99-1716-PCO-EU the Commission overruled the IOUs' procedural objections, clarified the scope of the docket, identified specific issues to be addressed, and confirmed its intent to conduct a formal evidentiary proceeding in this docket and take the actions it deems appropriate; and

WHEREAS, Reliant Energy Power Generation, Inc (Reliant Energy), Florida Industrial Power Users Group (FIPUG), PG&E Generating Company (PG&E), the Legal Environmental Assistance Foundation, Inc. (LEAF), and Duke Energy North America, LLC, and Duke Energy New Smyrna Beach Power Company, Ltd., LLP (Duke Energy), (hereinafter referred to as Intervenors), filed Petitions to Intervene in which they alleged the actions contemplated by the Commission in this docket would affect their substantial interests; and

WHEREAS, the Commission granted Intervenors' petitions to intervene, and Intervenors have participated as full parties to the proceeding; and

WHEREAS, on October 29, 1999, FPC, acting on behalf of the IOUs, submitted to the Commission Staff a proposal for the resolution of the issues in this proceeding; and

WHEREAS, upon receipt of the proposal the Commission continued the hearing scheduled for November 2, 1999 and convened on that date a conference of all parties for the purpose of discussing the proposal of the IOUs; and

WHEREAS, upon consideration of the IOUs' proposal, without waiving their respective litigation positions and for the purposes of compromise and settlement, the undersigned, representing all of the parties to this proceeding that have been identified by the Commission or allowed by Commission to intervene, have decided to prepare this Stipulation, and present it to the Commission for the purpose of concluding this docket.

NOW, THEREFORE, the parties stipulate and agree as follows:

1. The IOUs will each voluntarily adopt a minimum reserve margin planning criterion of twenty percent (20%).

2. The twenty percent (20%) reserve margin planning criterion will be a minimum; no maximum or cap will be represented or implied by this criterion.

3. No utility other than the three IOUs identified hereinabove is agreeing to adopt a twenty percent (20%) reserve margin planning criterion by virtue of this Stipulation.

4. The IOUs will calculate the minimum twenty percent (20%) reserve margin by employing their current methodology; i.e., Reserve Margin (%) = [(Total Firm Capacity – Peak Firm Demand)/Peak Firm Demand] x 100, where Total Firm Capacity will be based on generating capacity owned by the IOUs or capacity for which there is a firm commitment to these IOUs and

where Peak Firm Demand means total demand reduced by demand side resources.

5. The IOUs will undertake to implement the twenty percent reserve margin criterion over a transition period of four years, meaning that they will plan to achieve a twenty percent (20%) reserve margin by the Summer of 2004.

6. The IOUs agree to adopt the twenty percent (20%) reserve margin planning criterion with the good faith intention of maintaining that planning criterion for the indefinite future, but each IOU must reserve the prerogative individually to modify its planning criteria to adapt to relevant circumstances. By the same token, it is understood that the Commission remains free to initiate an investigation or to take other appropriate action to review and to respond to any changes that the IOUs may make in the future regarding their planning criteria.

7. Should any IOU exercise its prerogative to change its twenty percent (20%) minimum reserve margin planning criterion discussed herein, such IOU will make a good faith effort to provide notice of the change to the Commission.

8. Neither the adoption by the IOUs of the minimum twenty percent (20%) planning criterion nor the approval of this Stipulation by the Commission shall be deemed to create any presumption that capacity additions must be through any particular mix of generation and/or demand-side resources. Nor shall said adoption or approval be deemed to create any presumption with respect to any proposals for adding generating capacity or create a presumption that a generating capacity addition proposed by any entity is not needed. All current and future proceedings under the Electrical Power Plant Siting Act, including those for the consideration of merchant plants, and all statutes, rules, regulations, and policies bearing on the Commission's determination of need for new generation (including the need determination criteria in § 403.519, Florida Statutes); the IOUs' obligation to solicit proposals for generating capacity; and the

obligations of the IOUs to otherwise prudently avail themselves of reasonably available conservation alternatives and cost-effective resource options; and the obligations of the IOUs to best serve their retail customers through their respective resource planning processes, are unaffected by this Stipulation and the approval thereof.

9. The parties acknowledge that for all regulatory purposes, the Commission shall retain the ability and discretion to consider all facts and circumstances applicable to a given utility and/or peninsular Florida. Further, with respect to the evaluation of the adequacy of reserves in peninsular Florida, the Commission may employ any methodology and may consider any facts and circumstances it deems appropriate, subject to applicable legal requirements.

10. The Commission is encouraged to take the following actions in conjunction with the approval of this Stipulation:

A. Convene a workshop, with the participation and the assistance of the Regulatory Assistance Project, to receive and consider information regarding how distributed resources, both demand and supply-side, may be used to meet Florida's energy service reliability needs, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

B. Convene a workshop for the consideration of the appropriate relationship between the non-firm load of an individual utility and the total reserves required to maintain the utility's appropriate minimum reserve margin, to be followed by any additional proceedings and/or actions relative to this matter that the Commission deems appropriate.

11. The parties enter into this Stipulation for the purpose of effecting a compromise and of achieving closure of this docket. By its participation in this Stipulation, no party expresses its endorsement of any individual provision included by any other party.

12. By entering this Stipulation, no party waives any position it has taken with respect to any aspect of this proceeding or any of the issues identified in this proceeding or any other proceeding. Further, no party waives the right and opportunity to petition the Commission to institute any action designed to provide any relief deemed appropriate or desirable by that party at any time.

13. The parties to this Stipulation agree that, by approving this Stipulation, the Commission does not waive its right and ability, pursuant to governing law, to initiate any proceeding or take any action for which it has requisite jurisdiction and authority.

14. In the event the Commission declines to approve this Stipulation in its entirety, it shall become null and void.

AGREED this 14th day of December 1999.

Matthew M. Childs
Charles A. Guyton
Steel Hector
215 South Monroe Street, Ste. 601
Tallahassee, FL 32301-1804
Attorneys for Florida Power & Light Company

James A. McGee
Legal Department MC A5E
Florida Power Corporation
Post Office Box 14042
St. Petersburg, FL 33711

Gary L. Sasso
Carlton, Fields, Ward, Emmanuel, Smith & Cutler, P.A.
Post Office Box 2861
St. Petersburg, FL 33731-2861

Attorneys for Florida Power Corporation

James Beasley
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32301
Attorneys for Tampa Electric Co.

Florida Power
CORPORATION

Ten-Year Site Plan

2000-2009

Submitted To:

State of Florida
Public Service Commission

APRIL, 2000

TABLE OF CONTENTS

Page

TABLE OF CONTENTS (continued)

LIST OF REQUIRED SCHEDULES

FLORIDA POWER CORPORATION
CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
CT - Combustion Turbine (Gas Turbine)
CC - Combined Cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

UR - Nuclear (Uranium)
NG - Natural Gas
F06 - No. 6 Fuel Oil
F02 - No. 2 Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

WA - Water
TK - Truck
RR - Railroad
PL - Pipeline
UN - Unknown

Future Generating Unit Status

CA - Capability increase
FC - Conversion to alternate fuel
P - Planned but not authorized
RE - Scheduled for retirement
RP - Proposed for repowering
U - Under construction, less than 50% complete
V - Under construction, more than 50% complete

TABLE OF CONTENTS (continued)

Page

CHAPTER 4 ENVIRONMENTAL and LAND USE INFORMATION

INTRODUCTION

Section 186.801 of the Florida Statutes requires generating electric utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. It is compiled in accordance with FPSC Rules 25-22.070 through 25.072, Florida Administration Code.

Florida Power Corporation's (FPC) TYSP is based on projections of long-term planning requirements that are dynamic in nature and subject to change. These planning documents should be used for general guidance concerning FPC's planning assumptions and projections, and they should not be taken as an assurance that particular events discussed in the TYSP will materialize or that particular plans will be implemented. Information and projections pertinent to periods further out in time are inherently subject to the greatest uncertainty.

The TYSP document contains four chapters as described below:

CHAPTER 1
Description of EXISTING FACILITIES

CHAPTER 2
Forecast of ELECTRICAL POWER DEMAND and ENERGY CONSUMPTION

CHAPTER 3
Forecast of FACILITIES REQUIREMENTS

CHAPTER 4
ENVIRONMENTAL and LAND USE INFORMATION

Detailed schedules and a description of FPC's TYSP follow.

CHAPTER 1 Description of EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

FPC is an investor-owned electric utility. The company's common stock is held by Florida Progress Corporation which has over 41,000 registered shareholders. Approximately 17,500 of FPC shareholders live in Florida. In addition, millions of other people have an interest in the company due to investments made by insurance companies, mutual savings banks, and pension funds.

AREA OF SERVICE

The company's area of service (see Area of Service Map) encompasses approximately 20,000 square miles in over 30 Florida counties. The company supplies electricity at retail to approximately 350 communities and at wholesale to about 9 municipalities. Wholesale supplemental electric service also is supplied to Seminole Electric Cooperative, Inc. (SECI), Florida Municipal Power Agency (FMPA), and Reedy Creek Improvement District.

TRANSMISSION/DISTRIBUTION

The company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The FPC transmission system includes over 4,700 circuit miles of transmission lines and over 80 transmission substations. The distribution system includes over 25,000 circuit miles, with over 7,000 of those miles underground. FPC has over 270 distribution substations.

ENERGY MANAGEMENT

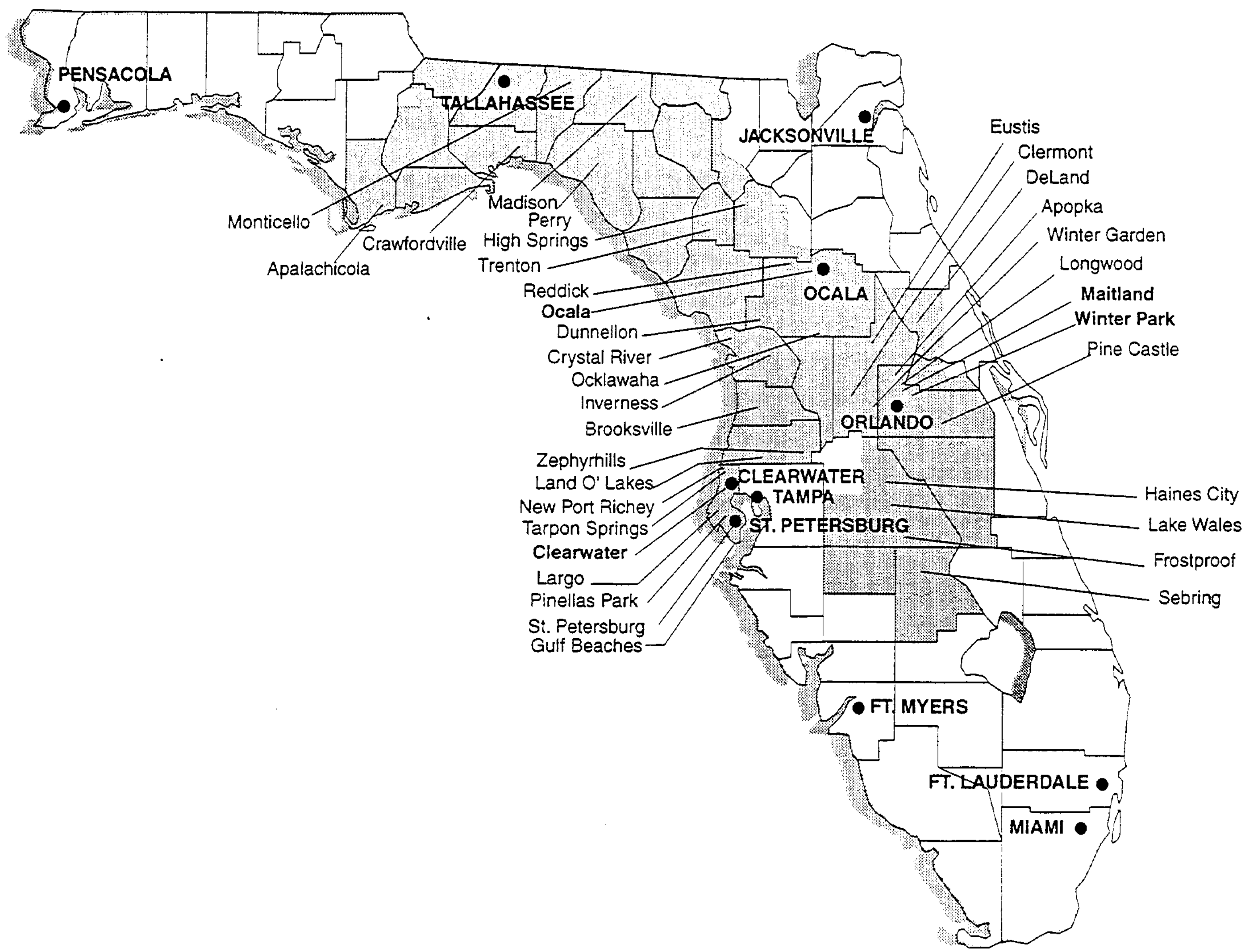
Florida Power customers participating in the company's Energy Management program are managing future growth and costs. Over 475,000 customers participated in the Energy Management program during the year. This excellent participation level provides over 870,000 KW of peak shaving capacity for use during high load periods.

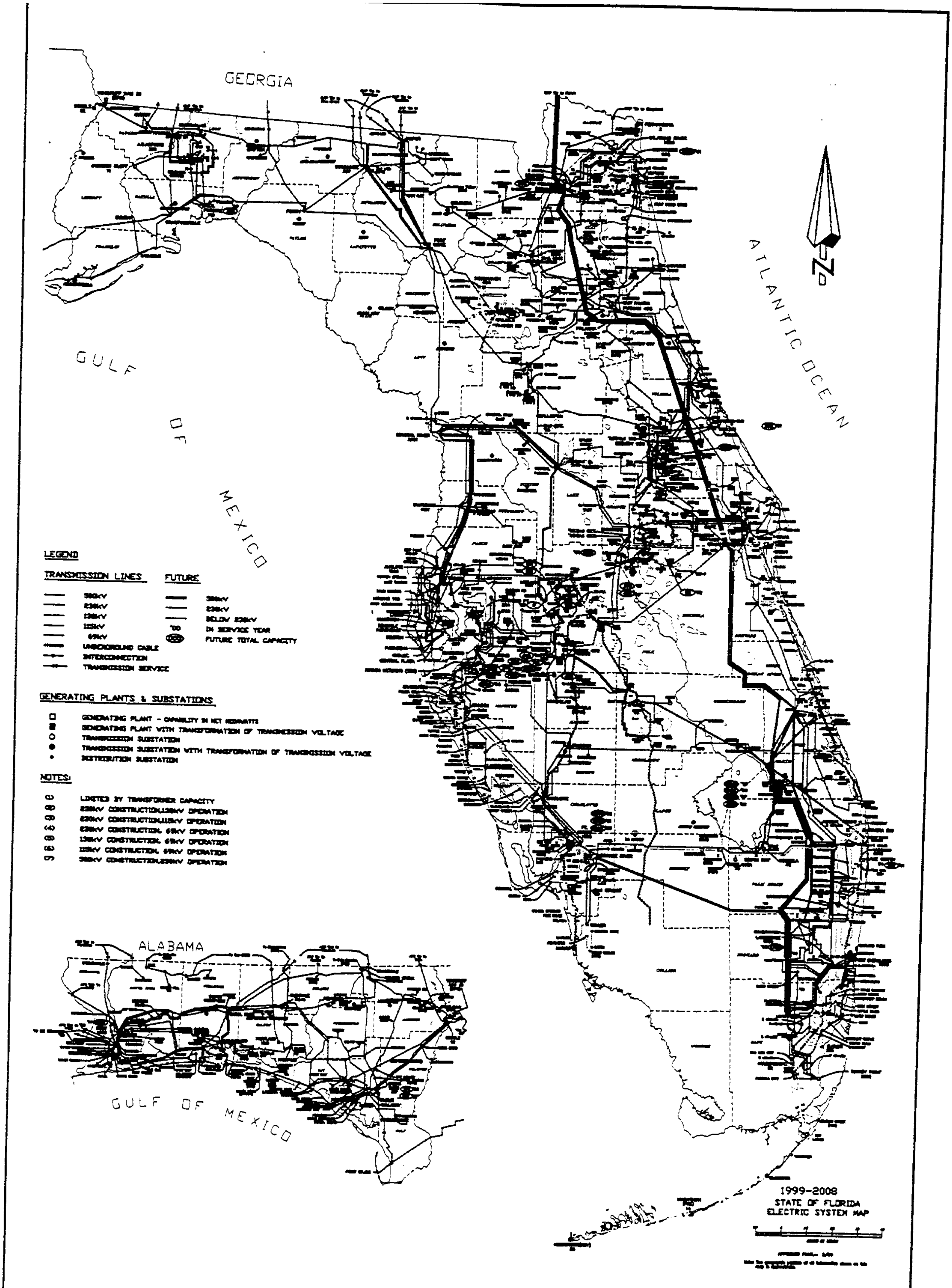
TOTAL CAPACITY RESOURCE

Florida Power has a total capacity resource of 9,567 MW. This capacity resource includes utility and non-utility purchased power, combustion turbine, nuclear, and fossil steam and combined cycle plants. Additional information on FPC's existing generating facilities is shown on Schedule 1.

Florida Power
CORPORATION

Florida Power Corporation • Area of Service




GEORGIA
ATLANTIC OCEAN
GULF OF MEXICO
LEGEND
TRANSMISSION LINES
FUTURE
500kV
230kV
138kV
115kV
69kV
UNDERGROUND CABLE
INTERCONNECTION
TRANSMISSION SERVICE
500kV
230kV
BELOW 230kV
IN SERVICE YEAR
FUTURE TOTAL CAPACITY
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT - CAPABILITY IN NET MEGAWATTS
GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
TRANSMISSION SUBSTATION
TRANSMISSION SUBSTATION WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
DISTRIBUTION SUBSTATION
NOTES:
(1) LIMITED BY TRANSFORMER CAPACITY
(2) 230kV CONSTRUCTION,138kV OPERATION
(3) 230kV CONSTRUCTION,115kV OPERATION
(4) 230kV CONSTRUCTION, 69kV OPERATION
(5) 138kV CONSTRUCTION, 69kV OPERATION
(6) 115kV CONSTRUCTION, 69kV OPERATION
(7) 500kV CONSTRUCTION,230kV OPERATION
ALABAMA
GULF OF MEXICO
1999-2008
STATE OF FLORIDA
ELECTRIC SYSTEM MAP

FLORIDA POWER CORPORATION

SCHEDULE I
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				FUEL		FUEL TRANSPORT.		ALT.				NET CAPABILITY	
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALT.	PRIMARY	ALT.	FUEL DAYS USE	COMMERCIAL IN-SERVICE MONTH/YEAR	EXPECTED RETIREMENT MONTH/YEAR	GEN. MAX. NAMEPLATE KW	SUMMER MW	WINTER MW
												993	1,044
ANCLOTE	1	PASCO CO.	ST	F06	NG	PL	PL		10/1974		556,200	498	522
	2	SECT.33,34	ST	F06	NG	PL	PL		10/1978		556,200	495	522
		T26S,R15E											
												52	64
AVON PARK	P1	HIGHLANDS CO.	CT	NG	F02	PL	TK		12/1968	12/2006	33,790	26	32
	P2		CT	F02		TK			12/1968	12/2006	33,790	26	32
												631	671
BARTOW	1	PINELLAS CO.	ST	F06		WA			09/1958		127,500	121	123
	2	SECT.20,21,22	ST	F06		WA			08/1961		127,500	119	121
	3	T30S,R16E	ST	NG	F06	PL	WA		07/1963		239,360	204	208
	P1, P3		CT	F02		WA			06/1972		111,400	92	106
	P2		CT	NG	F02	PL	WA		06/1972		55,700	46	53
	P4		CT	NG	F02	PL	WA		06/1972		55,700	49	60
												184	232
BAYBORO	P1-P4	PINELLAS CO.	CT	F02		WA,TK			04/1973		226,800	184	232
		SECT. 30											
		T31S,R17E											
												3,047	3,098
CRYSTAL	1	CITRUS CO.	ST	BIT		WA,RR			10/1966		440,550	379	383
RIVER	2	SECT.33	ST	BIT		WA,RR			11/1969		523,800	474	479
	3 *	T17S,R16E	NP	UR		TK			03/1977		890,460	765	782
	4		ST	BIT		WA,RR			12/1982		739,260	712	722
	5		ST	BIT		WA,RR			10/1984		739,260	717	732
												643	762
DEBARY	P1-P6	VOLUSIA CO.	CT	F02		TK,RR			04/1976		401,220	324	390
	P7-P9	SECT.16,19-21,	CT	NG	F02	PL	TK,RR		11/1992		345,000	240	279
	P10	28-30,T18S,R30E	CT	F02		TK,RR			11/1992		115,000	79	93
												122	134
HIGGINS	P1-P2	PINELLAS CO.	CT	NG	F02	PL	TK		04/1969	12/2005	67,580	54	64
	P3-P4	T25S,R16E	CT	NG	F02	PL	TK		12/1970	12/2005	85,850	68	70
												482	529
HINES ENERGY COMPLEX	1	POLK CO.	CC	NG	F02	PL	TK		04/1999		546,550	482	529
												789	912
INTERCESSION	P1-P6	OSCEOLA CO.	CT	F02		PL,TK			05/1974		340,200	294	366
CITY	P7-P10	SECT. 31	CT	NG	F02	PL	PL,TK		11/1993		460,000	352	376
	P11	T25S,R28E	CT	F02		PL,TK			01/1997		165,000	143	170
												13	16
RIO PINAR	P1	ORANGE CO.	CT	F02		TK			11/1970	12/2005	19,290	13	16
												307	347
SUWANNEE	1	SUWANNEE CO.	ST	NG	F06	PL	TK		11/1953	12/2003	34,500	32	33
RIVER	2	SECT. 26,	ST	NG	F06	PL	TK		11/1954	12/2003	37,500	31	32
	3	T1S,R11E	ST	NG	F06	PL	TK		10/1956	12/2003	75,000	80	81
	P1, P3		CT	NG	F02	PL	TK		11/1980		122,400	110	134
	P2		CT	F02		TK			11/1980		61,200	54	67
												207	223
TIGER BAY	1	POLK CO.	CC	NG		PL			08/1997		278,223	207	223
												154	194
TURNER	P1-P2	VOLUSIA CO.	CT	F02		TK			10/1970	12/2006	38,580	26	32
	P3	SECT. 1,	CT	F02		TK			08/1974		71,200	65	82
	P4	T19S,R30E	CT	F02		TK			08/1974		71,200	63	80
												35	41
UNIV. OF FLA.	P1	ALACHUA CO.	CT	NG		PL			01/1994		43,000	35	41
* REPRESENTS 91.8 % FPC OWNERSHIP OF UNIT												7,659	8,267

<u>CHAPTER 2</u> Forecast of ELECTRIC POWER DEMAND and ENERGY CONSUMPTION

<u>OVERVIEW</u>

The following Schedules 2, 3 and 4 represent FPC's history and forecast of customers, energy sales (GWh), and peak demand (MW). High and low scenarios are also presented for sensitivity purposes.

The base case was developed using both econometric and end-use forecasting methodologies to predict a forecast with a 50/50 probability, or most likely scenario. The high and low scenarios, which have a 90/10 probability of occurrence or an 80 percent probability of an outcome falling between the high and low cases, employed a Monte Carlo simulation procedure that studied 1,000 possible outcomes of retail demand and energy.

FPC's customer growth is expected to average 1.6 percent between 2000 and 2009, less than the ten-year historical average of 2.2 percent. Slower population growth -- based on the latest projection from the University of Florida's Bureau of Economic and Business Research -- results in a lower base case customer projection when compared to the rapid growth of the 1980s. The reduction in the projected energy and demand growth rates from historical rates is mainly due to an assumed loss of a short-term wholesale contract with Seminole Electric Cooperative, Incorporated. Projected retail sector growth is below the historical average due to slower population growth, less rapid economic expansion and improved appliance efficiencies in electric end-uses.

Net energy for load, which had grown at an average of 3.9 percent between 1990 and 1999, is expected to increase by 1.8 percent per year from 2000-2009 in the base case, 2.2 percent in the high case and 1.4 percent in the low case.

Summer net firm demand is expected to grow an average of 1.3 percent per year during the next ten years. This compares to the 2.8 percent (weather adjusted) average annual growth rate experienced throughout the last ten years. Winter net firm demand is projected to grow at 1.1 percent per year after having increased by 2.1 percent (weather adjusted) per year from 1990 to 1999. High and low summer growth rates for net firm demand are 1.7 percent and 0.9 percent per year, respectively, while high and low winter net firm demand growth rates are 1.5 percent and 0.8 percent, respectively.

ENERGY CONSUMPTION SCHEDULES

FPC's History and Forecast of Energy Consumption and Number of Customers by Customer Class are shown on Schedules 2.1, 2.2 and 2.3.

FORECAST OF ELECTRIC POWER DEMAND SCHEDULES

FPC's History and Forecast of Base, High and Low Summer Peak Demand are shown on Schedules 3.1.1, 3.1.2 and 3.1.3.

FPC's History and Forecast of Base, High, and Low Winter Peak Demand are shown on Schedules 3.2.1, 3.2.2 and 3.2.3.

FPC's History and Forecast of Base, High and Low Annual Net Energy for Load are shown on Schedules 3.3.1, 3.3.2 and 3.3.3.

FPC's Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month are shown on Schedule 4.

FLORIDA POWER CORPORATION

SCHEDULE 2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	FPC POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KW CONSUMPTION PER CUSTOM
1990	2,509,322	2.490	12,416	1,007,806	12,320	7,329	113,595	64,519
1991	2,563,805	2.489	12,624	1,029,901	12,257	7,489	114,657	65,317
1992	2,614,610	2.490	12,826	1,050,077	12,214	7,544	116,727	64,629
1993	2,679,005	2.488	13,373	1,076,657	12,421	7,885	119,811	65,812
1994	2,738,046	2.488	13,863	1,100,537	12,597	8,252	122,987	67,097
1995	2,798,959	2.489	14,938	1,124,679	13,282	8,612	126,189	68,248
1996	2,845,495	2.492	15,481	1,141,671	13,560	8,848	129,441	68,356
1997	2,892,998	2.493	15,080	1,160,611	12,993	9,257	132,504	69,864
1998	2,952,439	2.496	16,526	1,182,786	13,972	9,999	136,345	73,339
1999	3,033,192	2.500	16,245	1,213,470	13,387	10,327	140,897	73,294
2000	3,063,882	2.489	17,652	1,230,736	14,342	10,839	142,923	75,836
2001	3,118,440	2.490	18,163	1,252,598	14,501	11,191	145,775	76,767
2002	3,172,383	2.490	18,683	1,274,213	14,662	11,535	148,595	77,626
2003	3,225,899	2.490	19,184	1,295,656	14,807	11,876	151,392	78,447
2004	3,278,647	2.490	19,677	1,316,791	14,943	12,216	154,150	79,250
2005	3,326,558	2.488	20,099	1,337,264	15,030	12,557	156,820	80,073
2006	3,375,001	2.487	20,520	1,357,066	15,121	12,914	159,403	81,017
2007	3,421,748	2.486	20,911	1,376,186	15,195	13,259	161,896	81,897
2008	3,467,563	2.486	21,291	1,394,931	15,263	13,542	164,341	82,400
2009	3,513,221	2.485	21,672	1,413,612	15,331	13,831	166,778	82,930

FLORIDA POWER CORPORATION

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1990	3,456	3,115	1,109,470	0	21	1,658	24,880
1991	3,303	3,124	1,057,298	0	23	1,740	25,179
1992	3,254	3,137	1,037,297	0	24	1,765	25,413
1993	3,381	3,107	1,088,188	0	25	1,865	26,529
1994	3,580	3,186	1,123,666	0	26	1,954	27,675
1995	3,864	3,143	1,229,399	0	27	2,058	29,499
1996	4,223	2,927	1,442,774	0	26	2,205	30,784
1997	4,187	2,830	1,479,505	0	27	2,299	30,849
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,425	0	27	2.509	33,441
2000	4,326	2,560	1,689,844	0	29	2,664	35,510
2001	4,257	2,560	1,662,891	0	30	2,752	36,393
2002	4,287	2,560	1,674,609	0	31	2,842	37,378
2003	4,453	2,560	1,739,453	0	32	2,932	38,478
2004	4,494	2,560	1,755,469	0	32	3,023	39,443
2005	4,572	2,560	1,785,938	0	33	3,114	40,375
2006	4,623	2,560	1,805,859	0	33	3,204	41,295
2007	4,679	2,560	1,827,734	0	34	3,295	42,178
2008	4,731	2,560	1,848,047	0	34	3,386	42,984
2009	4,770	2,560	1,863,281	0	35	3,477	43,785

FLORIDA POWER CORPORATION

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
1990	1,548	1,377	27,805	10,983	1,135,499
1991	1,411	1,799	28,389	11,555	1,159,237
1992	1,471	1,817	28,702	12,229	1,182,170
1993	1,695	2,020	30,243	15,077	1,214,652
1994	1,819	1,680	31,174	17,181	1,243,891
1995	1,846	2,322	33,667	17,774	1,271,785
1996	2,089	1,841	34,715	18,034	1,292,073
1997	1,758	1,997	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,452	39,160	19,601	1,376,597
2000	2,977	2,359	40,846	20,101	1,396,320
2001	3,136	2,398	41,927	20,658	1,421,591
2002	1,691	2,260	41,330	21,210	1,446,578
2003	1,345	2,398	42,221	21,762	1,471,370
2004	1,339	2,486	43,268	22,315	1,495,816
2005	1,326	2,514	44,215	22,867	1,519,511
2006	1,354	2,566	45,214	23,418	1,542,447
2007	1,390	2,612	46,180	23,971	1,564,613
2008	1,423	2,658	47,066	24,523	1,586,355
2009	1,454	2,705	47,945	25,076	1,608,026

FLORIDA POWER CORPORATION

SCHEDULE 3.1.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1990	6,096	632	5,464	198	342	35	24	49	136	5,312
1991	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
1993	6,913	833	6,080	272	502	48	27	70	155	5,839
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,520	7,519	292	505	113	45	153	183	7,747
2000	8,633	1,277	7,356	327	464	126	48	155	75	7,439
2001	8,840	1,343	7,497	308	414	136	49	156	75	7,701
2002	8,518	867	7,651	305	351	149	50	157	75	7,431
2003	8,337	506	7,831	328	305	162	51	158	75	7,258
2004	8,421	436	7,985	329	269	175	52	160	75	7,361
2005	8,574	433	8,141	335	238	190	54	161	75	7,522
2006	8,782	493	8,289	339	210	204	55	162	75	7,737
2007	8,988	555	8,433	343	185	218	57	163	75	7,947
2008	9,191	618	8,573	346	163	232	59	164	75	8,152
2009	9,394	681	8,713	349	144	246	61	165	75	8,354

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2009):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.1.2
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1990	6,096	632	5,464	198	342	35	24	49	136	5,312
1991	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
1993	6,913	833	6,080	272	502	48	27	70	155	5,839
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,520	7,519	292	505	113	45	153	183	7,747
2000	8,737	1,277	7,460	327	464	126	48	155	75	7,543
2001	8,950	1,343	7,607	308	414	136	49	156	75	7,811
2002	8,656	867	7,789	305	351	149	50	157	75	7,569
2003	8,497	506	7,991	328	305	162	51	158	75	7,418
2004	8,646	436	8,210	329	269	175	52	160	75	7,586
2005	8,826	433	8,393	335	238	190	54	161	75	7,774
2006	9,092	493.	8,599	339	210	204	55	162	75	8,047
2007	9,304	555	8,749	343	185	218	57	163	75	8,263
2008	9,571	618	8,953	346	163	232	59	164	75	8,532
2009	9,819	681	9,138	349	144	246	61	165	75	8,779

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2009):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.1.3
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1990	6,096	632	5,464	198	342	35	24	49	136	5,312
1991	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
1993	6,913	833	6,080	272	502	48	27	70	155	5,839
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,520	7,519	292	505	113	45	153	183	7,747
2000	8,444	1,277	7,167	327	464	126	48	155	75	7,250
2001	8,629	1,343	7,286	308	414	136	49	156	75	7,490
2002	8,299	867	7,432	305	351	149	50	157	75	7,212
2003	8,068	506	7,562	328	305	162	51	158	75	6,989
2004	8,134	436	7,698	329	269	175	52	160	75	7,074
2005	8,251	433	7,818	335	238	190	54	161	75	7,199
2006	8,422	493	7,929	339	210	204	55	162	75	7,377
2007	8,589	555	8,034	343	185	218	57	163	75	7,548
2008	8,752	618	8,134	346	163	232	59	164	75	7,713
2009	8,916	681	8,235	349	144	246	61	165	75	7,876

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2009):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989/90	7,596	875	6,721	230	503	52	0	47	150	6,614
1990/91	6,225	774	5,451	163	490	51	0	52	153	5,316
1991/92	7,163	972	6,191	181	611	60	0	55	155	6,101
1992/93	7,191	851	6,340	155	599	67	0	57	159	6,154
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,717	941	6,776	318	663	124	17	117	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	9,993	1,647	8,346	326	849	229	21	119	190	8,259
2000/01	10,229	1,731	8,498	306	809	250	24	120	193	8,528
2001/02	9,940	1,274	8,666	304	744	273	27	121	190	8,282
2002/03	9,787	928	8,859	328	701	298	30	122	188	8,120
2003/04	9,902	877	9,025	329	673	325	33	123	189	8,230
2004/05	10,085	890	9,195	334	652	354	36	124	192	8,394
2005/06	10,322	968	9,354	337	635	383	39	125	195	8,609
2006/07	10,559	1,046	9,513	342	619	412	42	126	198	8,820
2007/08	10,793	1,129	9,664	345	605	441	46	127	200	9,029
2008/09	11,022	1,210	9,812	348	592	470	49	128	203	9,233
2009/10	11,254	1,291	9,963	350	580	498	52	129	206	9,440

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2010):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.2.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989/90	7,596	875	6,721	230	503	52	0	47	150	6,614
1990/91	6,225	774	5,451	163	490	51	0	52	153	5,316
1991/92	7,163	972	6,191	181	611	60	0	55	155	6,101
1992/93	7,191	851	6,340	155	599	67	0	57	159	6,154
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,717	941	6,776	318	663	124	17	117	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,115	1,647	8,468	326	849	229	21	119	190	8,381
2000/01	10,357	1,731	8,626	306	809	250	24	120	193	8,656
2001/02	10,099	1,274	8,825	304	744	273	27	121	190	8,441
2002/03	9,970	928	9,042	328	701	298	30	122	188	8,303
2003/04	10,159	877	9,282	329	673	325	33	123	189	8,487
2004/05	10,371	890	9,481	334	652	354	36	124	192	8,680
2005/06	10,673	968	9,705	337	635	383	39	125	195	8,960
2006/07	10,916	1,046	9,870	342	619	412	42	126	198	9,177
2007/08	11,220	1,129	10,091	345	605	441	46	127	200	9,456
2008/09	11,499	1,210	10,289	348	592	470	49	128	203	9,710
2009/10	11,788	1,291	10,497	350	580	498	52	129	206	9,974

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2010):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

SCHEDULE 3.2.3
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989/90	7,596	875	6,721	230	503	52	0	47	150	6,614
1990/91	6,225	774	5,451	163	490	51	0	52	153	5,316
1991/92	7,163	972	6,191	181	611	60	0	55	155	6,101
1992/93	7,191	851	6,340	155	599	67	0	57	159	6,154
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,717	941	6,776	318	663	124	17	117	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	9,783	1,647	8,136	326	849	229	21	119	190	8,049
2000/01	9,994	1,731	8,263	306	809	250	24	120	193	8,293
2001/02	9,697	1,274	8,423	304	744	273	27	121	190	8,039
2002/03	9,487	928	8,559	328	701	298	30	122	188	7,820
2003/04	9,584	877	8,707	329	673	325	33	123	189	7,912
2004/05	9,727	890	8,837	334	652	354	36	124	192	8,036
2005/06	9,924	968	8,956	337	635	383	39	125	195	8,211
2006/07	10,118	1,046	9,072	342	619	412	42	126	198	8,379
2007/08	10,308	1,129	9,179	345	605	441	46	127	200	8,544
2008/09	10,495	1,210	9,285	348	592	470	49	128	203	8,706
2009/10	10,692	1,291	9,401	350	580	498	52	129	206	8,878

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2010):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

SCHEDULE 3.3.1
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
BASE CASE

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) *
1990	28,629	173	145	506	24,880	1,548	1,377	27,805	53.4
1991	29,219	166	156	509	25,179	1,411	1,799	28,389	53.5
1992	29,561	174	170	516	25,414	1,471	1,817	28,702	46.8
1993	31,150	188	195	524	26,528	1,695	2,020	30,243	51.3
1994	32,135	205	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,682	219	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,797	235	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,739	254	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,936	275	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,362	298	339	565	33,441	3,267	2,452	39,160	53.7
2000	42,039	291	335	567	35,510	2,977	2,359	40,846	56.3
2001	43,138	309	337	565	36,393	3,136	2,398	41,927	56.1
2002	42,560	327	339	565	37,378	1,691	2,260	41,330	57.0
2003	43,473	347	341	565	38,478	1,345	2,398	42,221	59.4
2004	44,545	367	343	567	39,443	1,339	2,486	43,268	59.8
2005	45,513	388	345	565	40,375	1,326	2,514	44,215	60.1
2006	46,535	409	347	565	41,295	1,354	2,566	45,214	60.0
2007	47,523	429	349	565	42,178	1,390	2,612	46,180	59.8
2008	48,432	449	351	567	42,984	1,423	2,658	47,066	59.3
2009	49,332	469	353	565	43,785	1,454	2,705	47,945	59.3

NOTE : COLUMN (OTH) INCLUDES CONSERVATION ENERGY FOR LIGHTING AND PUBLIC AUTHORITY CUSTOMERS, CUSTOMER-OWNED SELF-SERVICE COGENERATION AND LOAD CONTROL PROGRAMS.

* LOAD FACTOR FOR EACH HISTORICAL YEAR IS CALCULATED USING THE ACTUAL WINTER PEAK DEMAND;
LOAD FACTOR FOR EACH FUTURE YEAR IS CALCULATED USING THE NET FIRM WINTER PEAK DEMAND (SCHEDULE 3.2.1).

1990, 1993 AND 1998 HISTORICAL LOAD FACTORS ARE BASED ON THE ACTUAL SUMMER PEAK DEMAND;
PREVIOUS REPORTS WERE BASED ON A LOWER WINTER PEAK DEMAND.

FLORIDA POWER CORPORATION

SCHEDULE 3.3.2
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) *
1990	28,629	173	145	506	24,880	1,548	1,377	27,805	53.4
1991	29,219	166	156	509	25,179	1,411	1,799	28,389	53.5
1992	29,561	174	170	516	25,414	1,471	1,817	28,702	46.8
1993	31,150	188	195	524	26,528	1,695	2,020	30,243	51.3
1994	32,135	205	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,682	219	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,797	235	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,739	254	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,936	275	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,362	298	339	565	33,441	3,267	2,452	39,160	53.7
2000	42,784	291	335	567	36,193	2,977	2,421	41,591	56.5
2001	43,861	309	337	565	37,110	3,136	2,404	42,650	56.2
2002	43,529	327	339	565	38,243	1,691	2,364	42,298	57.2
2003	44,553	347	341	565	39,464	1,345	2,491	43,300	59.5
2004	45,933	367	343	567	40,770	1,339	2,547	44,656	59.9
2005	47,092	388	345	565	41,857	1,326	2,611	45,794	60.2
2006	48,430	409	347	565	43,089	1,354	2,666	47,109	60.0
2007	49,479	429	349	565	44,016	1,390	2,730	48,136	59.9
2008	50,749	449	351	567	45,170	1,423	2,789	49,382	59.5
2009	51,911	469	353	565	46,219	1,454	2,851	50,524	59.4

NOTE : COLUMN (OTH) INCLUDES CONSERVATION ENERGY FOR LIGHTING AND PUBLIC AUTHORITY CUSTOMERS, CUSTOMER-OWNED SELF-SERVICE COGENERATION AND LOAD CONTROL PROGRAMS.

* LOAD FACTOR FOR EACH HISTORICAL YEAR IS CALCULATED USING THE ACTUAL WINTER PEAK DEMAND;
LOAD FACTOR FOR EACH FUTURE YEAR IS CALCULATED USING THE NET FIRM WINTER PEAK DEMAND (SCHEDULE 3.2.2).

1990, 1993 AND 1998 HISTORICAL LOAD FACTORS ARE BASED ON THE ACTUAL SUMMER PEAK DEMAND;
PREVIOUS REPORTS WERE BASED ON A LOWER WINTER PEAK DEMAND.

FLORIDA POWER CORPORATION

SCHEDULE 3.3.3
HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
LOW LOAD FORECAST

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) *
1990	28,629	173	145	506	24,880	1,548	1,377	27,805	53.4
1991	29,219	166	156	509	25,179	1,411	1,799	28,389	53.5
1992	29,561	174	170	516	25,414	1,471	1,817	28,702	46.8
1993	31,150	188	195	524	26,528	1,695	2,020	30,243	51.3
1994	32,135	205	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,682	219	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,797	235	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,739	254	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,936	275	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,362	298	339	565	33,441	3,267	2,452	39,160	53.7
2000	41,203	291	335	567	34,702	2,977	2,331	40,010	56.6
2001	42,117	309	337	565	35,463	3,136	2,307	40,906	56.3
2002	41,567	327	339	565	36,401	1,691	2,244	40,336	57.3
2003	42,181	347	341	565	37,237	1,345	2,346	40,928	59.7
2004	43,092	367	343	567	38,092	1,339	2,384	41,815	60.2
2005	43,880	388	345	565	38,837	1,326	2,419	42,582	60.5
2006	44,688	409	347	565	39,553	1,354	2,460	43,367	60.3
2007	45,449	429	349	565	40,222	1,390	2,494	44,106	60.1
2008	46,126	449	351	567	40,808	1,423	2,528	44,759	59.6
2009	46,795	469	353	565	41,392	1,454	2,562	45,408	59.5

NOTE : COLUMN (OTH) INCLUDES CONSERVATION ENERGY FOR LIGHTING AND PUBLIC AUTHORITY CUSTOMERS, CUSTOMER-OWNED SELF-SERVICE COGENERATION AND LOAD CONTROL PROGRAMS.

* LOAD FACTOR FOR EACH HISTORICAL YEAR IS CALCULATED USING THE ACTUAL WINTER PEAK DEMAND;
LOAD FACTOR FOR EACH FUTURE YEAR IS CALCULATED USING THE NET FIRM WINTER PEAK DEMAND (SCHEDULE 3.2.3).

1990, 1993 AND 1998 HISTORICAL LOAD FACTORS ARE BASED ON THE ACTUAL SUMMER PEAK DEMAND;
PREVIOUS REPORTS WERE BASED ON A LOWER WINTER PEAK DEMAND.

FLORIDA POWER CORPORATION

SCHEDULE 4
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST		FORECAST	
	1999		2000		2001	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	8,318	2,855	8,259	3,110	8,528	3,213
FEBRUARY	6,964	2,511	7,160	2,890	7,410	2,955
MARCH	5,861	2,658	6,016	2,985	6,224	3,055
APRIL	6,197	3,116	5,694	2,918	5,938	2,953
MAY	6,726	3,296	6,666	3,637	6,948	3,696
JUNE	7,079	3,547	7,131	3,910	7,380	3,962
JULY	7,562	4,171	7,359	4,133	7,617	4,298
AUGUST	7,715	4,282	7,439	4,235	7,701	4,331
SEPTEMBER	7,216	3,679	6,938	3,757	7,183	3,851
OCTOBER	6,302	3,340	6,206	3,240	6,435	3,341
NOVEMBER	5,264	2,700	5,372	2,841	5,607	2,964
DECEMBER	6,791	3,005	6,831	3,190	7,065	3,308
TOTAL		39,160		40,846		41,927

FUEL REQUIREMENTS and ENERGY SOURCES

FPC's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel units) are shown on Schedule 5. FPC's two-year actual and ten-year projected energy sources, in GWh and percent, are shown by fuel type on Schedules 6.1 and 6.2, respectively. FPC's fuel requirements and energy sources reflect a diverse fuel supply system which is not dependent on any one fuel source. FPC expects its fuel diversity to be further enhanced with the addition of future planned combined cycle generation units fueled by natural gas. Natural gas consumption is projected to increase as plants are added to meet future load growth. FPC's coal, nuclear, and purchased power requirements are projected to remain relatively stable over the planning horizon.

SCHEDULE 5

FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	NUCLEAR		TRILLION BTU	60	60	66	59	66	59	66	59	66	59	66	59
(2)	COAL		1,000 TON	5,713	5,365	5,529	5,800	5,806	5,747	5,752	5,878	5,891	5,926	5,914	6,000
(3)	RESIDUAL	TOTAL	1,000 BBL	10,906	9,991	7,602	8,408	7,990	8,965	7,648	8,022	7,084	7,560	6,523	7,419
(4)		STEAM	1,000 BBL	10,906	9,991	7,602	8,408	7,990	8,965	7,648	8,022	7,084	7,560	6,523	7,419
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	1,873	1,672	2,381	3,514	3,026	3,790	1,969	3,197	1,423	2,361	1,067	1,971
(9)		STEAM	1,000 BBL	111	107	117	102	111	103	91	79	85	83	92	87
(10)		CC	1,000 BBL	0	0	4	110	203	253	145	218	68	115	48	83
(11)		CT	1,000 BBL	1,762	1,565	2,260	3,302	2,712	3,434	1,733	2,900	1,270	2,163	927	1,801
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	25,348	46,162	56,237	56,591	47,664	53,196	66,508	70,581	80,414	86,607	95,301	104,984
(14)		STEAM	1,000 MCF	1,260	6,726	681	0	0	0	0	0	0	0	0	0
(15)		CC	1,000 MCF	11,200	25,864	28,235	25,659	23,833	28,447	44,081	45,842	59,135	63,829	76,577	82,441
(16)		CT	1,000 MCF	12,888	13,572	27,321	30,932	23,831	24,749	22,427	24,739	21,279	22,778	18,724	22,543
(17)	OTHER (SPECIFY)			0	0	0	0	0	0	0	0	0	0	0	0

FLORIDA POWER CORPORATION

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	ANNUAL FIRM INTERCHANGE 1 /		GWh	-422	-463	98	102	82	103	63	103	60	84	45	75
(2)	NUCLEAR		GWh	5,863	5,842	6,330	5,654	6,378	5,666	6,377	5,657	6,351	5,648	6,360	5,655
(3)	COAL		GWh	14,892	14,149	14,308	15,146	15,176	15,057	15,039	15,398	15,408	15,534	15,475	15,745
(4)	RESIDUAL	TOTAL	GWh	7,031	6,214	4,760	5,306	5,036	5,711	4,855	5,142	4,496	4,832	4,128	4,745
(5)		STEAM	GWh	7,031	6,214	4,760	5,306	5,036	5,711	4,855	5,142	4,496	4,832	4,128	4,745
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	762	665	850	1,287	1,142	1,456	736	1,219	524	902	380	741
10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
11)		CC	GWh	0	0	3	85	159	198	107	167	49	83	34	60
12)		CT	GWh	762	665	847	1,202	983	1,258	629	1,052	475	819	346	681
13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
14)	NATURAL GAS	TOTAL	GWh	2,498	5,391	5,903	5,804	5,033	5,773	7,737	8,225	9,928	10,765	12,369	13,527
15)		STEAM	GWh	140	825	59	0	0	0	0	0	0	0	0	0
16)		CC	GWh	1,216	3,537	3,925	3,554	3,292	3,953	6,139	6,427	8,417	9,121	11,031	11,908
17)		CT	GWh	1,142	1,029	1,919	2,250	1,741	1,820	1,598	1,798	1,511	1,644	1,338	1,619
18)	OTHER 2 /														
	QF PURCHASES		GWh	5,419	5,462	5,741	5,734	5,653	5,619	5,628	5,616	5,615	5,571	5,476	4,594
	IMPORT FROM OUT OF STATE		GWh	2,179	2,581	2,856	2,894	2,830	2,836	2,833	2,855	2,832	2,844	2,833	2,863
	EXPORT TO OUT OF STATE		GWh	-459	-681	0	0	0	0	0	0	0	0	0	0
19)	NET ENERGY FOR LOAD		GWh	37,763	39,160	40,846	41,927	41,330	42,221	43,268	44,215	45,214	46,180	47,066	47,945

1 / NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN PENINSULAR FLORIDA.

2 / NET ENERGY PURCHASED (+) OR SOLD (-).

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	ANNUAL FIRM INTERCHANGE 1 /		%	-1.1%	-1.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.2%	0.1%	0.2%
(2)	NUCLEAR		%	15.5%	14.9%	15.5%	13.5%	15.4%	13.4%	14.7%	12.8%	14.0%	12.2%	13.5%	11.8%
(3)	COAL		%	39.4%	36.1%	35.0%	36.1%	36.7%	35.7%	34.8%	34.8%	34.1%	33.6%	32.9%	32.8%
(4)	RESIDUAL	TOTAL	%	18.6%	15.9%	11.7%	12.7%	12.2%	13.5%	11.2%	11.6%	9.9%	10.5%	8.8%	9.9%
(5)		STEAM	%	18.6%	15.9%	11.7%	12.7%	12.2%	13.5%	11.2%	11.6%	9.9%	10.5%	8.8%	9.9%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	2.0%	1.7%	2.1%	3.1%	2.8%	3.4%	1.7%	2.8%	1.2%	2.0%	0.8%	1.5%
10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
11)		CC	%	0.0%	0.0%	0.0%	0.2%	0.4%	0.5%	0.2%	0.4%	0.1%	0.2%	0.1%	0.1%
12)		CT	%	2.0%	1.7%	2.1%	2.9%	2.4%	3.0%	1.5%	2.4%	1.1%	1.8%	0.7%	1.4%
13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14)	NATURAL GAS	TOTAL	%	6.6%	13.8%	14.5%	13.8%	12.2%	13.7%	17.9%	18.6%	22.0%	23.3%	26.3%	28.2%
15)		STEAM	%	0.4%	2.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
16)		CC	%	3.2%	9.0%	9.6%	8.5%	8.0%	9.4%	14.2%	14.5%	18.6%	19.8%	23.4%	24.8%
17)		CT	%	3.0%	2.6%	4.7%	5.4%	4.2%	4.3%	3.7%	4.1%	3.3%	3.6%	2.8%	3.4%
18)	OTHER 2 /														
	QF PURCHASES		%	14.4%	13.9%	14.1%	13.7%	13.7%	13.3%	13.0%	12.7%	12.4%	12.1%	11.6%	9.6%
	IMPORT FROM OUT OF STATE		%	5.8%	6.6%	7.0%	6.9%	6.8%	6.7%	6.5%	6.5%	6.3%	6.2%	6.0%	6.0%
	EXPORT TO OUT OF STATE		%	-1.2%	-1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1 / NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN PENINSULAR FLORIDA.

2 / NET ENERGY PURCHASED (+) OR SOLD (-).

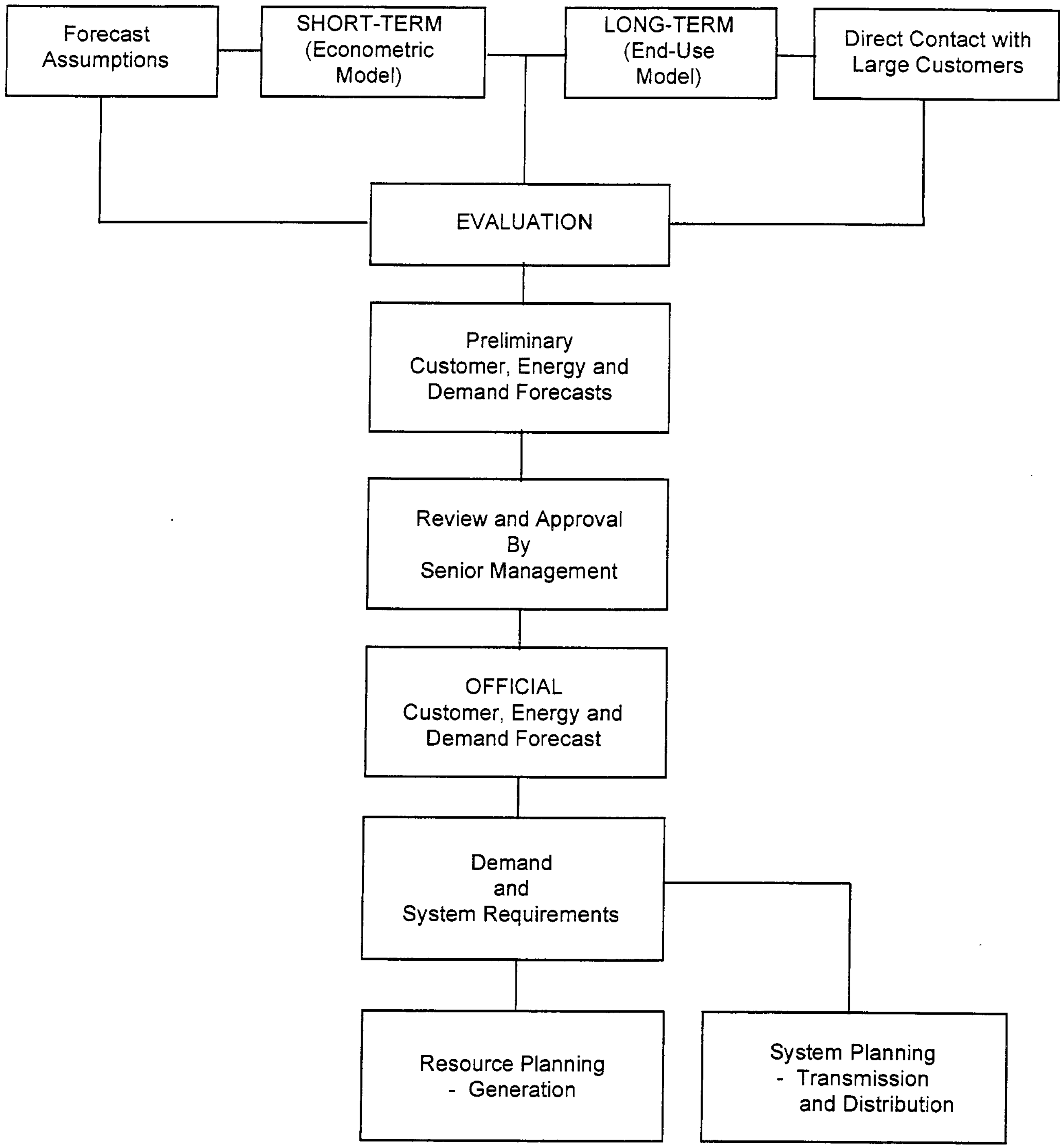
FORECASTING METHODS AND PROCEDURES

INTRODUCTION

The need for accurate forecasts of long-range electric energy consumption, customer growth, peak demand and system load shape is a crucial planning function for any electric utility. Accurate projections of a utility's future load growth require forecasting methodologies with the ability to account for a variety of factors influencing electric energy usage in both the short- and long-term planning horizons. FPC's forecasting framework utilizes the System for Hourly and Annual Peak and Energy Simulation (SHAPES-PC) end-use forecasting system as well as short-term econometric models to achieve this end. This chapter will describe the underlying methodology of both the econometric and end-use models including the assumptions incorporated within each. Also included is a description as to how Demand-Side Management (DSM) impacts affect the forecast, the development of high and low forecast scenarios and a review of DSM programs.

The following flow diagram entitled "Customer, Energy and Demand Forecast" gives a general description of FPC's forecasting process. Highlighted in the diagram is the blending of short-term and long-term modeling techniques based on a specific set of assumptions. Also accounted for is some direct contact with large customers. These inputs provide the forecaster at FPC with the tools needed to frame the most likely scenario of the company's future demand.

CUSTOMER, ENERGY AND DEMAND FORECAST



SHAPESPC.PPT

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Load Forecasting section of the Integrated Resource Planning and Forecasting Department develops these assumptions based on discussions with a number of departments within FPC, as well as through the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions form the basis for the forecast presented in this document.

GENERAL ASSUMPTIONS

1. Normal weather conditions are assumed. Normal weather reflects a ten-year average of service-area-weighted degree days in order to project kilowatt-hour sales. A twenty five-year average of service area weighted temperatures at the time of system seasonal peak is assumed to forecast seasonal megawatt peak demand.

2. The population projection produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida provides the basis for development of the customer forecast. This forecast incorporates "Population Studies," Bulletin No. 123, February 1999 as well as The Florida Long Term Forecast 1999.

3. The energy-intensive phosphate mining industry consumed over 34 percent of FPC's industrial class energy sales in 1999. This industry has consolidated in the past few years, leaving just a handful of players to influence industry supply conditions in the marketplace. A reduction in power consumption in this sector is assumed in this forecast as IMC-Agrico mines-out at several sites within FPC's territory. The return of a significant portion of this load in the Hardee county mining area is projected to occur as mining activity moves further south. Some loss of load and energy sales to Cargill has also been factored into the forecast due to the rearrangement of electric output from their self-service generator and corresponding purchase power agreement with FPC.

4. FPC supplies capacity and energy service to wholesale customers on a “full”, “partial”, and “supplemental” requirements basis. Full requirements customers' demand and energy are assumed to grow at rates determined by projected population levels as well as projected economic activity. Partial requirements customers' load is assumed to reflect levels currently requested by these customers under their contracts with FPC. The

forecast of energy and demand from partial requirements customers reflects their ability to receive dispatched energy from the Florida broker system any time it is more economical to do so. At seasonal peak conditions, however, their demand is assumed to reach full contract level. FPC's arrangement with Seminole Electric Cooperative, Incorporated (SECI) is to serve "supplemental" service over and above committed levels of self-generation and firm purchase contracts. SECI's projection of their system's demand and energy requirements serves as the basis for FPC's projection of this customer's supplemental service requirements. This forecast also includes two firm bulk power contracts with SECI. The first is a multi-part contract to serve 605 MW for three years beginning in 1999. An option to extend 455 MW of this contract for an additional seven years existed but was not exercised. The remaining 150 MW, a stratified intermediate contract transferred from the supplemental service contract, is assumed to continue throughout the forecast horizon. A second 3-year agreement with SECI to sell up to 300 MW of peaking capacity beginning January 1, 2000 has also been reflected in the forecast.

5. This forecast incorporates cost effective demand and energy reductions from FPC's dispatchable and non-dispatchable DSM programs that meet the conservation goals established by the Florida Public Service Commission in Order No. PSC-99-1942-FOF-EG issued October 1, 1999.

6. The expected energy and demand impacts of self-service cogeneration are subtracted from the forecast. The forecast assumes that FPC will supply the supplemental load of self-service cogeneration customers. Supplemental load is defined as the cogeneration customers' total electric load requirements less their normal generation output. While FPC offers "standby" service to all cogeneration customers, this forecast does not assume an unplanned need for standby power during peak periods.

7. This forecast assumes that the regulatory environment and the obligation to serve will continue throughout the forecast horizon. Wholesale customers that have given notice of contract termination are not included in the projections of energy and demand once their contract term expires.

8. The economic outlook for this ten-year forecast attempts to reflect the short-term outlook for the current business cycle as well as the long-term trend behavior for the economy. It is important to note however, that identification of the long-term trend in economic/demographic conditions represents the primary focus of this forecast. The purpose of the short-term outlook is only to show how the current business cycle is expected to evolve and eventually blend into the long-term. Beyond the short-term time horizon, only the long-run trends in economic and demographic conditions that cut through the peaks and troughs of future business cycles are considered in this forecast.

SHORT-TERM ECONOMIC ASSUMPTIONS

The short-term economic outlook calls for moderating economic growth throughout the forecast horizon. No "shocks" to any supply or demand conditions in the national economy are expected and thus no economic recession is incorporated in this forecast. The U.S. economy has just surpassed the previous record for longest business cycle expansion in the history of the country -- 106 months. No recognized sources are currently predicting an end to this expansion, which has ridden on a wave of freer world trade as well as significant improvement in worker productivity created by great technological leaps in several industries. These productivity improvements have created an economy where corporate earnings improve without any need to increase product prices. The result has been a sharp rise in corporate equities values, and investor wealth, without inflation. This "new economy" has not only created significant wealth through rising stock prices, but also through the creation of a significant number of new jobs. The national unemployment rate is now well below the level when inflationary pressures are expected to return. It is believed that some percentage of the currently strong consumer spending level is being driven by a "wealth effect" created by inflated investment values. Thus, the ability of the national economy to maintain this level of growth rests on a continuation of rising equity values.

The national unemployment rate has reached a 30-year low of 4 percent. This has resulted in greater spending power for the consumer and a high level of optimism in the economy. Looking ahead however, growth will taper off due to constraints upon the economy, which has been expanding for over nine years. Efforts on the part of the Federal Reserve Board (FRB) to restrain inflationary pressures will ultimately result in the application of tighter monetary policy. This has already resulted in higher short-term interest rates and should slow the economy. The objective of the FRB is to cool consumption and keep employment costs from rising rapidly. Higher interest rates discourage borrowing, especially in the consumer and housing sectors, and can induce higher saving as money market returns improve.

It is assumed in this forecast that the FRB will gradually cool the economy without bursting the stock market "bubble" and the impact of the wealth effect that we have been experiencing. Also assumed is the idea that in a presidential election year, cooler heads will prevail and extreme spending and/or tax-cutting programs will not be seriously proposed or implemented. Both have the potential to counteract the FRB strategy to slow the economy. If a significant change in either government spending or taxation takes place in 2000 or 2001, a risk of increased inflation will surely drive the FRB to further boost interest rates. This will not bode well for the economy or the economic assumption underlying this forecast.

On a regional basis, interest rate levels will continue to influence the pace of economic growth in Florida through their impacts on the construction, retirement and tourism industries. An increase in personal income growth is expected to continue, but not at the torrid pace experienced in recent years. Employment growth will moderate from the strong pace experienced in past years resulting in slower growth in total wages. Slower growth in hourly earnings as well as transfer payments should also hold down income growth in the years ahead.

Average use per residential customer will continue to grow as electricity prices are projected to decline in real dollar terms. Also contributing to this trend are homebuilders' surveys reporting increased median square footage in new homes and new apartments constructed. New housing preferences have continued to reflect larger living quarters than those seen in the existing housing stock.

LONG-TERM ECONOMIC ASSUMPTIONS

The long-term economic outlook assumes that changes in economic and demographic conditions will follow a trended behavior pattern. The main focus involves identifying these trends. No attempt is made to predict business cycle fluctuations during this period.

Population Growth Trends

This forecast assumes Florida will experience slower in-migration and population growth over the long term, as reflected in the BEBR projections.

- Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. This will continue to occur, but at less than historic rates for two reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the

Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Sixty years later, there now exists a smaller pool of retirees capable of migrating to Florida. Second, the enormous growth in population and corresponding development of the 1980s and 1990s made portions of Florida less desirable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

- With the bulk of Florida's in-migrants under age 45, the baby boom generation born between 1945 and 1963 helped fuel the rapid population increase Florida experienced during the 1980s. In fact, slower population in-migration to Florida can be expected as the baby boom generation enters the 40s and 50s age bracket. This age group has been significantly characterized as immobile when studies focusing on interstate population flows or job changes are conducted.

Economic Growth Trends

- Florida's rapid population growth of the 1980s created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also significant numbers of corporations migrating to Florida capitalizing on the low cost, low tax business environment. In this situation, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period. A cause for concern, however, is the passage of the North American Free Trade Agreement (NAFTA) as well as future trade agreements. At risk here is the bypassing of Florida by companies looking to relocate to a lower cost foreign environment. Mexico is expected to attract a formidable share of American manufacturing jobs that may have moved to Florida. Also, the stability of Florida's citrus and vegetable industry may be threatened when faced with greater competition from Mexico as tariffs are eliminated.

- The forecast assumes negative growth in real electricity price. That is, the change in the nominal, or current dollar, price of electricity over time is expected to be less than the overall rate of inflation. This also implies that fuel price escalation will track at or below the general rate of inflation throughout the forecast horizon.

- Real personal incomes are assumed to increase throughout the forecast period thereby boosting the average customer's ability to purchase electricity -- especially since the price of electricity is expected to increase at a rate below general inflation. As incomes grow faster than the price of electricity, consumers, on average, will remain inclined to purchase additional electric appliances and increase their utilization of existing end-uses.

FORECAST METHODOLOGY

The long-term forecast of MWh sales is produced utilizing SHAPES-PC, a large-scale end-use computer model. FPC has also developed short-term econometric models as a supplement to the long-term SHAPES-PC methodology. These short-term models are expressly designed to better capture the short-term business cycle fluctuations preceding the long-term trend path of customers' energy usage and peak demand. In particular, the monthly periodicity studied in this approach better captures near-term perturbations than the end-use forecasting framework. Also, easier and more timely model updates enable the short-term econometric model to more readily incorporate the most recent projections of input variables. Output from these short-term econometric models is used to develop the first five years of the load forecast. The SHAPES-PC model output is then used as the basis for the remaining years of the forecast horizon.

SHORT-TERM ECONOMETRIC MODEL

In the short-term econometric models, energy sales in major revenue classes that have historically shown a relationship to weather and economic/demographic indicators are modeled using monthly equations. Sales are regressed against "driver" variables that best explain monthly fluctuations over a historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting sources. These include Data Resources Incorporated (DRI), the University of Florida's Bureau of Economic and Business Research and Blue Chip Economic Indicators. Internal company forecasts are used for projections of electric price, weather conditions and the average number of monthly billing days. Projections of FPC's energy efficiency program impacts (conservation program reductions) and direct load control reductions are also incorporated into the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential KWh usage per customer is modeled as a function of real Florida personal income, cooling degree days, heating degree days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures short-term movements in customer usage. Projections of KWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual net new customers with FPC service area population growth. County level population projections are provided by the BEBR.

Commercial Sector

Commercial KWh use per customer is forecast based on commercial (non-agricultural, non-manufacturing and non-governmental) employment, the average number of billing days in each sales month and heating and cooling degree days. The measure of cooling degree days utilized here differs slightly from that used in the residential sector reflecting the unique behavior pattern of this class with respect to its cooling needs. Commercial customers are projected as a function of the number of residential customers served.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use, 34 percent in 1999, was consumed by the phosphate mining industry. Because this one industry dominates such a significant share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted by changes in short-term economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using the U.S. industrial production index for manufacturing (excluding motor vehicles), the real price of electricity to the industrial class, and the average number of sales month billing days. The particular industrial production index used in this equation best characterizes the industry make-up of the FPC service area that lacks a significant automotive manufacturing sector.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only five customers, the final forecast is heavily dependent upon information received from direct customer contact. FPC industrial customer representatives provide specific phosphate customer information regarding customer production schedules, area mine-out and start-up predictions, and changes in self-generation or energy supply situations over the near-term forecast horizon.

Other Retail Sectors

Street Lighting

Electricity sales to the street lighting class are projected to increase due to growth in the service area population base. Residential customers provide an excellent source of FPC specific data with which to capture the trends in historic and future population growth over time. A linear regression model based on the number of residential customers as well as the number of daylight hours per month is used to forecast street lighting MWh sales.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected using the short-term monthly econometric approach. The level of government services, and thus energy use per customer, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will impact the need for additional governmental services (i.e., schools, city services, etc.) thereby increasing SPA energy usage per customer. Monthly government employment has been determined to be the best indicator of the level of government services provided. This variable, adjusted for the number of SPA customers, along with heating and cooling degree days, the real price of electricity and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Intercept shift variables are also included in this model to account for the large change in school-related energy use in the billing months of January, July and August. SPA customers are projected linearly as a function of a time-trend.

Sales For Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor owned) as well as power agencies (Rural Electric Authority or Municipal).

Seminole Electric Cooperative, Incorporated (SECI) is a wholesale, or sales for resale, customer of FPC on both a supplemental contract basis and contract demand basis. Under the supplemental contract, FPC provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or firm purchase obligations. SECI provides FPC with a forecast of total monthly peak demands and energy for their load within the FPC control area. Monthly supplemental demands are calculated from the total demand levels they project in FPC's control area less their own ("committed") resources. Beyond supplemental service, FPC has signed two bulk power or "contract demand" agreements with SECI to serve stratified intermediate and peaking load. The first contract, an October 1995 agreement, has three pieces that impact the load and energy forecast in the years 1999 through 2001. The first two parts of this contract involve a 300 MW structured capacity sale and a 155 MW stratified peaking sale. The option to extend this sale for seven additional years beginning in 2002 was not exercised by SECI and, thus, will not be served by FPC. The third piece of the contract involves serving 150 MW of stratified intermediate demand and is assumed to remain a requirement on FPC's system throughout the forecast horizon. The load tied to this piece of the contract was carved out of the supplemental "pay as you take" contract and restructured to a contract demand. The second bulk power agreement with SECI, a three-year contract signed in July 1997, also involves load that would otherwise have been served via the supplemental service agreement. Beginning in the year 2000, FPC will supply 150 MW of stratified peaking demand. The amount of load increases to 300 MW in 2001 and 2002. This load is not projected to be served by FPC beyond the contract term.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. The majority of customers in this class are municipalities whose full energy requirements are met by FPC. The full requirement customers are modeled individually using local weather station data and population growth trends for that vicinity. Since the ultimate consumers of electricity in this sector are, to a large degree, residential and commercial customers, it is assumed that their use patterns will follow those of the FPC retail-based residential and commercial customer classes. FPC provides partial requirement service (PR) to a municipality (New Smyrna Beach), a power authority (Florida Municipal Power Agency) and a utility district (Reedy Creek Improvement District). In each case, these customers contract with FPC for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of each contract are subject to change each year. This means that the level and type of demand under contract can increase or decrease for each year of their contract. The demand forecast for each PR wholesale customer is derived using its historical coincident demand to contract demand relationship (including transmission delivery losses). The demand projections for the Florida Municipal Power Agency (FMPA) also include a "losses service" MW amount to account for the transmission losses FPC incurs when "wheeling" power to their customers in FPC's transmission area. The contract demand level for each PR customer in its last contract year determines the load upon the FPC system for the remaining years of the forecast horizon, unless the customer has notified FPC of their intention to not renew the contract.

The methodology for projecting MWh energy usage for the PR customers differs slightly from customer to customer. This category of service is sporadic in nature and exceptionally difficult to forecast because PR customers are capable of "brokering" their FPC capacity to purchase energy from other lower cost resources. For example, FMPA utilizes FPC's wholesale energy service only when more economical energy is unavailable. The forecast for FMPA is derived using annual historical load factor calculations to provide the expected level of energy sales based on the level of contracted MW nominated by FMPA. Average monthly-to- annual energy ratios are applied to the forecast in order to obtain monthly profiles. For Reedy Creek and New Smyrna Beach, recent growth trends and historic load factor calculations are utilized to provide the expected level of MWh sales. Again, these customers have alternative sources of supply to meet their needs. Purchases of energy from FPC will depend heavily on the price of available energy from other sources in the marketplace.

Demand-Side Management

Each projection of every retail class-of-business MWh energy sales forecast is reduced by estimated future energy savings due to FPC-sponsored and Florida Public Service Commission (FPSC)-approved dispatchable and non-dispatchable Demand-Side Management programs. Estimated energy savings for every non-dispatchable DSM program are calculated on a program-by-program basis and aggregated for each class-of-business on the program. Dispatchable DSM program energy savings are estimated within the Resource Planning Department's production costing models. These models determine the most cost-effective means to meet system requirements, including load control. The DSM projections incorporated in this demand and energy forecast meet the conservation goals established by the FPSC in Order No. PSC-99-1942-FOF-EG, issued October 1, 1999 in Docket No. 971005-EG.

LONG-TERM SHAPES-PC MODEL

Energy Forecast

In the SHAPES-PC model the projections of the various economic and demographic parameters are combined with consumption estimates and patterns of electricity usage to produce projections of annual energy consumption. The basic concept underlying the model structure involves breaking out numerous end-use categories for electricity consumption in order to establish homogeneous groups to forecast. SHAPES-PC is partitioned into three consumer categories: residential, commercial and industrial.

Residential Sector

The electricity consuming units in the residential sector are major household appliances. A total of seventeen major household appliances are explicitly treated in the model. The first step in estimating demand is to predict the number of units of each appliance type in the service area in a given year. The appliance stock is estimated as the saturation rate for a given appliance multiplied by the total number of residential customers. Appliance saturation rates are projected using an S-shaped logistic saturation function based on historical data from appliance saturation surveys and service area real personal income. The second major factor in the demand estimation equation is the connected load of the appliance. The term "connected load" is defined here as the power requirements or wattage of the appliance. This will tend to change over time as relative energy prices, appliance efficiencies and features change.

The last factor in the demand equation is the probability of the appliance operating at a given time. This term is called the use factor. It is necessary to distinguish between temperature, or weather sensitive use factors, and temperature insensitive use factors. The temperature insensitive use factors depend only on time, i.e., time of day, type of day and season. The type of day is important since weekday energy usage for many appliances differs from that of weekend and holiday usage. Similarly, there are seasonal variations in the use of many temperature insensitive appliances such as lighting. For other appliances, such as air conditioners, electric space heaters, and heat pumps, use factors depend not only on time of day, but also on temperature. These use factors indicate the probability of a space-conditioning device operating at a given time of day, day type and temperature. Combining the heating and cooling use factors with the expected occurrence of temperature conditions in a given period yields the energy requirements for that period. By specifying a temperature profile for a given day, the model is capable of simulating the weather sensitive load corresponding to that temperature profile.

Industrial Sector

The industrial sector model is designed to forecast energy consumption levels associated with selected manufacturing industries. Electric energy consumption in the industrial sector is significantly tied to the level of economic activity. The major driving forces affecting energy consumption are the real price of electricity, the level of economic activity in the service area, and the technologies, or processes, of the industries involved. Since energy requirements for a given measure of economic activity vary from one industry to another, it is necessary to assess the mix of the industrial sector. To capture the effect of industrial mix, the industrial sector is disaggregated into twelve categories. Thus, by projecting energy usage independently for each

2-digit Standard Industrial Code (SIC) category, the model captures changes in energy consumption due to changes in the industrial base.

There are numerous ways of measuring economic activity in the industrial sector. Due to the ready availability of historic employment data on a 2-digit SIC level, employment was used as this measure of activity. The level of annual energy consumption in any one of the twelve industries is calculated by multiplying the projected level of economic activity (expressed in employment) by the projected energy intensity (expressed as KWh usage per employee) of that sector. The calculation of energy intensity for each sector also incorporates the industrial production and capacity utilization indices for each sector to "normalize" the level of electric energy used per unit of output.

Commercial Sector

In the commercial sector, forecasts of annual energy consumption are derived for those customers falling into private, non-manufacturing business-types. Historic commercial energy sales are categorized into ten separate "building types" (e.g., retail, office, grocery, etc.) which are modeled individually. Commercial electricity consumption is determined by multiplying the floor space in each of these ten building categories by the energy intensity per square foot by category. This is done for three distinct end-uses: base (non-weather sensitive), heating and cooling. Floor space projections are developed based on a combination of historic and projected floor space per employee and employment projections by building type. Energy intensity per square foot is projected by building type using time trends with considerations for the three end-uses (i.e., weather sensitivity and base use). The model also factors in the influence of electric price on energy usage decisions as well as expected end-use saturation levels. Projections of KWh usage per square foot along with projected square footage for each building type yield commercial sector energy sales.

Customer Forecast

An increasing service area population translates directly into a greater number of homes requiring electricity and, consequently, into a greater number of commercial establishments to service these residences. Service area population serves as the driver for residential and (implicitly) commercial customers, which together comprise 98.4 percent of FPC's total customers. The Bureau of Economic and Business Research at the University of Florida provides population estimates and projections for the FPC service area that are used in the development of the residential customer forecast. In order to determine future residential customer growth, historic growth in residential customers is regressed against historic growth in service area population. The resulting statistical coefficients are then applied to the population growth forecast. Future commercial and street lighting customers are modeled as a function of total residential customers. Industrial and public authority sector customers are forecast via a time-trend approach given their relatively stable nature.

In the short-term, deviations from trend in the most recent time periods are scrutinized. This analysis, along with any specific input from regional field personnel regarding growth expectations, forms the basis for developing a short-term outlook that is consistent with recent history as well as the long-term projections for all customer classes.

Peak Demand Forecast

The forecast of peak demand also employs a dual methodology framework. The SHAPES-PC end-use model is used to develop class-of-business load shapes and an econometric approach is used to project specific disaggregated pieces of the demand forecast. Both techniques provide a unique perspective as to the make-up of total system demand.

The SHAPES-PC end-use model uses FPC load research sampled class of business load shapes to develop a weather normalized 8,760 hour (yearly) load shape for the residential, commercial, industrial, and "all other" classes to calibrate historic benchmarks. Projections in MW demand and energy are then based upon growth in residential customers, manufacturing employees, commercial floor space, increased saturation of class end-uses or energy intensity, and price elasticity.

The econometric approach to projecting seasonal peak demand employs a disaggregation technique that separates seasonal (winter and summer) peak hour system demand into five major components. These components consist of potential firm retail load, demand-side management program capability, wholesale demand, company use demand and interruptible demand.

Potential firm retail load refers to projections of FPC retail hourly seasonal net peak demand (excluding interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of FPC's Load Management program. The historical values of this series are constructed to show the size of FPC's firm retail net peak demand if no utility-induced conservation or load control had ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to total system customer levels at the time of the peak and coincident weather conditions without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data, regardless of which month the peak occurred. The projections become the potential retail demand projection for the months of January (winter) and August (summer), since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the month being projected.

Energy conservation and direct load control estimates are consistent with FPC's DSM goals that were established by the Commission in the 1999 DSM Goals Docket. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm retail demand.

Sales For Resale demand projections represent load supplied by FPC to other electric utilities, such as SECI, FMPA and other electric distribution companies. The SECI supplemental demand projection is based on their forecast of their service area within the FPC control area. The level of MW to be served by FPC is dependent upon the amount of resources SECI supplies to itself or contracts with others. An assumption has been made that beyond 2005 - the last year of committed capacity declaration - SECI will hold constant their level of self-serve resources. For the partial requirements customers demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels. Demand requirements continue out at the level indicated by the final year in their respective contracts. The full requirements municipal demand forecast is estimated for individual cities using linear econometric equations modeling both weather and economic impacts specific to each locale. The seasonal (winter and summer) projections become the January and August peak values, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month (November to March) relative to the winter peak, and each summer month (April to October) in relation to the summer peak demand.

FPC "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon. The interruptible and curtailable service load component is developed from historic trends, as well as the incorporation of specific information obtained from FPC's industrial service representatives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts. Since DSM program impacts represent a reduction in peak demand, they are assigned a negative value. Total system peak demand is then calculated as the arithmetic sum of these five components.

Both the end-use methodology and the disaggregated econometric methodology supply necessary information that go into the final projection of system peak demand.

HIGH AND LOW FORECAST SCENARIOS

The high and low bandwidth scenarios around the base MWh energy sales forecast are developed using a Monte Carlo simulation applied to a multivariate regression model that closely replicates the base retail MWh energy forecast in aggregate. This model accounts for variation in Gross Domestic Product, retail customers and electric price. The base forecasts for these variables were developed based on input from Data Resources Inc. and internal company price projections. Variation around the base forecast predictor variables used in the Monte Carlo simulation was based on an 80 percent confidence interval calculated around variation in each variable's historic growth rate. While the total number of degree days (weather) were also incorporated into the model specification, the high and low scenarios do not attempt to capture extreme weather conditions. Normal weather conditions were assumed in all three scenarios.

The Monte Carlo simulation was produced through the estimation of 1,000 scenarios for each year of the forecast horizon. These simulations allowed for random normal variation in the growth trajectories of the economic input variables (while accounting for cross-correlation amongst these variables), as well as simultaneous variation in the equation (model error) and coefficient estimates. These scenarios were then sorted and rank ordered from one to a thousand, while the simulated scenario with no variation was adjusted to equal the base forecast.

The low retail scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate probability of occurrence of .10. The high retail scenario similarly represents a bandwidth forecast with an approximate probability of occurrence of .90. In both scenarios the high and low peak demand bandwidth forecasts are projected from the energy forecasts using the load factor implicit in the base forecast scenario.

CONSERVATION

On October 25, 1994 the FPSC approved a set of numeric conservation goals for FPC in Docket No. 930549-EG, Order No. PSC-94-1313-FOF-EG. Later, in 1995, the Commission also approved FPC's Demand Side Management (DSM) Plan for meeting the conservation goals (in Docket No. 941171-EG, Order Nos. PSC-95-0691-FOF-EI and PSC-95-1344-S-EG). The following tables present FPC's historical DSM performance by showing the Commission approved conservation goals as well as the conservation savings actually achieved through its DSM programs for the period 1994 through 1999.

Historical Residential Conservation Goals and Achievements

	Cumulative Summer MW		Cumulative Winter MW		Cumulative GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
1994	11	24	43	46	12	15
1995	30	43	86	85	24	29
1996	50	70	133	137	38	45
1997	71	100	184	196	60	66
1998	93	126	236	252	78	89
1999	116	145	290	292	100	114

Historical Commercial/Industrial Conservation Goals and Achievements

	Cumulative Summer MW		Cumulative Winter MW		Cumulative GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
1994	0.3	10	0.05	10	2	32
1995	3	33	3	32	19	81
1996	8	48	7	46	40	137
1997	15	55	13	52	71	147
1998	24	63	20	58	110	158
1999	35	70	29	65	155	164

Most recently in Docket 971007-EG, Order No. PSC-99-1942-FOF-EG, issued October 1, 1999, the FPSC established new conservation goals for FPC that span the ten-year period from

2000 through 2009. As required by Rule 25-17.0021(4), Florida Administration Code, FPC then submitted for Commission approval a new DSM Plan that was specifically designed to meet the new conservation goals. The forecasts contained in this Ten-Year Site Plan document are based on FPC's proposed DSM Plan and, therefore, appropriately reflect the level of DSM savings required to meet the new Commission-established conservation goals. FPC currently offers four residential programs, eight commercial and industrial programs, and one research and development program. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all DSM resources are acquired in a cost-effective manner and that the program savings are durable. Following is a brief description of these programs.

Residential Programs

Home Energy Check Program

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bill through low-cost or no-cost energy-saving practices and measures. The program provides customers with three types of energy audits: Level 1 - customer-completed mail-in audit; Level 2 - free walk-through audit; and Level 3 - paid walk-through audit. The Home Energy Check Program serves as the foundation of the Home Energy Improvement Program in that the audit is a prerequisite for participation in the retrofit of water heaters, heating and air conditioning units.

Home Energy Improvement Program

This is the umbrella program to improve energy efficiency for existing homes. It combines efficiency improvements to the thermal envelope with upgraded home energy equipment and appliances. The program provides incentives for ceiling insulation upgrades, reduced duct leakage, high efficiency electric heat pumps, heat recovery units, and dedicated heat pump water heaters.

Residential New Construction Program

This program promotes energy efficient new home construction in order to provide customers with more efficient cooling and heating consumption combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient building design and construction. The program promotes the sealing of air conditioning duct systems using mastic for lasting results. The program provides incentives to the builder for high efficiency electric heat pumps, heat recovery units and heat pump water heaters. The highest level of the program incorporates the Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising.

Residential Energy Management Program

This is a voluntary customer program that allows FPC to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customer's premises. These interruptions are at FPC's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bill. FPC is currently in the process of developing new Energy Management program options that will focus on winter peak utilization and will provide more cost-effective program options for FPC's customers.

Commercial/Industrial (C/I) Programs

Business Energy Check Program

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facility, recommendations on how they can improve the environmental conditions of their facility while saving on their electricity bill, and information on low-cost energy efficiency measures. The Business Energy Check consists of two types of audits: Level 1 - free walk-through audit, and Level 2 - paid walk-through audit. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business Program

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to FPC and its customers. The Better Business Program promotes energy efficient heating, ventilation, air conditioning (HVAC), motors, and water heating equipment, as well as some building retrofit measures (in particular, roof insulation upgrade, duct leakage test and repair, and window film retrofit).

Commercial/Industrial New Construction Program

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the state energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives will be provided for high efficiency HVAC equipment, motors, heat recovery units, and duct leakage testing and repair.

Innovation Incentive Program

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for customers in FPC's service territory. The intent of the program is to encourage legitimate energy efficiency measures that reduce KW demand and/or KWh energy, but are not addressed by other programs. Energy efficiency opportunities are identified by FPC representatives during a Business Energy Check audit. If a candidate project meets program specifications, it will be eligible for an incentive payment, subject to FPC approval.

Commercial Energy Management Program (Rate Schedule GSLM-1)

This direct load control program reduces FPC's demand during peak or emergency conditions. The program is available to customers who have electric space cooling equipment suitable for interruptible operation, and are eligible for service under the Rate Schedule GS-1, GST-1, GSD-1, or GSDT-1. The program is also applicable to customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: 1) water heater(s), 2) central electric heating systems(s), 3) central electric cooling system(s), and/or 4) swimming pool pump(s). The customer will receive a monthly credit on their bill depending on the type of equipment in the program and the interruption schedule.

Standby Generation Program

This demand control program reduces FPC's demand based upon the indirect control of customer generation equipment. This is a voluntary program available to all commercial, industrial and agricultural customers who have on-site generation capability and are willing to reduce their FPC demand when FPC deems it necessary. The customers participating in the Standby Generation program receive a monthly credit on their electricity bill according to the demonstrated ability of the customer to reduce demand at FPC's request.

Interruptible Service Program

This direct load control program reduces FPC's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 KW or more, who are willing to have their power interrupted. FPC will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for this ability to interrupt load, customers participating in the Interruptible Service program receive a monthly interruptible demand credit applied to their electric bill. In response to customer requests and discussions with the FPSC, FPC has been implementing improvements in the way in which these customer resources are called upon during periods of capacity shortage. Customer response has been favorable to the improvements that have been implemented.

Curtailable Service

This direct load control program reduces FPC's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 KW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit applied to their electric bill.

Research and Development Program

Technology Development Program

The primary purpose of this program is to establish a system to "pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001, {5}(f), Florida Administration Code). FPC will undertake certain development and demonstration projects that have promise to become cost-effective demand and energy efficiency programs. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field testing with actual customers.

CHAPTER 3 Forecast of FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

Overview of the Current Forecast

Supply-Side Resources: FPC has a Total Capacity Resource of 9,567 MW, as shown in Table 3.1, which reflects an increase of 35 MW from FPC's 1999 Ten-Year Site Plan. This capacity resource includes utility purchased power (469 MW), non-utility purchased power (831 MW), combustion turbine (2,775 MW), nuclear (782 MW), fossil steam (3,958 MW) and combined cycle plants (752 MW). Table 3.2 shows FPC's contracts for firm capacity provided by QFs.

Demand-Side Programs: FPC has experienced excellent levels of participation in its Demand-Side Management Programs. Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. FPC's 2000 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 971005-EG. This Plan also includes the effects of program attrition experienced in 1998 and 1999 as well as the projected program transitions which are expected to commence upon approval of FPC's recent program filings.

Capacity and Demand Forecast: FPC's forecast of capacity and demand for the projected summer and winter peaks are shown on Schedules 7.1 and 7.2, respectively. FPC's forecast of capacity and demand is based on serving expected growth in retail requirements in its regulated service area and meeting commitments to wholesale power customers who have entered into supply contracts with FPC. In its planning process, FPC balances its supply plan for the needs of retail and wholesale customers and endeavors to ensure that cost-effective resources are available to meet the needs across the customer base. Over the years, as wholesale markets have grown more competitive, FPC has remained active in the competitive solicitations while planning in a manner that maintains an appropriate balance of commitments and resources within the overall regulated supply framework.

Base Expansion Plan: FPC's planned supply resource additions and changes are shown in Schedule 8 and are referred to as FPC's Base Expansion Plan. This Plan includes 2,550 MW of proposed new capacity additions over the next ten years, including the 282 MW combustion turbine addition currently underway at Intercession City. As identified in Schedule 8, FPC's next planned need is a 567 MW (winter) power block in November 2003. In accordance with Rule 25-22.082 (F.A.C.), FPC issued a request for proposals (RFP) on January 26, 2000 to solicit competitive proposals for supply-side alternatives to its planning/bid evaluation benchmark, a second gas-fired combined cycle unit at the Hines Energy Complex. FPC will establish a plan to address this need when it has identified a resource plan that offers the most value to FPC and its customers.

FPC's Base Expansion Plan projects requirements for additional combined cycle units with proposed in-service dates of 2005, 2007 and 2009. These high efficiency gas-fired combined cycle units help the FPC system meet the growing energy requirements of its customer base and also contribute to meeting the requirements of the 1990 Clean Air Act Amendments. Fuel switching, SO_2 emission allowance purchases, re-dispatching of system generation and technology improvements are additional avenues available to FPC to ensure compliance with these important environmental requirements. (Status reports and specifications for new generation facilities are included in Schedule 9).

Existing Resources: Future changes to FPC's existing resources include a gas conversion at Suwannee River P2; turbine efficiency upgrades at Crystal River 1, 2 and 4; inlet fogging installations at Debary P7-10 to increase summer capacity; and plant retirements.

TABLE 3.1

FLORIDA POWER CORPORATION
TOTAL CAPACITY RESOURCE
Power Plants And Purchased Power

Plants	Number Of Units	Net Dependable Capability KW Winter
Nuclear Steam Plant		
Crystal River	1	782,000 *
Fossil Steam (FS) and Combined Cycle (CC) Plants		
Crystal River (FS)	4	2,316,000
Anclote (FS)	2	1,044,000
Paul L. Bartow (FS)	3	452,000
Suwannee River (FS)	3	146,000
Hines Energy Complex (CC)	1	529,000
Tiger Bay (CC)	1	223,000
Total FS and CC	14	4,710,000
Total Steam (Nuclear, FS and CC)	15	5,492,000
Combustion Turbines		
DeBary	10	762,000
Intercession City	11	912,000
Bayboro	4	232,000
Bartow	4	219,000
Suwannee	3	201,000
Turner	4	194,000
Higgins	4	134,000
Avon Park	2	64,000
University of Florida	1	41,000
Rio Pinar	1	16,000
Total Combustion Turbines	44	2,775,000
Total Units	59	
Total Net Generating Capability		**8,267,000**
** Adjusted for sale of 8.2% of total capacity*		
Purchased Power		
Qualifying Facilities	15	831,000
Investor Owned Utilities	2	469,000
TOTAL CAPACITY RESOURCE		**9,567,000**

TABLE 3.2

FLORIDA POWER CORPORATION
QUALIFYING FACILITY GENERATION CONTRACTS
AS OF DECEMBER 31, 1999

FACILITY NAME	FIRM CAPACITY (MW)
BAY COUNTY RES. RECOV.	11
CARGILL	15
CFR-BIOGEN	74
DADE COUNTY RES. RECOV.	43
EL DORADO	114
LAKE COGEN	110
LAKE COUNTY RES. RECOV.	13
LFC JEFFERSON	8
LFC MADISON	8
MULBERRY	79
ORLANDO COGEN	79
PASCO COGEN	109
PASCO COUNTY RES. RECOV.	23
PINELLAS COUNTY RES. RECOV. 1	40
PINELLAS COUNTY RES. RECOV. 2	15
RIDGE GENERATING STATION	40
ROYSTER	31
TIMBER ENERGY 1	13
US AGRICHEM	6
TOTAL	**831**

FLORIDA POWER CORPORATION

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2000	7,553	469	0	831	8,853	7,439	1,414	19%	0	1,414	19%
2001	7,817	469	0	831	9,117	7,701	1,416	18%	0	1,416	18%
2002	7,834	469	0	818	9,121	7,431	1,690	23%	0	1,690	23%
2003	7,834	469	0	818	9,121	7,258	1,864	26%	0	1,864	26%
2004	8,186	469	0	818	9,473	7,361	2,112	29%	0	2,112	29%
2005	8,186	479	0	818	9,483	7,522	1,961	26%	0	1,961	26%
2006	8,546	479	0	818	9,843	7,737	2,106	27%	0	2,106	27%
2007	8,468	479	0	813	9,760	7,947	1,813	23%	0	1,813	23%
2008	8,963	479	0	798	10,240	8,152	2,088	26%	0	2,088	26%
2009	8,963	479	0	689	10,131	8,354	1,776	21%	0	1,776	21%

FLORIDA POWER CORPORATION

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2000/01	8,590	469	0	831	9,890	8,528	1,362	16%	0	1,362	16%
2001/02	8,607	469	0	831	9,907	8,282	1,625	20%	0	1,625	20%
2002/03	8,607	469	0	818	9,894	8,120	1,774	22%	0	1,774	22%
2003/04	9,028	469	0	818	10,315	8,230	2,085	25%	0	2,085	25%
2004/05	9,028	479	0	818	10,325	8,394	1,931	23%	0	1,931	23%
2005/06	9,445	479	0	818	10,742	8,609	2,133	25%	0	2,133	25%
2006/07	9,349	479	0	813	10,641	8,820	1,821	21%	0	1,821	21%
2007/08	9,916	479	0	798	11,193	9,029	2,163	24%	0	2,163	24%
2008/09	9,916	479	0	689	11,084	9,233	1,851	20%	0	1,851	20%
2009/10	10,483	479	0	548	11,510	9,440	2,070	22%	0	2,070	22%

FLORIDA POWER CORPORATION

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY

ADDITIONS AND CHANGES

(JANUARY 1, 2000 THROUGH DECEMBER 31, 2009)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
												NET CAPABILITY			
				FUEL		FUEL TRANSPORT.		CONST.	COMMERCIAL	EXPECTED	GEN. MAX.				
	UNIT		UNIT					START	IN-SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	LOCATION	TYPE	PRIMARY	ALT.	PRIMARY	ALT.	MONTH/YEAR	MONTH/YEAR	MONTH/YEAR	KW	MW	MW	STATUS	NOTES
CRYSTAL RIVER	4	CITRUS CO.	ST	BIT		WA,RR			04/2000			17	17	CA	1
DEBARY	P7-9	VOLUSIA CO.	CT	NG	FO2	PL	TK,RR		05/2000			15	0	CA	2
DEBARY	P10	VOLUSIA CO.	CT	FO2		TK,RR			05/2000			5	0	CA	2
CRYSTAL RIVER	2	CITRUS CO.	ST	BIT		WA,RR			12/2000			24	24	CA	1
INTERCESSION CITY	P12-14	OSCEOLA CO.	CT	NG	FO2	PL	PL,TK	03/1999	12/2000			240	282	U	
SUWANNEE RIVER	P2	SUWANNEE CO.	CT	NG	FO2	PL	TK		05/2001			--	--	FC	3
CRYSTAL RIVER	1	CITRUS CO.	ST	BIT		WA,RR			12/2001			17	17	CA	1
HINES ENERGY COMPLEX	2	POLK CO.	CC	NG	FO2	PL	TK	08/2000	11/2003			495	567	P	
SUWANNEE RIVER	1-3	SUWANNEE CO.	ST	NG	FO6	PL	TK			12/2003	147,000	(143)	(146)	RE	4
HINES ENERGY COMPLEX	3	POLK CO.	CC	NG	FO2	PL	TK	08/2002	11/2005			495	567	P	
HIGGINS	P1-4	PINELLAS CO.	CT	FO2	NG	TK	PL			12/2005	153,430	(122)	(134)	RE	4
RIO PINAR	P1	ORANGE CO.	CT	FO2		TK				12/2005	19,290	(13)	(16)	RE	4
AVON PARK	P1	HIGHLANDS CO.	CT	FO2	NG	TK	PL			12/2006	33,790	(26)	(32)	RE	4
AVON PARK	P2	HIGHLANDS CO.	CT	FO2		TK				12/2006	33,790	(26)	(32)	RE	4
TURNER	P1-2	VOLUSIA CO.	CT	FO2		TK,WA				12/2006	38,580	(26)	(32)	RE	4
HINES ENERGY COMPLEX	4	POLK CO.	CC	NG	FO2	PL	TK	08/2004	11/2007			495	567	P	
HINES ENERGY COMPLEX	5	POLK CO.	CC	NG	FO2	PL	TK	08/2006	11/2009			495	567	P	

NOTES :

1 / CAPABILITY INCREASE (TURBINE EFFICIENCY UPGRADE).

2 / CAPABILITY INCREASE (INLET FOGGING INSTALLATION).

3 / FUEL CONVERSION TO NATURAL GAS; NO CHANGE IN NET CAPABILITY.

4 / RETIREMENT CAPACITIES ARE IN PARENTHESES. CONSIDERATION FOR POTENTIAL LIFE EXTENSIONS OF THESE FACILITIES WILL BE INCLUDED IN FUTURE STUDIES.

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	INTERCESSION CITY P12 - 14
(2)	CAPACITY	
	a. SUMMER:	240 MW
	b. WINTER:	282 MW
(3)	TECHNOLOGY TYPE:	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	a. FIELD CONSTRUCTION START-DATE:	3/1999
	b. COMMERCIAL IN-SERVICE DATE:	12/2000 (EXPECTED)
(5)	FUEL	
	a. PRIMARY FUEL:	NATURAL GAS
	b. ALTERNATE FUEL:	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION (NATURAL GAS) WATER INJECTION (DISTILLATE OIL)
(7)	COOLING METHOD:	AIR
(8)	TOTAL SITE AREA:	165 ACRES
(9)	CONSTRUCTION STATUS:	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS:	SITE PERMITTED
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF):	2.88 %
	FORCED OUTAGE FACTOR (FOF):	3.00 %
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %
	ASSUMED CAPACITY FACTOR (%):	15.00 %
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	13,272 BTU/KWH

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #2
(2)	CAPACITY	
	a. SUMMER:	495 MW
	b. WINTER:	567 MW
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	a. FIELD CONSTRUCTION START-DATE:	8/2000
	b. COMMERCIAL IN-SERVICE DATE:	11/2003 (EXPECTED)
(5)	FUEL	
	a. PRIMARY FUEL:	NATURAL GAS
	b. ALTERNATE FUEL:	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	COOLING METHOD:	COOLING PONDS
(8)	TOTAL SITE AREA:	8,200 ACRES
(9)	CONSTRUCTION STATUS:	PLANNED
(10)	CERTIFICATION STATUS:	SITE PERMITTED
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF):	4.41 %
	FORCED OUTAGE FACTOR (FOF):	3.70 %
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %
	ASSUMED CAPACITY FACTOR (%):	70.00 %
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #3
(2)	CAPACITY	
	a. SUMMER:	495 MW
	b. WINTER:	567 MW
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	a. FIELD CONSTRUCTION START-DATE:	8/2002
	b. COMMERCIAL IN-SERVICE DATE:	11/2005 (EXPECTED)
(5)	FUEL	
	a. PRIMARY FUEL:	NATURAL GAS
	b. ALTERNATE FUEL:	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	COOLING METHOD:	COOLING PONDS
(8)	TOTAL SITE AREA:	8,200 ACRES
(9)	CONSTRUCTION STATUS:	PLANNED
(10)	CERTIFICATION STATUS:	SITE PERMITTED
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF):	4.41 %
	FORCED OUTAGE FACTOR (FOF):	3.70 %
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %
	ASSUMED CAPACITY FACTOR (%):	70.00 %
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #4
(2)	CAPACITY	
	a. SUMMER:	495 MW
	b. WINTER:	567 MW
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	a. FIELD CONSTRUCTION START-DATE:	8/2004
	b. COMMERCIAL IN-SERVICE DATE:	11/2007 (EXPECTED)
(5)	FUEL	
	a. PRIMARY FUEL:	NATURAL GAS
	b. ALTERNATE FUEL:	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	COOLING METHOD:	COOLING PONDS
(8)	TOTAL SITE AREA:	8,200 ACRES
(9)	CONSTRUCTION STATUS:	PLANNED
(10)	CERTIFICATION STATUS:	SITE PERMITTED
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF):	4.41 %
	FORCED OUTAGE FACTOR (FOF):	3.70 %
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %
	ASSUMED CAPACITY FACTOR (%):	70.00 %
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #5
(2)	CAPACITY	
	a. SUMMER:	495 MW
	b. WINTER:	567 MW
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	a. FIELD CONSTRUCTION START-DATE:	8/2006
	b. COMMERCIAL IN-SERVICE DATE:	11/2009 (EXPECTED)
(5)	FUEL	
	a. PRIMARY FUEL:	NATURAL GAS
	b. ALTERNATE FUEL:	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	COOLING METHOD:	COOLING PONDS
(8)	TOTAL SITE AREA:	8,200 ACRES
(9)	CONSTRUCTION STATUS:	PLANNED
(10)	CERTIFICATION STATUS:	SITE PERMITTED
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF):	4.41 %
	FORCED OUTAGE FACTOR (FOF):	3.70 %
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %
	ASSUMED CAPACITY FACTOR (%):	70.00 %
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH

FLORIDA POWER CORPORATION

SCHEDULE 10
STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

HINES ENERGY COMPLEX SITE

(1)	POINT OF ORIGIN AND TERMINATION:	BARCOLA SUBSTATION - HINES ENERGY COMPLEX
(2)	NUMBER OF LINES:	1 (SECOND CIRCUIT OF DOUBLE CIRCUIT CONSTRUCTION)
(3)	RIGHT-OF-WAY:	EXISTING TRANSMISSION LINE AND HINES ENERGY COMPLEX SITE
(4)	LINE LENGTH:	3 MILES
(5)	VOLTAGE:	230 KV
(6)	ANTICIPATED CONSTRUCTION TIMING:	MID 2003 IN-SERVICE, START CONSTRUCTION EARLY 2002
(7)	ANTICIPATED CAPITAL INVESTMENT:	$ 1,800,000
(8)	SUBSTATIONS:	N/A
(9)	PARTICIPATION WITH OTHER UTILITIES:	N/A

INTEGRATED RESOURCE PLANNING OVERVIEW

FPC employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customer's future energy needs. FPC's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis.

An overview of FPC's IRP Process is shown in Figure 1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for FPC to pursue over the next ten years to meet the company's reliability criteria. The resulting ten year plan, the Integrated Optimal Plan, is then tested under different sensitivity scenarios to identify variances, if any, that would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust under sensitivity analysis and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The IRP Process".

The Integrated Resource Plan provides FPC with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations and the most current dynamics of the business and regulatory environments.

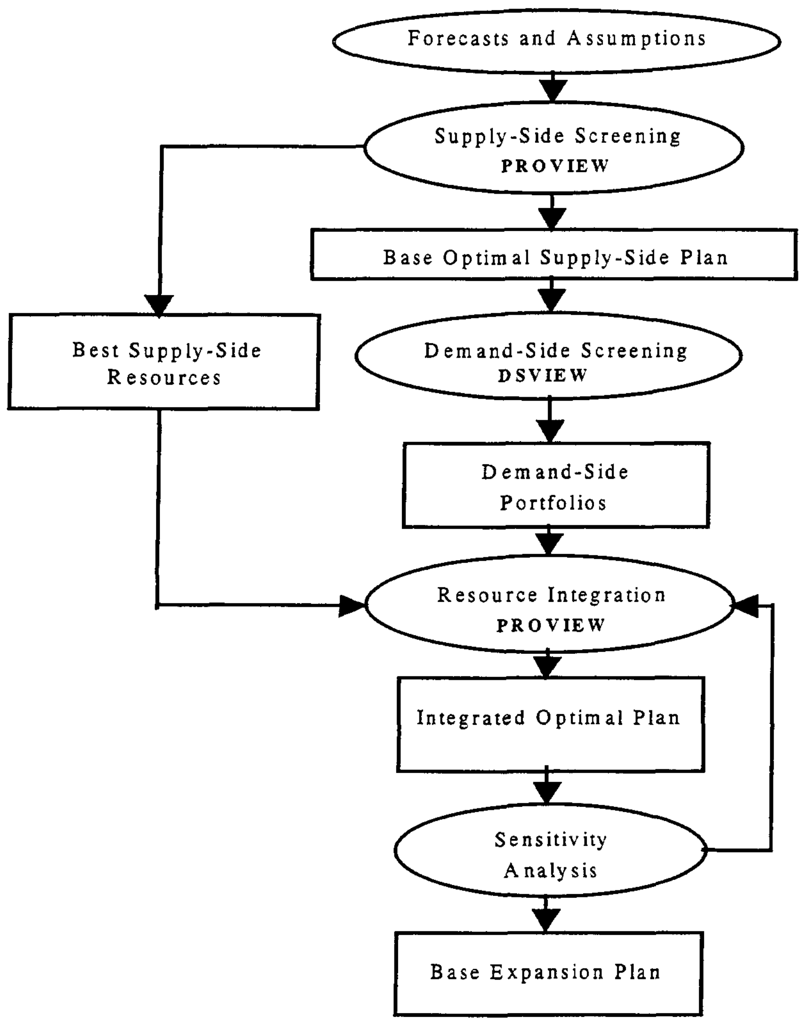


Figure 1: IRP Process Overview

THE IRP PROCESS

Forecasts and Assumptions

The evaluation of possible supply-side and demand-side alternatives, and development of the optimal plan, is the longest and most demanding part of the IRP process. These steps together comprise the integration process which begins with the development of forecasts and collection of input data. Base forecasts that reflect FPC's view of the most likely future scenarios are developed, along with high and low forecasts that reflect alternative future scenarios. Computer models used in the process are brought up-to-date to reflect this data, along with the latest operating parameters and maintenance schedules for FPC's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

FPC plans its resources to meet dual reliability criteria; reserve margin (over forecasted firm peak demand) and Loss of Load Probability (LOLP). The reserve margin criterion is deterministic and provides a measure of FPC's ability to meet its forecasted seasonal peak load. In December 1999, the Florida Public Service Commission (FPSC) approved a joint proposal from the three major investor-owned utilities (Florida Power, Florida Power & Light and Tampa Electric) to increase minimum planning reserve levels to 20 percent by the summer of 2004 (Docket No. 981890-EU, Order No. PSC-99-2507-S-EU). Upon receiving acceptance from the FPSC of this proposal, FPC raised its targeted *minimum reserve margin to 20 percent* for the summer of 2004 and beyond and adapted this TYSP to meet this revised minimum level. In the interim period, FPC will maintain reserves above the *current minimum threshold of 15 percent.*

LOLP is a probabilistic criterion, which is a measure of FPC's ability to meet its load throughout the year taking into consideration unit failures, unit maintenance, and assistance from other utilities. FPC's minimum reliability level threshold of *0.1 days per year LOLP* is an appropriate target for FPC's system and is very well supported in the industry. Typically, resource additions are triggered to meet reserve margin thresholds before LOLP becomes a factor, but FPC feels that this is still a meaningful supplemental reliability measure.

Supply-Side Screening

Potential supply-side resources are screened to determine those that are the most cost-effective. Data used for the screening analysis is compiled from various industry sources and FPC's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters, and overall resource feasibility.

Economic evaluation of generation alternatives is performed using the PROVIEW optimization program. The optimization program evaluates revenue requirements for specific resource plans generated from multiple combinations of future resource additions that meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements. The optimization run produces the optimal supply-side only resource plan, which is considered the "Base Optimal Supply-Side Plan."

Demand-Side Screening

Like supply-side resources, data about large numbers of potential demand-side resources is also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (building code), or not applicable to FPC's customers. The demand-side screening model, DSVIEW, is updated with cost data and load impact parameters for each potential DSM measure to be evaluated.

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten year planning horizon to determine the benefit or detriment that the addition of this demand-side resource provides to the overall system. DSVIEW calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test. Demand-side programs that pass the RIM test are then bundled together to create demand-side portfolios. These portfolios contain the appropriate DSM options and make the optimization solvable with the DSVIEW model.

Resource Integration And The Integrated Optimal Plan

The cost-effective generation alternatives and the demand-side portfolios developed in the screening process can then be optimized together to formulate an Integrated Optimal Plan. The optimization program considers all possible future combinations of supply-side and demand-side alternatives that meet the company's reliability criteria in each year of the ten-year study period and reports those that provide both flexibility and low revenue requirements for FPC's ratepayers.

Developing the Base Expansion Plan

The plans that provide the lowest revenue requirements are then further tested using sensitivity analysis. The economics of the plan are evaluated under high and low forecast scenarios for load, fuel and financial assumptions to ensure that the plan does not unduly burden the company or the ratepayers if the future unfolds in a manner significantly different from the base forecasts. From the sensitivity assessment, the ten year plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review it evolves as the Base Expansion Plan.

KEY CORPORATE FORECASTS

Fuel Forecast

Base Fuel Case: The base case fuel price forecast was developed from the expected or most likely course of events. General market conditions for all fuels are expected to be relatively stable when viewed from an average annual cost basis. Coal prices are also expected to be relatively stable month to month; however, oil and natural gas prices are expected to be highly volatile on a day to day and month to month basis.

The base cost for coal is based on the existing contractual structure between Electric Fuels Corporation (EFC) and FPC and both contract and spot market coal and transportation arrangements between EFC and its various suppliers. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by Tariff and rates tend to change less frequently than commodity prices.

High Fuel Case: FPC's high case fuel forecast is based on the premise that fuel prices are high in a relatively high inflation economic environment on a worldwide basis. The forecast is based on an approximate probability of 25 percent (vs. 50 percent for the base case). Coal prices in the high case were developed based on the effect the coal market and inflation have on contract supply, spot supply, quality differences and the various transportation cost drivers. FPC developed the high case oil and natural gas forecast based on the same general market environment and inflation levels as those used for coal. Since oil and natural gas supply are primarily purchased at market prices, consideration for current contract escalation was not required. Any expected increase in transportation cost is also included in the overall projected price increases.

Low Fuel Case: FPC's low case fuel forecast is based on the premise that fuel prices are low in a low inflation economic environment on a worldwide basis. The forecast is based on an approximate probability of 25 percent (vs. 50 percent for the base case). Coal prices in the low case were developed based on the effect the coal market and inflation have on contract supply, spot supply, quality differences and the various transportation cost drivers. FPC developed the low case oil and natural gas forecast based on the same general market environment and inflation levels as those used for coal. Since oil and natural gas supply are primarily purchased at market prices, no consideration is given for current contract escalation. Any expected change in transportation cost is also included in the overall projected price variations.

Special Fuel Case: A constant oil and gas to coal differential fuel sensitivity forecast was also developed to examine the premise that the current differential price of oil and gas to coal could remain constant over time.

Financial Forecast

Base Financial Case: The Base Financial Case was a combination of FPC's current financial assumptions for incremental costs and standard accounting practices, and DRI/McGraw-Hill's *The U.S. Economy, November 1999.* The income tax, depreciation rates and capital structure were based on FPC's corporate financial assumptions. The inflation rate and debt interest rates were based on DRI/McGraw Hill's *The U.S. Economy, November 1999.* In general, the economy has a balanced growth path and a stable inflation rate.

Optimistic Financial Case: In the Optimistic Financial Case there is high growth and low stable inflation rate. DRI/McGraw Hill's *The U.S. Economy, November 1999* was used for forecasted interest rates and inflation rates. Due to low inflation, interest rates remain low, which enhances business development. FPC's composite cost of capital was adjusted to reflect the low inflation rates.

Pessimistic Financial Case: In the Pessimistic Financial Case there is low growth and high inflation. DRI/McGraw Hill's *The U.S. Economy, November 1999* was used for forecasted interest rates and inflation rates. Due to high inflation, interest rates remain high, which depresses consumer expenditures. FPC's composite cost of capital was adjusted to reflect the high inflation rates.

CURRENT PLANNING RESULTS

TYSP Supply-Side Resources

In this TYSP, FPC's supply-side resources include the completion of three combustion turbine units at the Intercession City Site by December 2000 followed by the projected combined cycle expansion of the Hines Energy Complex (HEC) with Units 2 through 5 forecast to be in service by November 2003, 2005, 2007 and 2009, respectively. The new units at Hines are state-of-the-art combined cycle units similar to HEC Unit 1 (currently in service). As new advancements in combined cycle technologies mature, FPC will continue to examine the merits of these new alternatives to ensure the lowest possible expansion costs.

Plan Sensitivities

Sensitivities to load, fuel and financial forecasts were analyzed against the base plan. The base plan of constructing combined cycle units on gas was determined to be robust with respect to changes in the load, fuel and financial forecasts. The low load forecast sensitivity required less combined cycle generation. The high load forecast, which included increased retail demand and wholesale customer retention, indicated that additional combined cycle and combustion turbine units would potentially be required.

The high and low fuel forecast sensitivity results did not suggest any significant reconsideration of the base plan. The low fuel forecast did not point to any changes to the base plan. The high fuel forecast indicated a potential increase in benefits for future advanced technology combined cycle units (as the technologies mature) versus the current state-of-the-art combined cycle units. The additional sensitivity, holding the current differential price of oil and gas to coal constant over time, pointed toward a slight decrease in the value for combined cycle units. However, the variances resulting from these fuel sensitivities were not significant enough to consider departure from the base plan.

Request for Proposals

In accordance with Rule 25-22.082 (F.A.C.), FPC issued a request for proposals (RFP) on January 26, 2000 to solicit competitive proposals for supply-side alternatives to its planning/bid evaluation benchmark, a second gas-fired combined cycle unit at the Hines Energy Complex. FPC will establish a plan to address this need when it has identified a resource plan that offers the most value to FPC and its customers.

TRANSMISSION PLANNING

FPC's transmission planning assessment practices are developed to test the ability of the planned system to meet criteria. This involves the use of loadflow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer, with any one generator scheduled out for maintenance. FPC normally runs this analysis for system load levels from minimum to peak for all possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, less probable criteria, to assure the system meets FPC and Florida Reliability Coordinating Council, Inc. (FRCC) criteria. These studies include the loss of multiple generators or lines, and combinations of each, and some load loss is permissible under these more severe disturbances. These credible, less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

As noted in the FPC reliability criteria, some remedial actions are allowed to reduce system loadings, in particular, sectionalizing is allowed to reduce loading on lower voltage lines for bulk system contingencies, but the risk to load on the sectionalized system must be reasonable (it would not be considered prudent to operate for long periods with a sectionalized system). Also, the number of remedial action steps and the overall complexity of the scheme is evaluated to determine overall acceptability.

Presently, FPC uses the following reference documents to calculate Available Transfer Capability (ATC) for required transmission path postings on the Florida Open Access Same-Time Information System (OASIS):

- FRCC: FRCC ATC Calculation and Coordination Procedures, December 1, 1999, which is posted on the FRCC website: (WWW.FRCC.COM/FRCC_ATC_COORD_DEC99.PDF)
- NERC: Transmission Transfer Capability, May 1995
- NERC: Available Transfer Capability - Definitions and Determination, May 1996

FPC uses the FRCC Capacity Benefit Margin (CBM) methodology to assess its CBM needs. This methodology is:

"FRCC Transmission Providers make an assessment of the CBM needed on their respective systems by using either deterministic or probabilistic generation reliability analysis. The appropriate amount of transmission interface capability is then reserved for CBM on a per interface basis, taking into account the amount of generation available on other interconnected systems, the respective load peaking diversities of those systems, and Transmission Reliability Margin (TRM). Operating reserves may be included if appropriate in TRM and subsequently subtracted from the CBM if needed."

FPC currently has zero CBM reserved on each of its interfaces (posted paths). FPC's CBM on each path is currently established through the transmission provider functions within FPC using deterministic and probabilistic generation reliability analysis.

Currently, FPC proposes no bulk transmission additions that must be certified under the Florida Transmission Line Siting Act (TLSA). FPC's proposed future bulk transmission line additions are shown below:

FLORIDA POWER CORPORATION LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS 2000-2009					
LINE OWNERSHIP	TERMINALS	TERMINALS	LINE LENGTH CKT. MILES	COMMERCIAL IN-SERVICE DATE (MO/YR)	NOMINAL OPERATING VOLTAGE (kV)
FPC	LAKE BRYAN	INTERCESSION CITY #2	10	11/2000	230
FPC, OUC	RIO PINAR	STANTON #2	3	12/2000	230
FPC	TAYLOR CREEK	HOLOPAW	1	11/2002	230
FPC	HINES ENERGY COMPLEX	BARCOLA #2	3	05/2003	230
FPC, TECO	BARCOLA	PEBBLEDALE	1 *	05/2003	230
FPC	LAKE BRYAN	WINDERMERE #2	10	05/2005	230
FPC	HINES ENERGY COMPLEX	WEST LAKE WALES #1	21	05/2005	230
FPC	INTERCESSION CITY	WEST LAKE WALES #2	30	05/2007	230
FPC	PERRY	DRIFTON	35	05/2007	230
FPC	HINES ENERGY COMPLEX	WEST LAKE WALES #2	21	05/2009	230
FPC	INTERCESSION CITY	GIFFORD	10	05/2009	230
FPC	GIFFORD	AVALON	10	05/2009	230

* Rebuild existing circuit

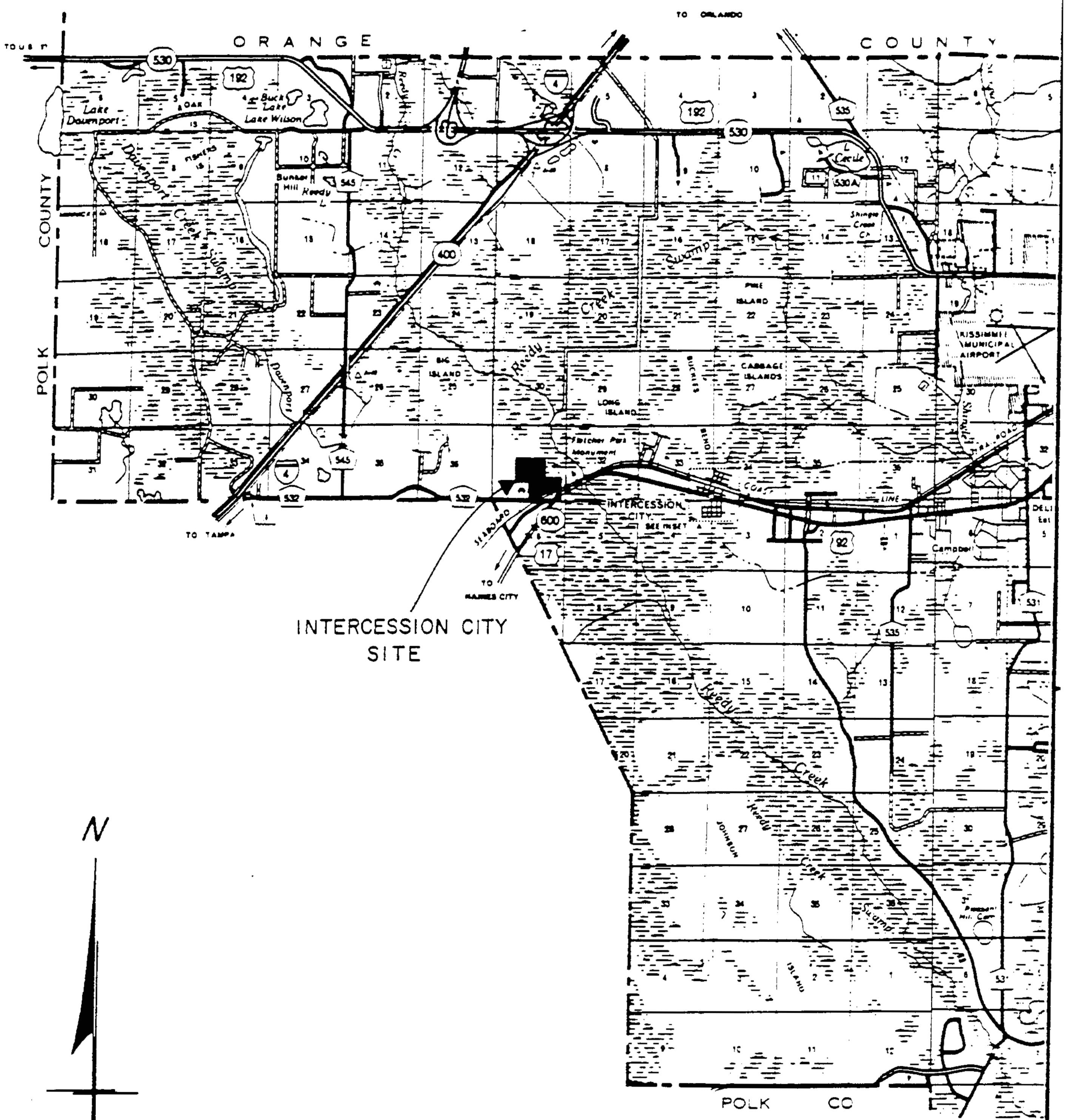
CHAPTER 4 ENVIRONMENTAL and LAND USE INFORMATION

PREFERRED SITES

FPC's base expansion plan proposes new generation at the Intercession City (IC) site in Osceola County and the Hines Energy Complex (HEC) site in Polk County. The IC site is an existing site with three additional combustion turbine units planned for December 2000. The HEC site is an existing site with the first additional combined cycle unit planned for November 2003. The preferred sites of IC and HEC meet all of FPC's siting requirements for capacity throughout the planning horizon. FPC's existing sites, as identified in Table 3.1 of Chapter 3, have been permitted and include the capability to further develop generation and still operate within their individual site permit limits. All appropriate permitting requirements have been addressed for FPC's preferred sites as discussed in the following site descriptions. Therefore, detail environmental or land use data is not included. The base expansion plan does not include any potential sites for new generating facilities.

INTERCESSION CITY SITE

Intercession City was chosen as the preferred site for installation of three additional combustion turbine peaking units by December 2000. The seasonal ratings for the Intercession City capacity addition are projected to be 240 MW summer (80 MW each) and 282 MW winter (94 MW each). The Intercession City Site consists of 165 acres in Osceola County (reference DWG IV-4), two miles west of Intercession City. The site is immediately west of Reedy Creek and the adjacent Reedy Creek Swamp. The site is adjacent to a secondary effluent pipeline from a municipal waste-water treatment plant, an oil pipeline, and a natural gas lateral serving the Kissimmee Utility Authority Cane Island facility. The Florida Department of Environmental Protection air rules currently list all of Osceola County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by FPC's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations. The existing 230 kV transmission grid will accommodate these additional combustion turbine peaking units.



PRODUCTION ENGINEERING DEPARTMENT

PARTIAL AREA MAP
OSCEOLA CO. FL.

DRAWN BY	DATE	SCALE
G.S.K.	2-27-90	NONE
CHECKED BY	DATE	DISCIPLINE
APPROVED BY	DATE	PLANT/UNIT
DATA PROCESS NO.		SHEET
DWG. NO.	IV - 4	

Florida Power

NO.	DESCRIPTION

HINES ENERGY COMPLEX SITE

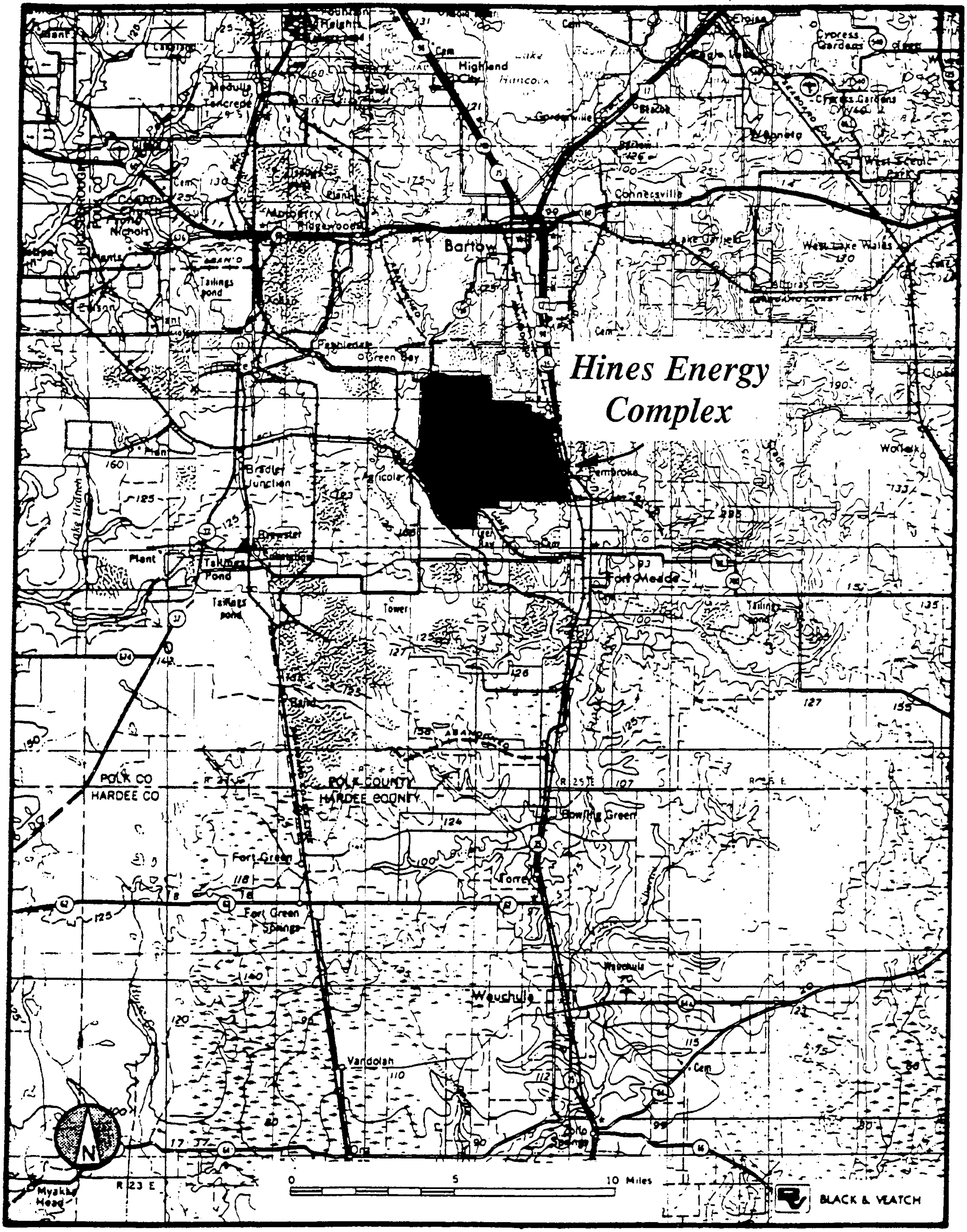
In 1990, FPC completed a state-wide search for a new 3,000 MW coal capable power plant site. As a result of this work, a large tract of mined out phosphate land in south-central Polk County was selected as the primary alternative. This 8,200 acre site is located near the cities of Fort Meade and Homeland, south of S. R. 640 and west of U.S. 17/98 (reference the Polk County Site map). It is an area that has been extensively mined and remains predominantly unreclaimed.

The governor and cabinet approved site certification for ultimate site development and construction of the first 470 MW increment on January 25, 1994, in accordance with the rules of the Power Plant Siting Act. Due to the thorough screening during the selection process, and the disturbed nature of the site, there were no major environmental limitations. As would be the situation at any location in the state, air emissions and water consumption were significant issues during the licensing process.

As future generation units are added, the remaining network of on-site clay settling ponds will be converted to cooling ponds and combustion waste storage areas to support power plant operations. Given the disturbed nature of the property, considerable development has been required in order to make it usable for electric utility application. An industrial rail network and an adequate road system service the site.

The first combined cycle unit at this site, with a capacity of 482 MW summer and 529 MW winter, began commercial operation in April 1999. The transmission improvements associated with this first unit were the rebuilding of the 230/115 kV double circuit Barcola to Ft. Meade line by increasing the conductor sizes and converting the line to double circuit 230 kV operation.

The transmission improvement associated with the second combined cycle unit at this site, planned for November 2003, is an additional 230 kV circuit from the Hines Energy Complex to Barcola.



Hines Energy Complex (Polk County)

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

The need for accurate forecasts of long-range electric energy consumption, customer growth, peak demand and system load shape is a crucial planning function for any electric utility. Accurate projections of a utility's future load growth require forecasting methodologies with the ability to account for a variety of factors influencing electric energy usage in both the short- and long-term planning horizons. FPC's forecasting framework utilizes the System for Hourly and Annual Peak and Energy Simulation (SHAPES-PC) end-use forecasting system as well as short-term econometric models to achieve this end. This chapter will describe the underlying methodology of both the econometric and end-use models including the assumptions incorporated within each. Also included is a description as to how Demand-Side Management (DSM) impacts affect the forecast, the development of high and low forecast scenarios and a review of DSM programs.

The following flow diagram entitled "Customer, Energy and Demand Forecast" gives a general description of FPC's forecasting process. Highlighted in the diagram is the blending of short-term and long-term modeling techniques based on a specific set of assumptions. Also accounted for is some direct contact with large customers. These inputs provide the forecaster at FPC with the tools needed to frame the most likely scenario of the company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Load Forecasting section of the Financial Analysis Department develops these assumptions based on discussions with a number of departments within FPC, as well as through the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions form the basis for the forecast presented in this document.

GENERAL ASSUMPTIONS

1. Normal weather conditions are assumed. Normal weather reflects a ten-year average of service-area-weighted degree days in order to project kilowatt-hour sales. A twenty five-year average of service area weighted temperatures at time of system seasonal peak is assumed to forecast seasonal megawatt peak demand.

2. The population projection produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida provides the basis for development of the customer forecast. This forecast incorporates "Population Studies," Bulletin No. 123, February 1999 as well as The Florida Long Term Forecast 1999.

3. The energy-intensive phosphate mining industry consumed over 34 percent of FPC's industrial class energy sales in 1999. This industry has consolidated in the past few years leaving just a handful of players to influence industry supply conditions in the marketplace. A reduction in power consumption in this sector is assumed in this forecast as IMC-Agrico mines-out at several sites within FPC territory. The return of a significant portion of this load in the Hardee county mining area is projected to occur as mining activity moves further south. Some loss of load and energy sales to Cargill has also been factored into the forecast due to the rearrangement of electric output from their self-service generator and corresponding purchase power agreement with FPC.

4. FPC supplies capacity and energy service to wholesale customers on a "full", "partial", and "supplemental" requirements basis. Full requirements customers' demand and energy are assumed to grow at rates determined by projected population levels as well as projected economic activity. Partial requirements customers' load is assumed to reflect levels currently requested by these customers under their contracts with FPC. The forecast of energy and demand from partial requirements customers reflects their ability to receive dispatched energy from the Florida broker system any time it is more economical to do so.

At seasonal peak conditions, however, their demand is assumed to reach full contract level. FPC's arrangement with Seminole Electric Cooperative, Incorporated (SECI) is to serve "supplemental" service over and above committed levels of self-generation and firm purchase contracts. SECI's projection of their system's demand and energy requirements serves as the basis for our projection of this customer's supplemental service requirements. This forecast also includes two firm bulk power contracts with SECI. The first is a multi-part contract to serve 605 MW for three years beginning in 1999. An option to extend 455 MW of this contract for an additional seven years existed but was not exercised. The remaining 150 MW, a stratified intermediate contract transferred from the supplemental service contract, is assumed to continue throughout the forecast horizon. A second 3-year agreement with SECI to sell up to 300 MW of peaking capacity beginning January 1, 2000 has also been reflected in the forecast.

5. This forecast incorporates cost effective demand and energy reductions from FPC's dispatchable and non-dispatchable DSM programs that meet the conservation goals established by the Florida Public Service Commission in Order No. PSC-99-1942-FOF-EG issued October 1, 1999..

6. The expected energy and demand impacts of self-service cogeneration are subtracted from the forecast. The forecast assumes that FPC will supply the supplemental load of self-service cogeneration customers. Supplemental load is defined as the cogeneration customers' total electric load requirements less their normal generation output. While FPC offers "standby" service to all cogeneration customers, this forecast does not assume an unplanned need for standby power during peak periods.

7. This forecast assumes that the regulatory environment and the obligation to serve will continue throughout the forecast horizon. Wholesale customers that have given notice of contract termination are not included in the projections of energy and demand once their contract term expires.

8. The economic outlook for this 10-year forecast attempts to reflect the short-term outlook for the current business cycle as well as the long-term trend behavior for the economy. It is important to note however, that identification of the long-term trend in economic/demographic conditions represents the primary focus of this forecast. The purpose of the short-term outlook is only to show how the current business cycle is expected to evolve and eventually blend into the long-term. Beyond the short-term time horizon, only the long-run trends in economic and demographic conditions that cut through the peaks and troughs of future business cycles are considered in this forecast.

SHORT-TERM ECONOMIC ASSUMPTIONS

The short-term economic outlook calls for moderating economic growth throughout the forecast horizon. No "shocks" to any supply or demand conditions in the national economy are expected and thus no economic recession is incorporated in this forecast. The U.S. economy has just surpassed the previous record for longest business cycle expansion in the history of the country -- 106 months. No recognized sources are currently predicting an end to this expansion, which has ridden on a wave of freer world trade as well as significant improvement in worker productivity created by great technological leaps in several industries. These productivity improvements have created an economy where corporate earnings improve without any need to increase product prices. The result has been a sharp rise in corporate equities values, and investor wealth, without inflation. This "new economy" has not only created significant wealth through rising stock prices, but also through the creation of a significant number of new jobs. The national unemployment rate is now well below the level when inflationary pressures are expected to return. It is believed that some percentage of the currently strong consumer spending level is being driven by a "wealth effect" created by inflated investment values. Thus, the ability of the national economy to maintain this level of growth rests on a continuation of rising equity values.

The national unemployment rate has reached a 30-year low to 4%. This has resulted in greater spending power for the consumer and a high level of optimism in the economy. Looking ahead however, growth will taper off due to constraints upon the economy, which has been expanding for over nine years. Efforts on the part of the Federal Reserve Board

(FRB) to restrain inflationary pressures will ultimately result in the application of tighter monetary policy. This has already resulted in higher short-term interest rates and should slow the economy. The objective of the FRB is to cool consumption and keep employment costs from rising rapidly. Higher interest rates discourage borrowing, especially in the consumer and housing sectors, and can induce higher saving as money market returns improve.

It is assumed in this forecast that the FRB will gradually cool the economy without bursting the stock market "bubble" and the impact of the wealth effect that we have been experiencing. Also assumed is the idea that in a presidential election year, cooler heads will prevail and extreme spending and/or tax-cutting programs will not be seriously proposed or implemented. Both have the potential to counteract the FRB strategy to slow the economy. If a significant change in either government spending or taxation takes place in 2000 or 2001, a risk of increased inflation will surely drive the FRB to further boost interest rates. This will not bode well for the economy or the economic assumption underlying this forecast.

On a regional basis, interest rate levels will continue to influence the pace of economic growth in Florida through their impacts on the construction, retirement and tourism industries. Personal income growth is expected to continue growing but not at the torrid pace experienced in recent years. Employment growth will moderate from the strong pace experienced in past years resulting in slower growth in total wages. Slower growth in hourly earnings as well as transfer payments should also hold down income growth in the years ahead.

Average use per residential customer will continue to grow as electricity prices are projected to decline in real dollar terms. Also contributing to this trend are homebuilders' surveys reporting increased median square footage in new homes and new apartments constructed. New housing preferences have continued to reflect larger living quarters than that seen in the existing housing stock.

LONG-TERM ECONOMIC ASSUMPTIONS

The long-term economic outlook assumes that changes in economic and demographic conditions will follow a trended behavior pattern. The main focus involves identifying these trends. No attempt is made to predict business cycle fluctuations during this period.

Population Growth Trends

This forecast assumes Florida will experience slower in-migration and population growth over the long term, as reflected in the BEBR projections.

- Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. This will continue to occur, but at less than historic rates for two reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Sixty years later, there now exists a smaller pool of retirees capable of migrating to Florida. Second, the enormous growth in population and corresponding development of the 1980s and 1990s made portions of Florida less desirable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

- With the bulk of Florida's in-migrants under age 45, the baby boom generation born between 1945 and 1963 helped fuel the rapid population increase Florida experienced during the 1980s. In fact, slower population in-migration to Florida can be expected as the baby boom generation enters the 40s and 50s age bracket. This age group has been significantly characterized as immobile when studies focusing on interstate population flows or job changes are conducted.

Economic Growth Trends

- Florida's rapid population growth of the 1980s created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also significant numbers of corporations migrating to Florida capitalizing on the low cost, low tax business environment. In this situation, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period. A cause for concern, however, is the passage of the North American Free Trade Agreement (NAFTA) as well as future trade agreements. At risk here is the bypassing of Florida by companies looking to relocate to a lower cost foreign environment. Mexico is expected to attract a formidable share of American manufacturing jobs that may have moved to Florida. Also, the stability of Florida's citrus and vegetable industry may be threatened when faced with greater competition from Mexico as tariffs are eliminated.

- The forecast assumes negative growth in real electricity price. That is, the change in the nominal, or current dollar, price of electricity over time is expected to be less than the overall rate of inflation. This also implies that fuel price escalation will track at or below the general rate of inflation throughout the forecast horizon.

- Real personal incomes are assumed to increase throughout the forecast period thereby boosting the average customer's ability to purchase electricity -- especially since the price of electricity is expected to increase at a rate below general inflation. As incomes grow faster than the price of electricity, consumers, on average, will remain inclined to purchase additional electric appliances and increase their utilization of existing end-uses.

FORECAST METHODOLOGY

The long-term forecast of MWh sales is produced utilizing SHAPES-PC, a large-scale end-use computer model. FPC has also developed short-term econometric models as a supplement to the long-term SHAPES-PC methodology. These short-term models are expressly designed to better capture the short-term business cycle fluctuations preceding the long-term trend path of customers' energy usage and peak demand. In particular, the monthly periodicity studied in this approach better captures near-term perturbations than the end-use forecasting framework. Also, easier and more timely model updates enable the short-term econometric model to more readily incorporate the most recent projections of input variables. Output from these short-term econometric models is used to develop the first five years of the load forecast. The SHAPES-PC model output is then used as the basis for the remaining years of the forecast horizon.

SHORT-TERM ECONOMETRIC MODEL

In the short-term econometric models, energy sales in major revenue classes that have historically shown a relationship to weather and economic/demographic indicators are modeled using monthly equations. Sales are regressed against "driver" variables that best explain monthly fluctuations over a historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. These include Data Resources Incorporated (DRI), the University of Florida's Bureau of Economic and Business Research and Blue Chip Economic Indicators. Internal company forecasts are used for projections of electric price, weather conditions and the average number of monthly billing days. Projections of FPC's energy efficiency program impacts (conservation program reductions) and direct load control reductions are also incorporated into the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real Florida personal income, cooling degree days, heating degree days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures short-term movements in customer usage. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual net new customers with FPC service area population growth. County level population projections are provided by the BEBR.

Commercial Sector

Commercial kWh use per customer is forecast based on commercial (non-agricultural, non-manufacturing and non-governmental) employment, the average number of billing days in each sales month and heating and cooling degree days. The measure of cooling degree days utilized here differs slightly from that used in the residential sector reflecting the unique behavior pattern of this class with respect to its cooling needs. Commercial customers are projected as a function of the number of residential customers served.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use, 34 percent in 1999, was consumed by the phosphate mining industry. Because this one industry dominates such a significant share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted by changes in short-term economic activity. However, adequately explaining sales levels require separate explanatory variables. Non-phosphate industrial energy sales are modeled using the U.S. industrial production index for manufacturing (excluding motor vehicles), the real price of electricity to the industrial class, and the average number of sales month billing days. The particular industrial production index used in this equation best characterizes the industry make-up of the FPC service area that lacks a significant automotive manufacturing sector.

The industrial phosphate mining industry is modeled using customer-specific information with respect to expected market conditions. Since this sub-sector is comprised of only five customers, the final forecast is heavily dependent upon information received from direct customer contact. FPC industrial customer representatives provide specific phosphate customer information regarding customer production schedules, area mine-out and start-up predictions, and changes in self-generation or energy supply situations over the near-term forecast horizon.

Other Retail Sectors

Street Lighting

Electricity sales to the street lighting class are projected to increase due to growth in the service area population base. Residential customers provide an excellent source of FPC specific data with which to capture the trends in historic and future population growth over time. A linear regression model based on the number of residential customers as well as the number of daylight hours per month is used to forecast street lighting MWh sales.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected using the short-term monthly econometric approach. The level of government services, and thus energy use per customer, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will impact the need for additional governmental services (i.e., schools, city services, etc.) thereby increasing SPA energy usage per customer. Monthly government employment has been determined to be the best indicator of the level of government services provided. This variable, adjusted for the number of SPA customers, along with heating and cooling degree days the real price of electricity and the average number of sales month billing days, result in a significant level of explained variation over the historical sample period. Intercept shift variables are also included in this model to account for the large change in school-related energy use in the billing months of January, July and August. SPA customers are projected linearly as a function of a time-trend.

Sales For Resale Sector

The Sales for Resale sector encompasses all firm sales to other electric power entities. This includes sales to other utilities (municipal or investor owned) as well as power agencies (Rural Electric Authority or Municipal).

Seminole Electric Cooperative, Incorporated (SECI) is a wholesale, or sales for resale, customer of FPC on both a supplemental contract basis and contract demand basis. Under the supplemental contract FPC provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or firm purchase obligations. SECI provides FPC with a forecast of total monthly peak demands and energy for their load within the FPC control area. Monthly supplemental demands are calculated from the total demand levels they project in FPC's control area less their own ("committed") resources. Beyond supplemental service, FPC has signed two bulk power or "contract demand" agreements with SECI to serve stratified intermediate and peaking load. The first contract, an October 1995 agreement, has three pieces that impact the load and energy forecast in the years 1999 to 2001. The first two parts of this contract involve a 300 MW structured capacity sale and a 155 MW stratified peaking sale. The option to extend this sale for seven additional years beginning in 2002 was not exercised by SECI and, thus, will not be served by FPC. The third piece of the contract involves serving 150 MW of stratified intermediate demand and is assumed to remain a requirement on the system throughout the forecast horizon. The load tied to this piece of the contract was carved out of the supplemental "pay as you take" contract and restructured to a contract demand. The second bulk power agreement with SECI, a three-year contract signed in July 1997, also involves load that would otherwise have been served via the supplemental service agreement. Beginning in the year 2000, FPC will supply 150 MW of stratified peaking demand. The amount of load increases to 300 MW in 2001 and 2002. This load is not projected to be served by FPC beyond the contract term.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. The majority of customers in this class are municipalities whose full energy requirements are met by FPC. The full requirement customers are modeled individually using local weather station data and population growth trends for that vicinity. Since the ultimate consumers of electricity in this sector are, to a large degree, residential and commercial customers, it is assumed that their use patterns will follow those of the FPC retail-based residential and commercial customer classes. FPC serves partial requirement service (PR) to a municipality, New Smyrna Beach, a power authority (Florida Municipal Power Agency) and a utility district (Reedy Creek Improvement District). In each case, these customers contract with FPC for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of each contract are subject to change each year. This means that the level and type of demand under contract can increase or decrease for each year of their contract. The demand forecast for each PR wholesale customer is derived using its historical coincident demand to contract demand relationship (including transmission delivery losses). The demand projections for the Florida Municipal Power Agency (FMPA) also include a "losses service" MW amount to account for the transmission losses FPC incurs when "wheeling" power to their customers in FPC's transmission area. The contract demand level for each PR customer in its last contract year determines the load upon the FPC system for the remaining years of the forecast horizon unless the customer has notified FPC of a willingness to not renew their contract.

The methodology for projecting MWh energy usage for the partial requirements (PR) customers differs slightly from customer to customer. This category of service is sporadic in nature and exceptionally difficult to forecast because PR customers are capable of "brokering" their FPC capacity to purchase energy from other lower cost resources. For example, FMPA utilizes FPC's wholesale energy service only when more economical energy is unavailable. The forecast for FMPA is derived using annual historical load factor calculations to provide the expected level of energy sales based on the level of contracted MW nominated by FMPA. Average monthly-to-annual energy ratios are applied to the forecast in order to obtain monthly profiles. For Reedy Creek and New Smyrna Beach, recent growth trends and historic load factor calculations are utilized to provide the expected level of MWh sales. Again, these customers have alternative sources of supply to meet their needs. Purchases of energy from FPC will depend heavily on the price of available energy from other sources in the marketplace.

Demand-Side Management

Each projection of every retail class-of-business MWh energy sales forecast is reduced by estimated future energy savings due to FPC-sponsored and Florida Public Service Commission (FPSC)-approved dispatchable and non-dispatchable Demand-Side Management programs. Estimated energy savings for every non-dispatchable DSM program are calculated on a program-by-program basis and aggregated for each class-of-business on the program. Dispatchable DSM program energy savings are estimated within the Resource Planning Department's production costing models. These models determine the most cost-effective means to meet system requirements, including load control. The DSM projections incorporated in this demand and energy forecast meet the new conservation goals established by the FPSC in Order No. PSC-99-1942-FOF-EG, issued October 1, 1999 in Docket No. 971005-EG.

LONG-TERM SHAPES-PC MODEL

Energy Forecast

In the SHAPES-PC model the projections of the various economic and demographic parameters are combined with consumption estimates and patterns of electricity usage to produce projections of annual energy consumption. The basic concept underlying the model structure involves breaking out numerous end-use categories for electricity consumption in order to establish homogeneous groups to forecast. SHAPES-PC is partitioned into three consumer categories: residential, commercial and industrial.

Residential Sector

The electricity consuming units in the residential sector are major household appliances. A total of seventeen major household appliances are explicitly treated in the model. The first step in estimating demand is to predict the number of units of each appliance type in the service area in a given year. The appliance stock is estimated as the saturation rate for a given appliance multiplied by the total number of residential customers. Appliance saturation rates are projected using an S-shaped logistic saturation function based on historical data from appliance saturation surveys and service area real personal income. The second major factor in the demand estimation equation is the connected load of the appliance. The term "connected load" is defined here as the power requirements or wattage of the appliance. This will tend to change over time as relative energy prices, appliance efficiencies and features change.

The last factor in the demand equation is the probability of the appliance operating at a given time. This term is called the use factor. It is necessary to distinguish between temperature, or weather sensitive use factors, and temperature insensitive use factors. The temperature insensitive use factors depend only on time, i.e., time of day, type of day and season. The type of day is important since weekday energy usage for many appliances differs from that of weekend and holiday usage. Similarly, there are seasonal variations in the use of many temperature insensitive appliances such as lighting. For other appliances, such as air conditioners, electric space heaters, and heat pumps, use factors depend not only on time of day, but also on temperature. These use factors indicate the probability of a space-conditioning device operating at a given time of day, day type and temperature. Combining the heating and cooling use factors with the expected occurrence of temperature conditions in a given period yields the energy requirements for that period. By specifying a temperature profile for a given day, the model is capable of simulating the weather sensitive load corresponding to that temperature profile.

Industrial Sector

The industrial sector model is designed to forecast energy consumption levels associated with selected manufacturing industries. Electric energy consumption in the industrial sector is significantly tied to the level of economic activity. The major driving forces affecting energy consumption are the real price of electricity, the level of economic activity in the service area, and the technologies, or processes, of the industries involved. Since energy requirements for a given measure of economic activity vary from one industry to another, it is necessary to assess the mix of the industrial sector. To capture the effect of industrial mix, the industrial sector is disaggregated into twelve categories. Thus, by projecting energy usage independently for each 2-digit Standard Industrial Code (SIC) category, the model captures changes in energy consumption due to changes in the industrial base.

There are numerous ways of measuring economic activity in the industrial sector. Due to the ready availability of historic employment data on a 2-digit SIC level, employment was used as this measure of activity. The level of annual energy consumption in any one of the twelve industries is calculated by multiplying the projected level of economic activity (expressed in employment) by the projected energy intensity (expressed as kWh usage per employee) of that sector. The calculation of energy intensity for each sector also incorporates the industrial production and capacity utilization indices for each sector to "normalize" the level of electric energy used per unit of output.

Commercial Sector

In the commercial sector, forecasts of annual energy consumption are derived for those customers falling into private, non-manufacturing business-types. Historic commercial energy sales are categorized into ten separate "building types" (e.g., retail, office, grocery, etc.) which are modeled individually. Commercial electricity consumption is determined by multiplying the floor space in each of these ten building categories by the energy intensity per square foot by category. This is done for three distinct end-uses: base (non-weather sensitive), heating and cooling. Floor space projections are developed based on a combination of historic and projected floor space per employee and employment projections by building type. Energy intensity per square foot is projected by building type using time trends with considerations for the three end-uses (i.e., weather sensitivity and base use). The model also factors in the influence of electric price on energy usage decisions as well as expected end-use saturation levels. Projections of kWh usage per square foot along with projected square footage for each building type yield commercial sector energy sales.

Customer Forecast

An increasing service area population translates directly into a greater number of homes requiring electricity and, consequently, into a greater number of commercial establishments to service these residences. Service area population serves as the driver for residential and (implicitly) commercial customers, which together comprise 98.4 percent of FPC total customers. The Bureau of Economic and Business Research at the University of Florida provides population estimates and projections for the FPC service area that are used in the development of the residential customer forecast. In order to determine future residential customer growth, historic growth in residential customers is regressed against historic growth in service area population. The resulting statistical coefficients are then applied to the population growth forecast. Future commercial and street lighting customers are modeled as a function of total residential customers. Industrial and public authority sector customers are forecast via a time-trend approach given their relatively stable nature.

In the short-term, deviations from trend in the most recent time periods are scrutinized. This analysis, along with any specific input from regional field personnel regarding growth expectations, forms the basis for developing a short-term outlook that is consistent with recent history as well as the long-term projections for all customer classes.

Peak Demand Forecast

The forecast of peak demand also employs a dual methodology framework. The SHAPES-PC end-use model is used to develop class-of-business load shapes and an econometric approach is used to project specific disaggregated pieces of the demand forecast. Both techniques provide a unique perspective as to the make-up of total system demand.

The SHAPES-PC end-use model uses FPC load research sampled class of business load shapes to develop a weather normalized 8,760 hour (yearly) load shape for the residential, commercial, industrial, and "all other" classes to calibrate historic benchmarks. Projections in MW demand and energy are then based upon growth in residential customers, manufacturing employees, commercial floor space, increased saturation of class end-uses or energy intensity, and price elasticity.

The econometric approach to projecting seasonal peak demand employs a disaggregation technique that separates seasonal (winter and summer) peak hour system demand into five major components. These components consist of potential firm retail load, demand-side management program capability, wholesale demand, company use demand and interruptible demand.

Potential firm retail load refers to projections of FPC retail hourly seasonal net peak demand (excluding interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of FPC's Load Management program. The historical values of this series are constructed to show the size of FPC's firm retail net peak demand had no utility-induced conservation or load control ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to total system customer levels at the time of the peak and coincident weather conditions without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data regardless to which month the peak occurred. The projections become the potential retail demand projection for the month of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the month being projected.

Energy conservation and direct load control estimates are consistent with FPC's DSM goals that have been filed with the Florida Public Service Commission in the 1999 DSM Goals Docket. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm retail demand.

Sales For Resale demand projections represent load supplied by FPC to other electric utilities such as Seminole Electric Cooperative, Incorporated, the Florida Municipal Power Agency, and other electric distribution companies. The SECI supplemental demand projection is based on their forecast of their service area within the FPC control area. The level of MW to be served by FPC is dependent upon the amount of resources SECI supplies to itself or contracts with others. An assumption has been made that beyond 2005 - the last year of committed capacity declaration - SECI will hold constant their level of self-serve resources. For the partial requirements customers demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels. Demand requirements continue out at the level indicated by the final year in their respective contracts. The full requirements municipal demand forecast is estimated for individual cities using linear econometric equations modeling both weather and economic impacts specific to each locale. The seasonal (winter and summer) projections become the January and August peak values, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month (November to March) relative to the winter peak, and each summer month (April to October) in relation to the summer peak demand.

FPC "company use" at the time of system peak is estimated using load research metering studies and is assumed to remain stable over the forecast horizon. The interruptible and curtailable service load component is developed from historic trends, as well as the incorporation of specific information obtained from FPC's industrial service representatives.

Each of the peak demand components described above is a positive value except for the DSM program MW impacts. Since DSM program impacts represent a reduction in peak demand, they are assigned a negative value. Total system peak demand is then calculated as the arithmetic sum of these five components.

Both the end-use methodology and the disaggregated econometric methodology supply necessary information that go into the final projection of system peak demand.

HIGH AND LOW FORECAST SCENARIOS

The high and low bandwidth scenarios around the base MWh energy sales forecast are developed using a Monte Carlo simulation applied to a multivariate regression model that closely replicates the base retail MWh energy forecast in aggregate. This model accounts for variation in Gross Domestic Product, retail customers and electric price. The base forecasts for these variables were developed based on input from Data Resources Inc. and internal company price projections. Variation around the base forecast predictor variables used in the Monte Carlo simulation was based on an 80 percent confidence interval calculated around variation in each variable's historic growth rate. While the total number of degree days (weather) were also incorporated into the model specification, the high and low scenarios do not attempt to capture extreme weather conditions. Normal weather conditions were assumed in all three scenarios.

The Monte Carlo simulation was produced through the estimation of 1,000 scenarios for each year of the forecast horizon. These simulations allowed for random normal variation in the growth trajectories of the economic input variables (while accounting for cross-correlation amongst these variables), as well as simultaneous variation in the equation (model error) and coefficient estimates. These scenarios were then sorted and rank ordered from one to a thousand, while the simulated scenario with no variation was adjusted to equal the base forecast.

The low retail scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate probability of occurrence of .10. The high retail scenario similarly represents a bandwidth forecast with an approximate probability of occurrence of .90. In both scenarios the high and low peak demand bandwidth forecasts are projected from the energy forecasts using the load factor implicit in the base forecast scenario.

MODEL DOCUMENTATION

SHORT TERM ECONOMETRIC MODELS

RESIDENTIAL CLASS:

RUPC = F (CON, ABDAYS, LRP2, RHDD, CDD, LRFPI2, HDD_SQ, CCDD__SQ)

where:

RUPC	=	Residential KWh use per customer adjusted for historical DSM program impacts
CON	=	Intercept term
ABDAYS	=	Average number of billing days in sales month
LRP2	=	Log of the residential price of electricity deflated by Consumer Price Index - 2 month average in cents per KWh
HDD	=	Heating degree days - system-weighted using St. Pete, Orlando, and Tallahassee weather stations
CDD	=	Residential cooling degree days - system-weighted using St. Pete, Orlando, and Tallahassee weather stations
LRFPI2	=	Log of Florida Total Personal Income per household - deflated by the Personal Consumption Expenditures Implicit Price Deflator - 2 month average in millions of 1992 dollars
HDD_SQ	=	Square of heating degree days
CCDD_SQ	=	Square of commercial cooling degree days
AR(1)	=	1^{st} order autoregressive error term
SAR(1)	=	1^{st} order seasonal autoregressive error term

COMMERCIAL CLASS:

CUPC = **F (CON, ABDAYS, HDD_SQ, CCDD, BMLTHR, LEMPCOM3)**

where:

CUPC	=	Commercial kWh use per customer adjusted for historical DSM program impacts
CON	=	Intercept term
ABDAYS	=	Average number of billing days in sales month
HDD	=	Heating degree days squared
CCDD	=	Commercial cooling degree days
BMLTHR	=	number of lighting hours in each billing month (darkness)
LEMPCOM3	=	Log of Florida commercial sector employment - 3 month average in thousands
AR(1)	=	1^{st} order autoregressive error term

INDUSTRIAL CLASS: NON-PHOSPHATE SUBSECTOR

IWO = **F(CON, ABDAYS, LIPM3, IP2, BMLTHR)**

where:

IWO	=	MWh energy sales to non-phosphate industrial customers adjusted for historical DSM program impacts
CON	=	Intercept term
ABDAYS	=	Average number of billing days in sales month
LIPM3	=	Log of the Industrial Production Index - Manufacturing, excluding motor vehicles & parts - 3 month average, 1992 = 100
IP2	=	Industrial price of electricity deflated by the Consumer Price Index - 2 month average in cents per KWh
BMLTHR	=	number of lighting hours in each billing month (darkness)

PUBLIC AUTHORITY CLASS:

SPAUPC	=	**F(CON, ABDAYS, HDD, CCDD, EGOV_PC3, SCH_VAC, SPAC_DUM, CSS_DUM, LSP3)**

where:

SPAUPC	=	SPA kWh use per customer adjusted for historical DSM program impacts
CON	=	Intercept term
ABDAYS	=	Average number of billing days in sales month
HDD	=	Heating degree days
CCDD	=	Commercial cooling degree days
EGOV_PC3	=	Florida government employment per SPA customer - 2 month average in thousands
SCH_VAC	=	Intercept shift variable for January, July, and August to account for seasonal school load
SPAC_DUM	=	Intercept shift variable to account for historical rate migration impacts on the number of SPA customers
CSS_DUM	=	Intercept shift variable to account for the impacts of customer counts In the new customer service system
LSP3	=	Log of the SPA price of electricity deflated by the Consumer Price Index - 3 month average in cents per KWh
AR(1)	=	1^{st} order autoregressive error term
SAR(1)	=	1^{st} order seasonal autoregressive error term

STREET & HIGHWAY LIGHTING CLASS:

SHL	=	**F(BMLTHR, RES_CUSA, SHL_DUM)**

where:

SHL	=	MWh energy sales to the SHL customers adjusted for historical DSM program impacts
BMLTHR	=	number of lighting hours in each billing month (darkness)
RES_CUSA	=	number of residential customers – adjusted for event driven billing

SHL_DUM = Intercept shift variable to account for the impacts of the new customer service system

AR(1) = 1^{st} order autoregressive error term

SAR(1) = 1^{st} order seasonal autoregressive error term

SHAPES END-USE MODEL

RESIDENTIAL END USE APPLIANCES:

1. Ranges
2. Frost-free Refrigerator
3. Standard Refrigerator
4. Standard Freezer
5. Dishwasher
6. Washer
7. Dryer
8. Water Heater
9. Microwave
10. Color TV
11. Black & White TV
12. Room A/C
13. Central A/C
14. Heating - Resistance
15. Heat Pump
16. Lighting
17. Miscellaneous

INDUSTRIAL CATEGORIES:

Manufacturing Industries Modeled in SHAPES-PC Industrial Model:

1. SIC 20 - Food & Kindred Products
2. SIC 26 - Paper & Allied Products
3. SIC 27 - Printing & Publishing
4. SIC 28 - Chemicals & Allied Products
5. SIC 30 - Rubber & Miscellaneous Plastic Products
6. SIC 32 - Stone, Clay & Glass Products
7. SIC 34 - Fabricated Metal Industries
8. SIC 35 - Non-Electrical Machinery
9. SIC 36 - Electric & Electrical Equipment
10. SIC 38 - Instruments & Related Products
11. All Other Manufacturing SICs

COMMERCIAL BUILDING TYPES:

Commercial Building Types Modeled in SHAPES-PC Commercial Model:

1. Offices
2. Retail
3. Grocery and Other Food Stores
4. Eating & Drinking Places (Restaurants)
5. Hotel, and other Lodging Places
6. Health & Hospital Facilities
7. Educational Facilities
8. Transportation, Communication, Public Utility Industry Facilities
9. All Other Commercial Building Types

FLORIDA POWER CORPORATION

SCHEDULE 2.1
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	FPC POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1990	2,509,322	2.490	12,416	1,007,806	12,320	7,329	113,595	64,519
1991	2,563,805	2.489	12,624	1,029,901	12,257	7,489	114,657	65,317
1992	2,614,610	2.490	12,826	1,050,077	12,214	7,544	116,727	64,629
1993	2,679,005	2.488	13,373	1,076,657	12,421	7,885	119,811	65,812
1994	2,738,046	2.488	13,863	1,100,537	12,597	8,252	122,987	67,097
1995	2,798,959	2.489	14,938	1,124,679	13,282	8,612	126,189	68,248
1996	2,845,495	2.492	15,481	1,141,671	13,560	8,848	129,441	68,356
1997	2,892,998	2.493	15,080	1,160,611	12,993	9,257	132,504	69,864
1998	2,952,439	2.496	16,526	1,182,786	13,972	9,999	136,345	73,339
1999	3,033,192	2.500	16,245	1,213,470	13,387	10,327	140,897	73,294
2000	3,063,882	2.489	17,652	1,230,736	14,342	10,839	142,923	75,836
2001	3,118,440	2.490	18,163	1,252,598	14,501	11,191	145,775	76,767
2002	3,172,383	2.490	18,683	1,274,213	14,662	11,535	148,595	77,626
2003	3,225,899	2.490	19,184	1,295,656	14,807	11,876	151,392	78,447
2004	3,278,647	2.490	19,677	1,316,791	14,943	12,216	154,150	79,250
2005	3,326,558	2.488	20,099	1,337,264	15,030	12,557	156,820	80,073
2006	3,375,001	2.487	20,520	1,357,066	15,121	12,914	159,403	81,017
2007	3,421,748	2.486	20,911	1,376,186	15,195	13,259	161,896	81,897
2008	3,467,563	2.486	21,291	1,394,931	15,263	13,542	164,341	82,400
2009	3,513,221	2.485	21,672	1,413,612	15,331	13,831	166,778	82,930

FLORIDA POWER CORPORATION

SCHEDULE 2.2
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR		AVERAGE NO. OF	AVERAGE KWh CONSUMPTION	RAILROADS AND RAILWAYS	STREET & HIGHWAY LIGHTING	OTHER SALES TO PUBLIC AUTHORITIES	TOTAL SALES TO ULTIMATE CONSUMERS
1990	3,456	3,115	1,109,470	0	21	1,658	24,880
1991	3,303	3,124	1,057,298	0	23	1,740	25,179
1992	3,254	3,137	1,037,297	0	24	1,765	25,413
1993	3,381	3,107	1,088,188	0	25	1,865	26,529
1994	3,580	3,186	1,123,666	0	26	1,954	27,675
1995	3,864	3,143	1,229,399	0	27	2,058	29,499
1996	4,223	2,927	1,442,774	0	26	2,205	30,784
1997	4,187	2,830	1,479,505	0	27	2,299	30,849
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,425	0	27	2,509	33,441
2000	4,326	2,560	1,689,844	0	29	2,664	35,510
2001	4,257	2,560	1,662,891	0	30	2,752	36,393
2002	4,287	2,560	1,674,609	0	31	2,842	37,378
2003	4,453	2,560	1,739,453	0	32	2,932	38,478
2004	4,494	2,560	1,755,469	0	32	3,023	39,443
2005	4,572	2,560	1,785,938	0	33	3,114	40,375
2006	4,623	2,560	1,805,859	0	33	3,204	41,295
2007	4,679	2,560	1,827,734	0	34	3,295	42,178
2008	4,731	2,560	1,848,047	0	34	3,386	42,984
2009	4,770	2,560	1,863,281	0	35	3,477	43,785

FLORIDA POWER CORPORATION

SCHEDULE 2.3
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND
NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
1990	1,548	1,377	27,805	10,983	1,135,499
1991	1,411	1,799	28,389	11,555	1,159,237
1992	1,471	1,817	28,702	12,229	1,182,170
1993	1,695	2,020	30,243	15,077	1,214,652
1994	1,819	1,680	31,174	17,181	1,243,891
1995	1,846	2,322	33,667	17,774	1,271,785
1996	2,089	1,841	34,715	18,034	1,292,073
1997	1,758	1,997	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,452	39,160	19,601	1,376,597
2000	2,977	2,359	40,846	20,101	1,396,320
2001	3,136	2,398	41,927	20,658	1,421,591
2002	1,691	2,260	41,330	21,210	1,446,578
2003	1,345	2,398	42,221	21,762	1,471,370
2004	1,339	2,486	43,268	22,315	1,495,816
2005	1,326	2,514	44,215	22,867	1,519,511
2006	1,354	2,566	45,214	23,418	1,542,447
2007	1,390	2,612	46,180	23,971	1,564,613
2008	1,423	2,658	47,066	24,523	1,586,355
2009	1,454	2,705	47,945	25,076	1,608,026

FLORIDA POWER CORPORATION

SCHEDULE 3.1.1
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1990	6,096	632	5,464	198	342	35	24	49	136	5,312
1991	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
1993	6,913	833	6,080	272	502	48	27	70	155	5,839
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,520	7,519	292	505	113	45	153	183	7,747
2000	8,633	1,277	7,356	327	464	126	48	155	75	7,439
2001	8,840	1,343	7,497	308	414	136	49	156	75	7,701
2002	8,518	867	7,651	305	351	149	50	157	75	7,431
2003	8,337	506	7,831	328	305	162	51	158	75	7,258
2004	8,421	436	7,985	329	269	175	52	160	75	7,361
2005	8,574	433	8,141	335	238	190	54	161	75	7,522
2006	8,782	493	8,289	339	210	204	55	162	75	7,737
2007	8,988	555	8,433	343	185	218	57	163	75	7,947
2008	9,191	618	8,573	346	163	232	59	164	75	8,152
2009	9,394	681	8,713	349	144	246	61	165	75	8,354

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2009):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.1.2
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1990	6,096	632	5,464	198	342	35	24	49	136	5,312
1991	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
1993	6,913	833	6,080	272	502	48	27	70	155	5,839
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,520	7,519	292	505	113	45	153	183	7,747
2000	8,737	1,277	7,460	327	464	126	48	155	75	7,543
2001	8,950	1,343	7,607	308	414	136	49	156	75	7,811
2002	8,656	867	7,789	305	351	149	50	157	75	7,569
2003	8,497	506	7,991	328	305	162	51	158	75	7,418
2004	8,646	436	8,210	329	269	175	52	160	75	7,586
2005	8,826	433	8,393	335	238	190	54	161	75	7,774
2006	9,092	493	8,599	339	210	204	55	162	75	8,047
2007	9,304	555	8,749	343	185	218	57	163	75	8,263
2008	9,571	618	8,953	346	163	232	59	164	75	8,532
2009	9,819	681	9,138	349	144	246	61	165	75	8,779

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2009):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.1.3
HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1990	6,096	632	5,464	198	342	35	24	49	136	5,312
1991	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
1993	6,913	833	6,080	272	502	48	27	70	155	5,839
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,520	7,519	292	505	113	45	153	183	7,747
2000	8,444	1,277	7,167	327	464	126	48	155	75	7,250
2001	8,629	1,343	7,286	308	414	136	49	156	75	7,490
2002	8,299	867	7,432	305	351	149	50	157	75	7,212
2003	8,068	506	7,562	328	305	162	51	158	75	6,989
2004	8,134	436	7,698	329	269	175	52	160	75	7,074
2005	8,251	433	7,818	335	238	190	54	161	75	7,199
2006	8,422	493	7,929	339	210	204	55	162	75	7,377
2007	8,589	555	8,034	343	185	218	57	163	75	7,548
2008	8,752	618	8,134	346	163	232	59	164	75	7,713
2009	8,916	681	8,235	349	144	246	61	165	75	7,876

Historical Values (1990-1999):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2000 - 2009):
Cols. (2) - (4) forecasted peak without load control and conservation.
Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.2.1
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989/90	7,596	875	6,721	230	503	52	0	47	150	6,614
1990/91	6,225	774	5,451	163	490	51	0	52	153	5,316
1991/92	7,163	972	6,191	181	611	60	0	55	155	6,101
1992/93	7,191	851	6,340	155	599	67	0	57	159	6,154
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,717	941	6,776	318	663	124	17	117	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	9,993	1,647	8,346	326	849	229	21	119	190	8,259
2000/01	10,229	1,731	8,498	306	809	250	24	120	193	8,528
2001/02	9,940	1,274	8,666	304	744	273	27	121	190	8,282
2002/03	9,787	928	8,859	328	701	298	30	122	188	8,120
2003/04	9,902	877	9,025	329	673	325	33	123	189	8,230
2004/05	10,085	890	9,195	334	652	354	36	124	192	8,394
2005/06	10,322	968	9,354	337	635	383	39	125	195	8,609
2006/07	10,559	1,046	9,513	342	619	412	42	126	198	8,820
2007/08	10,793	1,129	9,664	345	605	441	46	127	200	9,029
2008/09	11,022	1,210	9,812	348	592	470	49	128	203	9,233
2009/10	11,254	1,291	9,963	350	580	498	52	129	206	9,440

Historical Values (1990-1999):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2000 - 2010):
Cols. (2) - (4) forecasted peak without load control and conservation.
Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.2.2
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989/90	7,596	875	6,721	230	503	52	0	47	150	6,614
1990/91	6,225	774	5,451	163	490	51	0	52	153	5,316
1991/92	7,163	972	6,191	181	611	60	0	55	155	6,101
1992/93	7,191	851	6,340	155	599	67	0	57	159	6,154
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,717	941	6,776	318	663	124	17	117	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,115	1,647	8,468	326	849	229	21	119	190	8,381
2000/01	10,357	1,731	8,626	306	809	250	24	120	193	8,656
2001/02	10,099	1,274	8,825	304	744	273	27	121	190	8,441
2002/03	9,970	928	9,042	328	701	298	30	122	188	8,303
2003/04	10,159	877	9,282	329	673	325	33	123	189	8,487
2004/05	10,371	890	9,481	334	652	354	36	124	192	8,680
2005/06	10,673	968	9,705	337	635	383	39	125	195	8,960
2006/07	10.916	1,046	9,870	342	619	412	42	126	198	9,177
2007/08	11,220	1,129	10,091	345	605	441	46	127	200	9,456
2008/09	11,499	1,210	10,289	348	592	470	49	128	203	9,710
2009/10	11,788	1,291	10,497	350	580	498	52	129	206	9,974

Historical Values (1990-1999):

Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.

Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

Projected Values (2000 - 2010):

Cols. (2) - (4) forecasted peak without load control and conservation.

Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.

Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.

Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

FLORIDA POWER CORPORATION

SCHEDULE 3.2.3
HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989/90	7,596	875	6,721	230	503	52	0	47	150	6,614
1990/91	6,225	774	5,451	163	490	51	0	52	153	5,316
1991/92	7,163	972	6,191	181	611	60	0	55	155	6,101
1992/93	7,191	851	6,340	155	599	67	0	57	159	6,154
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,717	941	6,776	318	663	124	17	117	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	9,783	1,647	8,136	326	849	229	21	119	190	8,049
2000/01	9,994	1,731	8,263	306	809	250	24	120	193	8,293
2001/02	9,697	1,274	8,423	304	744	273	27	121	190	8,039
2002/03	9,487	928	8,559	328	701	298	30	122	188	7,820
2003/04	9,584	877	8,707	329	673	325	33	123	189	7,912
2004/05	9,727	890	8,837	334	652	354	36	124	192	8,036
2005/06	9,924	968	8,956	337	635	383	39	125	195	8,211
2006/07	10,118	1,046	9,072	342	619	412	42	126	198	8,379
2007/08	10,308	1,129	9,179	345	605	441	46	127	200	8,544
2008/09	10,495	1,210	9,285	348	592	470	49	128	203	8,706
2009/10	10,692	1,291	9,401	350	580	498	52	129	206	8,878

Historical Values (1990-1999):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = actual capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2000 - 2010):
Cols. (2) - (4) forecasted peak without load control and conservation.
Cols. (5) - (9) = load control/conservation capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

DEMAND-SIDE MANAGEMENT PLAN

OF

FLORIDA POWER CORPORATION

DECEMBER 29, 1999

TABLE OF CONTENTS

INTRODUCTION

In accordance with Sections 25-17.001-.005, Florida Administrative Code, the Florida Public Service Commission (FPSC) established numeric conservation goals for Florida Power Corporation (FPC), as set forth in Order No. PSC-99-1942-FOF-EG, issued October 1, 1999, in Docket No. 971005-EG. In response to this Order, FPC submits this Demand Side Management (DSM) Plan to the FPSC for approval.

FPC has designed its DSM Plan to achieve the conservation goals set forth by the FPSC. This plan provides FPC's customers with comprehensive DSM services while resulting in electric rates that are lower than they would have been if this Plan were not implemented. The DSM Plan consists of five (5) residential programs, eight (8) commercial and industrial (C/I) programs, and one research and development program.

The programs contained in FPC's DSM Plan will necessitate several tariff revisions or additions, which are shown in legislative format in the Appendix of this document. Upon FPSC approval of these programs, FPC will submit the related tariffs to Staff for administrative approval.

This document is organized into six sections. The first section presents an overview of FPC's proposed DSM Plan, summarizing the goals and cumulative impacts of the plan. Section II discusses some general issues associated with demand-side management planning and implementation, including program operation, cost-effectiveness, program monitoring and evaluation, and cost-recovery. Section III presents FPC's proposed residential programs. Section IV presents FPC's proposed commercial/industrial programs. Section V presents FPC's Technology Development program.

I. PROGRAM GOALS AND CUMULATIVE IMPACT

I. PROGRAM GOALS AND CUMULATIVE IMPACT

Florida Power Corporation's DSM Plan has specifically been designed to efficiently acquire all cost-effective DSM resources necessary to meet the conservation goals established by the FPSC in Order No. PSC-99-1942-FOF-EG. The DSM Plan consists of five (5) residential programs, eight (8) commercial and industrial (C/I) programs, and one research and development program:

RESIDENTIAL PROGRAMS	COMMERCIAL/INDUSTRIAL PROGRAMS
Home Energy Check	Business Energy Check
Home Energy Improvement	Better Business
New Construction	C/I New Construction
Low Income Weatherization Assistance	Innovation Incentive
Residential Energy Management	Commercial Energy Management
	Standby Generation
	Interruptible Service
	Curtailable Service
Technology Development	

These DSM programs have been integrally designed to achieve the conservation goals established by the FPSC, while minimizing the rate impacts on all FPC customers. In designing these DSM programs, the following multiple objectives were addressed:

- Achieve the annual conservation goals established by the FPSC for 2000-2009
- Minimize rate impacts to all FPC customers
- Base program designs on customer needs
- Implement mechanisms to minimize free ridership
- Capture all cost-effective DSM resources, including cost-effective lost opportunities
- Provide customers with added value -- efficiency, convenience, productivity, comfort and reliability, and
- Utilize market involvement, such as dealers and home builders, where appropriate.

Tables I-1 and I-2 present the cumulative demand and energy impacts projected to be achieved by this DSM Plan as compared to the Commission-established goals for each year during the planning period 2000-2009, for the residential and C/I sectors, respectively. FPC's DSM Plan is designed to meet or exceed the Commission-established energy and demand goals.

Table I-1
Florida Power Corp.
Residential Market Segment Demand and Energy Data

Year	Projected Summer Demand Savings (MW)		Commission Approved Summer MW Goal (Cum.)	Projected Winter Demand Savings (MW)		Commission Approved Winter MW Goal (Cum.)	Projected Annual Energy Savings (GWh)		Commission Approved Annual GWh Goal (Cum.)
	Incremental	Cumulative		Incremental	Cumulative		Incremental	Cumulative	
2000	10	10	10	30	30	30	16	16	15
2001	10	20	20	34	64	64	18	34	32
2002	12	32	32	38	102	102	18	52	50
2003	13	45	45	40	142	142	20	72	69
2004	13	58	58	43	185	185	20	92	88
2005	14	72	72	44	229	229	21	113	108
2006	13	85	85	43	272	271	21	134	127
2007	14	99	99	41	313	312	20	154	147
2008	13	112	112	39	352	352	20	174	166
2009	13	125	125	37	389	389	20	194	185

NOTE: Commission Approved Goals are pursuant to Order No. PSC-99-1942-FOF-EG.
The incremental values may not exactly add to the cumulative values due to rounding.

Table I-2
Florida Power Corp.
Commercial/Industrial Market Segment Demand and Energy Data

Year	Projected Summer Demand Savings (MW)		Commission Approved Summer MW Goal (Cum.)	Projected Winter Demand Savings (MW)		Commission Approved Winter MW Goal (Cum.)	Projected Annual Energy Savings (GWh)		Commission Approved Annual GWh Goal (Cum.)
	Incremental	Cumulative		Incremental	Cumulative		Incremental	Cumulative	
2000	4	4	3.8	4	4	3.8	2	2	2
2001	4	8	8	4	8	7	2	4	4
2002	5	13	11	4	12	11	2	6	6
2003	4	17	15	4	16	15	2	8	8
2004	4	21	19	4	20	18	2	10	10
2005	4	25	23	4	24	22	2	12	12
2006	5	30	26	5	29	26	2	14	13
2007	4	34	30	4	33	30	2	16	15
2008	4	38	34	4	37	33	2	18	17
2009	4	42	38	4	41	37	2	20	19

NOTE: Commission Approved Goals are pursuant to Order No. PSC-99-1942-FOF-EG.
The incremental values may not exactly add to the cumulative values due to rounding.

II. PROGRAM INTRODUCTION

II. PROGRAM INTRODUCTION

A. PROGRAM OPERATION

The focal point for both the residential and the C/I sector programs is an energy audit program (Home Energy Check for residential and Business Energy Check for C/I). The energy audit programs serve multiple purposes to satisfy the needs of FPC, its customers, and the Commission:

1. Educate customers by providing an overview of typical energy use.
2. Identify opportunities for improving energy efficiency at the customer's home or facility.
3. Serve as the marketing tool to introduce customers to FPC's other conservation programs.
4. Assist FPC in minimizing free ridership in the other DSM programs.
5. Satisfy the Commission's mandate to offer energy audit services to all customers.

For the residential sector, FPC has consolidated most measures into two "umbrella" programs -- the Home Energy Improvement program for existing customers and the New Construction program for new home builders. The creation of these comprehensive programs provides significant benefits over implementing measure-specific programs, including the following:

- Increased program cost-effectiveness through lower program administration, implementation, monitoring, and evaluation costs by minimizing redundant functions.
- More efficient program delivery because each customer can be more comprehensively addressed.
- Improved marketability to customers through concise, consistent, and comprehensive program packaging.

For the C/I sector, FPC has also consolidated most of the measures into "umbrella" programs -- the Better Business program for existing customers and the C/I New Construction program for new construction buildings. These "umbrella" programs provide the same benefits as described above. But in the commercial and industrial sectors, because the facilities and systems are more complex than in the residential sector, there are additional opportunities for conservation from customer-specific technology improvements, as well as from alternative rates. Thus, for the C/I sector, FPC's DSM Plan also includes the Innovation Incentive program for customized efficiency improvements, as well as the Standby Generation, Interruptible Service, and Curtailable Service programs.

B. COST-EFFECTIVENESS

All programs submitted in this DSM Plan have been analyzed for cost-effectiveness using the Commission-approved tests described in Rule 25-17.008, Florida Administrative Code. FPC's DSM Plan has specifically been designed to efficiently acquire all cost-effective DSM resources necessary to meet the Commission-established goals for FPC. The programs were evaluated based on the Rate Impact Measure (RIM) test to ensure that the DSM programs result in lower electric rates than supply-side alternatives.

In order to conduct the cost-effectiveness analysis, the DSView model (produced by New Energy Associates) was used to evaluate the DSM programs against potentially avoidable supply-side capacity. In contrast to static models such as the Florida Integrated Resource Evaluator (FIRE) model, DSView is a more sophisticated dynamic model which more nearly simulates the operation of the power system. For example, DSView is directly integrated with other supply-side planning models, thereby allowing variables such as marginal fuel costs, hourly production costs, and generation equivalency to be computed and applied more accurately than under the FIRE model. Because of this fundamental modeling concept difference, DSView will produce different results from the FIRE model.

A summary of the cost-effectiveness results for each of the DSM programs included in this DSM Plan are shown in Table II-1. In addition, detailed program cost-effectiveness results are presented at the end of each program discussion in Sections III and IV of this document. These detailed results consist of one page each for the RIM, Participant, and Total Resource Cost (TRC) Tests.

Table II-1

Summary of Demand Side Management Programs
Included in Proposed Plan
Period 2000-2009

DSM Measure	Rate Impact Measure Test			Participant Test			Total Resource Cost Test			Program Status
	PV Total Benefits ($000)	PV Total Costs ($000)	B / C Ratio	PV Total Benefits ($000)	PV Total Costs ($000)	B / C Ratio	PV Total Benefits ($000)	PV Total Costs ($000)	B / C Ratio	
Home Energy Check	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing
Home Energy Improvement	58,937	52,999	1.11	50,154	19,452	2.58	58,937	22,297	2.64	Modified
Residential New Construction	45,795	40,630	1.13	35,305	11,740	3.01	45,795	17,065	2.68	Modified
Low Income Weatherization	1,630	1,602	1.02	1,330	0	9999	1,630	272	5.99	New
Res Year-Round Energy Mgmt	82,516	98,117	0.81	69,545	2	9999	82,514	28,572	2.76	Modified
Res Winter-Only Energy Mgmt	37,282	28,800	1.24	11,277	0	9999	37,282	17,524	2.05	Modified
Business Energy Check	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing
Better Business	6,537	5,776	1.13	5,602	1,963	2.85	6,537	2,137	3.06	Modified
C/I New Construction	1,948	1,855	1.05	1,727	448	3.86	1,948	576	3.38	Modified
Innovation Incentive	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing
Commercial Energy Management	144	187	0.79	56	0	9999	144	131	1.13	Modified
Standby Generation	7,226	6,323	1.14	5,598	0	9999	7,226	725	9.97	Existing
Interruptible Service	272	270	1.00	190	0	9999	272	80	3.39	Existing
Curtailable Service	634	479	1.32	251	0	9999	634	228	2.77	Existing
Technology Development	NA	NA	NA	NA	NA	NA	NA	NA	NA	Existing

NOTES:

(1) Home Energy Check and Business Energy Check are FPSC-mandated programs; therefore, no cost-effectiveness analysis was conducted for these programs.

(2) Innovation Incentive projects are individually evaluated for cost-effectiveness; only projects that pass both the RIM and Participant Tests are approved.

(3) Technology Development projects are individually evaluated for cost-effectiveness.

C. PROGRAM MONITORING AND EVALUATION

Program monitoring and evaluation are important components of DSM implementation. They serve the purpose of ensuring that all DSM resources are acquired in a cost-effective manner. Specifically, program monitoring includes tracking program data and ensuring quality control. Program evaluation results document the energy and demand impacts and cost-effectiveness of the program, as well as suggest ways that the program can be improved by increasing savings, reducing costs, or increasing participation.

While there is a great need to regularly evaluate programs to ensure their cost-effectiveness, there is an equally great need to utilize the evaluation method that is most cost-effective. Imprudent expenditures on evaluation can significantly affect the overall cost-effectiveness of a program to its detriment. Just as FPC's DSM Plan is limited to cost-effective programs, only cost-effective evaluation efforts should be used to evaluate these programs. The level of evaluation effort must be balanced with the need for evaluation. For example, the programs that provide the largest portion of the total DSM impact should be given the greatest evaluation emphasis. Programs (or measures) that provide small per unit impacts or which have had relatively low levels of participation should be evaluated using approaches that can be justified given their relative contribution to the total net benefits.

Therefore, while there are many methods available to evaluate the impacts of these programs, FPC will determine on a program-by-program basis the most cost-effective evaluation method based on factors such as participation levels, program performance, dollars invested, the level of uncertainty of measure performance, etc.

D. COST-RECOVERY

FPC submits the programs herein described for approval and for inclusion as cost recoverable Conservation and Energy Efficiency Programs (under current FPSC-approved procedures) pursuant to Rule 25-17.015, and requests permission to recover all costs associated with the development and administration of this DSM Plan.

In addition, FPC intends to maintain its work toward administering and negotiating cogeneration contracts, and will continue to seek recovery of all associated administrative costs through the Energy Conservation Cost Recovery (ECCR) Clause.

FPC will make every effort toward the most appropriate transition from its existing DSM programs to any new or modified programs submitted in this Plan. As such, FPC seeks to recover all costs incurred through the implementation of those existing programs during the transition period. This is in accordance with approved Program Participation Standards which allow, in the event of program discontinuance, the extension of current recommendations and rebate amounts for up to two years from the date of program discontinuance or until the rebate is paid, whichever is sooner.

FPC has designed each of the DSM programs to pass the RIM test; therefore, each program is cost-effective on its own merit. This should not rule out the possibility that the Company may request incentives or recovery of lost revenues in the future.

III. RESIDENTIAL CONSERVATION PROGRAMS

III. RESIDENTIAL CONSERVATION PROGRAMS

Florida Power Corporation's DSM Plan includes five (5) residential programs:

A. **Home Energy Check** - residential energy audits

B. **Home Energy Improvement** - "umbrella" program for existing homes

C. **New Construction** - "umbrella" program for new residential construction, multi-family, and manufactured homes

D. **Low Income Weatherization Assistance Program** - "umbrella" program for the weatherization of low income family homes

E. **Residential Energy Management** - residential load control

Each program is described in detail in the following sections.

A. HOME ENERGY CHECK PROGRAM

Program Start Date: ▸ 1995

Policies and Procedures

The Home Energy Check is FPC's residential energy audit program, which provides its customers with an analysis of their current energy use and recommendations on how they can save on their electricity bill through low-cost or no-cost energy-saving practices and measures. It also serves as the foundation of the Home Energy Improvement program in that it serves as a prerequisite for participation in any of the retrofit-type components of the Home Energy Improvement program. The exception is an emergency replacement of high efficient heat pump(s). This requirement exists so that FPC can: 1) provide the customer with an overview of typical energy use, 2) verify that the action requested (e.g., additional attic insulation) will address the customer's problem, and 3) help to minimize free ridership in the Home Energy Improvement program.

The Home Energy Check program provides customers with four types of energy audits:

Level 1: Customer-completed Mail-In Audit (Do-It-Yourself Home Energy Check)

Level 2: Free Walk-Through Audit (current Home Energy Check)

Level 3: Paid Walk-Through Audit (current Home Energy Analysis)

Level 4: Home Energy Rating (Class I, II, III energy ratings)

All residential customers of FPC are eligible to receive any of the above energy audits. There is no charge for the Level 1 or Level 2 audits, while there is a $15 customer charge for the Level 3 audit. When a customer requests a Home Energy Check, they will be given the option of either receiving a Level 1 audit survey in the mail or scheduling a Level 2 or Level 3 walk-through audit. A FPC auditor will usually conduct the audit, although FPC may also work with other agencies and/or utilities as an extension of FPC's services, in which case an approved auditor from another organization may conduct the audit. The Home Energy Rating as outlined in FPC's "Florida Energy Gauge Ratings" rate tariff (Section II, sheet number 2.6) is available to all eligible FPC customers upon request.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants [2]	Cumulative Penetration Level (%)
2000	1,230,736	1,230,736	22,500	2%
2001	1,252,598	1,252,598	46,500	4%
2002	1,274,213	1,274,213	71,000	6%
2003	1,295,656	1,295,656	96,000	7%
2004	1,316,791	1,316,791	121,200	9%
2005	1,337,264	1,337,264	146,370	11%
2006	1,357,066	1,357,066	171,770	13%
2007	1,376,186	1,376,186	197,270	14%
2008	1,394,931	1,394,931	222,770	16%
2009	1,413,612	1,413,612	248,270	18%

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*
2. *Annual Number of Program Participants is the projected number of cumulative energy audits that will be conducted.*

Savings Estimates

The total program savings were developed by estimating impacts for each audit level and for low-cost energy efficiency measures promoted through the program. The total program savings are shown in the following table.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	275	0.085	0.085	6,190,000	1,910	1,910
2001	269	0.083	0.083	12,505,000	3,858	3,858
2002	267	0.082	0.082	18,984,000	5,856	5,856
2003	267	0.082	0.082	25,629,000	7,906	7,906
2004	267	0.082	0.082	32,314,000	9,968	9,968
2005	266	0.082	0.082	38,973,000	12,021	12,021
2006	266	0.082	0.082	45,675,000	14,089	14,089
2007	266	0.082	0.082	52,411,000	16,166	16,166
2008	266	0.082	0.082	59,146,000	18,243	18,243
2009	265	0.082	0.082	65,882,000	20,321	20,321

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	289	0.089	0.090	6,501,357	1,994	2,022
2001	282	0.087	0.088	13,134,002	4,026	4,084
2002	281	0.086	0.087	19,938,895	6,112	6,200
2003	280	0.086	0.087	26,918,139	8,252	8,370
2004	280	0.086	0.087	33,939,394	10,404	10,553
2005	280	0.086	0.087	40,933,342	12,548	12,727
2006	279	0.086	0.087	47,972,453	14,706	14,916
2007	279	0.086	0.087	55,047,273	16,874	17,115
2008	279	0.085	0.087	62,121,044	19,043	19,314
2009	279	0.085	0.087	69,195,865	21,211	21,514

Per customer impacts vary from year to year because of the changing mix of audit participants in the various audit levels, as well as the mix of low-cost measures assumed to be installed in any given year.

Impact Evaluation Plan

The range of possible recommendations resulting from the audit, and the inclusion of both technological and behavioral recommendations suggests the need to survey Home Energy Check participants to determine what specific conservation actions have been implemented within each market segment due to the completed audit. These survey results, combined with the participant-specific data gathered during the audit, will be used to determine the savings that can be directly attributable to the Home Energy Check program.

B. HOME ENERGY IMPROVEMENT PROGRAM

Program Start Date: ▸ 1995

▸ Proposed modification for 2000

Policies and Procedures

The Home Energy Improvement program is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program seeks to meet the following overall goals:

- Improve customer comfort levels through efficient equipment and home thermal integrity upgrades.
- Obtain energy and demand impacts that are accurate, sustainable, and measurable.
- Enhance contractor awareness of new technologies.
- Educate customers about additional opportunities associated with an energy efficient home.
- Obtain cost effective resources from the marketplace.
- Minimize "lost opportunities" in the existing home market.

The program provides incentives for attic insulation upgrades, duct testing and repair, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters. The program eligibility requirements to qualify for participation are as follows:

- The home must be metered by Florida Power.
- The home is required to have a residential energy audit prior to participation for the attic insulation and duct test and repair.
- Duct repairs must be sealed with mastic meeting UL 181 specifications consistent with duct manufacturer's requirements.
- New construction homes do not qualify under this program.
- High efficient heat pump incentives will be paid for replacing existing electric heat pumps and/or electric resistance heat.

Incentive Levels and specific eligibility requirements for each measure promoted in this program will be presented in the "Program Participation Standards."

Attic Insulation Upgrade

This portion of the program encourages customers to add insulation to the ceiling area by paying a portion of the installed cost. The home must have an existing insulation level of less than R-12 to participate. The customer must have either whole house electric cooling or electric heating to be eligible for this program. The maximum incentive available will be $100 per residence, the specific incentive is determined by the resulting insulation level.

Duct Test and Repair

This portion of the program is designed to encourage eligible customers to improve their central duct system by reducing the air leakage rate. This is accomplished by performing a duct leakage test, then offering to repair the leakage that is discovered by the duct test. The home must have central ducted electric cooling and electric heat to participate in this measure. For a duct test, FPC will pay up to a maximum of $30 for the first unit and $20 for each additional unit at the same address. For the duct repair, FPC will pay an incentive of up to $100 per unit. For multi-family rental units, FPC will pay all the costs up to $100 per unit (top floor only) and no test is required.

High Efficiency Electric Heat Pumps

For high efficient electric heat pumps, FPC will provide an incentive up to $350 per unit. The specific incentive available is dependent upon the efficiency level of the unit installed and the type of electric heat the new equipment is replacing. In order to qualify for an incentive both the air handler and the outdoor condensing unit shall be replaced, and both units shall be new. This program seeks to accommodate emergency replacement situations by allowing a participant to have a Home Energy Check conducted after the installation and still be eligible for the incentive.

High Efficiency Alternate Water Heating

The high efficiency water heating portion of this program promotes technologies that heat water more efficiently than a standard electric water heater and save energy. The incentive depends on the type of technology being installed. For heat recovery units, FPC will provide an incentive of $100 per residence. For dedicated heat pump water heaters, FPC will provide an incentive of $200 per unit.

Supplemental Incentive Bonus

To maximize the implementation of energy efficiency measures per participant, an incentive bonus is provided to high efficiency electric heat pump participants who also implement ceiling insulation upgrade, duct leakage repair, or both, within 90 days, before or after, of the installation date of the high efficiency electric heat pump. The purpose of this incentive is to offset some of the customer's large capital outlay to install more than one energy efficiency measure. The maximum incentive bonus a customer can receive is $50.

Financing

FPC is offering as an alternative to the incentives, a financing option. The financing option is an interest free (12 Month) installment-billing plan. As an alternative to receiving an incentive, the customer may choose to finance their energy efficient measure for up to one-year interest free.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2000	1,230,736	61,537	12,434	20%
2001	1,252,598	123,074	25,578	21%
2002	1,274,213	184,611	39,112	21%
2003	1,295,656	246,148	52,665	21%
2004	1,316,791	307,685	65,822	21%
2005	1,337,264	369,222	78,266	21%
2006	1,357,066	430,759	89,725	21%
2007	1,376,186	492,296	100,047	20%
2008	1,394,931	553,833	109,185	20%
2009	1,413,612	615,370	117,179	19%

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*
2. *Total number of Eligible Customers is based on an estimate of the cumulative number of central heat pumps and air conditioners that are replaced each year.*
3. *Annual number of Measure Participants is the projected number of cumulative measure installations from all measures promoted through this program. Because customers can install multiple measures, the actual number of participants will be less.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	538	0.968	0.388	6,694,000	12,040	4,824
2001	537	0.962	0.389	13,741,000	24,612	9,957
2002	536	0.958	0.390	20,981,000	37,468	15,261
2003	536	0.956	0.391	28,223,000	50,314	20,573
2004	536	0.955	0.391	35,277,000	62,871	25,721
2005	536	0.957	0.390	41,973,000	74,879	30,554
2006	536	0.960	0.390	48,181,000	86,148	34,957
2007	538	0.965	0.388	53,827,000	96,568	38,861
2008	539	0.972	0.387	58,889,000	106,105	42,246
2009	541	0.980	0.385	63,385,000	114,787	45,130

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	565	1.010	0.410	7,030,708	12,567	5,107
2001	564	1.004	0.411	14,432,172	25,690	10,541
2002	562	1.000	0.412	22,036,344	39,109	16,156
2003	562	0.997	0.413	29,642,616	52,517	21,780
2004	562	0.996	0.413	37,051,433	65,624	27,230
2005	562	0.998	0.412	44,084,241	78,158	32,347
2006	562	1.002	0.412	50,604,504	89,921	37,008
2007	565	1.007	0.410	56,534,498	100,797	41,142
2008	566	1.015	0.409	61,851,116	110,752	44,725
2009	568	1.023	0.407	66,573,265	119,814	47,779

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach given the number and type of measures being promoted. Some measures provide large per unit impacts while other yield relatively smaller impacts. The total impact from all smaller-impact measures could be potentially less than the uncertainty around an impact estimate of just one large measure. Consequently, the impact evaluation will place greater emphasis on the larger impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis represents the primary methods that will be used to estimate demand and energy impacts. These analyses will be supported by residential end-use metering data.

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	58,937	52,999	5,938	1.11
Participant	50,154	19,452	30,702	2.58
Total Resource Cost	58,937	22,297	36,640	2.64

PROGRAM: Home Energy Improvement

PARTICIPANT TEST

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	495	1797	0	2292	3009	0	3009	-717
2001	1001	1873	0	2874	3103	0	3103	-229
2002	1565	1914	0	3479	3154	0	3154	325
2003	2119	1912	0	4031	3148	0	3148	883
2004	2648	1871	0	4519	3101	0	3101	1418
2005	3153	1792	0	4945	3009	0	3009	1936
2006	3623	1687	0	5310	2893	0	2893	2417
2007	4041	1566	0	5607	2755	0	2755	2852
2008	4434	1441	0	5875	2615	0	2615	3260
2009	4850	1320	0	6170	2478	0	2478	3692
2010	4928	0	0	4928	0	0	0	4928
2011	5010	0	0	5010	0	0	0	5010
2012	5096	0	0	5096	0	0	0	5096
2013	5183	0	0	5183	0	0	0	5183
2014	5267	0	0	5267	0	0	0	5267
2015	5355	0	0	5355	0	0	0	5355
2016	5441	0	0	5441	0	0	0	5441
2017	5532	0	0	5532	0	0	0	5532
2018	5621	0	0	5621	0	0	0	5621
2019	5715	0	0	5715	0	0	0	5715
2020	5810	0	0	5810	0	0	0	5810
2021	5906	0	0	5906	0	0	0	5906
2022	6003	0	0	6003	0	0	0	6003
2023	6103	0	0	6103	0	0	0	6103
2024	6202	0	0	6202	0	0	0	6202
2025	6305	0	0	6305	0	0	0	6305
2026	6407	0	0	6407	0	0	0	6407
2027	6514	0	0	6514	0	0	0	6514
2028	6619	0	0	6619	0	0	0	6619
NOMINAL	136946	17173	0	154119	29265	0	29265	124854
NPV	38657	11497	0	50154	19452	0	19452	30702

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 2.58

PROGRAM: Home Energy Improvement

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	254	405	0	0	659	3009	0	0	0	445	3454	-2795
2001	498	827	0	0	1325	3103	0	0	0	465	3568	-2243
2002	689	1258	665	0	2612	3154	0	0	0	476	3630	-1018
2003	1025	1681	855	0	3561	3148	0	0	0	476	3624	-63
2004	1358	2103	278	0	3739	3101	0	0	0	465	3566	173
2005	2648	2508	791	0	5947	3009	0	0	0	445	3454	2493
2006	5681	2889	2035	0	10605	2893	0	0	0	417	3310	7295
2007	1872	3244	1934	0	7050	2755	0	0	0	385	3140	3910
2008	3308	3571	804	0	7683	2615	0	0	0	352	2967	4716
2009	2368	3870	495	0	6733	2478	0	0	0	320	2798	3935
2010	2906	3870	538	0	7314	0	0	0	0	0	0	7314
2011	2423	3870	526	0	6819	0	0	0	0	0	0	6819
2012	2489	3870	43	0	6402	0	0	0	0	0	0	6402
2013	2477	3870	568	0	6915	0	0	0	0	0	0	6915
2014	2492	3870	623	0	6985	0	0	0	0	0	0	6985
2015	2537	3870	604	0	7011	0	0	0	0	0	0	7011
2016	2579	3870	665	0	7114	0	0	0	0	0	0	7114
2017	2598	3870	642	0	7110	0	0	0	0	0	0	7110
2018	2597	3870	703	0	7170	0	0	0	0	0	0	7170
2019	2615	3870	683	0	7168	0	0	0	0	0	0	7168
2020	2750	3870	1434	0	8054	0	0	0	0	0	0	8054
2021	2776	3870	1460	0	8106	0	0	0	0	0	0	8106
2022	3350	3870	1522	0	8742	0	0	0	0	0	0	8742
2023	2867	3870	1552	0	8289	0	0	0	0	0	0	8289
2024	2832	3870	1620	0	8322	0	0	0	0	0	0	8322
2025	2858	3870	1649	0	8377	0	0	0	0	0	0	8377
2026	3356	3870	1720	0	8946	0	0	0	0	0	0	8946
2027	2944	3870	1753	0	8567	0	0	0	0	0	0	8567
2028	3005	3870	1830	0	8705	0	0	0	0	0	0	8705
NOMINAL	72152	95886	27992	0	196030	29265	0	0	0	4246	33511	162519
NPV	22218	28719	8000	0	58937	19452	0	0	0	2845	22297	36640

UTILITY DISCOUNT RATE: 8.53%

BENEFIT/COST RATIO (COL. 5/COL. 11): 2.64

PROGRAM: Home Energy Improvement

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	254	405	0	0	659	0	0	0	445	1797	495	2737	-2078
2001	498	827	0	0	1325	0	0	0	465	1873	1001	3339	-2014
2002	689	1258	665	0	2612	0	0	0	476	1914	1565	3955	-1343
2003	1025	1681	855	0	3561	0	0	0	476	1912	2119	4507	-946
2004	1358	2103	278	0	3739	0	0	0	465	1871	2648	4984	-1245
2005	2648	2508	791	0	5947	0	0	0	445	1792	3153	5390	557
2006	5681	2889	2035	0	10605	0	0	0	417	1687	3623	5727	4878
2007	1872	3244	1934	0	7050	0	0	0	385	1566	4041	5992	1058
2008	3308	3571	804	0	7683	0	0	0	352	1441	4434	6227	1456
2009	2368	3870	495	0	6733	0	0	0	320	1320	4850	6490	243
2010	2906	3870	538	0	7314	0	0	0	0	0	4928	4928	2386
2011	2423	3870	526	0	6819	0	0	0	0	0	5010	5010	1809
2012	2489	3870	43	0	6402	0	0	0	0	0	5096	5096	1306
2013	2477	3870	568	0	6915	0	0	0	0	0	5183	5183	1732
2014	2492	3870	623	0	6985	0	0	0	0	0	5267	5267	1718
2015	2537	3870	604	0	7011	0	0	0	0	0	5355	5355	1656
2016	2579	3870	665	0	7114	0	0	0	0	0	5441	5441	1673
2017	2598	3870	642	0	7110	0	0	0	0	0	5532	5532	1578
2018	2597	3870	703	0	7170	0	0	0	0	0	5621	5621	1549
2019	2615	3870	683	0	7168	0	0	0	0	0	5715	5715	1453
2020	2750	3870	1434	0	8054	0	0	0	0	0	5810	5810	2244
2021	2776	3870	1460	0	8106	0	0	0	0	0	5906	5906	2200
2022	3350	3870	1522	0	8742	0	0	0	0	0	6003	6003	2739
2023	2867	3870	1552	0	8289	0	0	0	0	0	6103	6103	2186
2024	2832	3870	1620	0	8322	0	0	0	0	0	6202	6202	2120
2025	2858	3870	1649	0	8377	0	0	0	0	0	6305	6305	2072
2026	3356	3870	1720	0	8946	0	0	0	0	0	6407	6407	2539
2027	2944	3870	1753	0	8567	0	0	0	0	0	6514	6514	2053
2028	3005	3870	1830	0	8705	0	0	0	0	0	6619	6619	2086
NOMINAL	72152	95886	27992	0	196030	0	0	0	4246	17173	136946	158365	37665
NPV	22218	28719	8000	0	58937	0	0	0	2845	11497	38657	52999	5938

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.11

C. NEW CONSTRUCTION

Program Start Date: ‣ 1995
‣ Proposed modification for 2000

Policies and Procedures

The New Construction program is an "umbrella" program for the New Construction, Multi-family, and Manufactured Home building segments.

The New Construction program promotes energy efficient construction in order to provide customers with more efficient dwellings combined with improved environmental comfort.

The objectives of the program include the following goals:

- Educate builders and builder/owners and property managers[1] about energy efficient construction design to increase the supply of energy efficient homes.
- Educate customers and realtors about energy efficient construction design to increase the demand for energy efficient homes.
- Obtain energy and demand impacts that are accurate, sustainable, and measurable.
- Enhance contractor awareness of new technologies.
- Obtain cost effective resources from the marketplace.
- Minimize "lost opportunities" in the new home market.

The program provides education and information to the design community on energy efficient equipment and construction. The program provides the following:

- Financial incentives for energy efficient equipment.
- "Third party" endorsement/certification and FPC's seal of approval.
- Cooperative advertising for the most energy efficient builders.

[1] Contractors, builders, builder/owners, and property managers are synonymous.

The program facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. Builders that express interest in participating in this program will be required to fulfill pre-qualification requirements. Then, as builders inform FPC regarding their plans to design and build additional homes, FPC representatives will provide assistance to ensure that the design and construction of the home(s) meet program requirements. Home certification criteria include the following:

- The home must be metered by Florida Power.
- The builder must meet requirements listed in the Program Participation Standards.
- The heating source must be an all electric heat pump. No resistance heat is allowed except as back up heat. Straight air with electric strip is not allowed to participate.2
- Duct sealing integrity, insulation levels, and equipment efficiencies, sizing and installations must meet specific program requirements.

This program has three levels of participation with various options within each level. The builder is offered a choice of energy efficiency measures that more closely meet the home's design criteria. Program details such as builder qualification criteria, home certification requirements and incentive levels for high efficient equipment promoted by this program will be presented in the Program Participation Standards.

High Efficiency Electric Heat Pumps

For electric heat pumps, FPC will provide an incentive up to a maximum of $300 per unit. The specific incentive amount is dependent on the energy efficiency of the equipment. The Program Participation Standards will specify additional qualifying criteria for incentive eligibility.

High Efficiency Alternate Electric Water Heating

The high efficiency alternate electric water heating incentive is based on the type of alternate water heating equipment that is installed. For heat recovery units, FPC will provide an incentive of $100. For Dedicated Heat Pump Water Heaters the incentive is $200. Manufacturer specifications for equipment installation must be followed.

[2] Exception would be for multi-family housing above three stories in height.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2000	1,230,736	22,742	6,562	29%
2001	1,252,598	45,484	14,939	33%
2002	1,274,213	68,226	25,220	37%
2003	1,295,656	90,968	37,345	41%
2004	1,316,791	113,710	51,114	45%
2005	1,337,264	136,452	66,240	49%
2006	1,357,066	159,194	82,424	52%
2007	1,376,186	181,936	99,330	55%
2008	1,394,931	204,678	116,646	57%
2009	1,413,612	227,420	134,120	59%

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*
2. *Total number of eligible new homes constructed in FPC's territory.*
3. *Annual Number of Measure Participants is the projected number of cumulative measure applications from all measures promoted by this program. Because customer can install multiple measures, the actual number of participants will be less.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	470	0.864	0.425	3,083,000	5,670	2,786
2001	469	0.870	0.426	7,011,000	12,995	6,370
2002	469	0.875	0.428	11,826,000	22,059	10,788
2003	469	0.879	0.429	17,500,000	32,814	16,018
2004	468	0.882	0.430	23,937,000	45,075	21,972
2005	468	0.884	0.431	31,006,000	58,578	28,520
2006	468	0.886	0.431	38,569,000	73,054	35,537
2007	468	0.888	0.432	46,465,000	88,186	42,868
2008	468	0.889	0.432	54,554,000	103,691	50,379
2009	468	0.890	0.432	62,715,000	119,337	57,959

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	493	0.902	0.450	3,238,074	5,918	2,949
2001	492	0.908	0.451	7,363,653	13,564	6,743
2002	492	0.913	0.453	12,420,847	23,025	11,421
2003	492	0.918	0.454	18,380,250	34,251	16,958
2004	491	0.921	0.455	25,141,031	47,049	23,261
2005	491	0.923	0.456	32,565,601	61,143	30,194
2006	491	0.925	0.456	40,509020	76,253	37,623
2007	491	0.927	0.457	48,802,189	92,048	45,384
2008	491	0.928	0.457	57,298,066	108,232	53,336
2009	491	0.929	0.457	65,869,564	124,563	61,361

Impact Evaluation Plan

The Residential New Construction program includes the installation of varied types of measures. As such, the impact evaluation plan should address interactive effects of multiple measures. In order to capture the impacts of these measures, engineering simulations and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts, although the specific method may vary depending on measure-specific participation levels. These analyses may be supported by residential end-use metering data, where feasible.

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	45,795	40,630	5,165	1.13
Participant	35,305	11,740	23,565	3.01
Total Resource Cost	45,795	17,065	28,730	2.68

PROGRAM: New Construction

PARTICIPANT TEST

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	227	107	0	334	1075	0	1075	-741
2001	509	110	0	619	1299	0	1299	-680
2002	879	112	0	991	1527	0	1527	-536
2003	1309	113	0	1422	1745	0	1745	-323
2004	1789	113	0	1902	1937	0	1937	-35
2005	2321	114	0	2435	2093	0	2093	342
2006	2887	114	0	3001	2223	0	2223	778
2007	3471	116	0	3587	2304	0	2304	1283
2008	4091	117	0	4208	2358	0	2358	1850
2009	4781	117	0	4898	2377	0	2377	2521
2010	4859	0	0	4859	0	0	0	4859
2011	4940	0	0	4940	0	0	0	4940
2012	5025	0	0	5025	0	0	0	5025
2013	5108	0	0	5108	0	0	0	5108
2014	5191	0	0	5191	0	0	0	5191
2015	5279	0	0	5279	0	0	0	5279
2016	5365	0	0	5365	0	0	0	5365
2017	5454	0	0	5454	0	0	0	5454
2018	5542	0	0	5542	0	0	0	5542
2019	5634	0	0	5634	0	0	0	5634
2020	5726	0	0	5726	0	0	0	5726
2021	5821	0	0	5821	0	0	0	5821
2022	5917	0	0	5917	0	0	0	5917
2023	6018	0	0	6018	0	0	0	6018
2024	6115	0	0	6115	0	0	0	6115
2025	6217	0	0	6217	0	0	0	6217
2026	6317	0	0	6317	0	0	0	6317
2027	6422	0	0	6422	0	0	0	6422
2028	6526	0	0	6526	0	0	0	6526
NOMINAL	129740	1133	0	130873	18938	0	18938	111935
NPV	34568	737	0	35305	11740	0	11740	23565

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 3.01

PROGRAM: New Construction

TOTAL RESOURCE COST TEST

YEAR	BENEFITS (1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	COSTS (6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	117	145	0	0	262	1075	0	0	0	534	1609	-1347
2001	312	332	0	0	644	1299	0	0	0	619	1918	-1274
2002	402	564	348	0	1314	1527	0	0	0	708	2235	-921
2003	627	830	523	0	1980	1745	0	0	0	793	2538	-558
2004	907	1144	0	0	2051	1937	0	0	0	869	2806	-755
2005	2214	1489	804	0	4507	2093	0	0	0	932	3025	1482
2006	4302	1859	1331	0	7492	2223	0	0	0	982	3205	4287
2007	1630	2244	1412	0	5286	2304	0	0	0	1013	3317	1969
2008	3177	2640	267	0	6084	2358	0	0	0	1034	3392	2692
2009	2323	3038	522	0	5883	2377	0	0	0	1041	3418	2465
2010	2855	3038	551	0	6444	0	0	0	0	0	0	6444
2011	2378	3038	555	0	5971	0	0	0	0	0	0	5971
2012	2439	3038	55	0	5532	0	0	0	0	0	0	5532
2013	2459	3038	19	0	5516	0	0	0	0	0	0	5516
2014	2467	3038	54	0	5559	0	0	0	0	0	0	5559
2015	2489	3038	638	0	6165	0	0	0	0	0	0	6165
2016	2526	3038	679	0	6243	0	0	0	0	0	0	6243
2017	2550	3038	678	0	6266	0	0	0	0	0	0	6266
2018	2544	3038	719	0	6301	0	0	0	0	0	0	6301
2019	2567	3038	721	0	6326	0	0	0	0	0	0	6326
2020	2631	3038	767	0	6436	0	0	0	0	0	0	6436
2021	2657	3038	766	0	6461	0	0	0	0	0	0	6461
2022	3226	3038	812	0	7076	0	0	0	0	0	0	7076
2023	2772	3038	1600	0	7410	0	0	0	0	0	0	7410
2024	2775	3038	1637	0	7450	0	0	0	0	0	0	7450
2025	2808	3038	1701	0	7547	0	0	0	0	0	0	7547
2026	3298	3038	1746	0	8082	0	0	0	0	0	0	8082
2027	2893	3038	1808	0	7739	0	0	0	0	0	0	7739
2028	2947	3038	1850	0	7835	0	0	0	0	0	0	7835
NOMINAL	67292	72007	22563	0	161862	18938	0	0	0	8525	27463	134399
NPV	19643	20336	5817	0	45795	11740	0	0	0	5325	17065	28730

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.68

PROGRAM: New Construction

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	117	145	0	0	262	0	0	0	534	107	227	868	-606
2001	312	332	0	0	644	0	0	0	619	110	509	1238	-594
2002	402	564	348	0	1314	0	0	0	708	112	879	1699	-385
2003	627	830	523	0	1980	0	0	0	793	113	1309	2215	-235
2004	907	1144	0	0	2051	0	0	0	869	113	1789	2771	-720
2005	2214	1489	804	0	4507	0	0	0	932	114	2321	3367	1140
2006	4302	1859	1331	0	7492	0	0	0	982	114	2887	3983	3509
2007	1630	2244	1412	0	5286	0	0	0	1013	116	3471	4600	686
2008	3177	2640	267	0	6084	0	0	0	1034	117	4091	5242	842
2009	2323	3038	522	0	5883	0	0	0	1041	117	4781	5939	-56
2010	2855	3038	551	0	6444	0	0	0	0	0	4859	4859	1585
2011	2378	3038	555	0	5971	0	0	0	0	0	4940	4940	1031
2012	2439	3038	55	0	5532	0	0	0	0	0	5025	5025	507
2013	2459	3038	19	0	5516	0	0	0	0	0	5108	5108	408
2014	2467	3038	54	0	5559	0	0	0	0	0	5191	5191	368
2015	2489	3038	638	0	6165	0	0	0	0	0	5279	5279	886
2016	2526	3038	679	0	6243	0	0	0	0	0	5365	5365	878
2017	2550	3038	678	0	6266	0	0	0	0	0	5454	5454	812
2018	2544	3038	719	0	6301	0	0	0	0	0	5542	5542	759
2019	2567	3038	721	0	6326	0	0	0	0	0	5634	5634	692
2020	2631	3038	767	0	6436	0	0	0	0	0	5726	5726	710
2021	2657	3038	766	0	6461	0	0	0	0	0	5821	5821	640
2022	3226	3038	812	0	7076	0	0	0	0	0	5917	5917	1159
2023	2772	3038	1600	0	7410	0	0	0	0	0	6018	6018	1392
2024	2775	3038	1637	0	7450	0	0	0	0	0	6115	6115	1335
2025	2808	3038	1701	0	7547	0	0	0	0	0	6217	6217	1330
2026	3298	3038	1746	0	8082	0	0	0	0	0	6317	6317	1765
2027	2893	3038	1808	0	7739	0	0	0	0	0	6422	6422	1317
2028	2947	3038	1850	0	7835	0	0	0	0	0	6526	6526	1309
NOMINAL	67292	72007	22563	0	161862	0	0	0	8525	1133	129740	139398	22464
NPV	19643	20336	5817	0	45795	0	0	0	5325	737	34568	40630	5165

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.13

D. LOW INCOME WEATHERIZATION ASSISTANCE PROGRAM

Program Start Date: ▸ 2000

Policies and Procedures

The Low-Income Weatherization Assistance program (LIWAP) is the umbrella program to improve energy efficiency for low-income customers in existing residential housing. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program seeks to meet the following goals:

- Integrate FPC's LIWAP procedures with the Department of Community Affairs (DCA) and local weatherization providers to deliver energy efficiency measures to low-income families.
- Identify and educate contractors and low income customers about energy saving opportunities to improve home energy efficiency.
- Increase low-income families' participation in FPC's DSM programs.
- Minimize "lost opportunities" in the existing marketplace.

The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters. The program eligibility requirements to qualify for participation are as follows:

- The residence must be in FPC's service area and be a residential FPC metered customer.
- Must meet Florida's weatherization low-income criteria in addition to income requirements required by DCA.
- Homes must be greater than two years old.
- Homes having previously received FPC incentives for listed measures are not eligible for the same measure. Attic insulation and duct repairs have special exemptions as outlined in the Home Energy Improvement Program.
- A DCA approved provider or their approved contractors must perform all work. FPC approved contractors may be used.

Incentive levels and specific eligibility requirements for each measure promoted in this program will be presented in the Program Participation Standards.

Attic Insulation Upgrade

This portion of the program encourages customers to add insulation to the ceiling area by paying a portion of the installed cost. The home must have an existing insulation level of less than R-12 to participate. The customer must have either whole house electric cooling or electric heating to be eligible for this program. The maximum incentive available will be $100 per residence, the specific incentive is determined by the resulting insulation level.

Duct Test and Repair

This portion of the program is designed to encourage eligible customers to improve their central duct system by reducing the air leakage rate. This is accomplished by performing a duct leakage test, then offering to repair the leakage that is discovered by the duct test. The home must have central ducted electric cooling and electric heat to participate in this measure. For a duct test, FPC will pay up to a maximum of $30 for the first unit and $20 for each additional unit at the same address. For the duct repair, FPC will pay an incentive of up to $100 per unit.

Reduced Air Infiltration

The weatherization provider must demonstrate a minimum reduction of air infiltration into the home of 1500 cfm at 50 pascals to receive a $75 incentive. The home must not exceed ASHRAE Standard 92.2-1989 for acceptable indoor air quality.

Water Heater Wrap/Replacement

The weatherization provider will wrap the water heater with an insulation value of at least R-6 side and R-8 top and insulate the pipes a minimum of 3 feet extending from the tank. The temperature will be set down to 120 degrees. To defray the cost of purchasing a high efficiency water heater, in lieu of installing an insulating jacket, the same $25 incentive would apply.

High Efficiency Electric Heat Pumps

For high efficient electric heat pumps, FPC will provide an incentive up to $350 per unit. The specific incentive available is dependent upon the efficiency level of the unit installed and the type of electric heat the new equipment is replacing. In order to qualify for an incentive, both the air handler and the outdoor condensing unit shall be replaced, and both units shall be new. This program seeks to accommodate emergency replacement situations by allowing a participant to have a home energy audit conducted after the installation and still be eligible for the incentive.

High Efficiency Alternate Water Heating

The high efficiency water heating portion of this program promotes technologies that heat water more efficiently than a standard electric water heater and save energy. The incentive depends on the type of technology being installed. For heat recovery units, FPC will provide an incentive of $100 per residence. For dedicated heat pump water heaters, FPC will provide an incentive of $200 per unit.

Heating and Air Conditioning Maintenance

To maximize efficiency a $40 incentive will be provided for a Heating & Air Conditioning contractor to perform service/tune-up maintenance on existing electric central heating and air conditioning systems.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2000	1,230,736	1,500	293	20%
2001	1,252,598	3,030	768	25%
2002	1,274,213	4,591	1,293	28%
2003	1,295,656	6,183	1,818	29%
2004	1,316,791	7,808	2,343	30%
2005	1,337,264	9,466	2,868	30%
2006	1,357,066	11,157	3,393	30%
2007	1,376,186	12,882	3,918	30%
2008	1,394,931	14,642	4,443	30%
2009	1,413,612	16,437	4,968	30%

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*
2. *Total number of Eligible Customers that are weatherized by local weatherization assistance providers.*
3. *Annual Number of Measure Participants is the projected number of cumulative measure installations from all measures promoted by this program. Because customers can install multiple measures, the actual number of participants will be less.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	354	0.574	0.255	104,000	168	75
2001	360	0.596	0.260	276,000	457	200
2002	354	0.594	0.254	458,000	768	328
2003	352	0.593	0.251	640,000	1,078	457
2004	351	0.592	0.250	822,000	1,388	586
2005	350	0.592	0.249	1,004,000	1,698	714
2006	350	0.592	0.248	1,186,000	2,008	843
2007	349	0.592	0.248	1,369,000	2,318	971
2008	349	0.592	0.248	1,551,000	2,628	1,100
2009	349	0.591	0.247	1,733,000	2,938	1,228

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	371	0.599	0.270	109,231	175	79
2001	378	0.622	0.275	289,882	477	211
2002	371	0.620	0.269	481,037	801	347
2003	369	0.619	0.266	672,192	1,125	483
2004	368	0.618	0.265	863,346	1,448	620
2005	367	0.618	0.264	1,054,501	1,772	755
2006	367	0.618	0.263	1,245,655	2,095	892
2007	366	0.618	0.263	1,437,860	2,419	1,027
2008	366	0.618	0.263	1,629,015	2,743	1,164
2009	366	0.617	0.261	1,820,169	3,066	1,300

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach given the number and type of measures being promoted. Some measures provide large per unit impacts while other yield relatively smaller impacts. The total impact from all smaller-impact measures could be potentially less than the uncertainty around an impact estimate of just one large measure. Consequently, the impact evaluation will place greater emphasis on the larger impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis represents the primary methods that will be used to estimate demand and energy impacts. These analyses will be supported by residential end-use metering data.

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	1,630	1,602	28	1.02
Participant	1,330	0	1,330	9999
Total Resource Cost	1,630	272	1,358	5.99

PROGRAM: Low Income Weatherization Assistance

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	8	29	0	37	0	0	0	37
2001	21	48	0	69	0	0	0	69
2002	34	52	0	86	0	0	0	86
2003	48	52	0	100	0	0	0	100
2004	62	52	0	114	0	0	0	114
2005	76	52	0	128	0	0	0	128
2006	90	52	0	142	0	0	0	142
2007	103	52	0	155	0	0	0	155
2008	117	52	0	169	0	0	0	169
2009	133	52	0	185	0	0	0	185
2010	135	0	0	135	0	0	0	135
2011	138	0	0	138	0	0	0	138
2012	145	0	0	145	0	0	0	145
2013	142	0	0	142	0	0	0	142
2014	145	0	0	145	0	0	0	145
2015	147	0	0	147	0	0	0	147
2016	149	0	0	149	0	0	0	149
2017	152	0	0	152	0	0	0	152
2018	154	0	0	154	0	0	0	154
2019	157	0	0	157	0	0	0	157
2020	159	0	0	159	0	0	0	159
2021	162	0	0	162	0	0	0	162
2022	166	0	0	166	0	0	0	166
2023	167	0	0	167	0	0	0	167
2024	170	0	0	170	0	0	0	170
2025	173	0	0	173	0	0	0	173
2026	176	0	0	176	0	0	0	176
2027	179	0	0	179	0	0	0	179
2028	181	0	0	181	0	0	0	181
NOMINAL	3689	493	0	4182	0	0	0	4182
NPV	1013	317	0	1330	0	0	0	1330

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Low Income Weatherization Assistance

TOTAL RESOURCE COST TEST

YEAR	BENEFITS (1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	COSTS (6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	4	6	0	0	10	0	0	0	0	36	36	-26
2001	11	16	0	0	27	0	0	0	0	41	41	-14
2002	15	26	12	0	53	0	0	0	0	43	43	10
2003	23	36	16	0	75	0	0	0	0	43	43	32
2004	31	47	24	0	102	0	0	0	0	43	43	59
2005	36	57	22	0	115	0	0	0	0	43	43	72
2006	111	68	45	0	224	0	0	0	0	43	43	181
2007	48	78	42	0	168	0	0	0	0	43	43	125
2008	53	89	49	0	191	0	0	0	0	43	43	148
2009	60	99	58	0	217	0	0	0	0	43	43	174
2010	62	99	59	0	220	0	0	0	0	0	0	220
2011	62	99	61	0	222	0	0	0	0	0	0	222
2012	60	99	0	0	159	0	0	0	0	0	0	159
2013	64	99	64	0	227	0	0	0	0	0	0	227
2014	65	99	67	0	231	0	0	0	0	0	0	231
2015	66	99	68	0	233	0	0	0	0	0	0	233
2016	68	99	71	0	238	0	0	0	0	0	0	238
2017	68	99	73	0	240	0	0	0	0	0	0	240
2018	70	99	75	0	244	0	0	0	0	0	0	244
2019	105	99	77	0	281	0	0	0	0	0	0	281
2020	72	99	79	0	250	0	0	0	0	0	0	250
2021	73	99	82	0	254	0	0	0	0	0	0	254
2022	67	99	85	0	251	0	0	0	0	0	0	251
2023	75	99	87	0	261	0	0	0	0	0	0	261
2024	77	99	90	0	266	0	0	0	0	0	0	266
2025	78	99	93	0	270	0	0	0	0	0	0	270
2026	80	99	96	0	275	0	0	0	0	0	0	275
2027	81	99	99	0	279	0	0	0	0	0	0	279
2028	83	99	101	0	283	0	0	0	0	0	0	283
NOMINAL	1768	2403	1695	0	5866	0	0	0	0	421	421	5445
NPV	507	700	422	0	1630	0	0	0	0	272	272	1358

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 5.99

PROGRAM: Low Income Weatherization Assistance

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	4	6	0	0	10	0	0	0	36	29	8	73	-63
2001	11	16	0	0	27	0	0	0	41	48	21	110	-83
2002	15	26	12	0	53	0	0	0	43	52	34	129	-76
2003	23	36	16	0	75	0	0	0	43	52	48	143	-68
2004	31	47	24	0	102	0	0	0	43	52	62	157	-55
2005	36	57	22	0	115	0	0	0	43	52	76	171	-56
2006	111	68	45	0	224	0	0	0	43	52	90	185	39
2007	48	78	42	0	168	0	0	0	43	52	103	198	-30
2008	53	89	49	0	191	0	0	0	43	52	117	212	-21
2009	60	99	58	0	217	0	0	0	43	52	133	228	-11
2010	62	99	59	0	220	0	0	0	0	0	135	135	85
2011	62	99	61	0	222	0	0	0	0	0	138	138	84
2012	60	99	0	0	159	0	0	0	0	0	145	145	14
2013	64	99	64	0	227	0	0	0	0	0	142	142	85
2014	65	99	67	0	231	0	0	0	0	0	145	145	86
2015	66	99	68	0	233	0	0	0	0	0	147	147	86
2016	68	99	71	0	238	0	0	0	0	0	149	149	89
2017	68	99	73	0	240	0	0	0	0	0	152	152	88
2018	70	99	75	0	244	0	0	0	0	0	154	154	90
2019	105	99	77	0	281	0	0	0	0	0	157	157	124
2020	72	99	79	0	250	0	0	0	0	0	159	159	91
2021	73	99	82	0	254	0	0	0	0	0	162	162	92
2022	67	99	85	0	251	0	0	0	0	0	166	166	85
2023	75	99	87	0	261	0	0	0	0	0	167	167	94
2024	77	99	90	0	266	0	0	0	0	0	170	170	96
2025	78	99	93	0	270	0	0	0	0	0	173	173	97
2026	80	99	96	0	275	0	0	0	0	0	176	176	99
2027	81	99	99	0	279	0	0	0	0	0	179	179	100
2028	83	99	101	0	283	0	0	0	0	0	181	181	102
NOMINAL	1768	2403	1695	0	5866	0	0	0	421	493	3689	4603	1263
NPV	507	700	422	0	1630	0	0	0	272	317	1013	1602	28

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.02

E. RESIDENTIAL ENERGY MANAGEMENT PROGRAM

Program Start Date:
- 1981
- Program modified in 1995
- Proposed modification for 2000

Policies and Procedures

Residential Energy Management is a voluntary customer program that allows FPC to reduce peak demand and defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customers premises. These controlled interruptions are at FPC's option, during specified time periods, and coincident with hours of peak demand.

FPC has recently determined that it is no longer cost-effective under the RIM test to continue adding new participants to the current Residential Energy Management program, as described in rate schedule RSL-1. (Pages III-33 through III-35 present the results of all three Commission-approved tests of cost-effectiveness.) The Company also recognizes and seeks to balance the broad range of issues associated with a program whose participation rate is about forty-percent of it's entire residential customer base. As a result, FPC is proposing to modify the program in such a way as to improve program cost-effectiveness, ensure adequate near-term reserve margins, minimize customer reaction and inconvenience, and optimize reserve margin mix in the long-term. This proposal involves modifying the current program into two components.

Year-Round Energy Management

The Year-Round Energy Management component of the program will be the current Residential Energy Management Program (rate schedule RSL-1). However, because it is no longer cost-effective to add new participants to the existing program, FPC is proposing to close this component of the program to all customers who are not current participants. All existing Residential Energy Management program participants will be allowed to remain on the year-round program if they do not change their control schedule. Therefore, no existing participants will be affected by this change, as long as they remain on their existing control schedule. Also, prior to April 1, 2001 all new occupants of an active Energy Management equipped residence will be treated as an existing participant and allowed on the year-round component, if they maintain the same Energy Management control schedule as the previous occupants and do not require a service trip. Any participant that alters their current control schedule such that it requires a service trip, will no longer be eligible to continue on this Year-Round component of the program.

Maintaining existing program participants on the Energy Management program through the winter of 2001 is especially important given the relatively large amount of non-firm load provided by this program, as well as the need to provide a minimum fifteen percent reserve margin. Any significant loss of program participation directly increases firm load, and reduces FPC's already tight near-term planned reserve margins. This is the primary reason behind allowing new occupants of an active Energy Management equipped home to automatically continue service under the previous occupants Year-Round Energy Management rate schedule prior to April 1, 2001. In addition, this transition period will provide the time needed to organize and complete the operational components required to actually implement these proposed changes (i.e., contractor support and training, systems programming, etc.). However, the Company also recognizes the need to begin shifting program participation away from the Year-Round Energy Management Component. To meet both of these objectives, FPC proposes to substantially reduce the number of existing participants on the year-round component of the program beginning April 1, 2001. As of this date, FPC expects to have sufficient reserves to allow a ramping down of the year-round program component with no deleterious effects on reserve margins. The ramp-down will be accomplished by no longer offering new occupants of an active Energy Management equipped residence the ability to continue the previous occupant's service under the Year-Round Energy Management rate schedule. This strategy is expected to minimize any negative customer reaction, since it does not affect existing participants that do not change their occupancy status or control schedule.

Proposed changes to the RSL-1 rate schedule (in legislative format) are presented in the Appendix to this document.

Winter-Only Energy Management

The proposed Winter-Only Energy Management component of the program represents a modified, cost-effective version of the current Residential Energy Management program, and is outlined in the proposed new rate schedule RSL-2 (see Appendix). It provides for winter only (November through March) direct load control of customer's electric water heating and central electric heating appliances. Eligible participants must have both appliances on the program and will receive monthly credits during the potential control months. The amount of the credits are identical to those under the current Residential Energy Management program (rate schedule RSL-1) except that they are payable only during the winter months.

Since no new participation will be eligible for the Year-Round Energy Management component, this new Winter Only Energy Management component will enable FPC to continue to provide customers a cost-effective alternative to standard residential service that can help lower their electric bills as well as reduce FPC's winter peak demand. The program solidly passes the RIM Test, with benefit-cost ratios of 1.24. Pages III-37 through III-39 present the results for all three Commission-approved tests of cost-effectiveness.

There are three primary differences between the current Residential Energy Management Program (i.e., proposed Year-Round Residential Energy Management component) and the proposed Winter-Only Energy Management component:

- The current program offers customers a credit for the ability to exercise direct load control on any combination of their electric pool pump, water heating, central heating, and/or central cooling appliances. The proposed Winter-Only Energy Management component only provides a credit for direct load control of electric water heating and central electric heating appliances.

- The current program allows direct load control to be exercised throughout the year and pays an incentive every month of the year. The proposed Winter-Only Energy Management component allows the use of direct load control only during the five winter months of November through March, and only provides a credit during those winter months.

- The current program offers two possible control schedules for electric central heating equipment: 10 minutes maximum control or 16.5 minutes maximum control in any 30 minute period. For the proposed Winter-Only Energy Management component, only one heating schedule will be offered: 16.5 minute maximum control in any 30 minute period.

Program Participation

Cumulative program participation estimates beginning in the year 2000 are shown in the following table, and reflect new equipment installations under the Winter-Only Energy Management component of the program. There are no new participants (i.e., new Energy Management installations) projected for the Year-Round Energy Management component.

Winter-Only Energy Management

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Program Participants [3]	Cumulative Penetration Level (%)
2000	1,230,736	605,337	5,000	.008%
2001	1,252,598	622,827	10,625	.017%
2002	1,274,213	640,119	16,875	.026%
2003	1,295,656	657,273	23,750	.036%
2004	1,316,791	674,181	31,250	.046%
2005	1,337,264	690,560	38,750	.056%
2006	1,357,066	706,401	45,625	.065%
2007	1,376,186	721,697	51,875	.072%
2008	1,394,931	736,693	57,500	.078%
2009	1,413,612	751,638	62,500	.083%

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*

2. *Total numbers of eligible customers are all residential customers not already on the Residential Energy Management program.*

Savings Estimates

The total program savings shown in the following tables reflect the demand and energy savings associated with the new program participants projected for the Winter-Only Energy Management component of the program. Since there will be no new participants or savings from the Year-Round Energy Management component, only the savings from the Winter-Only component will be used to meet FPC's Commission approved conservation goals.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	2.110	0	0	10,550	0
2001	0	2.110	0	0	22,419	0
2002	0	2.110	0	0	35,606	0
2003	0	2.110	0	0	50,113	0
2004	0	2.110	0	0	65,938	0
2005	0	2.110	0	0	81,763	0
2006	0	2.110	0	0	96,269	0
2007	0	2.110	0	0	109,456	0
2008	0	2.110	0	0	121,325	0
2009	0	2.110	0	0	131,875	0

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	2.202	0	0	11,012	0
2001	0	2.202	0	0	23,400	0
2002	0	2.202	0	0	37,165	0
2003	0	2.202	0	0	52,307	0
2004	0	2.202	0	0	68,826	0
2005	0	2.202	0	0	85,344	0
2006	0	2.202	0	0	100,485	0
2007	0	2.202	0	0	114,250	0
2008	0	2.202	0	0	126,639	0
2009	0	2.202	0	0	137,651	0

Impact Evaluation Plan

FPC is in the process of conducting a residential end-use metering study that will be used to estimate the appliance level, and duty-cycle impacts of residential load control. This end-use metering data will be used to perform engineering and statistical analysis to estimate the impacts of the program.

Cost-Effectiveness

1. The following economic results for the current year-round Residential Energy Management program:

Current Year-Round Residential Energy Management Program

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	82,516	98,117	-15,601	0.81
Participant	69,545	2	69,543	9999
Total Resource Cost	82,514	28,572	53,942	2.76

PROGRAM: Current (Year-Round) Residential Energy Management

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	5	701	0	706	0	0	0	706
2001	0	1490	0	1490	0	2	2	1488
2002	20	2366	0	2386	0	0	0	2386
2003	21	3331	0	3352	0	0	0	3352
2004	58	4382	0	4440	0	0	0	4440
2005	207	5434	0	5641	0	0	0	5641
2006	377	6398	0	6775	0	0	0	6775
2007	837	7275	0	8112	0	0	0	8112
2008	1327	8063	0	9390	0	0	0	9390
2009	1439	8764	0	10203	0	0	0	10203
2010	1482	8764	0	10246	0	0	0	10246
2011	1486	8764	0	10250	0	0	0	10250
2012	1538	8764	0	10302	0	0	0	10302
2013	1535	8764	0	10299	0	0	0	10299
2014	1583	8764	0	10347	0	0	0	10347
2015	1584	8764	0	10348	0	0	0	10348
2016	1641	8764	0	10405	0	0	0	10405
2017	1637	8764	0	10401	0	0	0	10401
2018	1690	8764	0	10454	0	0	0	10454
2019	1691	8764	0	10455	0	0	0	10455
2020	1729	8764	0	10493	0	0	0	10493
2021	1747	8764	0	10511	0	0	0	10511
2022	1803	8764	0	10567	0	0	0	10567
2023	1804	8764	0	10568	0	0	0	10568
2024	1845	8764	0	10609	0	0	0	10609
2025	1864	8764	0	10628	0	0	0	10628
2026	1927	8764	0	10691	0	0	0	10691
2027	1926	8764	0	10690	0	0	0	10690
2028	1969	8764	0	10733	0	0	0	10733
NOMINAL	36772	214720	0	251492	0	2	2	251490
NPV	8831	60714	0	69545	0	2	2	69543

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Current (Year-Round) Residential Energy Management

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	151	0	0	153	0	0	0	0	1863	1863	-1710
2001	0	320	0	0	320	0	29	0	0	2166	2195	-1875
2002	0	508	1488	0	1996	0	1398	0	0	2482	3880	-1884
2003	0	715	1476	0	2191	0	1385	0	0	2813	4198	-2007
2004	0	941	2987	0	3928	0	2514	0	0	3160	5674	-1746
2005	0	1167	3085	0	4252	0	869	0	0	3289	4158	94
2006	0	1374	4131	0	5505	0	1315	0	0	3191	4506	999
2007	0	1562	4104	0	5666	0	752	0	0	3090	3842	1824
2008	3522	1732	5950	0	11204	0	0	0	0	2986	2986	8218
2009	3048	1882	7103	0	12033	0	0	0	0	2877	2877	9156
2010	2809	1882	7219	0	11910	0	0	0	0	1122	1122	10788
2011	2863	1882	7551	0	12296	0	0	0	0	1165	1165	11131
2012	2815	1882	7654	0	12351	0	0	0	0	1211	1211	11140
2013	2779	1882	7937	0	12598	0	0	0	0	1258	1258	11340
2014	2401	1882	8098	0	12381	0	0	0	0	1307	1307	11074
2015	2962	1882	8437	0	13281	0	0	0	0	1358	1358	11923
2016	3062	1882	8664	0	13608	0	0	0	0	1411	1411	12197
2017	3170	1882	8968	0	14020	0	0	0	0	1466	1466	12554
2018	3171	1882	9167	0	14220	0	0	0	0	1523	1523	12697
2019	3358	1882	9532	0	14772	0	0	0	0	1583	1583	13189
2020	3198	1882	9484	0	14564	0	0	0	0	1644	1644	12920
2021	3584	1882	10133	0	15599	0	0	0	0	1709	1709	13890
2022	3804	1882	10357	0	16043	0	0	0	0	1775	1775	14268
2023	3832	1882	10770	0	16484	0	0	0	0	1850	1850	14634
2024	3573	1882	10716	0	16171	0	0	0	0	1927	1927	14244
2025	4015	1882	11449	0	17346	0	0	0	0	2008	2008	15338
2026	4660	1882	11723	0	18265	0	0	0	0	2093	2093	16172
2027	4329	1882	12169	0	18380	0	0	0	0	2181	2181	16199
2028	4078	1882	12108	0	18068	0	0	0	0	2272	2272	15796
NOMINAL	71035	46110	212460	0	329605	0	8262	0	0	58780	67042	262563
NPV	15963	13585	52966	0	82514	0	5450	0	0	23122	28572	53942

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.76

PROGRAM: Current (Year-Round) Residential Energy Management

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	151	0	0	153	0	0	0	1863	701	5	2569	-2416
2001	0	320	0	2	322	29	0	0	2166	1490	0	3685	-3363
2002	0	508	1488	0	1996	1398	0	0	2482	2366	20	6266	-4270
2003	0	715	1476	0	2191	1385	0	0	2813	3331	21	7550	-5359
2004	0	941	2987	0	3928	2514	0	0	3160	4382	58	10114	-6186
2005	0	1167	3085	0	4252	869	0	0	3289	5434	207	9799	-5547
2006	0	1374	4131	0	5505	1315	0	0	3191	6398	377	11281	-5776
2007	0	1562	4104	0	5666	752	0	0	3090	7275	837	11954	-6288
2008	3522	1732	5950	0	11204	0	0	0	2986	8063	1327	12376	-1172
2009	3048	1882	7103	0	12033	0	0	0	2877	8764	1439	13080	-1047
2010	2809	1882	7219	0	11910	0	0	0	1122	8764	1482	11368	542
2011	2863	1882	7551	0	12296	0	0	0	1165	8764	1486	11415	881
2012	2815	1882	7654	0	12351	0	0	0	1211	8764	1538	11513	838
2013	2779	1882	7937	0	12598	0	0	0	1258	8764	1535	11557	1041
2014	2401	1882	8098	0	12381	0	0	0	1307	8764	1583	11654	727
2015	2962	1882	8437	0	13281	0	0	0	1358	8764	1584	11706	1575
2016	3062	1882	8664	0	13608	0	0	0	1411	8764	1641	11816	1792
2017	3170	1882	8968	0	14020	0	0	0	1466	8764	1637	11867	2153
2018	3171	1882	9167	0	14220	0	0	0	1523	8764	1690	11977	2243
2019	3358	1882	9532	0	14772	0	0	0	1583	8764	1691	12038	2734
2020	3198	1882	9484	0	14564	0	0	0	1644	8764	1729	12137	2427
2021	3584	1882	10133	0	15599	0	0	0	1709	8764	1747	12220	3379
2022	3804	1882	10357	0	16043	0	0	0	1775	8764	1803	12342	3701
2023	3832	1882	10770	0	16484	0	0	0	1850	8764	1804	12418	4066
2024	3573	1882	10716	0	16171	0	0	0	1927	8764	1845	12536	3635
2025	4015	1882	11449	0	17346	0	0	0	2008	8764	1864	12636	4710
2026	4660	1882	11723	0	18265	0	0	0	2093	8764	1927	12784	5481
2027	4329	1882	12169	0	18380	0	0	0	2181	8764	1926	12871	5509
2028	4078	1882	12108	0	18068	0	0	0	2272	8764	1969	13005	5063
NOMINAL	71035	46110	212460	2	329607	8262	0	0	58780	214720	36772	318534	11073
NPV	15963	13585	52966	2	82516	5450	0	0	23122	60714	8831	98117	-15601

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 0.81

Cost-Effectiveness (Cont'd)

2. The following economic results are for the proposed new Winter-Only Energy Management program component:

Winter-Only Energy Management

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	37,282	28,800	8,482	1.24
Participant	11,277	0	11,277	9999
Total Resource Cost	37,282	17,524	19,759	2.05

PROGRAM: Winter-Only Residential Energy Management

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	1	124	0	125	0	0	0	125
2001	0	264	0	264	0	0	0	264
2002	4	419	0	423	0	0	0	423
2003	2	589	0	591	0	0	0	591
2004	21	775	0	796	0	0	0	796
2005	19	961	0	980	0	0	0	980
2006	49	1132	0	1181	0	0	0	1181
2007	51	1287	0	1338	0	0	0	1338
2008	84	1426	0	1510	0	0	0	1510
2009	78	1550	0	1628	0	0	0	1628
2010	88	1550	0	1638	0	0	0	1638
2011	81	1550	0	1631	0	0	0	1631
2012	88	1550	0	1638	0	0	0	1638
2013	81	1550	0	1631	0	0	0	1631
2014	94	1550	0	1644	0	0	0	1644
2015	84	1550	0	1634	0	0	0	1634
2016	97	1550	0	1647	0	0	0	1647
2017	87	1550	0	1637	0	0	0	1637
2018	102	1550	0	1652	0	0	0	1652
2019	89	1550	0	1639	0	0	0	1639
2020	105	1550	0	1655	0	0	0	1655
2021	92	1550	0	1642	0	0	0	1642
2022	109	1550	0	1659	0	0	0	1659
2023	95	1550	0	1645	0	0	0	1645
2024	113	1550	0	1663	0	0	0	1663
2025	99	1550	0	1649	0	0	0	1649
2026	116	1550	0	1666	0	0	0	1666
2027	102	1550	0	1652	0	0	0	1652
2028	122	1550	0	1672	0	0	0	1672
NOMINAL	2153	37977	0	40130	0	0	0	40130
NPV	540	10737	0	11277	0	0	0	11277

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Winter-Only Residential Energy Management

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	1	90	0	0	91	0	0	0	0	976	976	-885
2001	0	191	0	0	191	0	5	0	0	1087	1092	-901
2002	0	304	780	0	1084	0	770	0	0	1203	1973	-889
2003	0	427	882	0	1309	0	808	0	0	1324	2132	-823
2004	0	562	1652	0	2214	0	1588	0	0	1450	3038	-824
2005	0	697	1582	0	2279	0	1467	0	0	1496	2963	-684
2006	18	821	2343	0	3182	0	0	0	0	1459	1459	1723
2007	0	933	2767	0	3700	0	508	0	0	1420	1928	1772
2008	0	1034	3380	0	4414	0	729	0	0	1381	2110	2304
2009	0	1124	3804	0	4928	0	693	0	0	1340	2033	2895
2010	0	1124	3869	0	4993	0	682	0	0	692	1374	3619
2011	0	1124	4044	0	5168	0	661	0	0	708	1369	3799
2012	0	1124	4125	0	5249	0	638	0	0	724	1362	3887
2013	0	1124	4303	0	5427	0	603	0	0	741	1344	4083
2014	0	1124	4401	0	5525	0	602	0	0	758	1360	4165
2015	0	1124	4574	0	5698	0	563	0	0	777	1340	4358
2016	0	1124	4674	0	5798	0	543	0	0	796	1339	4459
2017	0	1124	4862	0	5986	0	518	0	0	815	1333	4653
2018	0	1124	4979	0	6103	0	475	0	0	836	1311	4792
2019	0	1124	5168	0	6292	0	444	0	0	857	1301	4991
2020	0	1124	5295	0	6419	0	406	0	0	879	1285	5134
2021	0	1124	5493	0	6617	0	389	0	0	902	1291	5326
2022	0	1124	5625	0	6749	0	373	0	0	926	1299	5450
2023	0	1124	5839	0	6963	0	333	0	0	953	1286	5677
2024	0	1124	5983	0	7107	0	110	0	0	981	1091	6016
2025	0	1124	6207	0	7331	0	271	0	0	1010	1281	6050
2026	0	1124	6356	0	7480	0	240	0	0	1040	1280	6200
2027	0	1124	6598	0	7722	0	210	0	0	1071	1281	6441
2028	217	1124	6769	0	8110	0	0	0	0	1104	1104	7006
NOMINAL	236	27539	116354	0	144129	0	14629	0	0	29706	44335	99794
NPV	31	8114	29137	0	37282	0	6100	0	0	11424	17524	19759

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.05

PROGRAM: Winter-Only Residential Energy Management

RATE IMPACT MEASURE TEST

YEAR	BENEFITS (1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	COSTS (6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	1	90	0	0	91	0	0	0	976	124	1	1101	-1010
2001	0	191	0	0	191	5	0	0	1087	264	0	1356	-1165
2002	0	304	780	0	1084	770	0	0	1203	419	4	2396	-1312
2003	0	427	882	0	1309	808	0	0	1324	589	2	2723	-1414
2004	0	562	1652	0	2214	1588	0	0	1450	775	21	3834	-1620
2005	0	697	1582	0	2279	1467	0	0	1496	961	19	3943	-1664
2006	18	821	2343	0	3182	0	0	0	1459	1132	49	2640	542
2007	0	933	2767	0	3700	508	0	0	1420	1287	51	3266	434
2008	0	1034	3380	0	4414	729	0	0	1381	1426	84	3620	794
2009	0	1124	3804	0	4928	693	0	0	1340	1550	78	3661	1267
2010	0	1124	3869	0	4993	682	0	0	692	1550	88	3012	1981
2011	0	1124	4044	0	5168	661	0	0	708	1550	81	3000	2168
2012	0	1124	4125	0	5249	638	0	0	724	1550	88	3000	2249
2013	0	1124	4303	0	5427	603	0	0	741	1550	81	2975	2452
2014	0	1124	4401	0	5525	602	0	0	758	1550	94	3004	2521
2015	0	1124	4574	0	5698	563	0	0	777	1550	84	2974	2724
2016	0	1124	4674	0	5798	543	0	0	796	1550	97	2986	2812
2017	0	1124	4862	0	5986	518	0	0	815	1550	87	2970	3016
2018	0	1124	4979	0	6103	475	0	0	836	1550	102	2963	3140
2019	0	1124	5168	0	6292	444	0	0	857	1550	89	2940	3352
2020	0	1124	5295	0	6419	406	0	0	879	1550	105	2940	3479
2021	0	1124	5493	0	6617	389	0	0	902	1550	92	2933	3684
2022	0	1124	5625	0	6749	373	0	0	926	1550	109	2958	3791
2023	0	1124	5839	0	6963	333	0	0	953	1550	95	2931	4032
2024	0	1124	5983	0	7107	110	0	0	981	1550	113	2754	4353
2025	0	1124	6207	0	7331	271	0	0	1010	1550	99	2930	4401
2026	0	1124	6356	0	7480	240	0	0	1040	1550	116	2946	4534
2027	0	1124	6598	0	7722	210	0	0	1071	1550	102	2933	4789
2028	217	1124	6769	0	8110	0	0	0	1104	1550	122	2776	5334
NOMINAL	236	27539	116354	0	144129	14629	0	0	29706	37977	2153	84465	59664
NPV	31	8114	29137	0	37282	6100	0	0	11424	10737	540	28800	8482

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.24

IV. COMMERCIAL/INDUSTRIAL CONSERVATION PROGRAMS

IV. COMMERCIAL/INDUSTRIAL CONSERVATION PROGRAMS

Florida Power Corporation's DSM Plan includes eight (8) commercial/industrial programs:

A. **Business Energy Check** - C/I energy audits

B. **Better Business** - "umbrella" program for existing facilities

C. **C/I New Construction** - "umbrella" program for new construction facilities

D. **Innovation Incentive** - custom measures

E. **Commercial Energy Management** - C/I load control: Rate Tariff GSLM-1

F. **Standby Generation** - Rate Tariff GSLM-2

G. **Interruptible Service** - Rate Tariff IS-2

H. **Curtailable Service** - Rate Tariff CS-2

Each program is described in detail in the following sections.

A. BUSINESS ENERGY CHECK PROGRAM

Program Start Date: 1995

Policies and Procedures

The Business Energy Check is FPC's energy audit program. It provides commercial and industrial (C/I) customers with an assessment of the current energy usage at their facility and information on low-cost energy efficiency measures. This program serves as the foundation for FPC's other DSM programs targeted toward existing C/I construction and, in most cases, it is a prerequisite for participation in the other C/I programs.

The Business Energy Check consists of two types of audits:

Level 1: Free Walk-Through Audit (Inspection)

Level 2: Paid Walk-Through Audit (Energy Analysis)

All commercial, industrial, and governmental retail customers of FPC are eligible to have either level conducted on any of their buildings located in FPC's service territory. There is no charge for the Level 1 inspection, while there is a nominal customer charge for the Level 2 energy analysis. When a customer requests a Business Energy Check, they will be given the option of scheduling a Level 1 inspection or a Level 2 energy analysis. The specific details on the procedures for each level of audit will be presented in the Program Participation Standards.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants [2]	Cumulative Penetration Level (%)
2000	163,576	145,483	1,000	1%
2001	166,984	148,335	2,000	1%
2002	170,356	151,155	3,000	2%
2003	173,705	153,952	4,000	3%
2004	177,016	156,710	5,000	3%
2005	180,239	159,380	6,000	4%
2006	183,373	161,963	7,000	4%
2007	186,419	164,456	8,000	5%
2008	189,416	166,901	9,000	5%
2009	192,406	169,338	10,000	6%

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*

2. *Annual Number of Program Participants is the cumulative number of audits thatare projected to be conducted.*

Savings Estimates

The total program savings were developed based on historical FPC audits and a review of C/I audit impacts. These estimates include impacts directly resulting from the standard audit recommendations, including the installation of low-cost energy efficiency measures. In addition, customer-specific savings may result from site-specific recommendations that the auditor makes at the time of the audit, but which are not included in the standard audit form. These impacts will be calculated on a case-by-case basis and added to the standard impacts. The total program savings are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	300	0.14	0.14	300,000	140	140
2001	300	0.14	0.14	600,000	280	280
2002	300	0.14	0.14	900,000	420	420
2003	300	0.14	0.14	1,200,000	560	560
2004	300	0.14	0.14	1,500,000	700	700
2005	300	0.14	0.14	1,800,000	840	840
2006	300	0.14	0.14	2,100,000	980	980
2007	300	0.14	0.14	2,400,000	1,120	1,120
2008	300	0.14	0.14	2,700,000	1,260	1,260
2009	300	0.14	0.14	3,000,000	1,400	1,400

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	315	0.15	0.15	315,270	146	148
2001	315	0.15	0.15	630,540	293	295
2002	315	0.15	0.15	945,810	439	443
2003	315	0.15	0.15	1,261,080	586	591
2004	315	0.15	0.15	1,576,350	732	739
2005	315	0.15	0.15	1,891,620	879	886
2006	315	0.15	0.15	2,206,890	1,025	1,034
2007	315	0.15	0.15	2,522,160	1,172	1,182
2008	315	0.15	0.15	2,837,430	1,318	1,330
2009	315	0.15	0.15	3,152,700	1,465	1,477

Impact Evaluation Plan

The range of possible recommendations resulting from the audit, and the inclusion of both technological and behavioral recommendations suggests the need to carefully survey participants to determine what specific actions have been undertaken due to the completed audit. Initially, the use of site-specific engineering estimates is likely to be the most cost-effective method of estimating program impacts, although the use of statistical analysis technique may also be considered, depending on the participation levels actually achieved.

B. BETTER BUSINESS PROGRAM

Program Start Date: ▸ 1995

▸ Proposed modification for 2000

Policies and Procedures

The Better Business program is the umbrella efficiency program for existing commercial and industrial customers. Better Business builds on the Business Energy Check by using the audit to initiate FPC involvement in the customer's facility (participating in Business Energy Check is a prerequisite for receiving most of the incentives). This program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to FPC and its customers. Better Business promotes energy efficient heating, ventilation, air conditioning, motors, and some building retrofit measures (in particular, roof insulation upgrade, duct leakage test and repair, and window film retrofit). FPC proposes to remove incentives for Heat Recovery Units, which have previously been offered through this program.

The general eligibility requirements are as follows:

- The participant must be a FPC commercial, industrial, or governmental customer.
- Equipment must be installed in facilities located in the FPC service territory and served by a metered FPC account.
- A Business Energy Check audit (Level 1 or 2) must be completed prior to the purchase or installation of all measures (with the exception of motors).
- The participant must be willing to allow FPC to inspect the installation of all measures and equipment prior to receiving any incentive payments.
- All equipment installations shall meet manufacturers' instructions and specifications.

Incentive levels and specific eligibility requirements for each measure promoted in this program will be presented in the Program Participation Standards and will be subject to revision based on changes in market conditions, such as baseline or code revisions, evaluation findings, or technological advances.

HVAC Equipment

The HVAC equipment component of Better Business provides customers with information on high efficiency HVAC equipment and financial incentives for the purchase of very high efficiency unitary heat pumps and air conditioners, packaged rooftop units, packaged terminal heat pumps (PTHPs), and water-cooled and air-cooled chillers. The incentive is calculated for each unit based on the kW difference between the high efficiency unit and the program-specified baseline efficiency (at ARI Standard Test Rating Conditions) and is calculated using a dollar per kW reduced incentive up to a maximum of $100/kW reduced.

Motors

The program promotes the installation of high efficiency polyphase motors through a simple incentive structure. The incentive for any given motor is calculated based on the motor size and a specified $/hp. The maximum incentive amount will be $2.00 per hp and the specific incentive amount will be a function of the motor size. To maintain cost-effectiveness, a minimum number of motors per application will be established for motors that are 25 hp and smaller. The Business Energy Check is not required to receive this incentive.

Roof Insulation Upgrade

This portion of the program encourages customers who have electric space heat to add insulation to the roof area by paying for a portion of the installed cost. The facility must have an existing roof insulation level less than R-12 to participate and must be heated by electricity in order to receive the incentive. Heat loss and heat gain calculations must show that the additional insulation would result in heating and/or cooling energy use reductions in order to be eligible for an incentive. The maximum incentive amount will be $100 per customer and the specific incentive amount that a customer is eligible to receive will be a function of the resulting insulation level.

Duct Leakage Test and Repair

This portion of the program is designed to promote energy efficiency through improved duct system sealing. Through the use of an inspection tool, such as a blower-door, duct leaks can be identified and repaired. This program component applies to HVAC equipment and systems that are no larger than 65,000 Btu/h. A customer must have electric heating (no facilities with combustion appliances are allowed to participate) and a centrally-ducted cooling system, either air conditioning or heat pump, to be eligible for this program. If a building has excess ventilation such that the building can not be pressurized, the building may not be eligible for participation. For the duct test, FPC will pay an incentive of up to a maximum of $30 for the first unit tested and $20 for each additional unit tested. For the duct repair, FPC will pay an incentive of up to a maximum of $100 per unit. The duct repair incentive amount is dependent on the type of electric heating system.

Window Film

FPC will provide customers with an incentive to install window film having a shading coefficient of 0.45 or less on existing east or west windows with shading coefficients of 0.84 or higher. The maximum incentive will be a flat amount per square-foot of window film installed. The total incentive per customer can not exceed $125. An exception to this limitation will be made for facilities with multiple guest rooms, such as hotels, motels, hospitals, and assisted-care living facilities, which may receive incentives up to a maximum of $50 per room.

Financing

FPC is also offering interest-free installment billing (over a 12-month period). As an alternative to receiving an incentive payment, customers may opt to finance up to $500 through installment billing. Installment billing allows the customer to spread the cost over 12 months at no interest. The installment billing payments will be billed monthly.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Measure Participants [2]	Cumulative Penetration Level (%)
2000	938,991	938,991	4,123	0.4%
2001	966,999	966,999	8,151	1%
2002	996,029	996,029	12,347	1%
2003	1,026,116	1,026,116	16,571	2%
2004	1,048,843	1,048,843	20,756	2%
2005	1,072,198	1,072,198	24,947	2%
2006	1,096,103	1,096,103	28,693	3%
2007	1,120,653	1,120,653	32,260	3%
2008	1,139,300	1,139,300	35,714	3%
2009	1,158,339	1,158,339	39,001	3%

1. *Total Number of Customers is the forecast of commercial floorspace (in 000s of sq.ft.).*
2. *Annual Number of Measure Participants is the cumulativefloorspace (in 000s sq.ft.) projected to participate, assuming no measure overlap.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	337	0.14	0.19	1,390,261	560	787
2001	302	0.13	0.16	2,464,851	1,049	1,297
2002	290	0.12	0.15	3,575,760	1,532	1,847
2003	283	0.12	0.14	4,695,076	2,019	2,400
2004	281	0.12	0.14	5,830,782	2,514	2,962
2005	281	0.12	0.14	7,013,017	3,016	3,561
2006	281	0.12	0.14	8,076,121	3,471	4,094
2007	284	0.12	0.14	9,162,477	3,932	4,647
2008	282	0.12	0.14	10,082,487	4,374	5,021
2009	288	0.12	0.14	11,228,961	4,841	5,628

At the Generator						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	354	0.14	0.20	1,460,973	586	831
2001	318	0.13	0.17	2,590,312	1,098	1,368
2002	304	0.13	0.16	3,757,766	1,603	1,949
2003	298	0.13	0.15	4,934,055	2,113	2,533
2004	295	0.13	0.15	6,127,569	2,631	3,126
2005	295	0.13	0.15	7,369,980	3,156	3,758
2006	296	0.13	0.15	8,487,196	3,632	4,321
2007	298	0.13	0.15	9,628,847	4,114	4,904
2008	297	0.13	0.15	10,595,686	4,576	5,299
2009	303	0.13	0.15	11,800,515	5,066	5,940

Per measure impacts for 2000-2009 are per 1000 sq.ft., assuming no overlap.

Per measure impacts vary from year to year because of the changing mix of measures assumed to be installed in any given year.

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach given the number and type of measures being promoted. Some measures provide large per unit impacts while others yield relatively smaller impacts. The total impact from all smaller-impact measures could potentially be less than the uncertainty around an impact estimate of just one large-impact measure. Consequently, the impact evaluation will place greater emphasis on the larger-impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts. On-site metering may also be used where feasible and cost-effective.

Cost Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	6,537	5,776	761	1.13
Participant	5,602	1,963	3,639	2.85
Total Resource Cost	6,537	2,137	4,400	3.06

PROGRAM: Better Business

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	77	55	0	132	524	0	524	-392
2001	134	54	0	188	251	0	251	-63
2002	201	58	0	259	293	0	293	-34
2003	266	53	0	319	231	0	231	88
2004	332	54	0	386	235	0	235	151
2005	402	58	0	460	277	0	277	183
2006	465	52	0	517	237	0	237	280
2007	531	54	0	585	255	0	255	330
2008	600	58	0	658	294	0	294	364
2009	677	60	0	737	316	0	316	421
2010	687	0	0	687	0	0	0	687
2011	698	0	0	698	0	0	0	698
2012	709	0	0	709	0	0	0	709
2013	720	0	0	720	0	0	0	720
2014	731	0	0	731	0	0	0	731
2015	742	0	0	742	0	0	0	742
2016	754	0	0	754	0	0	0	754
2017	765	0	0	765	0	0	0	765
2018	777	0	0	777	0	0	0	777
2019	789	0	0	789	0	0	0	789
2020	801	0	0	801	0	0	0	801
2021	814	0	0	814	0	0	0	814
2022	827	0	0	827	0	0	0	827
2023	839	0	0	839	0	0	0	839
2024	852	0	0	852	0	0	0	852
2025	866	0	0	866	0	0	0	866
2026	879	0	0	879	0	0	0	879
2027	893	0	0	893	0	0	0	893
2028	906	0	0	906	0	0	0	906
NOMINAL	18734	556	0	19290	2913	0	2913	16377
NPV	5239	363	0	5602	1963	0	1963	3639

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 2.85

PROGRAM: Better Business

TOTAL RESOURCE COST TEST

YEAR	BENEFITS (1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	COSTS (6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	43	37	0	0	80	524	0	0	0	26	550	-470
2001	107	59	0	0	166	251	0	0	0	26	277	-111
2002	102	87	26	0	215	293	0	0	0	28	321	-106
2003	143	112	38	0	293	231	0	0	0	26	257	36
2004	186	138	24	0	348	235	0	0	0	26	261	87
2005	1332	165	54	0	1551	277	0	0	0	27	304	1247
2006	312	189	40	0	541	237	0	0	0	26	263	278
2007	286	214	45	0	545	255	0	0	0	27	282	263
2008	1468	241	46	0	1755	294	0	0	0	28	322	1433
2009	366	268	55	0	689	316	0	0	0	28	344	345
2010	500	268	55	0	823	0	0	0	0	0	0	823
2011	374	268	59	0	701	0	0	0	0	0	0	701
2012	377	268	0	0	645	0	0	0	0	0	0	645
2013	382	268	63	0	713	0	0	0	0	0	0	713
2014	362	268	63	0	693	0	0	0	0	0	0	693
2015	391	268	67	0	726	0	0	0	0	0	0	726
2016	398	268	66	0	732	0	0	0	0	0	0	732
2017	399	268	72	0	739	0	0	0	0	0	0	739
2018	406	268	71	0	745	0	0	0	0	0	0	745
2019	407	268	76	0	751	0	0	0	0	0	0	751
2020	413	268	75	0	756	0	0	0	0	0	0	756
2021	415	268	81	0	764	0	0	0	0	0	0	764
2022	417	268	80	0	765	0	0	0	0	0	0	765
2023	425	268	86	0	779	0	0	0	0	0	0	779
2024	435	268	84	0	787	0	0	0	0	0	0	787
2025	437	268	91	0	796	0	0	0	0	0	0	796
2026	446	268	92	0	806	0	0	0	0	0	0	806
2027	448	268	97	0	813	0	0	0	0	0	0	813
2028	457	268	95	0	820	0	0	0	0	0	0	820
NOMINAL	12234	6602	1701	0	20537	2913	0	0	0	268	3181	17356
NPV	4113	1970	454	0	6537	1963	0	0	0	174	2137	4400

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 3.06

PROGRAM: Better Business

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	43	37	0	0	80	0	0	0	26	55	77	158	-78
2001	107	59	0	0	166	0	0	0	26	54	134	214	-48
2002	102	87	26	0	215	0	0	0	28	58	201	287	-72
2003	143	112	38	0	293	0	0	0	26	53	266	345	-52
2004	186	138	24	0	348	0	0	0	26	54	332	412	-64
2005	1332	165	54	0	1551	0	0	0	27	58	402	487	1064
2006	312	189	40	0	541	0	0	0	26	52	465	543	-2
2007	286	214	45	0	545	0	0	0	27	54	531	612	-67
2008	1468	241	46	0	1755	0	0	0	28	58	600	686	1069
2009	366	268	55	0	689	0	0	0	28	60	677	765	-76
2010	500	268	55	0	823	0	0	0	0	0	687	687	136
2011	374	268	59	0	701	0	0	0	0	0	698	698	3
2012	377	268	0	0	645	0	0	0	0	0	709	709	-64
2013	382	268	63	0	713	0	0	0	0	0	720	720	-7
2014	362	268	63	0	693	0	0	0	0	0	731	731	-38
2015	391	268	67	0	726	0	0	0	0	0	742	742	-16
2016	398	268	66	0	732	0	0	0	0	0	754	754	-22
2017	399	268	72	0	739	0	0	0	0	0	765	765	-26
2018	406	268	71	0	745	0	0	0	0	0	777	777	-32
2019	407	268	76	0	751	0	0	0	0	0	789	789	-38
2020	413	268	75	0	756	0	0	0	0	0	801	801	-45
2021	415	268	81	0	764	0	0	0	0	0	814	814	-50
2022	417	268	80	0	765	0	0	0	0	0	827	827	-62
2023	425	268	86	0	779	0	0	0	0	0	839	839	-60
2024	435	268	84	0	787	0	0	0	0	0	852	852	-65
2025	437	268	91	0	796	0	0	0	0	0	866	866	-70
2026	446	268	92	0	806	0	0	0	0	0	879	879	-73
2027	448	268	97	0	813	0	0	0	0	0	893	893	-80
2028	457	268	95	0	820	0	0	0	0	0	906	906	-86
NOMINAL	12234	6602	1701	0	20537	0	0	0	268	556	18734	19558	979
NPV	4113	1970	454	0	6537	0	0	0	174	363	5239	5776	761

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.13

C. COMMERCIAL/INDUSTRIAL NEW CONSTRUCTION PROGRAM

Program Start Date: ▸ 1995

▸ Proposed modification for 2000

Policies and Procedures

The primary goal of the FPC's Commercial/Industrial (C/I) New Construction program is to foster the design and construction of energy efficient buildings. The new construction program will: 1) provide education and information to the design community on all aspects of energy efficient building design; 2) require that the building design, at a minimum, surpass the state energy code; 3) provide financial incentives for specific energy efficient equipment; and 4) provide energy design awards to building design teams. The program will simultaneously target building developers/owners and the building design community and will work one-on-one with them throughout a new construction project. FPC will focus on developing relationships with the key decision-makers of commercial and industrial new construction so as to be able to get involved early in the design process. FPC proposes to remove incentives for Duct Leakage Testing and Repair, which have previously been offered through this program.

The general eligibility requirements are as follows:

- The new construction project location must be established within FPC's service territory.
- The new construction building must be served by a FPC account prior to the issuance of any incentive payment.
- The participant must be willing to allow FPC to inspect the installation of all measures and equipment prior to receiving any incentive payments.
- All equipment installations shall meet manufacturers' instructions and specifications.

Incentives will be provided for high efficiency HVAC equipment, motors, and heat recovery units. Incentive levels and specific eligibility requirements for each of the measures promoted in this program will be presented in the Program Participation Standards and will be subject to revision based on changes in market conditions, such as baseline or code revisions, evaluation findings, or technological advances.

HVAC Equipment

The HVAC equipment component of C/I New Construction provides customers with information on high efficiency HVAC equipment and financial incentives for the purchase of very high efficiency unitary heat pumps and air conditioners, packaged rooftop units, packaged terminal heat pumps (PTHPs), and water-cooled and air-cooled chillers. The incentive is calculated for each unit based on the kW difference between the high efficiency unit and the program-specified baseline efficiency (at ARI Standard Test Rating Conditions) and is calculated using a dollar per kW reduced incentive up to $100/kW reduced.

Motors

The program promotes the installation of high efficiency polyphase motors through a simple incentive structure. The incentive for any given motor is calculated based on the motor size and a specified $/hp. The maximum incentive amount will be up to $2.00 per hp and the specific incentive amount will be a function of the motor size. To maintain cost-effectiveness, a minimum number of motors per application will be established for motors that are 25 hp and smaller.

Heat Recovery Units

The program promotes the installation of heat recovery units for water heating by providing an incentive for each unit installed. FPC will pay a maximum incentive of up to $100 per unit when installed on heat pumps or straight air units that are five tons or less.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2}	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2000	938,991	27,037	1,613	6%
2001	966,999	55,045	3,154	6%
2002	996,029	84,075	4,912	6%
2003	1,026,116	114,162	6,892	6%
2004	1,048,843	136,889	9,085	7%
2005	1,072,198	160,245	11,464	7%
2006	1,096,103	184,149	13,811	7%
2007	1,120,653	208,700	16,248	8%
2008	1,139,300	227,346	18,777	8%
2009	1,158,339	246,385	21,349	9%

1. *Total Number of Customers is the forecast of commercial floorspace (in 000s of sq.ft.).*
2. *Total Number of Eligible Customers is the forecast of cumulative commercialfloorspace additions after 1999 (in 000s of sq.ft.),*
3. *Annual Number of Measure Participants is the cumulativefloorspace (in 000s of sq.ft.) projected to participate, assuming no measure overlap.*

Savings Estimates

Total program savings were developed by first estimating the total savings for each individual measure based on each measure's (1) per customer savings and, (2) annual projected participation. The total program savings were then computed as the sum of the individual measure savings, and are shown in the following tables.

At the Meter						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	226	0.13	0.15	364,326	214	248
2001	216	0.13	0.14	679,977	395	455
2002	207	0.12	0.14	1,016,653	584	669
2003	199	0.11	0.13	1,374,479	782	889
2004	193	0.11	0.12	1,753,030	989	1,116
2005	188	0.11	0.12	2,150,031	1,204	1,349
2006	183	0.10	0.11	2,531,132	1,408	1,569
2007	180	0.10	0.11	2,922,778	1,618	1,793
2008	177	0.10	0.11	3,325,734	1,833	2,022
2009	175	0.10	0.11	3,736,460	2,052	2,256

At the Generator						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	237	0.14	0.16	382,870	2245	261
2001	227	0.13	0.15	714,588	413	480
2002	218	0.12	0.14	1,068,401	611	706
2003	210	0.12	0.14	1,444,440	818	938
2004	203	0.11	0.13	1,842,259	1,036	1,178
2005	197	0.11	0.12	2,259,468	1,260	1,423
2006	193	0.11	0.12	2,659,967	1,474	1,655
2007	189	0.10	0.12	3,071,547	1,693	1,892
2008	186	0.10	0.11	3,495,014	1,918	2,134
2009	184	0.10	0.11	3,926,646	2,147	2,381

Per measure impacts for 2000-2009 are per 1000 sq.ft., assuming no overlap.

Per measure impacts vary from year to year because of the changing mix of measures assumed to be installed in any given year.

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach, given the number and type of measures being promoted. Some measures provide large per unit impacts while others yield relatively smaller impacts. The total impact from all smaller-impact measures could potentially be less than the uncertainty around an impact estimate of just one large-impact measure. Consequently, the impact evaluation will place greater emphasis on the larger-impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts. On-site metering may also be used, where feasible and cost-effective.

Cost Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	1,948	1,855	93	1.05
Participant	1,727	448	1,279	3.86
Total Resource Cost	1,948	576	1,372	3.38

PROGRAM: Commercial/Industrial New Construction

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	20	9	0	29	73	0	73	-44
2001	38	7	0	45	63	0	63	-18
2002	57	8	0	65	65	0	65	0
2003	78	8	0	86	67	0	67	19
2004	100	9	0	109	69	0	69	40
2005	123	9	0	132	71	0	71	61
2006	146	9	0	155	68	0	68	87
2007	169	9	0	178	69	0	69	109
2008	194	9	0	203	70	0	70	133
2009	221	9	0	230	72	0	72	158
2010	225	0	0	225	0	0	0	225
2011	228	0	0	228	0	0	0	228
2012	232	0	0	232	0	0	0	232
2013	235	0	0	235	0	0	0	235
2014	239	0	0	239	0	0	0	239
2015	243	0	0	243	0	0	0	243
2016	246	0	0	246	0	0	0	246
2017	250	0	0	250	0	0	0	250
2018	254	0	0	254	0	0	0	254
2019	258	0	0	258	0	0	0	258
2020	262	0	0	262	0	0	0	262
2021	266	0	0	266	0	0	0	266
2022	270	0	0	270	0	0	0	270
2023	274	0	0	274	0	0	0	274
2024	279	0	0	279	0	0	0	279
2025	283	0	0	283	0	0	0	283
2026	287	0	0	287	0	0	0	287
2027	292	0	0	292	0	0	0	292
2028	296	0	0	296	0	0	0	296
NOMINAL	6065	86	0	6151	687	0	687	5464
NPV	1672	55	0	1727	448	0	448	1279

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 3.86

PROGRAM: Commercial/Industrial New Construction

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	12	12	0	0	24	73	0	0	0	20	93	-69
2001	24	22	0	0	46	63	0	0	0	19	82	-36
2002	30	32	8	0	70	65	0	0	0	19	84	-14
2003	43	43	11	0	97	67	0	0	0	20	87	10
2004	57	54	7	0	118	69	0	0	0	20	89	29
2005	191	66	18	0	275	71	0	0	0	20	91	184
2006	96	77	10	0	183	68	0	0	0	20	88	95
2007	93	88	15	0	196	69	0	0	0	20	89	107
2008	134	100	15	0	249	70	0	0	0	20	90	159
2009	121	111	19	0	251	72	0	0	0	20	92	159
2010	123	111	19	0	253	0	0	0	0	0	0	253
2011	123	111	20	0	254	0	0	0	0	0	0	254
2012	126	111	20	0	257	0	0	0	0	0	0	257
2013	126	111	21	0	258	0	0	0	0	0	0	258
2014	102	111	22	0	235	0	0	0	0	0	0	235
2015	129	111	23	0	263	0	0	0	0	0	0	263
2016	132	111	22	0	265	0	0	0	0	0	0	265
2017	132	111	24	0	267	0	0	0	0	0	0	267
2018	134	111	24	0	269	0	0	0	0	0	0	269
2019	134	111	25	0	270	0	0	0	0	0	0	270
2020	137	111	26	0	274	0	0	0	0	0	0	274
2021	137	111	27	0	275	0	0	0	0	0	0	275
2022	140	111	28	0	279	0	0	0	0	0	0	279
2023	141	111	29	0	281	0	0	0	0	0	0	281
2024	144	111	28	0	283	0	0	0	0	0	0	283
2025	144	111	31	0	286	0	0	0	0	0	0	286
2026	147	111	31	0	289	0	0	0	0	0	0	289
2027	148	111	33	0	292	0	0	0	0	0	0	292
2028	151	111	32	0	294	0	0	0	0	0	0	294
NOMINAL	3351	2714	588	0	6653	687	0	0	0	198	885	5768
NPV	991	801	156	0	1948	448	0	0	0	128	576	1372

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 3.38

PROGRAM: Commercial/Industrial New Construction

RATE IMPACT MEASURE TEST

YEAR	BENEFITS (1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	COSTS (6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	12	12	0	0	24	0	0	0	20	9	20	49	-25
2001	24	22	0	0	46	0	0	0	19	7	38	64	-18
2002	30	32	8	0	70	0	0	0	19	8	57	84	-14
2003	43	43	11	0	97	0	0	0	20	8	78	106	-9
2004	57	54	7	0	118	0	0	0	20	9	100	129	-11
2005	191	66	18	0	275	0	0	0	20	9	123	152	123
2006	96	77	10	0	183	0	0	0	20	9	146	175	8
2007	93	88	15	0	196	0	0	0	20	9	169	198	-2
2008	134	100	15	0	249	0	0	0	20	9	194	223	26
2009	121	111	19	0	251	0	0	0	20	9	221	250	1
2010	123	111	19	0	253	0	0	0	0	0	225	225	28
2011	123	111	20	0	254	0	0	0	0	0	228	228	26
2012	126	111	20	0	257	0	0	0	0	0	232	232	25
2013	126	111	21	0	258	0	0	0	0	0	235	235	23
2014	102	111	22	0	235	0	0	0	0	0	239	239	-4
2015	129	111	23	0	263	0	0	0	0	0	243	243	20
2016	132	111	22	0	265	0	0	0	0	0	246	246	19
2017	132	111	24	0	267	0	0	0	0	0	250	250	17
2018	134	111	24	0	269	0	0	0	0	0	254	254	15
2019	134	111	25	0	270	0	0	0	0	0	258	258	12
2020	137	111	26	0	274	0	0	0	0	0	262	262	12
2021	137	111	27	0	275	0	0	0	0	0	266	266	9
2022	140	111	28	0	279	0	0	0	0	0	270	270	9
2023	141	111	29	0	281	0	0	0	0	0	274	274	7
2024	144	111	28	0	283	0	0	0	0	0	279	279	4
2025	144	111	31	0	286	0	0	0	0	0	283	283	3
2026	147	111	31	0	289	0	0	0	0	0	287	287	2
2027	148	111	33	0	292	0	0	0	0	0	292	292	0
2028	151	111	32	0	294	0	0	0	0	0	296	296	-2
NOMINAL	3351	2714	588	0	6653	0	0	0	198	86	6065	6349	304
NPV	991	801	156	0	1948	0	0	0	128	55	1672	1855	93

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.05

D. INNOVATION INCENTIVE PROGRAM

Program Start Date: ▸ 1992
▸ Modified in 1995

Policies and Procedures

The Innovation Incentive program promotes a reduction in kW and kWh by subsidizing energy conservation projects for customers in the FPC service territory. The intent of the program is to encourage legitimate energy efficiency measures that reduce peak kW demand and/or kWh energy, but which are not addressed by other programs.

Energy efficiency opportunities are identified by FPC representatives during a Business Energy Check audit and are presented to the customer as part of the Business Energy Check report. Requirements for participation in this program are also explained to the customer at that time. If the customer chooses to implement modifications to effect energy efficiency improvements that are not addressed in other FPC energy efficiency programs, the modifications would be eligible for consideration under this program.

Representative examples of energy efficient technologies that would be considered under this program include, but are not limited to, refrigeration equipment replacements to improve efficiency, thermal energy storage systems, microwave drying systems, and inductive heating systems to replace resistance heating systems.

The program is available to all business customers in FPC's territory for projects that reduce peak demand by a minimum of 10 kW.

Program eligibility requirements to qualify for participation are as follows:

- Participant must be located in the FPC service territory and be a metered business customer.
- The customer is required to have an audit (any level) completed by FPC prior to participation in the program, except in the case of new construction projects.
- Projects must reduce or shift peak demand by a minimum of 10 kW.
- The participant must be willing to allow FPC to inspect the installations of all measures and equipment.

If the described project meets the program specifications, FPC will provide project approval and projected incentive payment amounts. Engineering designs, cost estimates, and energy savings projections must be submitted under a professional seal, when necessary. The customer may be required to monitor the project after completion to verify kW and kWh savings. Monitoring methods shall be approved by FPC. Costs for monitoring equipment should be included in the overall project cost estimate.

FPC will perform a customer-specific cost-effectiveness analysis for each project being considered under the Innovation Incentive program, using the Commission-approved cost-effectiveness tests described in Rule 25-17.008, Florida Administrative Code. To receive an incentive, each project must pass the Rate Impact Measure (RIM) and Participant tests of cost-effectiveness. The customer's incentive shall be based upon the RIM results, with the maximum allowable rebate being $150 per peak kW reduced or shifted to an off peak period.

After FPC has reviewed and approved the project, a contract will be executed between FPC and the customer, in which FPC agrees to subsidize the customer upon completion of the project.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	3,333	1	0
2001	166,984	3,398	3	0
2002	170,356	3,463	4	0
2003	173,705	3,527	6	0
2004	177,016	3,590	7	0
2005	180,239	3,651	8	0
2006	183,373	3,710	9	0
2007	186,419	3,767	10	0
2008	189,416	3,823	11	0
2009	192,406	3,879	12	0

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*
2. *Total Number of Eligible Customers is based on the total number of customers whose peak monthly demand exceeds 100 kW.*

Savings Estimates

The total program savings are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	120,047	70	70	120,047	70	70
2001	120,047	70	70	360,141	210	210
2002	120,047	70	70	480,188	280	280
2003	120,047	70	70	720,282	420	420
2004	120,047	70	70	840,329	490	490
2005	120,047	70	70	960,376	560	560
2006	120,047	70	70	1,080,423	630	630
2007	120,047	70	70	1,200,470	700	700
2008	120,047	70	70	1,320,517	770	770
2009	120,047	70	70	1,440,564	840	840

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	126,157	73	73	126,157	73	74
2001	126,157	73	73	378,472	220	222
2002	126,157	73	73	504,630	293	295
2003	126,157	73	73	456,944	439	443
2004	126,157	73	73	883,102	513	517
2005	126,157	73	73	1,009,259	586	591
2006	126,157	73	73	1,135,417	659	665
2007	126,157	73	73	1,261,574	732	739
2008	126,157	73	73	1,387,731	806	813
2009	126,157	73	73	1,513,889	879	886

Impact Evaluation Plan

To verify the estimated savings for each project, an engineering/billing analysis based on customer-specific site and usage data will be performed. Monitoring will continue until FPC has reasonable assurance that the project will remain in place and produce cost-effective energy savings for its estimated life. An incentive will not be issued to the customer until FPC is reasonably sure of the projected savings.

Cost Effectiveness

Each individual project will be analyzed for cost-effectiveness at the time of project submittal to FPC, using the Commission-approved tests of cost-effectiveness. Therefore, total program cost-effectiveness results are not shown. All projects must achieve a benefit-cost ratio of at least 1.0 on the RIM and Participant tests to receive an incentive under this program.

E. COMMERCIAL ENERGY MANAGEMENT PROGRAM

Program Start Date:
- 1983
- Modified in 1995
- Proposed modification for 2000

Policies and Procedures

The Commercial Energy Management program is a direct load control program that reduces FPC's demand during peak or emergency conditions. FPC will have direct control of the customer's selected participating equipment. The customer will receive a monthly credit on their bill depending on the interruption schedule and the devices which are participating in the program. *(Please refer to the GSLM-1 tariff for details.)*

The program is available to FPC customers eligible for service under the GS-1, GST-1, GSD-1, or GSDT-1 rate schedules, and who elect service under the GSLM-1 rate schedule and have electric space cooling equipment suitable for interruptible operation. The program is also applicable to customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: (1) water heater(s), (2) central electric heating system(s), (3) central electric cooling system(s), and/or (4) swimming pool pump(s). Customers must be within the range of the Company's load management system in order to be eligible for the program.

Like the Residential Energy Management Program, FPC has determined that it is no longer cost-effective under the RIM test to continue adding new participants to the Commercial Energy Management program. (Pages IV-28 through IV-30 present the results of all three Commission-approved tests of cost-effectiveness.) As a result, the Company is proposing to close the program to new participants.

Domestic Commercial Energy Management

Currently, for domestically utilized equipment (i.e., the domestic (household) commercial portion of the Commercial Energy Management program), the GSLM-1 rate schedule simply references the Residential Energy Management's RSL-1 tariff in regard to control schedules and credit structure. FPC's proposed domestic commercial modifications will continue this direct link, as well as include a reference to the proposed new RSL-2 (Winter-Only) rate schedule, for all existing buildings that have an active Energy Management installation. The primary changes to the Domestic Commercial Energy Management portion of the program are as follows:

- The program will be closed to new participation, such that there will be no new domestic Commercial Energy Management installations.

- All existing domestic commercial Energy Management participants will be allowed to remain on the existing year-round program as long as they do not change their current control schedule.
- Prior to April 1, 2001, all new customer accounts associated with an active Energy Management-equipped building will be treated as an existing participant and allowed on the existing year-round program, if they maintain the same control schedules as the previous customer and do not require a service trip. If any changes in control schedule are made, then the customer will only be eligible for the proposed new Winter-Only RSL-2 rate schedule. (For details on this Winter-Only rate schedule, please see the Residential Energy Management Program, and the proposed RSL-2 rate schedule.)
- Beginning April 1, 2001, new customer accounts associated with an active Energy Management equipped building will no longer be eligible to continue the previous participant's service under the existing year-round Energy Management rate schedule. However, they will be eligible for the proposed new Winter-Only RSL-2 rate schedule.

Non-Domestic Commercial Energy Management

The non-domestic portion of the Commercial Energy Management Program is a summer-only component that offers an incentive for direct load control of electric cooling equipment. This is opposite of the direction FPC seeks to move the Residential Energy Management program, which would only allow new participants on a winter-only control schedule. FPC is, therefore, proposing that this non-domestic portion of the program be closed to new participation. All existing non-domestic commercial Energy Management participants will be allowed to remain on the existing program, as long as they do not change their current control schedule such that it requires a service trip. However, new customer accounts will not be eligible to continue a previous participant's service under this program.

Proposed changes to the GSLM-1 rate schedule (in legislative format) are presented in the Appendix to this document.

Program Participation

Given FPC's proposal to close the Commercial Energy Management Program to new participants, there are not projected to be any new participation during the 2000-2009 period.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	145,483	0	0%
2001	166,984	148,335	0	0%
2002	170,356	151,155	0	0%
2003	173,705	153,952	0	0%
2004	177,016	156,710	0	0%
2005	180,239	159,380	0	0%
2006	183,373	161,963	0	0%
2007	186,419	164,456	0	0%
2008	189,416	166,901	0	0%
2009	192,406	169,338	0	0%

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*

Savings Estimates

The total program savings for the Winter-Only Energy Management component of the program are shown in the following tables. Since there will be no new participants or savings from the Commercial Energy Management component, this program will not be used to meet FPC's Commission-approved conservation goals.

At the Meter						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

At the Generator						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

Impact Evaluation Plan

Since FPC is proposing to close this program to all new participation, and allow attrition to slowly end the existing program, FPC plans to maintain only a minimal evaluation effort that will use existing resources to address the domestic (household) portion of this program. As noted in the Residential Energy Management Program, FPC is in the process of conducting a residential end-use metering study that will be used to estimate the appliance level, and duty-cycle impacts of residential load control. This same data will be applied to the domestic portion of the Commercial Energy Management program to improve program impact estimates.

Cost Effectiveness

The following economic results are for the current Commercial Energy Management Program:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	144	187	-43	0.79
Participant	56	0	56	9999
Total Resource Cost	144	131	13	1.13

PROGRAM: Commercial Energy Management

PARTICIPANT TEST

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	0	1	0	1	0	0	0	1
2001	0	1	0	1	0	0	0	1
2002	0	2	0	2	0	0	0	2
2003	0	3	0	3	0	0	0	3
2004	0	3	0	3	0	0	0	3
2005	3	4	0	7	0	0	0	7
2006	0	5	0	5	0	0	0	5
2007	0	6	0	6	0	0	0	6
2008	0	6	0	6	0	0	0	6
2009	0	7	0	7	0	0	0	7
2010	1	7	0	8	0	0	0	8
2011	1	7	0	8	0	0	0	8
2012	1	7	0	8	0	0	0	8
2013	1	7	0	8	0	0	0	8
2014	1	7	0	8	0	0	0	8
2015	1	7	0	8	0	0	0	8
2016	1	7	0	8	0	0	0	8
2017	1	7	0	8	0	0	0	8
2018	1	7	0	8	0	0	0	8
2019	1	7	0	8	0	0	0	8
2020	1	7	0	8	0	0	0	8
2021	1	7	0	8	0	0	0	8
2022	1	7	0	8	0	0	0	8
2023	1	7	0	8	0	0	0	8
2024	1	7	0	8	0	0	0	8
2025	1	7	0	8	0	0	0	8
2026	1	7	0	8	0	0	0	8
2027	1	7	0	8	0	0	0	8
2028	1	7	0	8	0	0	0	8
NOMINAL	22	171	0	193	0	0	0	193
NPV	6	50	0	56	0	0	0	56

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Commercial Energy Management

TOTAL RESOURCE COST TEST

YEAR	BENEFITS (1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	COSTS (6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	11	11	-11
2001	0	0	0	0	0	0	0	0	0	11	11	-11
2002	0	0	1	0	1	0	1	0	0	11	12	-11
2003	0	0	1	0	1	0	1	0	0	11	12	-11
2004	0	0	2	0	2	0	1	0	0	11	12	-10
2005	0	0	194	0	194	0	20	0	0	11	31	163
2006	2	0	2	0	4	0	0	0	0	11	11	-7
2007	0	0	2	0	2	0	1	0	0	11	12	-10
2008	0	0	4	0	4	0	1	0	0	11	12	-8
2009	0	0	4	0	4	0	1	0	0	11	12	-8
2010	0	0	4	0	4	0	1	0	0	10	11	-7
2011	0	0	5	0	5	0	1	0	0	10	11	-6
2012	0	0	3	0	3	0	1	0	0	10	11	-8
2013	0	0	3	0	3	0	0	0	0	10	10	-7
2014	0	0	3	0	3	0	1	0	0	10	11	-8
2015	0	0	3	0	3	0	1	0	0	10	11	-8
2016	0	0	3	0	3	0	1	0	0	10	11	-8
2017	0	0	4	0	4	0	0	0	0	10	10	-6
2018	0	0	4	0	4	0	0	0	0	10	10	-6
2019	0	0	4	0	4	0	1	0	0	10	11	-7
2020	0	0	4	0	4	0	0	0	0	10	10	-6
2021	0	0	4	0	4	0	1	0	0	10	11	-7
2022	0	0	4	0	4	0	0	0	0	10	10	-6
2023	0	0	4	0	4	0	0	0	0	10	10	-6
2024	0	0	4	0	4	0	0	0	0	10	10	-6
2025	0	0	4	0	4	0	0	0	0	10	10	-6
2026	0	0	5	0	5	0	0	0	0	10	10	-5
2027	0	0	5	0	5	0	0	0	0	10	10	-5
2028	0	0	5	0	5	0	0	0	0	10	10	-5
NOMINAL	2	0	285	0	287	0	34	0	0	300	334	-47
NPV	1	0	143	0	144	0	18	0	0	113	131	13

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 1.13

PROGRAM: Commercial Energy Management

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	11	1	0	12	-12
2001	0	0	0	0	0	0	0	0	11	1	0	12	-12
2002	0	0	1	0	1	1	0	0	11	2	0	14	-13
2003	0	0	1	0	1	1	0	0	11	3	0	15	-14
2004	0	0	2	0	2	1	0	0	11	3	0	15	-13
2005	0	0	194	0	194	20	0	0	11	4	3	38	156
2006	2	0	2	0	4	0	0	0	11	5	0	16	-12
2007	0	0	2	0	2	1	0	0	11	6	0	18	-16
2008	0	0	4	0	4	1	0	0	11	6	0	18	-14
2009	0	0	4	0	4	1	0	0	11	7	0	19	-15
2010	0	0	4	0	4	1	0	0	10	7	1	19	-15
2011	0	0	5	0	5	1	0	0	10	7	1	19	-14
2012	0	0	3	0	3	1	0	0	10	7	1	19	-16
2013	0	0	3	0	3	0	0	0	10	7	1	18	-15
2014	0	0	3	0	3	1	0	0	10	7	1	19	-16
2015	0	0	3	0	3	1	0	0	10	7	1	19	-16
2016	0	0	3	0	3	1	0	0	10	7	1	19	-16
2017	0	0	4	0	4	0	0	0	10	7	1	18	-14
2018	0	0	4	0	4	0	0	0	10	7	1	18	-14
2019	0	0	4	0	4	1	0	0	10	7	1	19	-15
2020	0	0	4	0	4	0	0	0	10	7	1	18	-14
2021	0	0	4	0	4	1	0	0	10	7	1	19	-15
2022	0	0	4	0	4	0	0	0	10	7	1	18	-14
2023	0	0	4	0	4	0	0	0	10	7	1	18	-14
2024	0	0	4	0	4	0	0	0	10	7	1	18	-14
2025	0	0	4	0	4	0	0	0	10	7	1	18	-14
2026	0	0	5	0	5	0	0	0	10	7	1	18	-13
2027	0	0	5	0	5	0	0	0	10	7	1	18	-13
2028	0	0	5	0	5	0	0	0	10	7	1	18	-13
NOMINAL	2	0	285	0	287	34	0	0	300	171	22	527	-240
NPV	1	0	143	0	144	18	0	0	113	50	6	187	-43

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 0.79

F. STANDBY GENERATION PROGRAM

Program Start Date:
- 1993
- Modified in 1995

Policies and Procedures

The Standby Generation program is a demand control program that will reduce FPC's demand based upon the indirect control of customer equipment. The program is a voluntary program available to all commercial and industrial customers who have on-site generation capability and are willing to reduce their FPC demand when FPC deems it necessary. The program is offered through the General Service Load Management-2 (GSLM-2) rate schedule.

FPC will have no direct control of the customer's equipment, but will rely upon the customer to initiate the generation upon being notified by FPC and continue running it until FPC notifies the customer that the generation is no longer needed. FPC does not restrict other use of the equipment by the customer.

Standby Generation program participants will receive a monthly credit on their energy bill according to the demonstrated ability of the customer to reduce demand at FPC's request. The credit will be based upon the load served by the customer's generator, which would have been served by FPC if the Standby Generation program were not in operation. By compensating the customer for the use of their on-site generation, FPC can impact the commercial and industrial market while minimizing rate impacts.

The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the GS-1, GST-1, GSD-1 or GSDT-1 Rate Schedules.
- Customer must have standby generation that will allow facility demand reduction at the request of FPC.
- Customer's Standby Generation Capacity calculation must be at least 50 kW.
- Customer must be within the range of FPC's load management system.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	538	5	1%
2001	166,984	549	10	2%
2002	170,356	559	15	3%
2003	173,705	570	20	4%
2004	177,016	580	25	4%
2005	180,239	590	30	5%
2006	183,373	599	35	6%
2007	186,419	608	40	7%
2008	189,416	618	45	7%
2009	192,406	627	50	8%

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*
2. *Total Number of Eligible Customers is based on the total number of customers having on-site generation.*

Savings Estimates

The kW and kWh savings estimates for this program were determined from historical data and are presented below.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	5,910	600	600	29,550	3,000	3,000
2001	5,910	600	600	59,100	6,000	6,000
2002	5,910	600	600	88,650	9,000	9,000
2003	5,910	600	600	118,200	12,000	12,000
2004	5,910	600	600	147,750	15,000	15,000
2005	5,910	600	600	177,300	18,000	18,000
2006	5,910	600	600	206,850	21,000	21,000
2007	5,910	600	600	236,400	24,000	24,000
2008	5,910	600	600	265,950	27,000	27,000
2009	5,910	600	600	295,500	30,000	30,000

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	6,211	628	633	31,054	3,139	3,166
2001	6,211	628	633	62,108	6,278	6,332
2002	6,211	628	633	93,162	9,418	9,498
2003	6,211	628	633	124,216	12,557	12,664
2004	6,211	628	633	155,270	15,696	15,830
2005	6,211	628	633	186,325	18,835	18,995
2006	6,211	628	633	217,379	21,974	22,161
2007	6,211	628	633	248,433	25,114	25,327
2008	6,211	628	633	279,487	28,253	28,493
2009	6,211	628	633	310,541	31,392	31,659

Impact Evaluation Plan

FPC uses on-site metering to measure the generation capability of each Standby Generation program participant to reduce load at the time they join the program. The customer and a FPC representative will observe the metering tests to determine the load that the standby generator carries. This system testing will also determine the initial readings that will be recorded in order to determine the incentive that the customer will receive on their bill each month. Engineering analysis is used to estimate on-going program savings for each participant based upon monitoring their generator usage.

Cost Effectiveness

The economic results of the program are as follows.

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	7,226	6,323	903	1.14
Participant	5,598	0	5,598	9999
Total Resource Cost	7,226	725	6,501	9.97

PROGRAM: Standby Generation

PARTICIPANT TEST

YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
	BENEFITS				COSTS			
1999	0	0	0	0	0	0	0	0
2000	2	75	0	77	0	0	0	77
2001	5	149	0	154	0	0	0	154
2002	6	224	0	230	0	0	0	230
2003	5	298	0	303	0	0	0	303
2004	13	373	0	386	0	0	0	386
2005	12	447	0	459	0	0	0	459
2006	14	522	0	536	0	0	0	536
2007	18	596	0	614	0	0	0	614
2008	15	671	0	686	0	0	0	686
2009	30	745	0	775	0	0	0	775
2010	37	745	0	782	0	0	0	782
2011	29	745	0	774	0	0	0	774
2012	37	745	0	782	0	0	0	782
2013	30	745	0	775	0	0	0	775
2014	36	745	0	781	0	0	0	781
2015	28	745	0	773	0	0	0	773
2016	32	745	0	777	0	0	0	777
2017	27	745	0	772	0	0	0	772
2018	35	745	0	780	0	0	0	780
2019	28	745	0	773	0	0	0	773
2020	31	745	0	776	0	0	0	776
2021	29	745	0	774	0	0	0	774
2022	32	745	0	777	0	0	0	777
2023	30	745	0	775	0	0	0	775
2024	33	745	0	778	0	0	0	778
2025	30	745	0	775	0	0	0	775
2026	34	745	0	779	0	0	0	779
2027	31	745	0	776	0	0	0	776
2028	35	745	0	780	0	0	0	780
NOMINAL	724	18255	0	18979	0	0	0	18979
NPV	199	5400	0	5598	0	0	0	5598

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Standby Generation

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	25	0	0	27	0	0	0	0	10	10	17
2001	6	50	0	0	56	0	0	0	0	10	10	46
2002	0	75	142	0	217	0	116	0	0	10	126	91
2003	0	100	149	0	249	0	136	0	0	10	146	103
2004	0	125	273	0	398	0	158	0	0	10	168	230
2005	650	150	446	0	1246	0	0	0	0	10	10	1236
2006	261	175	322	0	758	0	0	0	0	10	10	748
2007	0	200	293	0	493	0	51	0	0	10	61	432
2008	0	225	553	0	778	0	95	0	0	10	105	673
2009	0	250	635	0	885	0	81	0	0	10	91	794
2010	0	250	653	0	903	0	80	0	0	10	90	813
2011	0	250	675	0	925	0	77	0	0	10	87	838
2012	0	250	695	0	945	0	70	0	0	10	80	865
2013	0	250	718	0	968	0	69	0	0	10	79	889
2014	0	250	739	0	989	0	65	0	0	10	75	914
2015	0	250	764	0	1014	0	64	0	0	10	74	940
2016	0	250	785	0	1035	0	59	0	0	10	69	966
2017	0	250	812	0	1062	0	57	0	0	10	67	995
2018	0	250	835	0	1085	0	46	0	0	10	56	1029
2019	0	250	863	0	1113	0	45	0	0	10	55	1058
2020	0	250	887	0	1137	0	39	0	0	10	49	1088
2021	0	250	917	0	1167	0	35	0	0	10	45	1122
2022	0	250	943	0	1193	0	33	0	0	10	43	1150
2023	0	250	975	0	1225	0	25	0	0	10	35	1190
2024	0	250	1002	0	1252	0	19	0	0	10	29	1223
2025	0	250	1036	0	1286	0	15	0	0	10	25	1261
2026	0	250	1066	0	1316	0	12	0	0	10	22	1294
2027	0	250	1102	0	1352	0	4	0	0	10	14	1338
2028	4	250	1132	0	1386	0	0	0	0	10	10	1376
NOMINAL	923	6125	19412	0	26460	0	1451	0	0	290	1741	24719
NPV	552	1811	4863	0	7226	0	619	0	0	106	725	6501

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 9.97

PROGRAM: Standby Generation

RATE IMPACT MEASURE TEST

YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
	BENEFITS					COSTS							
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	25	0	0	27	0	0	0	10	75	2	87	-60
2001	6	50	0	0	56	0	0	0	10	149	5	164	-108
2002	0	75	142	0	217	116	0	0	10	224	6	356	-139
2003	0	100	149	0	249	136	0	0	10	298	5	449	-200
2004	0	125	273	0	398	158	0	0	10	373	13	554	-156
2005	650	150	446	0	1246	0	0	0	10	447	12	469	777
2006	261	175	322	0	758	0	0	0	10	522	14	546	212
2007	0	200	293	0	493	51	0	0	10	596	18	675	-182
2008	0	225	553	0	778	95	0	0	10	671	15	791	-13
2009	0	250	635	0	885	81	0	0	10	745	30	866	19
2010	0	250	653	0	903	80	0	0	10	745	37	872	31
2011	0	250	675	0	925	77	0	0	10	745	29	861	64
2012	0	250	695	0	945	70	0	0	10	745	37	862	83
2013	0	250	718	0	968	69	0	0	10	745	30	854	114
2014	0	250	739	0	989	65	0	0	10	745	36	856	133
2015	0	250	764	0	1014	64	0	0	10	745	28	847	167
2016	0	250	785	0	1035	59	0	0	10	745	32	846	189
2017	0	250	812	0	1062	57	0	0	10	745	27	839	223
2018	0	250	835	0	1085	46	0	0	10	745	35	836	249
2019	0	250	863	0	1113	45	0	0	10	745	28	828	285
2020	0	250	887	0	1137	39	0	0	10	745	31	825	312
2021	0	250	917	0	1167	35	0	0	10	745	29	819	348
2022	0	250	943	0	1193	33	0	0	10	745	32	820	373
2023	0	250	975	0	1225	25	0	0	10	745	30	810	415
2024	0	250	1002	0	1252	19	0	0	10	745	33	807	445
2025	0	250	1036	0	1286	15	0	0	10	745	30	800	486
2026	0	250	1066	0	1316	12	0	0	10	745	34	801	515
2027	0	250	1102	0	1352	4	0	0	10	745	31	790	562
2028	4	250	1132	0	1386	0	0	0	10	745	35	790	596
NOMINAL	923	6125	19412	0	26460	1451	0	0	290	18255	724	20720	5740
NPV	552	1811	4863	0	7226	619	0	0	106	5400	199	6323	903

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.14

G. INTERRUPTIBLE SERVICE PROGRAM

Program Start Date: ▸ 1996 for the IS-2 and IST-2 rate schedules.

Policies and Procedures

The Interruptible Service (IS) program is a direct load control program that reduces FPC's demand at times of capacity shortage during peak or emergency conditions. The program is available throughout the entire territory served by FPC to any non-residential customer who is willing to have their power interrupted. The program is currently offered through the Interruptible General Service (IS-2) and Interruptible General Service Time of Use (IST-2) rate schedules. The IS-1 and IST-1 rate schedules were closed to new customers in 1996, but remain active for those customers that were grandfathered onto the rate.

FPC will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. If purchased power is available at the time of potential interruption, customers who choose not to have their load interrupted will be assessed at the price of that purchased power supplied. Customers participating in the Interruptible Service program will receive a monthly interruptible demand credit based on their billing demand and billing load factor. The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the IS-2 or IST-2 Rate Schedules.
- Average billing demand must be 500 kW or more.
- Available at primary, transmission, and secondary service voltages.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	869	0	0
2001	166,984	891	0	0
2002	170,356	913	1	0
2003	173,705	936	1	0
2004	177,016	959	1	0
2005	180,239	983	1	0
2006	183,373	1,008	2	0
2007	186,419	1,033	2	0
2008	189,416	1,059	2	0
2009	192,406	1,086	2	0

1. Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.

Savings Estimates

Savings estimate for the Interruptible Service program are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	4,250	500	440	0	0	0
2001	4,250	500	440	0	0	0
2002	4,250	500	440	4,250	500	440
2003	4,250	500	440	4,250	500	440
2004	4,250	500	440	4,250	500	440
2005	4,250	500	440	4,250	500	440
2006	4,250	500	440	8,500	1000	880
2007	4,250	500	440	8,500	1000	880
2008	4,250	500	440	8,500	1000	880
2009	4,250	500	440	8,500	1000	880

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	4,466	523	464	0	0	0
2001	4,466	523	464	0	0	0
2002	4,466	523	464	4,466	523	464
2003	4,466	523	464	4,466	523	464
2004	4,466	523	464	4,466	523	464
2005	4,466	523	464	4,466	523	464
2006	4,466	523	464	8,933	1,046	929
2007	4,466	523	464	8,933	1,046	929
2008	4,466	523	464	8,933	1,046	929
2009	4,466	523	464	8,933	1,046	929

Impact Evaluation Plan

Program impacts are evaluated through on-site interval metering data of all Interruptible Service customers.

Cost-Effectiveness

The cost-effectiveness results of the Interruptible Service program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	272	270	2	1.00
Participant	190	0	190	9999
Total Resource Cost	272	80	192	3.39

PROGRAM: Interruptible Service

PARTICIPANT TEST

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0
2002	0	10	0	10	0	0	0	10
2003	0	10	0	10	0	0	0	10
2004	0	10	0	10	0	0	0	10
2005	1	10	0	11	0	0	0	11
2006	4	21	0	25	0	0	0	25
2007	7	21	0	28	0	0	0	28
2008	5	21	0	26	0	0	0	26
2009	5	21	0	26	0	0	0	26
2010	6	21	0	27	0	0	0	27
2011	6	21	0	27	0	0	0	27
2012	6	21	0	27	0	0	0	27
2013	6	21	0	27	0	0	0	27
2014	6	21	0	27	0	0	0	27
2015	6	21	0	27	0	0	0	27
2016	6	21	0	27	0	0	0	27
2017	6	21	0	27	0	0	0	27
2018	6	21	0	27	0	0	0	27
2019	6	21	0	27	0	0	0	27
2020	6	21	0	27	0	0	0	27
2021	6	21	0	27	0	0	0	27
2022	7	21	0	28	0	0	0	28
2023	7	21	0	28	0	0	0	28
2024	7	21	0	28	0	0	0	28
2025	7	21	0	28	0	0	0	28
2026	7	21	0	28	0	0	0	28
2027	7	21	0	28	0	0	0	28
2028	7	21	0	28	0	0	0	28
NOMINAL	143	523	0	666	0	0	0	666
NPV	36	154	0	190	0	0	0	190

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Interruptible Service

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	5	5	-5
2001	0	0	0	0	0	0	0	0	0	5	5	-5
2002	0	4	8	0	12	0	6	0	0	6	12	0
2003	0	4	6	0	10	0	5	0	0	5	10	0
2004	0	4	8	0	12	0	8	0	0	5	13	-1
2005	56	4	35	0	95	0	0	0	0	5	5	90
2006	0	9	14	0	23	0	1	0	0	6	7	16
2007	0	9	11	0	20	0	1	0	0	5	6	14
2008	0	9	19	0	28	0	3	0	0	5	8	20
2009	0	9	20	0	29	0	3	0	0	5	8	21
2010	0	9	20	0	29	0	3	0	0	5	8	21
2011	0	9	21	0	30	0	3	0	0	5	8	22
2012	0	9	22	0	31	0	2	0	0	5	7	24
2013	0	9	22	0	31	0	2	0	0	5	7	24
2014	0	9	23	0	32	0	2	0	0	5	7	25
2015	0	9	24	0	33	0	2	0	0	5	7	26
2016	0	9	24	0	33	0	2	0	0	5	7	26
2017	0	9	25	0	34	0	2	0	0	5	7	27
2018	0	9	26	0	35	0	2	0	0	5	7	28
2019	0	9	27	0	36	0	2	0	0	5	7	29
2020	0	9	28	0	37	0	1	0	0	5	6	31
2021	0	9	29	0	38	0	1	0	0	5	6	32
2022	0	9	30	0	39	0	1	0	0	5	6	33
2023	0	9	30	0	39	0	1	0	0	5	6	33
2024	0	9	31	0	40	0	1	0	0	5	6	34
2025	0	9	32	0	41	0	0	0	0	5	5	36
2026	0	9	34	0	43	0	0	0	0	5	5	38
2027	0	9	34	0	43	0	0	0	0	5	5	38
2028	0	9	35	0	44	0	0	0	0	5	5	39
NOMINAL	56	223	638	0	917	0	54	0	0	147	201	716
NPV	34	66	172	0	272	0	25	0	0	55	80	192

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 3.39

PROGRAM: Interruptible Service

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	5	0	0	5	-5
2001	0	0	0	0	0	0	0	0	5	0	0	5	-5
2002	0	4	8	0	12	6	0	0	6	10	0	22	-10
2003	0	4	6	0	10	5	0	0	5	10	0	20	-10
2004	0	4	8	0	12	8	0	0	5	10	0	23	-11
2005	56	4	35	0	95	0	0	0	5	10	1	16	79
2006	0	9	14	0	23	1	0	0	6	21	4	32	-9
2007	0	9	11	0	20	1	0	0	5	21	7	34	-14
2008	0	9	19	0	28	3	0	0	5	21	5	34	-6
2009	0	9	20	0	29	3	0	0	5	21	5	34	-5
2010	0	9	20	0	29	3	0	0	5	21	6	35	-6
2011	0	9	21	0	30	3	0	0	5	21	6	35	-5
2012	0	9	22	0	31	2	0	0	5	21	6	34	-3
2013	0	9	22	0	31	2	0	0	5	21	6	34	-3
2014	0	9	23	0	32	2	0	0	5	21	6	34	-2
2015	0	9	24	0	33	2	0	0	5	21	6	34	-1
2016	0	9	24	0	33	2	0	0	5	21	6	34	-1
2017	0	9	25	0	34	2	0	0	5	21	6	34	0
2018	0	9	26	0	35	2	0	0	5	21	6	34	1
2019	0	9	27	0	36	2	0	0	5	21	6	34	2
2020	0	9	28	0	37	1	0	0	5	21	6	33	4
2021	0	9	29	0	38	1	0	0	5	21	6	33	5
2022	0	9	30	0	39	1	0	0	5	21	7	34	5
2023	0	9	30	0	39	1	0	0	5	21	7	34	5
2024	0	9	31	0	40	1	0	0	5	21	7	34	6
2025	0	9	32	0	41	0	0	0	5	21	7	33	8
2026	0	9	34	0	43	0	0	0	5	21	7	33	10
2027	0	9	34	0	43	0	0	0	5	21	7	33	10
2028	0	9	35	0	44	0	0	0	5	21	7	33	11
NOMINAL	56	223	638	0	917	54	0	0	147	523	143	867	50
NPV	34	66	172	0	272	25	0	0	55	154	36	270	2

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.00

H. CURTAILABLE SERVICE PROGRAM

Program Start Date: ▸ 1996 for the CS-2 and CST-2 rate schedules.

Policies and Procedures

The Curtailable Service (CS) program is a direct load control program that will reduce FPC's demand at times of capacity shortage during peak or emergency conditions. The program is available throughout the entire territory served by FPC to any non-residential customer who agrees to curtail 25% of their average monthly billing demand. The program is currently offered through the Curtailable General Service (CS-2) and Curtailable General Service Time of Use (CST-2) rate schedules. The CS-1 and CST-1 rate schedules were closed to new customers in 1996, but remain active for those customers that were grandfathered onto the rate.

FPC will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. If purchased power is available at the time of potential curtailment, customers who choose not to reduce their load will be assessed at the price of that purchased power. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit based on their curtailable demand and billing load factor. The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the CS-2 or CST-2 Rate Schedules.
- Average billing demand must be 500 kW or more.
- Available at primary, transmission, and secondary service voltages.

Program Participation

Cumulative participation estimates for the program are shown in the following table.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	869	0	0
2001	166,984	891	0	0
2002	170,356	913	0	0
2003	173,705	936	0	0
2004	177,016	959	0	0
2005	180,239	983	0	0
2006	183,373	1,008	0	0
2007	186,419	1,033	0	0
2008	189,416	1,059	0	0
2009	192,406	1,086	0	0

1. Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.

Savings Estimates

Savings estimate for the Curtailable Service program are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

Impact Evaluation Plan

Program impacts are evaluated through on-site interval metering data of all Curtailable Service customers.

Cost-Effectiveness

Even though FPC is projecting no new participants for the Curtailable Service Program, in order to evaluate the program for cost-effectiveness a minimal level of participation (one participant every other year) was assumed. The cost-effectiveness results of the Curtailable Service program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	634	479	154	1.32
Participant	251	0	251	9999
Total Resource Cost	634	228	405	2.77

PROGRAM: Curtailable Service

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	0	4	0	4	0	0	0	4
2001	0	4	0	4	0	0	0	4
2002	0	9	0	9	0	0	0	9
2003	0	9	0	9	0	0	0	9
2004	1	13	0	14	0	0	0	14
2005	1	13	0	14	0	0	0	14
2006	7	17	0	24	0	0	0	24
2007	14	17	0	31	0	0	0	31
2008	23	22	0	45	0	0	0	45
2009	23	22	0	45	0	0	0	45
2010	24	22	0	46	0	0	0	46
2011	13	22	0	35	0	0	0	35
2012	13	22	0	35	0	0	0	35
2013	13	22	0	35	0	0	0	35
2014	14	22	0	36	0	0	0	36
2015	14	22	0	36	0	0	0	36
2016	14	22	0	36	0	0	0	36
2017	14	22	0	36	0	0	0	36
2018	15	22	0	37	0	0	0	37
2019	15	22	0	37	0	0	0	37
2020	7	22	0	29	0	0	0	29
2021	7	22	0	29	0	0	0	29
2022	7	22	0	29	0	0	0	29
2023	7	22	0	29	0	0	0	29
2024	8	22	0	30	0	0	0	30
2025	7	22	0	29	0	0	0	29
2026	8	22	0	30	0	0	0	30
2027	7	22	0	29	0	0	0	29
2028	8	22	0	30	0	0	0	30
NOMINAL	284	548	0	832	0	0	0	832
NPV	86	164	0	250	0	0	0	250

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Curtailable Service

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	4	0	0	4	0	0	0	0	15	15	-11
2001	0	4	0	0	4	0	0	0	0	15	15	-11
2002	0	8	18	0	26	0	15	0	0	15	30	-4
2003	0	8	14	0	22	0	13	0	0	15	28	-6
2004	0	12	32	0	44	0	21	0	0	15	36	8
2005	0	12	26	0	38	0	2	0	0	15	17	21
2006	29	16	35	0	80	0	0	0	0	15	15	65
2007	0	16	28	0	44	0	4	0	0	15	19	25
2008	0	19	60	0	79	0	11	0	0	15	26	53
2009	0	19	62	0	81	0	8	0	0	15	23	58
2010	0	19	64	0	83	0	9	0	0	15	24	59
2011	0	19	65	0	84	0	8	0	0	15	23	61
2012	0	19	67	0	86	0	7	0	0	15	22	64
2013	0	19	69	0	88	0	7	0	0	15	22	66
2014	0	19	71	0	90	0	7	0	0	15	22	68
2015	0	19	74	0	93	0	6	0	0	15	21	72
2016	0	19	76	0	95	0	6	0	0	15	21	74
2017	0	19	78	0	97	0	5	0	0	15	20	77
2018	0	19	81	0	100	0	5	0	0	15	20	80
2019	0	19	84	0	103	0	4	0	0	15	19	84
2020	0	19	84	0	103	0	4	0	0	15	19	84
2021	0	19	87	0	106	0	3	0	0	15	18	88
2022	0	19	90	0	109	0	4	0	0	15	19	90
2023	0	19	92	0	111	0	3	0	0	15	18	93
2024	0	19	95	0	114	0	2	0	0	15	17	97
2025	0	19	98	0	117	0	2	0	0	15	17	100
2026	0	19	101	0	120	0	1	0	0	15	16	104
2027	0	19	104	0	123	0	1	0	0	15	16	107
2028	0	19	108	0	127	0	0	0	0	15	15	112
NOMINAL	29	479	1863	0	2371	0	158	0	0	435	593	1778
NPV	16	147	470	0	633	0	70	0	0	160	230	403

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.77

PROGRAM: Curtailable Service

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	4	0	0	4	0	0	0	15	4	0	19	-15
2001	0	4	0	0	4	0	0	0	15	4	0	19	-15
2002	0	8	18	0	26	15	0	0	15	9	0	39	-13
2003	0	8	14	0	22	13	0	0	15	9	0	37	-15
2004	0	12	32	0	44	21	0	0	15	13	1	50	-6
2005	0	12	26	0	38	2	0	0	15	13	1	31	7
2006	29	16	35	0	80	0	0	0	15	17	7	39	41
2007	0	16	28	0	44	4	0	0	15	17	14	50	-6
2008	0	19	60	0	79	11	0	0	15	22	23	71	8
2009	0	19	62	0	81	8	0	0	15	22	23	68	13
2010	0	19	64	0	83	9	0	0	15	22	24	70	13
2011	0	19	65	0	84	8	0	0	15	22	13	58	26
2012	0	19	67	0	86	7	0	0	15	22	13	57	29
2013	0	19	69	0	88	7	0	0	15	22	13	57	31
2014	0	19	71	0	90	7	0	0	15	22	14	58	32
2015	0	19	74	0	93	6	0	0	15	22	14	57	36
2016	0	19	76	0	95	6	0	0	15	22	14	57	38
2017	0	19	78	0	97	5	0	0	15	22	14	56	41
2018	0	19	81	0	100	5	0	0	15	22	15	57	43
2019	0	19	84	0	103	4	0	0	15	22	15	56	47
2020	0	19	84	0	103	4	0	0	15	22	7	48	55
2021	0	19	87	0	106	3	0	0	15	22	7	47	59
2022	0	19	90	0	109	4	0	0	15	22	7	48	61
2023	0	19	92	0	111	3	0	0	15	22	7	47	64
2024	0	19	95	0	114	2	0	0	15	22	8	47	67
2025	0	19	98	0	117	2	0	0	15	22	7	46	71
2026	0	19	101	0	120	1	0	0	15	22	8	46	74
2027	0	19	104	0	123	1	0	0	15	22	7	45	78
2028	0	19	108	0	127	0	0	0	15	22	8	45	82
NOMINAL	29	479	1863	0	2371	158	0	0	435	548	284	1425	946
NPV	16	147	470	0	633	70	0	0	160	164	86	480	153

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.32

V. TECHNOLOGY DEVELOPMENT PROGRAM

V. TECHNOLOGY DEVELOPMENT PROGRAM

Program Start Date: ▸ 1995

Policies and Procedures

The purpose of this program is to establish a system for meeting the goals in Section 366.82(2), Florida Statutes, and Rule 25-17, Florida Administrative Code. Specifically, the following is stated in Rule 25-17.001, {5}(f): "Aggressively pursue research, development, and demonstration projects jointly with others as well as individual projects in individual service areas."

Florida Power Corporation will undertake certain development and demonstration projects which have promise to become cost-effective demand and energy efficiency programs. In general, each research and development project that is proposed and investigated will proceed as follows:

1. Project concept or idea development
2. Project research and design, including estimated costs and benefits
3. Conduct field test or pilot program
4. Evaluation of field test or pilot program, including cost-effectiveness
5. Acceptance or rejection of project for continuation as a program
6. If accepted in Item #5 above, application to the FPSC for approval to implement the program

Eligible customers will be determined during the project research and design phase, which will be dependent on the type of project being proposed and investigated. However, it is anticipated that only retail customers will be involved.

Each project that is proposed and investigated will have to meet one or more of the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17, Florida Administrative Code. If not, it will not proceed beyond the project concept or idea phase in Item #1 above.

Program Participation

In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program will require field testing with actual customers. These projects will offer services or products to eligible customers, after being defined in the project research and design phase, on a voluntary basis.

Examples of potential projects that may be funded under this program include demand reduction energy efficiency techniques, market transformation initiatives, indoor air quality measures, thermal energy storage technologies, and innovative metering approaches. All costs including incentives and rebates that are offered will be included as part of the pre-approved project expenditures under this program.

At the discretion of the Company, expenditures up to $800,000 annually may be made and recovered through the conservation cost recovery clause for all energy efficiency and conservation projects that are proposed and investigated. If any single project's expenditures exceed $100,000, a status report will be filed as a component of the Conservation Cost Recovery Projection and True-Up filings. The status report will identify each project under investigation with disbursements exceeding $100,000, the scope and purpose of the project, its development schedule identifying accomplishments and projections, and the project's actual and proposed expenditures for FPSC staff review. If any project (or combination of projects) expenditures are projected to exceed the $800,000 annual limit available under this program and are sufficiently worthy of special consideration, the Company will apply to the FPSC staff for approval to proceed.

Finally, the Company will account for and maintain records of all expenses for each project in accordance with Rule 25-17.015, Florida Administrative Code.

Savings Estimates

This program makes it possible to obtain and use actual data from field tests, instead of relying heavily on engineering assumptions, model results, estimates, and so forth. Benefit and cost figures derived from these projects will be more reliable and projectable, allowing better assessment of future demand reduction and energy efficiency programs submitted to the FPSC for approval.

A second benefit resulting from this development program is that the procedure uncovers benefits, costs, and disadvantages that may be overlooked by an engineering estimate or evaluation. During field tests, not only planned elements, but also unplanned elements are encountered. Actual experience on a small scale is obtained. This should facilitate the decision-making process and improve the success rate of approved programs.

Consequently, program savings were not estimated during the planning stage and are not included in the DSM Plan totals. Any impacts obtained by this program will be calculated for each individual project and will be reported to the FPSC to be counted toward achieving FPC's conservation goals.

Impact Evaluation Plan

The methodology for monitoring and evaluating a project that is submitted to the FPSC for approval as a program shall be determined during the project research and design phase and shall be refined during the field test or pilot program phase. Since projects will normally include a field test or pilot program, the data will be actual rather than estimated. In the event a project does not involve a field test or pilot program, the estimated or modeled savings will be fully documented with the methodology used.

Cost-Effectiveness

The cost-effectiveness of each project submitted to the FPSC for approval to be implemented as a program shall be analyzed and reported using the Commission-approved cost-effectiveness tests.

Planned Projects

FPC agreed to pursue the following as part of the Commission approved stipulation between FPC and the Legal Environmental Assistance Foundation (LEAF):

1. New Construction "Energy Star" Initiative -- HVAC Diagnostics

FPC proposed in the stipulation with LEAF to "Research and evaluate the energy impacts from required HVAC airflow and proper refrigerant charging through year-end 2000." This research will determine the feasibility of any future enhancement to the New Construction program involving these measures.

2. Photovoltaic Initiative – R&D Project

This proposed R&D project under FPC's Technology Development Program is designed to standardize pre-packaged, roof-mounted photovoltaic (PV) systems for manufactured buildings. The PV systems will be connected to the utility grid. The primary objective is to reduce the labor costs associated with the installation of PV systems in the field. This would be accomplished by installing PV system hardware and a balance of system components in a factory environment where the processes can be streamlined. The project will install an estimated 8 kWp of PV arrays in total. The system will be between 1 and 2 kWp each and will be installed on six to eight buildings. The proposed project will be responsive to the Federal Government's Million Solar Roofs initiative and current goals of the Florida Energy Office and Sandia National Labs and will provide the following benefits:

- The proposed PV project will provide education and develop efficiencies in the expanding manufactured building trade for the increased use of PV in the future.
- The proposed project will allow FPC to add a component of "green" power to its generation mix.
- With the assistance of the Florida Solar Energy Center, FPC will have the opportunity to monitor the proposed project and gain insight into the impact of distributed generation on FPC's grid.

APPENDIX -- PROPOSED
TARIFF REVISIONS AND ADDITIONS

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT

Availability:

Available only within the range of the Company's load management system.

As of ______________ available only to customers whose premises have active load management devices installed.

As of April 1, 2001, available only to customers taking service hereunder on this date.

Applicable:

To Customers eligible for residential service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the Customer's premises.

For new service requests after ~~the effective date of this tariff~~ April 1, 1995, customers who select the swimming pool pump schedule must also select at least one other schedule.

An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after ~~the effective date of this tariff.~~ April 1, 1995.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$8.85
Energy and Demand Charges:	
Non-Fuel Energy Charge:	*4.020¢ per kWh*
plus Energy Conservation Cost Recovery Factor:	See Sheet No. 6.105
plus Capacity Cost Recovery Factor:	See Sheet No. 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amounts:[1,2]

(a) Load Management Program (monthly credits)

Interruptible Equipment	Interruption Schedule			
	A	B	C	D
Water Heater	-	-	$3.50	-
Central Heating System[3]	$2.00	$8.00	-	-
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00
Central Cooling System[4]	$1.00	$5.00	-	-
Swimming Pool Pump	-	-	$2.50	-

(Continued on Page No. 2)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 1)

(b) Advanced Load Management Program (per day interrupted credits)

Interruptible Equipment

Central Cooling System[4] = $\$4.50 \times \left(\frac{\%}{50} - 1\right)$

Central Heating System[3] = $\$3.00 \times \left(\frac{\%}{50} - 1\right)$

$60 \leq \% \leq 100$

% = Customer selected maximum interruption %

Notes:
(1) Load management credits shall not exceed 40% of the Non-Fuel Charge associated with kWh consumption in excess of 600 kWh/month.
(2) For Central Heating and Cooling Systems, selection of Interruption Schedule A, Schedule B, Advanced Load Management is at the option of the Customer.
(3) For the billing months of November through March only.
(4) For the billing months of April through October only.

Interruption Schedules:

Schedule A Equipment interruptions will not exceed an accumulated total of 10 minutes during any 30-minute interval within the Company's designated Peak Periods.

Schedule B Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30-minute interval within the Company's designated Peak Periods.

Schedule C Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods. Where a thermal storage system has been installed hereunder, additional interruptions to the water heater will be made during periods of charging thermal storage system.

Schedule D The regular heating system may be interrupted continuously and alternative heating provided by means of a thermal storage system installed hereunder.

Advanced Under the Advanced Load Management Program, Customers may select from among company determined interruption schedules for the central heating systems and/or central cooling systems ranging from 18 minutes during any 30-minute interval to 30 minutes during any 30-minute interval.

Customers participating in the Advanced Load Management Program must also be Interruption Schedule B participants. Under the Advanced Load Management Program, Customers will receive an Advanced Load Management credit for each day (midnight to midnight) in which this program is implemented. This credit will be in addition to the Customer's monthly load management credits.

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March - All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October - All Days: 1:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service, (i.e., Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service, and Average Billing Plan), shall apply to service under this rate schedule.

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 2)

Special Provisions:

1. The Company shall be allowed reasonable access to the Customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the Customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized heating or cooling equipment, or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment type at that premise.

5. The limitation on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its load management system.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the Customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. An alternative thermal storage heating system is available to Customers who (a) have resistance strip heating solely as their central electric heating system, (b) have adequate space and provide access for installation and maintenance of a thermal storage system, (c) have an electric water heater circuit which can be utilized for charging a thermal storage system, and (d) have normal residential water heating and central heating requirements. The Company shall not be required to provide a thermal storage system where the Company deems the installation to be economically unjustified.

   For qualifying Customers, the Company will install, maintain, and operate a thermal storage system consisting of a thermal storage (water) tank, a pump, and a heat exchanging coil. The storage tank will be charged at the option and under the control of the Company. When this option is exercised, heating from this system will be available in place of the Customer's regular heating system. During periods that the storage tank is being charged, electric service to the Customer's regular water heater will be interrupted. An initial incentive payment of $50.00 shall be made to a participating Customer.

8. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A Customer may not change interruption schedules or the selection of electrical equipment installed with load management devices. ~~or~~ The customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. ~~However, in the event of any revision to the interruption schedules that may affect Customer, the Customer shall be allowed ninety (90) days from the effective date of the revision to transfer to another rate schedule.~~

8. If the Company determines that the effect of equipment interruptions has been offset by the Customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the Customer billed for all prior load management credits received over a period not in excess of six (6) months.

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:
Available only within the range of the Company's load management system.

Applicable:
To Customers eligible for residential service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months), and utilize **both** electric water heater and central electric heating systems:

Character of Service:
Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations.

Limitation of Service:
Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the Customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$8.85
Energy and Demand Charges:	
Non-Fuel Energy Charge:	4.020¢ per kWh
plus Energy Conservation Cost Recovery Factor:	See Sheet No. 6.105
plus Capacity Cost Recovery Factor:	See Sheet No. 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credits shall not exceed 40% of the Non-Fuel Charge associated with kWh consumption in excess of 600 kWh/month.
(2) For billing months of November through March only.

Appliance Interruption Schedule:

Heating — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods.

Water Heater — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

BY: W. C. Slusser, Jr., Director, Pricing Department
EFFECTIVE:

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 1)

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March - All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service, i.e., Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service, and Average Billing Plan, shall apply to service under this rate schedule.

Special Provisions:

1. The Company shall be allowed reasonable access to the Customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the Customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized heating or cooling equipment, or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment type at that premise.

5. The limitation on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its load management system.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the Customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A Customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. However, in the event of any revision to the interruption schedules which may affect Customer, the Customer shall be allowed ninety (90) days from the effective date of the revision to change schedules, or equipment, or transfer to another rate schedule. If a customer transfers to another rate schedule they are not eligible to request service under this rate schedule for 12 month from the date of the transfer.

8. If the Company determines that the effect of equipment interruptions has been offset by the Customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the Customer billed for all prior load management credits received over a period not in excess of six (6) months.

RATE SCHEDULE GSLM-1
GENERAL SERVICE - LOAD MANAGEMENT

Availability:

Available only within the range of the Company's load management system.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1, excluding those customers served under the General Service transition rates, and who elect service under this rate schedule and have electric space cooling equipment suitable for interruptible operation. Also applicable to those customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: (1) water heater(s), (2) central electric heating system(s), (3) central electric cooling system(s), and/or (4) swimming pool pump(s).

Rate Codes:

~~The assigned Rate Codes for service hereunder as related to its otherwise applicable Rate Schedule are as follows: GS-1 – 61(Secondary), 63(Primary),___(Transmission); GST-1 – (Unassigned); GSD-1 – 71(Secondary), 73(Primary),___(Transmission); GSDT-1 – 69(Secondary), 45(Primary),___(Transmission).~~

Limitation of Service:

Service to specified electrical equipment may be interrupted at the option of the Company by means of load management devices installed on the Customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

LOAD MANAGEMENT MONTHLY CREDIT AMOUNT

Interruptible Equipment	Interruption Schedule	Credit Based on Installed Capacity[1]	Applicable Billing Months
Electric Space Cooling[3]	A	$ 0.26 Per kW	April thru October
Electric Space Cooling[3]	B	$ 0.56 Per kW	April thru October
Domestically Utilized Equipment[2]	[Availability, Schedules and Credits of the otherwise applicable Rate Schedule RSL-1 or RSL-2 shall apply]		

Notes:
(1) Credit shall not exceed 50% of the Non-Fuel Energy and Demand Charges; nor, for otherwise applicable Rate Schedule GSDT-1, shall the credit exceed the On-Peak and Base demand charges.
(2) Equipment includes water heaters, central heating systems, central cooling systems, and swimming pool pumps when such equipment is installed on permanent residential structures and utilized for domestic purposes.
(3) Restricted to existing customer as of________.

Interruption Schedules:

Schedule A Interruptions will not exceed an accumulated total of 10 minutes during any 30-minute interval within the designated Peak Periods.

Schedule B Interruptions will not exceed an accumulated total of 16.5 minutes during any 30-minute interval within the designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE GSLM-1
GENERAL SERVICE - LOAD MANAGEMENT
(Continued from Page No. 1)

Peak Periods:

The designated Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March, All Days:	6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.
(2) For the calendar months of April through October, All Days:	1:00 p.m. to 10:00 p.m.

Special Provisions:

1. The Company shall be allowed reasonable access to the Customer's premises to install, maintain, inspect, test, and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the Customer's electrical equipment to insure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment. The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.

3. The Company shall not be required to install load management devices on electrical equipment, which would not be economically justified, for reasons such as excessive installation costs, oversized heating or cooling equipment, or abnormal utilization of equipment, including operating hours which are not considered within the designated Peak Periods.

4. If the Company determines that equipment operating schedules and/or business hours have reduced the ability of the Company to control electric demand during the above designated peak periods, then service under this rate will be discontinued.

5. Where multiple units (including standby or multi-stage) of space conditioning equipment are used to heat or cool a building, all of these units must be equipped with load management devices and normally must be controlled on the same interruption cycle.

6. Billing under this rate schedule will commence with the first complete billing period following installation of the load management devices. During the first year of service, a Customer may transfer to another rate schedule by notifying the Company forty-five days (45) in advance. After the first year of service, the Customer may transfer to another rate schedule by notifying the Company twelve (12) months in advance. However, in the event of any revision to the interruption schedules which may affect Customer, the Customer shall be allowed ninety (90) days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.

7. The limitations on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its load management system.

8. If the Company determines that the load management devices have been tampered with, or disconnected without notice, the Company may discontinue service under this rate schedule and bill for prior load management credits received by the Customer, plus applicable investigative charges.

9. If the Company determines that the effect of equipment interruptions have been offset by the Customer's use of supplementary or alternative electrical equipment, service under this rate schedule may be discontinued and the Customer billed for all prior load management credits received over a period not in excess of six (6) months.

10. For purposes of determining eligible credits related to domestically utilized equipment, the Customer shall provide the Company actual occupancy rates of permanent residential structures containing each type equipment for the previous winter (November through March) and summer (April through October) periods. Credits for the current billing period shall apply to the number of items of each installed type equipment multiplied by the corresponding previous seasonal period's occupancy rate.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Approval of demand-side management plan of Florida Power Corporation.	DOCKET NO. 991789-EG ORDER NO. PSC-00-0750-PAA-EG ISSUED: April 17, 2000

The following Commissioners participated in the disposition of this matter:

JOE GARCIA, Chairman
J. TERRY DEASON
SUSAN F. CLARK
E. LEON JACOBS, JR.
LILA A. JABER

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING DEMAND-SIDE MANAGEMENT PLAN

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

The Florida Energy Efficiency and Conservation Act (FEECA), Chapter 366.82, Florida Statutes, requires us to adopt goals to reduce and control the growth rates of electric consumption and weather-sensitive peak demand. In Docket No. 971005-EG (Order No. PSC-99-1942-FOF-EG, issued October 1, 1999), we set numeric demand-side management (DSM) goals for Florida Power Corporation (FPC). The goals were set after we accepted a joint stipulation between FPC and an intervenor, Legal Environmental Assistance Foundation, Inc. (LEAF), in Docket No. 971005-EG.

Rule 25-17.0021(4), Florida Administrative Code, states that within 90 days of a final order establishing goals, a utility shall submit a DSM plan designed to meet its goals. FPC timely filed its DSM Plan on December 29, 1999.

In Order No. 22176, issued November 14, 1989, in Docket No. 890737-PU, we stated that conservation programs will be evaluated using the following criteria:

1. Whether the program advances the policy objectives of Rule 25-17.001, Florida Administrative Code, and Sections 366.80 through 366.85, Florida Statutes, also known as the "Florida Energy Efficiency and Conservation Act" (FEECA);

2. Whether the program is directly monitorable and yields measurable results; and

3. Whether the program is cost-effective.

On December 29, 1999, FPC filed its DSM Plan. FPC's DSM Plan contains five residential programs, eight commercial and industrial (C/I) programs, and one research and development program. These programs are summarized in Attachment A and incorporated herein by reference. The tables in Attachment A, pages 10 and 14, illustrate each DSM program's projected demand and energy savings and contribution towards FPC's numeric DSM goals. Demand savings from FPC's DSM Plan are expected to meet the residential summer and winter peak demand goals set in Order No. PSC-99-1942-FOF-EG. FPC expects to slightly exceed its residential energy savings goal and all three commercial/industrial goals.

FPC's DSM programs are designed to minimize free riders, minimize rate impacts, and to meet our prescribed DSM goals. Accordingly, we find that the programs contained in FPC's DSM plan appear to meet the policy objectives of Rule 25-17.001, Florida Administrative Code, and FEECA. FPC's measurement plan to evaluate assumed demand and energy savings appears reasonable. Each program included in FPC's DSM plan is cost-effective under the rate impact measure (RIM), total resource cost (TRC), and Participants tests. However, it must be emphasized that we are not addressing the prudence of expenditures for the programs contained in FPC's DSM plan; such a review is performed annually in the Energy Conservation Cost Recovery docket.

Most of the programs in FPC's DSM Plan are either unchanged or minimally modified since we approved them in 1995. As discussed below, the only new program contained in FPC's DSM Plan is a Low Income Weatherization Assistance Program. The only substantial DSM program change is to FPC's existing year-round Residential and

Commercial Energy Management programs, which have been closed to new customers and replaced with a winter-only load management program.

FPC's Low Income Weatherization Assistance Program (LIWAP) is offered in response to the stipulation with LEAF in Docket No. 971005-EG. LIWAP is an umbrella program to improve energy efficiency for low-income customers in existing homes. FPC has been involved in conservation activities in the low-income segment for years through some of its other DSM programs. The new LIWAP will continue these activities. The primary goals of the LIWAP are to:

- Continue coordination with the Department of Community Affairs (DCA) and local weatherization providers to deliver energy efficiency measures to low-income families;

- Identify and educate contractors and low-income customers about opportunities to improve home energy efficiency;

- Increase participation of low income families in FPC's other DSM programs; and

- Minimize lost opportunities in the existing marketplace.

LIWAP provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, heating and air conditioning maintenance, high-efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters. FPC forecasts that demand and energy savings from LIWAP will contribute approximately one percent towards FPC's residential DSM goals. Total cost for the program is expected to be far less than one percent of the total cost of FPC's DSM Plan.

FPC's plan also contains substantial changes to the Residential Energy Management Program (RSL-1 tariff) and Commercial Energy Management Program (GSLM-1 tariff). Due to declining cost-effectiveness, these year-round load control programs will no longer be available to new customers. Existing customers can continue to receive monthly credits for year-round interruptions as long as no changes occur to the appliances being controlled or to the interruption schedule. Future residential and small commercial customers can participate in FPC's Winter-Only Energy Management Program (RSL-2 tariff), which provides for direct load control of electric water heating and central electric heating appliances between November and March. The monthly credit paid for both residential and small commercial participants in the winter-only program is the same as under the existing RSL-1 tariff, but is paid only between November and March. The amount of the credit remains unchanged from when the program was last modified in 1995.

FPC's research & development program, named the Technology Development Program, is essentially unchanged from what was approved by the Commission in 1995. FPC agreed to pursue certain projects in photovoltaics and energy efficiency as part of its stipulation with LEAF in the DSM Goals docket. A summary of the program is contained on page 15. Program expenses are capped at $800,000 per year, with a $100,000 annual cap on expenditures for any single project. FPC does not count any kW and kWh savings from its proposed Technology Development program. The purpose of this program is to research potential DSM programs, determine their estimated kW and kWh savings, and evaluate them for cost-effectiveness. If a legitimate DSM program results from FPC's research efforts, the program would be incorporated into the DSM Plan and its kW and kWh savings would be applied toward the goals.

Upon consideration, we hereby approve Florida Power Corporation's Demand-Side Management Plan, including approval for cost recovery. FPC's program standards shall clearly state the requirements for participation in the programs, customer eligibility requirements, details on how rebates or incentives will be processed, technical specifications on equipment eligibility, and necessary reporting requirements. If these program participation standards conform to the description of the programs contained in FPC's DSM Plan, they shall be approved administratively.

Based on the foregoing, it is therefore

ORDERED by the Florida Public Service Commission that Florida Power Corporation's Demand-Side Management Plan summarized in Attachment A to this Order, and incorporated by reference herein, is approved. It is further

ORDERED that Florida Power Corporation shall file program standards which clearly state the requirements for participation in the programs, customer eligibility requirements, details on how rebates or incentives will be processed, technical specifications on equipment eligibility, and necessary reporting requirements. If these program participation standards conform to the description of the programs contained in Florida Power Corporation's Demand-Side Management Plan, they shall be approved administratively. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket shall be closed.

By ORDER of the Florida Public Service Commission this 17th day of April, 2000.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

(S E A L)

DMC

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on May 8, 2000.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

FLORIDA POWER CORPORATION
DEMAND-SIDE MANAGEMENT PLAN

RESIDENTIAL PROGRAMS

1. **Home Energy Check**: Residential energy audit program. Company auditor examines home and makes recommendations on low-cost or no-cost energy-saving practices and measures. Offers four types of audits: *mail-in* (completed by customer), *free walk-through*, *paid walk-through* ($15 cost), and *home energy rating* (BERS audit promoted by DCA).

2. **Home Energy Improvement**: Umbrella program for existing homes. Combines thermal envelope efficiency improvements with upgraded equipment and appliances. Promotes the following energy-efficiency measures:

   a. **Attic Insulation Upgrade**: Encourages customers who have electric space heat to add ceiling insulation. FPC pays portion of the installed cost. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $100 per customer.

   b. **Duct Leakage Test and Repair**: Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. Customer must have electric heating and centrally-ducted cooling system to participate. FPC pays up to $30 per unit for duct leakage test and up to $100 per unit for duct repair.

   c. **High Efficiency Electric Heat Pumps**: Pays financial incentive, not exceeding $350 per unit, to replace existing electric heating equipment with high-efficiency electric heat pumps. Specific incentive based on minimum heating and/or cooling efficiency levels. Indoor air handler and outdoor condenser must both be replaced to qualify for this rebate.

   d. **High-Efficiency Alternate Electric Water Heating**: Promotes installation of high-efficiency alternative electric water heating equipment. Provides incentive of up to $100 for each heat recovery unit and up to $200 per unit for each dedicated heat pump water heater unit.

e. Supplemental Incentive Bonus: Encourages adoption of several energy-efficiency measures through an additional incentive of up to $50. Incentive is paid to a participant in FPC's high efficiency electric heat pump program who also implements the ceiling insulation upgrade, duct leakage repair, or both, within 90 days.

Home Energy Improvement program offers two financing options in lieu of rebates mentioned above: interest-free installment billing over 12 months, and financing assistance through participating financial institutions and/or Federal programs.

3. Residential New Construction: Umbrella program for new home construction, multi-family, and manufactured homes. Promotes energy-efficient construction which exceeds the building code. Provides information, education, and advice to home builders and contractors on energy-related issues and efficiency measures. Promotes energy-efficient electric heat pumps and alternate electric water heating units with incentives that are identical to those offered in the Home Energy Improvement program for existing homes.

4. Low Income Weatherization Assistance (LIWAP): Umbrella program for the weatherization of low income family homes. Offered pursuant to stipulation with LEAF in the DSM Goals docket. Efficiency measures and incentives are identical to those offered in FPC's Home Energy Improvement Program, with the following additions:

   a. Reduced Air Infiltration: A $75 incentive is paid for work which reduces air infiltration by a minimum specified amount.

   b. Water Heater Wrap / Replacement: Provides wrap for water heater and associated piping near the tank. A $25 incentive may be paid towards the purchase of a high-efficiency water heater in lieu of an insulating jacket.

5. **Residential Energy Management**: Voluntary load control program in which FPC reduces peak demand by interrupting electric service to water heaters and central electric heating units. Program is offered only during winter months (November through March). Existing program also interrupts service to pool pumps and central cooling units during summer months, but is no longer cost-effective and will be closed to new customers. Maximum monthly bill credit is $11.50, but is paid only during winter months when customer usage exceeds 600 kWh per month.

FPC'S RESIDENTIAL DSM PROGRAMS

DSM Program	Summer Peak Demand		Winter Peak Demand		Annual Energy Consumption		B/C Ratio (RIM)
	Savings (MW)	% of Goal	Savings (MW)	% of Goal	Savings (GWH)	% of Goal	
Home Energy Check	20.3	16.3	20.3	5.2	65.9	35.6	N/A
Home Energy Improvement	45.1	36.1	114.8	29.5	63.4	34.3	1.11
Residential New Construction	58.0	46.4	119.3	30.7	62.7	33.9	1.13
Low Income Weatherization Assistance	1.2	1.0	2.9	0.8	1.7	0.9	1.02
Res. Winter-Only Energy Management [1]	0.0	0.0	131.9	33.9	0.0	0.0	1.24
TOTAL SAVINGS	124.6	99.7	389.3	100.1	193.7	104.7	
GOAL	125.0		389.0		185.0		

[1] Winter-only program offered to new participants. Existing participants may continue on the old year-round program as long as there are no changes to the interruption schedule.

ATTACHMENT A

COMMERCIAL / INDUSTRIAL (C/I) PROGRAMS

1. **Business Energy Check**: C/I energy audit program. Offers a *free walk-through audit* (inspection) and a *paid walk-through audit* (energy analysis) whose cost varies based on facility's average monthly energy use.

2. **Better Business**: Umbrella efficiency program for existing C/I buildings. Gives customers information and advice on energy-related issues and efficiency measures. Provides incentives or financing for the following energy-efficiency measures:

   a. **HVAC Equipment**: Pays financial incentive, of up to $100 per kW reduced, for the purchase of high-efficiency HVAC equipment such as packaged terminal heat pumps, water-cooled and air-cooled chillers, and unitary heat pumps and air conditioners.

   b. **Motors**: Promotes installation of high-efficiency poly-phase motors. Incentives paid according to motor size on a per-horsepower basis, with larger motors receiving up to $2 per horsepower.

   c. **Roof Insulation Upgrade**: Encourages customers who have electric space heat to add roof insulation. FPC pays portion of the installed cost. Eligibility based on demonstration that additional insulation results in heating and/or cooling use reductions. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $100 per customer.

   d. **Duct Leakage Test and Repair**: Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. Customer must have electric heating and centrally-ducted cooling system to participate. FPC pays up to $30 per unit for duct leakage test and up to $100 per unit for duct repair.

   e. **Window Film**: Provides incentive for installation of window film having a shading coefficient of 0.45 or less on an existing window with a shading coefficient of 0.84 or greater. Incentive paid on a per-square foot of installed film basis; maximum incentive is $125 per customer. Facilities with multiple guest rooms (hotels, hospitals, etc.) are eligible for maximum incentive of $50 per room.

Better Business program offers two financing options in lieu of incentives mentioned above: interest-free installment billing over a 12 month period (amount not to exceed $500), and financing assistance through participating financial institutions and/or Federal programs.

3. __C/I New Construction__: Umbrella efficiency program for new C/I buildings. Provides information, education, and advice on energy-related issues and efficiency measures. Allows FPC to be involved early in the building's design process. Also provides incentives for energy-efficient equipment, such as HVAC equipment, motors, and heat recovery units, which exceed the building code. Incentive levels are identical to those offered in the Better Business program for existing buildings.

4. __Innovation Incentive__: Subsidizes demand and energy conservation projects, on a customer-specific basis, where cost-effective to all FPC customers. To be eligible, projects must reduce or shift a minimum of 10 kW. Rebates will be limited to $150 per kW reduced or shifted. Focuses on measures not offered in FPC's other DSM programs. Examples include *refrigeration equipment replacement, thermal energy storage, microwave drying systems,* and *inductive heating* (to replace resistance heat).

5. __Commercial Energy Management__: Voluntary load control program in which FPC reduces peak demand by interrupting electric service to water heaters and central electric heating units. Program is offered only to small commercial customers during winter months (November through March). Existing program for small commercial customers also interrupts service to pool pumps and central cooling units during summer months, but is no longer cost-effective and will be closed to new customers. Maximum monthly bill credit is $11.50, same as for residential load management participants, and is paid only during the winter months.

6. __Standby Generation__: Voluntary demand control program available to all C/I customers having on-site generation capability. Customer controls the equipment but operates it when needed by

FPC. Incentive based on the load served by the customer's generator and is based on FPC's GSLM-2 rate schedule.

7. **Interruptible Service**: Direct load control program. FPC interrupts service by disconnecting electric service at the breaker during peak or emergency conditions. Offered under FPC's IS-1 and IST-1 tariffs. Available to any non-residential customer with an average billing demand of at least 500 kW. Monthly credit paid to customer based on level of billing demand.

8. **Curtailable Service**: Direct load control program that is similar to interruptible service, only the customer's entire load is not shed. Offered under the CS-1 and CST-1 tariffs. Available to any non-residential customer with an average billing demand of at least 500 kW. Customer must be willing to reduce 25% of its average monthly billing demand upon request by FPC. Monthly credit paid to customer based on level of curtailable demand.

FPC'S COMMERCIAL / INDUSTRIAL DSM PROGRAMS

DSM Program	Summer Peak Demand		Winter Peak Demand		Annual Energy Consumption		B/C Ratio (RIM)
	Savings (MW)	% of Goal	Savings (MW)	% of Goal	Savings (GWH)	% of Goal	
Business Energy Check	1.4	3.7	1.4	3.8	3.0	15.8	N/A
Better Business	5.6	14.8	4.8	13.1	11.2	59.1	1.13
C/I New Construction	2.3	5.9	2.1	5.5	3.7	19.7	1.05
Innovation Incentive	0.8	2.2	0.8	2.3	1.4	7.6	N/A
Commercial Energy Management [2]	0.0	0.0	0.0	0.0	0.0	0.0	0.79
Standby Generation	30.0	78.9	30.0	81.1	0.3	1.6	1.14
Interruptible Service	0.9	2.3	1.0	2.7	8.5	44.7	1.00
Curtailable Service [3]	0.0	0.0	0.0	0.0	0.0	0.0	1.32
TOTAL SAVINGS	41.0	107.9	40.1	108.5	28.2	148.4	
GOAL	38.0		37.0		19.0		

[2] Closed to new participants. Existing participants may continue on the old year-round program as long as there are no changes to the interruption schedule.

[3] FPC does not forecast any new participants in this program.

RESEARCH & DEVELOPMENT PROGRAM

1. Technology Development Program: Program used by FPC to research, develop, and demonstrate potential cost-effective conservation programs. Includes field testing or a pilot program. Program expenses are capped at $800,000 per year. FPC will notify the Commission, through ECCR filings, if any single project's expenditures exceed $100,000.

   Examples of potential projects include demand reduction energy efficiency techniques, market transformation initiatives, indoor air quality measures, thermal energy storage technologies, and innovative metering techniques. FPC will provide a final report on each demonstration project or file and offer a permanent conservation program for each program investigated.

   FPC agreed to pursue the following projects as part of its stipulation with LEAF in the DSM goals docket:

   - New construction "energy star" initiative -- HVAC diagnostics
   - Photovoltaic initiative -- R&D project (including a "green power" component)

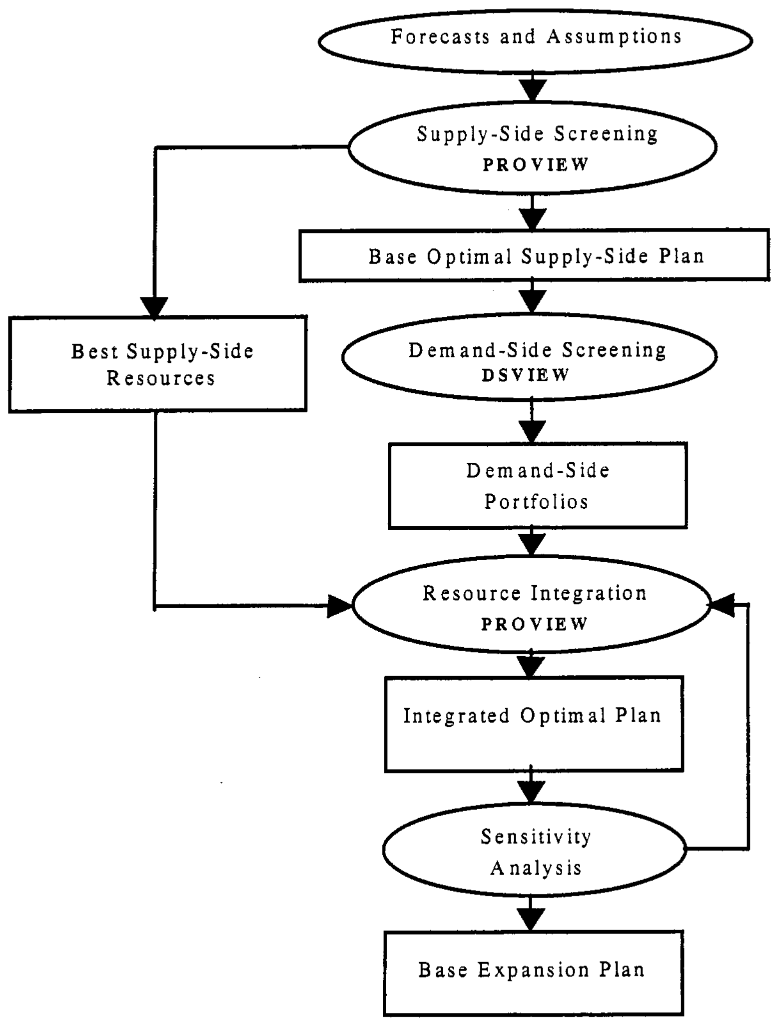


Figure 1: IRP Process Overview

Table 2-1 Wind Energy Conversion Performance and Costs	
Commercial Status	Commercial
Average Wind Speed (mph)	20
Performance:	
Power Capacity (MW_{rated})	10
Power Capacity ($MW_{average}$)	3.5
Energy Production (MWh/yr)	29,000
Capacity Factor (percent)	35
Costs:	
Capital Cost ($\$/kW_{rated}$)	1,100
Capital Cost ($\$/kW_{average}$)	3,200
O&M Costs:	
Fixed O&M ($\$/kW\text{-}yr_{average}$)	30
Variable O&M ($\$/MWh_{average}$)	5.0
Levelized Cost (cents/kWh)	5.3[1]
(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.	

Table 2-2 Solar Thermal – Parabolic Trough Performance and Costs	
Commercial Status	Commercial
Duty Cycle	Supplemental
Performance:	
Power Capacity (MW)	80
Energy Production (MWh/yr)	250,000
Capacity Factor (percent)	36
Costs:	
Capital Cost ($/kW)	2,870 - 3,600
O&M Costs:	
Fixed O&M ($/kW-yr)	47
Variable O&M ($/MWh)	4.1
Levelized Cost (cents/kWh)	13.2 – 21.2[1]
(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.	

Table 2-3 Utility-Scale Photovoltaics Performance and Costs	
Commercial Status	Commercial
Module Type	Single Crystalline
Array Type	Fixed-tilt
Duty Cycle	Supplemental
Performance:	
Module Efficiency (%)	12.0
Power Capacity (MW)	10
Energy Production (MWh/yr)	17,500
Capacity Factor (percent)	20
Costs:	
Capital Cost ($\$/kW_{rated}$)	2,000
Capital Cost ($\$/kW_{average}$)	10,000
O&M Costs:	
Fixed O&M ($\$/kW\text{-}yr_{average}$)	14
Variable O&M ($\$/MWh_{average}$)	2.0
Levelized Cost (cents/kWh)	13.0 – 19.9[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-4 Wood Chip Combustion Performance and Costs	
Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	50
Net Plant HHV Heat Rate (Btu/kWh)	12,500 to 17,500
Energy Capacity (MWh)	260,000
Capacity Factor (percent)	60
Costs:	
Capital Cost ($/kW)	1,450 - 1,850
O&M Costs:	
Fixed O&M ($/kW-yr)	24 - 48
Variable O&M ($/MWh)	4.0 - 5.0
Levelized Cost (cents/kWh)	6.7 – 13.6[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-5 Geothermal Performance and Costs	
Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	25
Energy Capacity (MWh)	175,000
Capacity Factor (percent)	80
Costs:	
Capital Cost ($/kW)	2,000 - 4,000
O&M Costs:	
Fixed O&M ($/kW-yr)	105
Variable O&M ($/MWh)	7.2
Levelized Cost (cents/kWh)	5.2 - 14.7[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-6 Hydroelectric Performance and Costs	
Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	10 to 1,500+
Energy Capacity (MWh)	Resource dependent
Capacity Factor (percent)	Resource dependent
Costs:	
Capital Cost ($/kW)	1,300 - 5,200
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 30
Variable O&M ($/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	5.9 – 13.0[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 3-1
Waste to Energy – Mass Burn Unit
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	15,500
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,000 - 3,000
O&M Costs:	
Fixed O&M ($/kW-yr)	100 - 150
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	7.2 - 12.3[1,2]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.
(2) Excludes tipping fee credit.

Table 3-2
Waste to Energy - RDF Unit
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	17,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,500 - 3,500
O&M Costs:	
Fixed O&M ($/kW-yr)	150 - 200
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	8.2 - 13.4[1,2]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.
(2) Excludes tipping fee credit.

Table 3-3 Landfill Gas - IC Engine Unit (Gas Collection/Processing Not Included) Performance and Costs	
Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	10
Net Plant Heat Rate (Btu/kWh)	8,500
Capacity Factor (percent)	60 - 75
Availability (percent)	93
Costs:	
Capital Cost ($/kW)	825
O&M Costs:	
Fixed O&M ($/kW-yr)	0.9[1]
Variable O&M ($/MWh)	6.7
Levelized Cost (cents/kWh)	2.0 - 4.0[2]

(1) Unstaffed site.
(2) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 3-4 Multi-Fuel CFB (~10 Percent TDF Co-Fire) Performance and Costs	
Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	11,000
TDF Tons per Day	100
Capacity Factor (percent)	60 - 75
Availability (percent)	85
Costs:	
Capital Cost ($/kW)	1,650
O&M Costs:	
Fixed O&M ($/kW-yr)	40
Variable O&M ($/MWh)	3.0
Levelized Cost (cents/kWh)	5.2 – 11.1[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-1 Humid Air Turbine Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	410
O&M Costs:	
Fixed O&M ($/kW-yr)	7 - 9
Variable O&M ($/MWh)	0.10 - 0.60
Levelized Cost (cents/kWh)	3.6 – 5.2[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-2 Kalina Cycle Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,025
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 12
Variable O&M ($/MWh)	0.1 - 0.5
Levelized Cost (cents/kWh)	4.8 – 7.0[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-3 Cheng Cycle Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,025
O&M Costs:	
Fixed O&M ($/kW-yr)	12
Variable O&M ($/MWh)	0.6
Levelized Cost (cents/kWh)	4.3 – 5.5[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-4 Supercritical Pulverized Coal Power Plant Performance and Costs	
Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	350 - 1,300
Net Plant Heat Rate (Btu/kWh)	9,300
Capacity Factor (percent)	60 - 75
Availability (percent)	78
Costs:	
Capital Cost ($/kW)	1,230
O&M Costs:	
Fixed O&M ($/kW-yr)	19 - 23
Variable O&M ($/MWh)	3.3
Levelized Cost (cents/kWh)	5.4 – 6.9[1]
(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.	

Table 4-5 PCFB Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	80 - 350
Net Plant Heat Rate (Btu/kWh)	8,600 (6,700 2nd generation)
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,300 - 2,050
O&M Costs:	
Fixed O&M ($/kW-yr)	40 – 80
Variable O&M ($/MWh)	3.5
Levelized Cost (cents/kWh)	5.2 – 6.2[1]
(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.	

Table 4-6 Magnetohydrodynamic Combined Cycle Plant Conceptual Performance and Costs	
Commercial Status	Development/Conceptual
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	10,300
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,300 - 2,500
O&M Costs:	
Fixed O&M ($/kW-yr)	20 - 35
Variable O&M ($/MWh)	1.0 - 3.1
Levelized Cost (cents/kWh)	6.7 - 13.5

Table 4-7 Fuel Cell Power Plant Performance and Costs	
Commercial Status	Commercially Available
Performance:	
Plant Capacity (MW)	0.2
Net Plant Heat Rate (Btu/kWh)	10,000
Capacity Factor (percent)	85
Costs:	
Capital Cost ($/kW)	4,100
O&M Costs:	
Fixed O&M ($/kW-yr)	330
Variable O&M ($/MWh)	0.84
Levelized Cost (cents/kWh)	7.4 – 8.6[1]
(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.	

Table 4-8 Ocean Wave Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	0.1 - 1.0
Net Plant Heat Rate (Btu/kWh)	N/A
Capacity Factor (percent)	25
Costs:	
Capital Cost ($/kW)	2,450
O&M Costs:	
Fixed O&M ($/kW-yr)	50 - 100
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)	6.7 – 41.4[1]
(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.	

Table 4-9 Ocean Tidal Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	20 - 240
Annual Energy Capacity (GWh)	35 - 500
Capacity Factor (percent)	20 - 25
Costs:	
Capital Cost ($/kW)	1,000 - 4,000
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 50
Variable O&M ($/MWh)	1.5 - 5.2
Levelized Cost (cents/kWh)	13.3 - 23.2

2000 Ten-Year Site Plan Analysis * No Future "CC" Capacity Additions * No "CC's"

		WINTER 00/01 Jan-2001	WINTER 01/02 Jan-2002	WINTER 02/03 Jan-2003	WINTER 03/04 Jan-2004	WINTER 04/05 Jan-2005	WINTER 05/06 Jan-2006	WINTER 06/07 Jan-2007	WINTER 07/08 Jan-2008	WINTER 08/09 Jan-2009	WINTER 09/10 Jan-2010
New FPC Capacity	MW	323	17	0	0	0	0	0	0	0	0
Total Available Capacity	**MW**	**9,890**	**9,907**	**9,894**	**9,748**	**9,758**	**9,608**	**9,507**	**9,492**	**9,383**	**9,242**
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	**MW**	**8,528**	**8,282**	**8,120**	**8,231**	**8,394**	**8,610**	**8,820**	**9,029**	**9,234**	**9,440**
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	1,517	1,364	998	687	462	149	-198
Normal Weather Reserve Margin (After All Load Control)	**%**	**16.0%**	**19.6%**	**21.9%**	**18.4%**	**16.3%**	**11.6%**	**7.8%**	**5.1%**	**1.6%**	**-2.1%**

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008	SUMMER 09 Aug-2009
New FPC Capacity	MW	0	264	17	0	0	0	0	0	0	0
Total Available Capacity	**MW**	**8,853**	**9,117**	**9,121**	**9,121**	**8,978**	**8,988**	**8,853**	**8,770**	**8,755**	**8,646**
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**7,439**	**7,701**	**7,431**	**7,258**	**7,361**	**7,522**	**7,737**	**7,947**	**8,152**	**8,354**
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	1,617	1,466	1,116	823	603	291
Normal Weather Reserve Margin (After All Load Control)	**%**	**19.0%**	**18.4%**	**22.7%**	**25.7%**	**22.0%**	**19.5%**	**14.4%**	**10.4%**	**7.4%**	**3.5%**

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
		Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
New FPC Capacity	MW	323	17	0	567	0	567	0	567	0	567
Total Available Capacity	**MW**	**9,890**	**9,907**	**9,894**	**10,315**	**10,325**	**10,742**	**10,641**	**11,193**	**11,084**	**11,510**
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	**MW**	**8,528**	**8,282**	**8,120**	**8,231**	**8,394**	**8,610**	**8,820**	**9,029**	**9,234**	**9,440**
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	2,132	1,821	2,163	1,850	2,070
Normal Weather Reserve Margin (After All Load Control)	**%**	**16.0%**	**19.6%**	**21.9%**	**25.3%**	**23.0%**	**24.8%**	**20.6%**	**24.0%**	**20.0%**	**21.9%**

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
New FPC Capacity	MW	0	264	17	0	495	0	495	0	495	0
Total Available Capacity	**MW**	**8,853**	**9,117**	**9,121**	**9,121**	**9,473**	**9,483**	**9,843**	**9,760**	**10,240**	**10,131**
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**7,439**	**7,701**	**7,431**	**7,258**	**7,361**	**7,522**	**7,737**	**7,947**	**8,152**	**8,354**
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	2,106	1,813	2,088	1,776
Normal Weather Reserve Margin (After All Load Control)	**%**	**19.0%**	**18.4%**	**22.7%**	**25.7%**	**28.7%**	**26.1%**	**27.2%**	**22.8%**	**25.6%**	**21.3%**

Florida Power
CORPORATION

January 26, 2000

Attention: Interested Parties

Subject: Request for Proposals

Attached, please find a copy of Florida Power Corporation's Request for Proposals and a diskette containing data tables appropriate for your use. Please direct any questions that you may have in writing to:

Michael D. Rib
Director, Resource Planning
Florida Power Corporation
263 13th Avenue South
St. Petersburg, FL 33701

Via Fax: (727) 826-4333
Via E-mail: rfpresponse@fpc.com

Sincerely,

Michael Rib

REQUEST FOR PROPOSALS
January 26, 2000

I. Purpose And Scope

In accordance with Rule 25-22.082, F.A.C., Florida Power Corporation (FPC) issues this request for proposals (RFP) to solicit and screen, for subsequent contract negotiations, competitive proposals for supply-side alternatives to its next planned generating unit. FPC invites proposals that will offer exceptional value to FPC and its customers. Proposals submitted pursuant to this RFP will be considered and evaluated against each other and against FPC's self-build options. FPC's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW (net) to be located at the Hines Energy Complex in Polk County, Florida and available November 30, 2003. For a more detailed description of this planned unit, refer to Attachment D.

Respondents are asked to provide capacity offered in their proposal at a level of firmness that is dedicated solely to FPC's use and subject to dispatch by FPC. For purposes of this solicitation, FPC is interested in long-term proposals with flexible contract options.

II. Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	1/26/2000	
Notice of Intent to Bid (NOI) Due	2/10/2000	NOIs should be received by FPC's RFP Contact by 3:00 P.M. EST
Pre-Bid Meeting	2/18/2000	Tampa Airport Marriott 10:00 A.M. - 12:30 P.M. EST Room To Be Determined
Proposals Due	3/27/2000	Proposals must be received by the RFP Contact by 3:00 P.M. EST

Short-list Determination	5/19/2000	If applicable
Complete Negotiations	8/1/2000	If applicable
File contract(s) with state Public Service Commission for approval	8/15/2000- 9/29/2000	If applicable

FPC reserves the right to revise, suspend, or terminate this schedule at its sole discretion. Any changes to the schedule will be provided, as appropriate, to Respondents that have submitted a timely NOI.

III. Proposal Guidelines

A. Instructions for Completing Forms

1. All Respondents are encouraged to submit a written Notice of Intent to Bid (NOI), using the form provided in Attachment A. Please submit the NOIs to the FPC RFP Contact by facsimile, Registered or Certified Mail, Return Receipt Requested, or overnight courier, by 3:00 P.M. EST, February 10, 2000. Voice telephone notices will not be acknowledged.

2. Respondents are also encouraged to attend the February 18, 2000 pre-bid meeting. This meeting is tentatively set to be held from 10:00 A.M. to 12:30 P.M. at the Tampa Airport Marriott (Room TBD). If this time or location change, FPC will notify Respondents who have submitted a NOI.

3. All Respondents must submit with their proposal a Proposal Summary using the form provided in Attachment B.

4. All proposals must be submitted in the format shown in the RFP response forms Attachment C and E. Respondents should, at the time of proposal submittal, supply any additional information not included in the forms if such information may be needed for a thorough understanding or evaluation of the proposal. All responses will be considered commitments to be used in defining any agreement between FPC and the Respondent that may arise from this RFP.

5. Proposals must be signed by a duly authorized officer of the Respondent.

6. A signed original and ten (10) copies of the proposal, including all attachments,

must be submitted along with the electronic forms provided on a 3.5" floppy diskette. The electronic forms may be obtained from FPC on floppy disk or downloaded from the Company website (www.fpc.com). In the event of a discrepancy between the electronic forms and the hard copy, the hard copy will be considered to be correct.

7. All proposals, including all attachments, must be properly completed and returned by overnight courier or Registered or Certified Mail, Return Receipt Requested, in both hard copy and electronic versions, to FPC's RFP Contact:

   Michael D. Rib
   Director, Resource Planning
   Florida Power Corporation
   263 13th Avenue South
   St. Petersburg, FL 33701
   Phone: (727)826-4387
   Fax: (727)826-4333
   E-mail: rfpresponse@fpc.com

   All proposals shall be received by FPC's RFP contact no later than 3:00 P.M. EST on March 27, 2000. Late or incomplete offers may be rejected by FPC. Offers must remain open until at least October 1, 2000. All inquiries and other communications relating in any manner to this RFP must be directed in writing or by facsimile or E-mail to FPC's RFP Contact. FPC may distribute Respondents' questions and FPC's answers to such questions to all other Respondents if FPC deems the question to be of general interest. Unsolicited contact about this process with other FPC personnel or attorneys or consultants retained by FPC may result in disqualification.

8. Complete information is needed to facilitate a timely evaluation. FPC may request clarifying or additional information at any time during the evaluation process, and Respondents will be expected to provide timely responses to facilitate the evaluation and decisionmaking process within the time constraints. Respondents must provide all data requested in the RFP and the applicable attachments. FPC may reject non-specific offers from further consideration.

9. Proposals must reflect any and all of the costs that FPC would be expected to pay for power delivered to FPC's System. If any portion of the total delivered cost of power is not intended to be clearly defined in the pricing outlined in the proposal, then a detailed description of the proposed approach regarding that portion of cost must be clearly delineated in the proposal. Prices and dollar figures quoted must be clearly stated in $US as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.

B. Confidentiality

FPC will take reasonable precautions and use reasonable efforts to protect any proprietary and confidential information contained in a proposal provided that such information is clearly identified by the Respondent as "Proprietary and Confidential" on the page on which proprietary and confidential information appears. Such information may, however, be made available under applicable state or federal law to regulatory commission(s), their staff(s), or other governmental agencies having an interest in these matters. FPC reserves the right to release such information to agents, contractors, or to its parent company or to subsidiaries thereof, for the purpose of evaluating the Respondent's proposal but such companies, agents, or contractors will be required to observe the same care with respect to disclosure as FPC. Under no circumstances will FPC or Florida Progress Corporation or their subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure during or after the solicitation process.

C. Proposal Evaluation Costs

1. To help defray the cost of performing the proposal evaluations, Respondents are required to submit, with the proposal, a non-refundable check payable to Florida Power Corporation for $10,000 for each proposal. Changes in the physical attributes, such as site, output, fuel, or technology changes will require the submission of a separate proposal and payment of another fee.

2. Neither FPC nor its representatives, affiliate companies, or parent company shall be liable for any expenses incurred in connection with preparation of a response to this RFP or for any costs, fees, or lost or foregone profits of unsuccessful Respondents. Respondents should prepare their proposals simply and economically, providing a straightforward and concise description of the Respondent's ability to meet the requirements of the RFP. Any Respondent that submits in its proposal to FPC any information that is determined by FPC to be substantially inaccurate, misleading, exaggerated, or incorrect shall be disqualified from consideration.

D. Regulatory Provisions

1. Any negotiated contract for the purchase of power between FPC and the Respondent will be conditioned upon approval or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation, including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission.

2. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:

Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

Respondents are required to forward copies of these actual published notices to FPC when they are available.

IV. General Specifications

A. Minimum Requirements for Proposals

In addition to the requirements of Section III above, proposals must also meet the minimum requirements set forth below. FPC, in its sole discretion, may reject any proposal that fails to respond adequately or completely to all or any part of this RFP.

1. Capacity offered must be at a level that is dedicated solely to FPC's use and subject to dispatch by FPC. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources will not be evaluated and will be rejected. Proposals must allow FPC the right to use this generating resource, including, but not limited to, electrical transmission services associated with the project, for any purpose that the company deems appropriate in its sole discretion.

2. The capacity must be available no later than November 30, 2003.

3. Proposal prices must reflect any and all costs that FPC will be expected to pay for power delivered to its system, as outlined in this RFP. Further, Respondents shall be responsible for absorbing all charges and costs for firm transmission service (including the cost of all attendant equipment, including but not limited to generator step-up transformers) to deliver each generating resource included in the proposal to the FPC control area, or to interconnect a generating resource to the FPC Transmission System.

4. A Respondent whose proposal is selected shall take all necessary actions to

satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on the Respondent by any federal, state, or local law, or ordinance, rule, or regulation concerning the generation, sale, or delivery of the power. FPC will cooperate with the Respondent to provide information or such other assistance as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise fully support all of FPC's regulatory requirements associated with this potential power supply arrangement.

5. A Respondent whose proposal is selected shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale, or delivery of power for the entire term of the proposed contract, and the Respondent shall include any such costs in its proposal.

6. The proposal must include unit commitment notification and dispatch scheduling provision details for the contract sale. Respondents must describe provisions that can and would be made to allow FPC to dispatch the proposed generating resources directly from FPC's control area energy management control system.

7. The Respondent's proposal must provide a milestone schedule that identifies key dates, including but not limited to dates for regulatory approvals, finalization of transmission and interconnection agreements, finalization of fuel supply arrangements, pre-construction milestones, and construction milestones, along with terms for default.

B. Electrical Transmission Requirements

Respondents are asked to provide the information that is necessary to understand and assess the transmission delivery path(s) and the FPC system impacts of the proposed power supply arrangements. Under the guidelines outlined herein, Attachments C and E provide detailed information requirements for each resource included in the proposal. Respondents who are placed on the "short list" shall provide reasonable assurances that they will be able to provide or secure adequate and reliable firm transmission capability for each generating resource included in the Respondent's proposal for the duration of the term of the power supply to FPC.

1. Definition of Terms

- FPC Transmission System: Transmission facilities owned, controlled, or operated by FPC.

- FPC Control Area: The FPC Transmission System bounded by FPC tie-line metering and telemetry which controls generation directly to maintain interchange schedules and frequency.

- Resource: Each specific generating resource or system power resource included in the Respondent's proposal.

2. External Resource Information Requirements

   a. For each Resource included in the proposal not directly connected to the FPC Transmission System (External Resource), the Respondent shall describe the location of the External Resource and specify in detail all transmission path(s) that will be utilized, the transmission service that will be purchased, and the name of each transmission provider required to deliver the External Resource to the FPC Control Area. The description of the location of each External Resource should include:

      - For specific generation, the specific delivery point on the transmission system where the generation is located.

      - For a system power offer, the transmission system(s) on which the power resources are located.

   b. Respondents are responsible for paying for and clearly delineating in their price quotes all charges and costs for firm transmission service to deliver power to the FPC Control Area.

   c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current Florida Reliability Coordinating Council (FRCC) load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

   d. For proposals included in the "short list" that include External Resources, the Respondents must demonstrate during the "short list" evaluation phase of this RFP that firm transmission service can be secured on all transmission paths required to deliver the External Resource to the FPC Control Area.

3. Internal Resource Information Requirements

   a. For each Resource included in the proposal that is directly connected to the FPC Transmission System (Internal Resource), the Respondent must describe the specific delivery point on the FPC Transmission System where the Resource is or is proposed to be located.

b. The Respondent shall include in the proposal the costs of all generation equipment up to and including the generator step-up transformer(s).

c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current FRCC load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

4. Transmission System Impact Study

During the "short list" evaluation phase of this RFP, FPC will perform a transmission system impact study to evaluate all proposals on the "short list" at the same time. All required information to conduct this study must have already been provided to FPC in accordance with the schedule provisions of this RFP. The cost of this study shall be pro-rated among all Respondents whose proposals are included on the "short list." Coincident with the determination by FPC of the "short list," FPC will issue System Impact Study Agreements to each Respondent included on the "short list."

C. <u>Non-Price Attributes</u>

1. At this time, FPC would view more favorably proposals that:

- Offer a greater degree of firmness and reliability;
- Offer shorter unit commitment notification and greater dispatch flexibility;
- Offer greater contract flexibility through creative proposal options potentially including, but not limited to:
    - The right for FPC to terminate early,
    - Supplemental capacity call options
    - Options to buy the generating asset at pre-determined prices.

  (Respondents must provide discrete cost or fee structures for proposed contract flexibility attributes.)

- Offer greater supplier performance assurances through parent guarantees, securities, deposits, or other means;

- Promote FPC transmission system reliability and integrity;
- Utilize commercially proven technologies;
- Minimize potential adverse environmental impacts; and
- Offer larger megawatt block sizes.

2. FPC will consider the following additional non-price attributes in its evaluation of proposals:

- Respondent's qualifications and experience;
- Technical and financial viability of the proposal;
- Project location (for example: grid location, zoning, community acceptance);
- Resource scheduling and dispatchability;
- Deliverability (interconnection and transmission), including system reliability and transmission related issues;
- Fuel supply, including, but not limited to:
    - Firmness of fuel supply,
    - Backup fuel supply,
    - Dual fuel capability,
    - Transportation flexibility,
    - Fuel management or tolling requirements;
- Water supply;
- Environmental compliance;
- Operational and maintenance plans;
- Performance criteria;
- Pricing structure;

- Potential for increases or decreases in FPC's cost of capital;
- The effect of Respondent's financing arrangements on FPC's system reliability;
- Any competitive advantage the financing arrangement may give the Respondent; and
- All factors that must be considered or discussed by FPC pursuant to F.A.C. Rule 25-22.081, .082.

3. This list of attributes is not intended to be all inclusive. Other innovative and cost effective offerings, which provide value to FPC and its customers, will be viewed favorably.

D. Performance Assurances

FPC will rely on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement and should be included in the Respondent's proposal. Performance guarantees and financial credit assurances will also be required of the Respondents, subject to negotiation, at FPC's discretion, and also should be included in Respondent's proposal.

V. Proposal Evaluation

A. Proposal Evaluation Procedure

1. FPC and/or independent consultants will evaluate proposals and recommend proposals, if any, which provide the most value to FPC and its customers. FPC reserves the right to evaluate the proposals in a manner that ultimately produces the most competitive responses from which to begin negotiations. Proposals that offer less than 530 MW may be combined with other proposals as supply-side alternatives to FPC's next planned generating unit. FPC shall determine in its sole discretion the value of any proposals and of any resulting agreement to FPC and its customers.

2. Information provided from each Respondent by the proposal due date will be used to develop a short list of proposals from which selection(s) could be made for direct negotiations. No additional information will be accepted after the proposal due date, except for clarifications requested by FPC and possible

transmission study results. FPC will evaluate the proposals in terms of price and non-price attributes.

3. FPC will perform an initial screening evaluation to identify and eliminate any proposals that are not responsive to the RFP, do not meet the minimum requirements set forth in the RFP, are clearly not economically competitive with other proposals, or are submitted by Respondents that lack appropriate creditworthiness or sufficient financial resources or qualifications to provide dependable and reliable service.

4. The proposals that pass the initial evaluation screen will be further evaluated based on qualitative and non-price attributes, as discussed at Section IV. C above, and using production costing methods and other models so that all reasonable cost impacts can be quantified. A selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will compete with each other and with any self-build options before FPC makes any final selection.

B. <u>Reservation of Rights</u>

1. FPC reserves the right, without qualification and in its sole discretion, to accept or reject any or all proposals for any reason or to make the award to that Respondent, who, in the opinion of FPC, will provide the most value to FPC and its customers. FPC also reserves the right to make an award to other than the lowest price offer or to the proposal evidencing the greatest technical ability if FPC determines that to do so would result in the greatest value to FPC and its customers. FPC may make an award of contract without further discussion.

2. FPC reserves the right to reject any, all, or portions of the proposals received for failure to meet any criteria set forth in this RFP. FPC also may decline to enter into a power purchase arrangement with any Respondent, or to abandon the project in its entirety. FPC reserves the right to revise the capacity needs forecast at any point during the RFP process or during negotiations and any such change may reduce, eliminate, or increase the amount of power sought.

3. Respondents should be aware that the following, without limitation, will be classified as non-responsive and will not be considered or evaluated if submitted:

   - proposals offering non-firm capacity or energy;

   - demand-side proposals;

   - incomplete, inaccurate, conditional, deceptive, misleading, ambiguous, exaggerated, or non-specific offers; or

- proposals that are not in conformance with the requirements and instructions contained herein.

4. Those who submit proposals do so without recourse against FPC or Florida Progress Corporation or any of Florida Progress Corporation's subsidiary companies for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Attachment A

Notice of Intent to Bid Form

Project Bidder
Respondent Contact Name: ______________________________
Title: ______________________________
Company Name: ______________________________
Address: ______________________________
____
Telephone: ______________________________
Facsimile: ______________________________
Project Name: ______________________________
Project Location: ______________________________

General Description of the Proposed Project:
____
____
____
(Attach additional sheets as needed)

Proposed Capacity Delivered to FPC: ______________________________
Contract Term: ______________________________
Power Generation Technology: ______________________________
Primary Fuel: ______________________________
Back-up Fuel: ______________________________
Specific Entity to Contract with FPC:
____

Respondent Classification:
(e.g., Utility, Power Marketer, EWG, QF, etc.):
____

Other Parties Involved in the Proposal:
____

Respondent Qualifications:
Describe similar projects developed by Respondent, identifying project capacity, location, contract commencement date and term, and any other information the Respondent considers appropriate. *(Attach additional sheets as needed)*
____
____
____

Respondent's Signature: ______________________________
(Title/Position)

Attachment B

Proposal Summary Form

Company/Respondent: ______________________________
Respondent Contact Name: ______________________________
Mailing Address: ______________________________
____
Telephone: ______________________________
Facsimile: ______________________________
General Description of the Proposed Project: ______________________________
____
____
(Attach additional sheets as needed)
Power Generation Technology: ______________________________
Unit(s) Name: ______________________________
Project Location: ______________________________
Contract Term: ______________________________
Unit(s) Summer MW Rating: ______________________________
Unit(s) Winter MW Rating: ______________________________
Unit(s) Fuel Type(s): ______________________________
Proposed Capacity (MW) Delivered to FPC: ______________________________
Proposed delivery point to FPC: ______________________________
Other Parties with an Interest in the Proposal: ______________________________
____

Certification: Respondent hereby certifies that all of the statements and representations made in this proposal, including all attachments, are true to the best of Respondent's knowledge and belief. Respondent agrees to be bound by its representations and the terms and conditions of the Request for Proposals. This proposal shall remain in effect until at least October 1, 2000.

Signed: ______________________________
Name: ______________________________
(Typed)
Title: ______________________________
Date: ______________________________

Attachment C

Respondents are requested to respond to the following data requests. All of this information is important to assist FPC in better understanding, among other things, the price and non-price attributes addressed in each alternative generating proposal, including their technical and financial viability, pricing structure, dispatchability, deliverability, water supply, environmental compliance, and performance criteria.

Certain data requirements in this RFP reference "Seasons," which will, for consistency, be defined as:

Winter	[December *through* February]
Summer	[June *through* September]
Shoulder	[Balance of the Months]

Section 1: General Proposal Information

Respondents are requested to provide brief but concise answers to the Data Requests below. If annual escalation is expected or if contract price will vary, include any such rates or indices.

1. Provide documentation of Respondent's previous experience providing the proposed product.

2. Provide the following information for your company:

   a. Annual reports and Form 10-K for the past three years. If these documents are not readily available, then audited financial statements for the past three years will be accepted.

   b. Dunn and Bradstreet identification number credit rating of the Respondent's senior debt securities. Any additional documentation needed to allow FPC to determine the Respondent's financial strength.

   c. Ten year summary of litigation activity related to (1) provision of energy products and services (fuel, power, ancillary services, engineering, on-site services), (2) lease option arrangements for assets, (3) purchases of energy products and services (as above), or (4) industrial construction projects (power plants, industrial plants, cogeneration facilities, etc.).

3. Provide copies of notices to be published, per Section III.D.2 of the RFP.

4. Provide a complete schedule of the proposed contract terms and conditions.

5. Provide a detailed list and summary of contract flexibility attributes included in the proposal as well as discrete cost or fee structures for each of the proposed attributes.

6. Present a detailed description of any security or credit instruments proposed by the Respondent to back its performance obligation.

7. Provide a detailed summary of any liquidated damages provisions included in the proposal and a description of the particular circumstance(s) they are intended to mitigate.

8. Describe whether or not this capacity has been offered in another RFP or is in any other way obligated or may be obligated to others, and under what conditions it would be released to serve this proposed sale.

9. Describe the firmness of the capacity in your offer.

10. Explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the energy after it has been scheduled.)

Section 2: Specific Supply Resource Information

1. For a proposal involving a specific unit(s), provide the following information using the data tables included where appropriate:

   a. (Proposed) Unit name and location.

   b. For new units, provide the schedule for licensing, permitting and construction, including the projected date of commercial operation.

   c. Descriptions (including models and manufacturers) of all of the major components.

   d. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation or other fixed price components. Clearly delineate whether each price component and/or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

   e. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

   f. Seasonal Unit ratings (MW, MVAR, MVA) based on the ambient condition assumptions of Winter (40°F), Summer (90°F), and Shoulder (59°F). If capacity being offered is less than the full capability of the generating unit(s), provide the full capability information for these same ambient conditions. Explain if and how unit performance degradation is accounted for over time. (See Table 3)

g. Generator capability curve.

h. Guaranteed availability. (See Table 4)

i. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation). (See Table 5)

j. For planned maintenance requirements, discuss the means by which FPC will be entitled to schedule the planned maintenance periods. (See Table 6)

k. Detailed Fuel Supply Plan (primary and secondary).

   i. Fuel type, on-site storage capability and inventory management plan, applicable fuel specifications, metering requirements. (See Table 9)

      - Natural Gas: Include interstate pipeline supplier, connection point, lateral length, type and quantity of firm, recallable, and interruptible transportation.
      - Oil: Include type, special specifications, storage tank description, number of hours of full load operation supported by the tank.
      - Other Fuels.

   ii. Any proposed tolling or other fuel procurement arrangements that would involve FPC in the fuel management process.

   iii. Operating limits on either the primary or secondary fuels, if any.

l. Describe any dispatch notice or scheduling requirements for this offer, including, but not limited to:

   i. Minimum run time per dispatch call, if any.

   ii. Minimum down time, if any.

   iii. Start up energy requirements.

   iv. Ramp Rate(s).

iv. Start up time from cold start and from hot start.

v. Start up costs from cold start and from hot start.

vi. Quick start capability (less than 10 minutes). (See Table 7)

m. Maximum and minimum operating levels, capacity breakpoints and corresponding net heat rates (in Btu/kWh, on a higher heating value basis). Provide on a seasonal basis, as outlined in the tables. (See Table 8a and 8b)

n. Maximum or minimum energy take per month, season, year, or contract period, if any.

o. A detailed water supply plan, including data requirements. (See Table 10).

p. A thorough description of anticipated environmental impact, environmental permitting requirements, and actions for compliance.

q. A complete description of any cogeneration aspects of the facility(s) including, but not limited to, fuel, steam, water, or power sales and any details related to qualifying facility status, if any.

r. A complete description of any actual or proposed energy or capacity sales, or sales of any other energy-related products (ancillary services, steam, tankage, etc.) to any other parties from this facility(s).

s. Any other limit on use or availability of resource's output, if any.

<u>Section 3: System Supply Resource Information</u>

1. For a system sale or other sales, please provide the following information. It is difficult to anticipate all possible system supply scenarios, but please use the existing tables to the extent that it is practical and provide any additional information needed in separate schedules, tables and/or forms.

   a. Seasonal Capacity (MW, MVAR, MVA) available for use on the FPC System. (See Table 3)

   b. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation, or other fixed price components. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

c. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

d. A description of the system from which the power will be provided, including the name, location, the installed capacity, capacity mix, fuel mix, technology mix, peak hour load, and reserve projections (with and without the proposed capacity sale) during the proposal period. In addition, provide all data requested in the tables. (See Table 11).

e. A detailed history of the system operations for the past five years including, but not limited to fuel mix, power sales and purchases (energy and demand) to native load and to non-native load, emergency power purchase requirements, historical reserve levels, and incidences of firm transmission interruptions. In addition, provide all data requested in the tables. (See Table 11)

f. In conjunction with the information and data provided in b. and c., please provide copies of the 1999 and 2000 EIA-411 filings and the 1999 Ten Year Site Plan for all systems from which power is to be sold under this proposal offering.

g. An explanation of the priority of this proposed transaction relative to all other supply commitments (existing and future) and any criteria under which the supply of system power by the Respondent might be curtailed or interrupted.

h. A description of any dispatch notice or scheduling requirements for this offer.

i. Guaranteed availability. (See Table 4)

j. Maximum or minimum energy take per month, year, contract period, if any.

k. A thorough description of anticipated environmental impact and compliance resulting from these power sales.

l. Any other limit on use or availability of resource, if any.

Section 4: Supplemental Transmission Information

1. Provide all information required in Section IV.B, Transmission Information Requirements,

of this RFP for each Internal or External Resource included in the Respondent's proposal. This data must be included with the Respondent's proposal when it is submitted.

2. If this data has already been supplied to FPC Transmission Planning associated with a current generation interconnection request on the FPC Transmission System, please clearly identify the request, the date of the request and the project(s) associated with the request.

3. Provide a schedule of the costs that the bidder will be responsible for paying for transmission service to deliver power to FPC's Control Area.

4. Describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the FPC Control Area. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.

5. Describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.

Section 5: Data Tables

Respondents are requested to complete the tables in the attached excel file labeled "Data Tables", as represented herein. Once the tables are completed electronically, the respondent is required to print the resulting data tables and include these printed tables in their proposal document. Add rows as necessary for additional years. If annual escalation is expected, include such escalation rates or indices. Please note any additions or modifications made to the tables. Do not leave blanks: write in "N/A" if topic is not applicable, or "0" if the value is zero. Respondents may provide additional tables, as required to better clarify their proposals. Such additional tables should follow the Water Requirements table, and be labeled "Additional Table - (Description)," and include appropriate units.

Table 1. Fixed Capacity Price Structure- ($/kW-month)

Season	Year: 2003	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2016	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2004	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2017	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2005	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2018	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2006	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2019	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2007	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2020	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2008	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2021	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2009	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2022	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2010	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2023	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2011	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2024	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
Summer	Price						Summer	Price					
	Escal. / Index							Escal. / Index					
Season	Year: 2012	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year: 2025	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal. / Index							Escal. / Index					
Shoulder	Price						Shoulder	Price					
	Escal. / Index							Escal. / Index					
	Price							Price					

Table 2a. Variable Price Structure, Primary Fuel - (units below)

	Year: 2003			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						
	Year: 2004			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						
	Year: 2005			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						
	Year: 2006			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						
	Year: 2007			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						
	Year: 2008			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						
	Year: 2009			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						
	Year: 2010			Emissions		All-In	
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						

	Year: 2016			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					
	Year: 2017			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					
	Year: 2018			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					
	Year: 2019			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					
	Year: 2020			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					
	Year: 2021			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					
	Year: 2022			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					
	Year: 2023			Emissions		All-In
Season	Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					

Table 3. Resource Capacity Rating- (units below)

		40°F		59°F		90°F	
Guaranteed Contract Rating	MW						
	MVAR						
	MVA						
Maximum Unit Rating	MW						
	MVAR						
	MVA						

Table 4. Guaranteed Availability- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 5. Equivalent Forced Outage Rate- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 6. Planned Maintenance Requirements- (Number of Outages/Year, Total Hours/Year)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number/year													
Maint Hrs/yr													
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number/year													
Maint Hrs/yr													

Table 7. Operational Parameters- (units below)

Minimum run time per dispatch call		Hours
Minimum down time between calls		Hours
Startup Energy		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 proce
Cost of Each Hot Start Beyond Those Included		Dollars
Number of Cold Starts per year		Maximum
Number of Cold Starts per year		Included in bid proce
Cost of Each Cold Start Beyond Those Included		Dollars
Quick Start Capability- Minutes to 1st MW		Minutes
Quick Start Capability- MW in ten minutes		MW
Start up time from cold start		Minutes
Start up cost from cold start		$
Start up time from hot start		Minutes
Start up costs from hot start		$

Table 8a. Capacity States on Primary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 8b. Capacity States on Secondary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

NOTE: Net Heat Rates are to be based on Higher Heating Value (HHV)

Table 9. Fuel Supply Requirements		Units
Primary Fuel Maximum Flow rate		
Primary Fuel Pressure Requirement		
Primary Fuel Metering Requirement		
Primary Fuel Storage Capacity		
Secondary Fuel Maximum Flow rate		
Secondary Fuel Pressure Requirement		
Secondary Fuel Metering Requirement		
Secondary Fuel Storage Capacity		

Table 10. Water Requirements		Units
Cooling		
Consumptive Use		
Other		

Table 11. System Reliability Parameters

	Actual					Forecast				
	1995	1996	1997	1998	1999	2003	2004	2005	2006	2007
Installed Capacity										
Contracted System Firm Capacity Purchases										
Contracted System Firm Capacity Sales										
Load Control Capability										
Seasonal Peak Requirements before Direct Load Control										
Firm Peak Requirements after Direct Load Control										
Capacity Margin before Direct Load Control										
Firm Reserve Margin after Direct Load Control										

Attachment D - Planned Unit Data

The following data represent the planned unit data estimates, which FPC utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on FPC's existing Hines Energy Complex site in Polk County, Florida.

2. Planned Size 530 MW (nominal).

3. Commercial Operation of the facility is proposed to be November 30, 2003.

4. The primary fuel is natural gas. Oil will be used as a backup fuel source.

5. The estimated total direct cost is $197.6 million.

6. The estimated annual levelized revenue requirement is $35.6 million over 25 years.

7. The estimated annual value of deferral of this unit is $48.95/kW-yr (03$).

8. The estimated annual fixed O&M is $2.2 million (03$). The estimated variable O&M is $1.11/MWH (03$).

9. The estimated delivered fuel cost is $2.66/MMBtu (03$), plus fixed transportation at the prevailing rate.

10. The following are estimates for:

Planned outage rate	7, 7, 14, 7, 7, 22 days/year (or 2.92%)
Forced outage rate	3.5 %
Heat rate at maximum capacity	6,975 Btu/kWh
Minimum load	250 MW
Ramp Rate	1 Hr.

11. The estimated transmission and interconnection costs for this unit are $5.6 million.

12. Supplemental site certification as well as amendment to related environmental permits will be required for this unit. It is FPC's plan to comply with all environmental standards of Local, Regional, State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.5 % per year
General escalation:	3.1 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.3 %
	55 % equity @ 12.0 %

Attachment E

Florida Power Corporation
Generation Interconnection Study
Data Request Form

INSTRUCTIONS

(*) denotes items that are required for both a Generation Interconnection Feasibility Study and a Generation Interconnection Study and must be completed and included in Respondent's proposal. All items on this form are required prior to the start of engineering design.

If a data item is unavailable, please provide an estimate and indicate it as an estimate. Please note that a restudy could be required if data assumptions change while the study is in progress.

Please fill out and attach a copy of Section II for each generator on the site.

Please use this form to supply the requested data. Submittal of manufacturer data sheets, other than generator characteristic curves, is not an acceptable alternative to completing this form.

SECTION I – Generation Site Data

A) **Contact Person** - Provide name and address of person completing this form

(*)1. Name: ______________________________

(*)2. Address: ______________________________

(*)3. City/State/Zip: ______________________________

(*)4. Telephone: ______________________________

(*)5. Date: ______________________________

B) **Site Location**

(*)1. County: ______________________________

(*)2. Section / Township / Range: ______________________

(*)3. Site Drawing: Include a site drawing indicating county, section, township, and range. In addition, for a Generation Interconnection Study, a preliminary equipment layout on the site, suitable for site plan permitting, is required.

C) Proposed Load Requirements for Site

(*)1. Required Date: ______________________

(*)2. Nature of Load (Station Service, Start-up Power, Etc.) ______________________

(*)3. Connected kVA Load: ______________

(*)4. Peak Demand kVA Load: ______________

(*)5. Expected Power Factor: ______________

(*)6. Service Voltage: ______________

(*)7. Anticipated Future Load Requirements (please describe): ______________

____

____

____

D) Other Site Information

(*)1. Net Generation Output (MVA) for Site @ 59°F Outdoor Ambient: __________

(*)2. Net Generation Output (MVA) for Site @ 90°F Outdoor Ambient: __________

(*)3. Proposed Interconnections with Other Systems (please describe):

____

____

E) In-Service Dates

(*)1. Required connection to grid for generator testing: ______________________

(*)2. Commercial in-service date: _______________________________________

SECTION II - Individual Generator Data

A) Unit Identification

(*) 1. Plant Name and Unit Number _________________________________

2. Manufacturer _________________________________

3. Generator Serial Number _________________________________

4. Turbine Serial Number _________________________________

B) Ratings and Capabilities

1. Nameplate kV Rating (nominal design voltage) ______________________

2. MVA Rating

	MVA Rating	@ Hydrogen Pressure
a.	__________	__________
b.	__________	__________
c.	__________	__________
d.	__________	__________

(*) 3. Gross MW Rating @ 59°F Outdoor Ambient ______________________

(*) 4. Net MW Rating @ 59°F Outdoor Ambient ______________________

(*) 5. Gross MW Rating @ 90°F Outdoor Ambient ______________________

(*) 6. Net MW Rating @ 90°F Outdoor Ambient ______________________

7. Rated Power Factor ______________________

8. Rated Speed ______________________

9. Rated Turbine Capability ______________________

10. Field Voltage at Rated Load ______________________

11. Field Current at Rated Load ______________________

12. No-load Field Voltage at Generator Rated Voltage ______________________

13. Air Gap Field Voltage at Generator Rated Voltage ______________________

14. Field Resistance ____ohms @ __________ °C

C) Inertia

(*) 1. WR^2 for Generator and Exciter ______________________ lb-ft^2

(*) 2. WR^2 for Turbine ______________________ lb-ft^2

(*) 3. Calculated H Constant ____________sec. @ ___________ MVA

D) Losses and Efficiency

1. Open circuit core loss ______________________ kW

2. Windage loss ______________________ kW

3. H_2 seal and exciter friction loss ______________________ kW

4. Stator I^2R Loss at rated power and voltage _________°C _____________ kW

5. Rotor I^2R Loss at rated power and voltage _________°C _____________ kW

6. Stray Load loss ______________________ kW

7. Excitation losses ______________________kW

E) **Generator Time Constants**

1. T'_{do} (Direct axis open circuit transient time constant) ______________ sec
2. T''_{do} (Direct axis open circuit subtransient time constant) ______________ sec
3. T'_{qo} (Quadature axis open circuit transient time constant) ______________ sec
4. T''_{qo} (Quadature axis open circuit subtransient time constant) ______________ sec
5. T_{a3} (Short circuit time constant) ______________ sec

F) **Generator Impedances**

(*) 1. MVA base for all impedance data ______________ MVA

(*) 2. kV base for all impedance data ______________ kV

Parameter		Description	p.u. value
(*) 3.	X_d	Direct axis synchronous reactance (unsaturated)	____________
4.	X_q	Quadrature axis synchronous reactance (unsaturated)	____________
(*) 5.	X'_d	Direct axis transient reactance (unsaturated)	____________
6.	X'_{ds}	Direct axis transient reactance (saturated)	____________
7.	X'_q	Quadrature axis transient reactance (unsaturated)	____________
8.	X'_{qs}	Quadrature axis transient reactance (saturated)	____________
(*) 9.	X''_d	Direct axis subtransient reactance (unsaturated)	____________
10.	X''_q	Quadrature axis subtransient reactance (unsaturated)	____________
11.	X_L	Armature leakage reactance	____________
12.	R_1	Positive sequence armature resistance at 75° C	____________
13.	R_2	Negative sequence armature resistance at 75° C	____________
14.	X_2	Negative sequence armature reactance at rated voltage	____________

15. X_0 Positive sequence armature resistance at 75° C ____________

16. R_{dc} Direct current armature resistance at 75° C ____________

17. Generator neutral grounding resistance ________ ohms

(*)18. Generator neutral grounding reactance ________ ohms

G) Required Characteristic Curves and Diagrams

(*) 1. Real and reactive power capability curves **(Maximum var capability, lagging and leading, is sufficient for Feasibility Study)**

2. Saturation curve, full load and no-load

3. "V" curves

4. Governor overspeed response curve

5. One-Line diagram showing generator and substation equipment connections

H) Excitation System Data

1. Excitation system type ________________________________

2. Voltage regulator model name ________________________________

3. Excitation system model, supply block diagram and model parameters in IEEE[1] or PSS/E format

4. Voltage compensation, supply block diagram and settings if used

5. Voltage regulator overexcitation limiters, supply block diagram and model parameters in IEEE[2] format.

6. Power System Stabilizer (if used), supply Power System Stabilizer block diagram and model parameters in IEEE or PSS/E format

I) Turbine Governor Data

1. Speed/Load governor model name ________________________________

---

[1] IEEE Standard 421.5-1992 "IEEE Recommended Practice for Excitation System Models for Power System Stability Studies"

[2] IEEE Committee Report, "Recommended Models for Overexcitation Limiting Devices," IEEE Transactions on Energy Conversion, Vol. 10, No. 4, December 1995

2. Governor model, supply block diagram and model parameters in IEEE[3,4] or PSS/E format

J) Generator Step-up Transformer Data

1. Manufacturer ______________________

2. Model Type ______________________

3. Serial Number ______________________

(*) 4. Rating ______________________ MVA

(*) 5. High voltage winding, nominal voltage ______________ kV

(*) 6. High voltage winding connection (wye/delta) ______________

(*) 7. Low voltage winding, nominal voltage ______________ kV

(*) 8. Low voltage winding connection (wye/delta) ______________

9. Transformer resistance ______________ p.u.

(*)10. Transformer reactance ______________ p.u.

(*)11. Transformer impedance base values ________ MVA ______ kV

12. Available tap settings

HV taps ______________________ kV

LV taps ______________________ kV

13. Expected tap settings

HV taps ______________________ kV

LV taps ______________________ kV

---

[3] IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbine Control Models for System Dynamic Studies," IEEE transactions on Power Apparatus and Systems, Vol. PAS-92, November, 1973

[4] W.I. Rowen, "simplified Mathematical Representations of Heavy Duty Gas Turbines," Transactions of ASME, Vol.105(1), 1983

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines Unit 2 Power Plant	))))	DOCKET NO. Submitted for filing: August 7, 2000

Exhibit JBC-2

DIRECT TESTIMONY OF JOHN B. CRISP

ON BEHALF OF FLORIDA POWER CORPORATION

ROBERT A. GLENN
Director, Regulatory Counsel Group
FLORIDA POWER CORPORATION
P.O. Box 14042
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

GARY L. SASSO
Florida Bar No. 622575
Carlton, Fields, Ward,
Emmanuel, Smith & Cutler
Post Office Box 2861
St. Petersburg, FL 33731
Telephone: (727) 821-7000
Telecopier: (727) 822-3768

CARLTON FIELDS

ATTORNEYS AT LAW

ONE PROGRESS PLAZA
200 CENTRAL AVENUE, SUITE 2300
ST. PETERSBURG, FLORIDA 33701-4352

MAILING ADDRESS:
P.O. BOX 2861, ST. PETERSBURG, FL 33731-2861
TEL (727) 821-7000 FAX (727) 822-3768

January 27, 2000

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

VIA FEDERAL EXPRESS

Re: Florida Power Corporation's Request for Proposals

Dear Ms. Bayo:

Pursuant to Rule 25-22.082, Florida Administrative Code, Florida Power Corporation is filing herewith an original and fifteen (15) copies of Florida Power Corporation's Request for Proposals.

We request you acknowledge receipt and filing of the above by stamping the additional copy of this letter and returning it to me in the self-addressed, stamped envelope provided.

If you or your Staff have any questions regarding this filing, please contact me at (727) 821-7000.

Very truly yours,

Gary L. Sasso

Enclosure

RECEIVED & FILED
FPSC-BUREAU OF RECORDS

JBC-2

DOCUMENT NUMBER-DATE
01253 JAN 28 8

FPSC-RECORDS/REPORTING

REQUEST FOR PROPOSALS
January 26, 2000

I. Purpose And Scope

In accordance with Rule 25-22.082, F.A.C., Florida Power Corporation (FPC) issues this request for proposals (RFP) to solicit and screen, for subsequent contract negotiations, competitive proposals for supply-side alternatives to its next planned generating unit. FPC invites proposals that will offer exceptional value to FPC and its customers. Proposals submitted pursuant to this RFP will be considered and evaluated against each other and against FPC's self-build options. FPC's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW (net) to be located at the Hines Energy Complex in Polk County, Florida and available November 30, 2003. For a more detailed description of this planned unit, refer to Attachment D.

Respondents are asked to provide capacity offered in their proposal at a level of firmness that is dedicated solely to FPC's use and subject to dispatch by FPC. For purposes of this solicitation, FPC is interested in long-term proposals with flexible contract options.

II. Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	1/26/2000	
Notice of Intent to Bid (NOI) Due	2/10/2000	NOIs should be received by FPC's RFP Contact by 3:00 P.M. EST
Pre-Bid Meeting	2/18/2000	Tampa Airport Marriott 10:00 A.M. - 12:30 P.M. EST Room To Be Determined
Proposals Due	3/27/2000	Proposals must be received by the RFP Contact by 3:00 P.M. EST

Short-list Determination	5/19/2000	If applicable
Complete Negotiations	8/1/2000	If applicable
File contract(s) with state Public Service Commission for approval	8/15/2000-9/29/2000	If applicable

FPC reserves the right to revise, suspend, or terminate this schedule at its sole discretion. Any changes to the schedule will be provided, as appropriate, to Respondents that have submitted a timely NOI.

III. Proposal Guidelines

A. Instructions for Completing Forms

1. All Respondents are encouraged to submit a written Notice of Intent to Bid (NOI), using the form provided in Attachment A. Please submit the NOIs to the FPC RFP Contact by facsimile, Registered or Certified Mail, Return Receipt Requested, or overnight courier, by 3:00 P.M. EST, February 10, 2000. Voice telephone notices will not be acknowledged.

2. Respondents are also encouraged to attend the February 18, 2000 pre-bid meeting. This meeting is tentatively set to be held from 10:00 A.M. to 12:30 P.M. at the Tampa Airport Marriott (Room TBD). If this time or location change, FPC will notify Respondents who have submitted a NOI.

3. All Respondents must submit with their proposal a Proposal Summary using the form provided in Attachment B.

4. All proposals must be submitted in the format shown in the RFP response forms Attachment C and E. Respondents should, at the time of proposal submittal, supply any additional information not included in the forms if such information may be needed for a thorough understanding or evaluation of the proposal. All responses will be considered commitments to be used in defining any agreement between FPC and the Respondent that may arise from this RFP.

5. Proposals must be signed by a duly authorized officer of the Respondent.

6. A signed original and ten (10) copies of the proposal, including all attachments.

must be submitted along with the electronic forms provided on a 3.5" floppy diskette. The electronic forms may be obtained from FPC on floppy disk or downloaded from the Company website (www.fpc.com). In the event of a discrepancy between the electronic forms and the hard copy, the hard copy will be considered to be correct.

7. All proposals, including all attachments, must be properly completed and returned by overnight courier or Registered or Certified Mail, Return Receipt Requested, in both hard copy and electronic versions, to FPC's RFP Contact:

Michael D. Rib
Director, Resource Planning
Florida Power Corporation
263 13th Avenue South
St. Petersburg, FL 33701
Phone: (727)826-4387
Fax: (727)826-4333
E-mail: rfpresponse@fpc.com

All proposals shall be received by FPC's RFP contact no later than 3:00 P.M. EST on March 27, 2000. Late or incomplete offers may be rejected by FPC. Offers must remain open until at least October 1, 2000. All inquiries and other communications relating in any manner to this RFP must be directed in writing or by facsimile or E-mail to FPC's RFP Contact. FPC may distribute Respondents' questions and FPC's answers to such questions to all other Respondents if FPC deems the question to be of general interest. Unsolicited contact about this process with other FPC personnel or attorneys or consultants retained by FPC may result in disqualification.

8. Complete information is needed to facilitate a timely evaluation. FPC may request clarifying or additional information at any time during the evaluation process, and Respondents will be expected to provide timely responses to facilitate the evaluation and decisionmaking process within the time constraints. Respondents must provide all data requested in the RFP and the applicable attachments. FPC may reject non-specific offers from further consideration.

9. Proposals must reflect any and all of the costs that FPC would be expected to pay for power delivered to FPC's System. If any portion of the total delivered cost of power is not intended to be clearly defined in the pricing outlined in the proposal, then a detailed description of the proposed approach regarding that portion of cost must be clearly delineated in the proposal. Prices and dollar figures quoted must be clearly stated in $US as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.

B. Confidentiality

FPC will take reasonable precautions and use reasonable efforts to protect any proprietary and confidential information contained in a proposal provided that such information is clearly identified by the Respondent as "Proprietary and Confidential" on the page on which proprietary and confidential information appears. Such information may, however, be made available under applicable state or federal law to regulatory commission(s), their staff(s), or other governmental agencies having an interest in these matters. FPC reserves the right to release such information to agents, contractors, or to its parent company or to subsidiaries thereof, for the purpose of evaluating the Respondent's proposal but such companies, agents, or contractors will be required to observe the same care with respect to disclosure as FPC. Under no circumstances will FPC or Florida Progress Corporation or their subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure during or after the solicitation process.

C. Proposal Evaluation Costs

1. To help defray the cost of performing the proposal evaluations, Respondents are required to submit, with the proposal, a non-refundable check payable to Florida Power Corporation for $10,000 for each proposal. Changes in the physical attributes, such as site, output, fuel, or technology changes will require the submission of a separate proposal and payment of another fee.

2. Neither FPC nor its representatives, affiliate companies, or parent company shall be liable for any expenses incurred in connection with preparation of a response to this RFP or for any costs, fees, or lost or foregone profits of unsuccessful Respondents. Respondents should prepare their proposals simply and economically, providing a straightforward and concise description of the Respondent's ability to meet the requirements of the RFP. Any Respondent that submits in its proposal to FPC any information that is determined by FPC to be substantially inaccurate, misleading, exaggerated, or incorrect shall be disqualified from consideration.

D. Regulatory Provisions

1. Any negotiated contract for the purchase of power between FPC and the Respondent will be conditioned upon approval or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation, including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission.

2. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:

Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

Respondents are required to forward copies of these actual published notices to FPC when they are available.

IV. General Specifications

A. Minimum Requirements for Proposals

In addition to the requirements of Section III above, proposals must also meet the minimum requirements set forth below. FPC, in its sole discretion, may reject any proposal that fails to respond adequately or completely to all or any part of this RFP.

1. Capacity offered must be at a level that is dedicated solely to FPC's use and subject to dispatch by FPC. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources will not be evaluated and will be rejected. Proposals must allow FPC the right to use this generating resource, including, but not limited to, electrical transmission services associated with the project, for any purpose that the company deems appropriate in its sole discretion.

2. The capacity must be available no later than November 30, 2003.

3. Proposal prices must reflect any and all costs that FPC will be expected to pay for power delivered to its system, as outlined in this RFP. Further, Respondents shall be responsible for absorbing all charges and costs for firm transmission service (including the cost of all attendant equipment, including but not limited to generator step-up transformers) to deliver each generating resource included in the proposal to the FPC control area, or to interconnect a generating resource to the FPC Transmission System.

4. A Respondent whose proposal is selected shall take all necessary actions to

satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on the Respondent by any federal, state, or local law, or ordinance, rule, or regulation concerning the generation, sale, or delivery of the power. FPC will cooperate with the Respondent to provide information or such other assistance as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise fully support all of FPC's regulatory requirements associated with this potential power supply arrangement.

5. A Respondent whose proposal is selected shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale, or delivery of power for the entire term of the proposed contract, and the Respondent shall include any such costs in its proposal.

6. The proposal must include unit commitment notification and dispatch scheduling provision details for the contract sale. Respondents must describe provisions that can and would be made to allow FPC to dispatch the proposed generating resources directly from FPC's control area energy management control system.

7. The Respondent's proposal must provide a milestone schedule that identifies key dates, including but not limited to dates for regulatory approvals, finalization of transmission and interconnection agreements, finalization of fuel supply arrangements, pre-construction milestones, and construction milestones, along with terms for default.

B. <u>Electrical Transmission Requirements</u>

Respondents are asked to provide the information that is necessary to understand and assess the transmission delivery path(s) and the FPC system impacts of the proposed power supply arrangements. Under the guidelines outlined herein, Attachments C and E provide detailed information requirements for each resource included in the proposal. Respondents who are placed on the "short list" shall provide reasonable assurances that they will be able to provide or secure adequate and reliable firm transmission capability for each generating resource included in the Respondent's proposal for the duration of the term of the power supply to FPC.

1. Definition of Terms

- FPC Transmission System: Transmission facilities owned, controlled, or operated by FPC.

- FPC Control Area: The FPC Transmission System bounded by FPC tie-line metering and telemetry which controls generation directly to maintain interchange schedules and frequency.

- Resource: Each specific generating resource or system power resource included in the Respondent's proposal.

2. External Resource Information Requirements

   a. For each Resource included in the proposal not directly connected to the FPC Transmission System (External Resource), the Respondent shall describe the location of the External Resource and specify in detail all transmission path(s) that will be utilized, the transmission service that will be purchased, and the name of each transmission provider required to deliver the External Resource to the FPC Control Area. The description of the location of each External Resource should include:

      - For specific generation, the specific delivery point on the transmission system where the generation is located.

      - For a system power offer, the transmission system(s) on which the power resources are located.

   b. Respondents are responsible for paying for and clearly delineating in their price quotes all charges and costs for firm transmission service to deliver power to the FPC Control Area.

   c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current Florida Reliability Coordinating Council (FRCC) load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

   d. For proposals included in the "short list" that include External Resources, the Respondents must demonstrate during the "short list" evaluation phase of this RFP that firm transmission service can be secured on all transmission paths required to deliver the External Resource to the FPC Control Area.

3. Internal Resource Information Requirements

   a. For each Resource included in the proposal that is directly connected to the FPC Transmission System (Internal Resource), the Respondent must describe the specific delivery point on the FPC Transmission System where the Resource is or is proposed to be located.

b. The Respondent shall include in the proposal the costs of all generation equipment up to and including the generator step-up transformer(s).

c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current FRCC load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

4. Transmission System Impact Study

During the "short list" evaluation phase of this RFP, FPC will perform a transmission system impact study to evaluate all proposals on the "short list" at the same time. All required information to conduct this study must have already been provided to FPC in accordance with the schedule provisions of this RFP. The cost of this study shall be pro-rated among all Respondents whose proposals are included on the "short list." Coincident with the determination by FPC of the "short list," FPC will issue System Impact Study Agreements to each Respondent included on the "short list."

C. <u>Non-Price Attributes</u>

1. At this time, FPC would view more favorably proposals that:

- Offer a greater degree of firmness and reliability;
- Offer shorter unit commitment notification and greater dispatch flexibility;
- Offer greater contract flexibility through creative proposal options potentially including, but not limited to:
  - The right for FPC to terminate early,
  - Supplemental capacity call options
  - Options to buy the generating asset at pre-determined prices.

  (Respondents must provide discrete cost or fee structures for proposed contract flexibility attributes.)
- Offer greater supplier performance assurances through parent guarantees, securities, deposits, or other means;

- Promote FPC transmission system reliability and integrity;
- Utilize commercially proven technologies;
- Minimize potential adverse environmental impacts; and
- Offer larger megawatt block sizes.

2. FPC will consider the following additional non-price attributes in its evaluation of proposals:

   - Respondent's qualifications and experience;
   - Technical and financial viability of the proposal;
   - Project location (for example: grid location, zoning, community acceptance);
   - Resource scheduling and dispatchability;
   - Deliverability (interconnection and transmission), including system reliability and transmission related issues;
   - Fuel supply, including, but not limited to:
     - Firmness of fuel supply,
     - Backup fuel supply,
     - Dual fuel capability,
     - Transportation flexibility,
     - Fuel management or tolling requirements;
   - Water supply;
   - Environmental compliance;
   - Operational and maintenance plans;
   - Performance criteria;
   - Pricing structure;

- Potential for increases or decreases in FPC's cost of capital;

- The effect of Respondent's financing arrangements on FPC's system reliability;

- Any competitive advantage the financing arrangement may give the Respondent; and

- All factors that must be considered or discussed by FPC pursuant to F.A.C. Rule 25-22.081, .082.

3. This list of attributes is not intended to be all inclusive. Other innovative and cost effective offerings, which provide value to FPC and its customers, will be viewed favorably.

D. Performance Assurances

FPC will rely on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement and should be included in the Respondent's proposal. Performance guarantees and financial credit assurances will also be required of the Respondents, subject to negotiation, at FPC's discretion, and also should be included in Respondent's proposal.

V. Proposal Evaluation

A. Proposal Evaluation Procedure

1. FPC and/or independent consultants will evaluate proposals and recommend proposals, if any, which provide the most value to FPC and its customers. FPC reserves the right to evaluate the proposals in a manner that ultimately produces the most competitive responses from which to begin negotiations. Proposals that offer less than 530 MW may be combined with other proposals as supply-side alternatives to FPC's next planned generating unit. FPC shall determine in its sole discretion the value of any proposals and of any resulting agreement to FPC and its customers.

2. Information provided from each Respondent by the proposal due date will be used to develop a short list of proposals from which selection(s) could be made for direct negotiations. No additional information will be accepted after the proposal due date, except for clarifications requested by FPC and possible

transmission study results. FPC will evaluate the proposals in terms of price and non-price attributes.

3. FPC will perform an initial screening evaluation to identify and eliminate any proposals that are not responsive to the RFP, do not meet the minimum requirements set forth in the RFP, are clearly not economically competitive with other proposals, or are submitted by Respondents that lack appropriate creditworthiness or sufficient financial resources or qualifications to provide dependable and reliable service.

4. The proposals that pass the initial evaluation screen will be further evaluated based on qualitative and non-price attributes, as discussed at Section IV. C above, and using production costing methods and other models so that all reasonable cost impacts can be quantified. A selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will compete with each other and with any self-build options before FPC makes any final selection.

B. <u>Reservation of Rights</u>

1. FPC reserves the right, without qualification and in its sole discretion, to accept or reject any or all proposals for any reason or to make the award to that Respondent, who, in the opinion of FPC, will provide the most value to FPC and its customers. FPC also reserves the right to make an award to other than the lowest price offer or to the proposal evidencing the greatest technical ability if FPC determines that to do so would result in the greatest value to FPC and its customers. FPC may make an award of contract without further discussion.

2. FPC reserves the right to reject any, all, or portions of the proposals received for failure to meet any criteria set forth in this RFP. FPC also may decline to enter into a power purchase arrangement with any Respondent, or to abandon the project in its entirety. FPC reserves the right to revise the capacity needs forecast at any point during the RFP process or during negotiations and any such change may reduce, eliminate, or increase the amount of power sought.

3. Respondents should be aware that the following, without limitation, will be classified as non-responsive and will not be considered or evaluated if submitted:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- incomplete, inaccurate, conditional, deceptive, misleading, ambiguous,

exaggerated, or non-specific offers; or

- proposals that are not in conformance with the requirements and instructions contained herein.

4. Those who submit proposals do so without recourse against FPC or Florida Progress Corporation or any of Florida Progress Corporation's subsidiary companies for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Attachment A

Notice of Intent to Bid Form

Project Bidder
Respondent Contact Name: ______________________
Title: ______________________
Company Name: ______________________
Address: ______________________
____
Telephone: ______________________
Facsimile: ______________________
Project Name: ______________________
Project Location: ______________________

General Description of the Proposed Project:

____
____
____
(Attach additional sheets as needed)

Proposed Capacity Delivered to FPC: ______________________
Contract Term: ______________________
Power Generation Technology: ______________________
Primary Fuel: ______________________
Back-up Fuel: ______________________
Specific Entity to Contract with FPC:
____

Respondent Classification:
(e.g., Utility, Power Marketer, EWG, QF, etc.):
____

Other Parties Involved in the Proposal:
____

Respondent Qualifications:
Describe similar projects developed by Respondent, identifying project capacity, location, contract commencement date and term, and any other information the Respondent considers appropriate. *(Attach additional sheets as needed)*

____
____
____

Respondent's Signature: ______________________
(Title/Position)

Attachment B

Proposal Summary Form

Company/Respondent:____
Respondent Contact Name:____
Mailing Address:____
____
Telephone:____
Facsimile:____
General Description of the Proposed Project:_________________________________
____
____
(Attach additional sheets as needed)
Power Generation Technology:____
Unit(s) Name:____
Project Location:____
Contract Term:____
Unit(s) Summer MW Rating:____
Unit(s) Winter MW Rating:____
Unit(s) Fuel Type(s):____
Proposed Capacity (MW) Delivered to FPC:_________________________________
Proposed delivery point to FPC:_______________________________________
Other Parties with an Interest in the Proposal: ______________________________
____

Certification: Respondent hereby certifies that all of the statements and representations made in this proposal, including all attachments, are true to the best of Respondent's knowledge and belief. Respondent agrees to be bound by its representations and the terms and conditions of the Request for Proposals. This proposal shall remain in effect until at least October 1, 2000.

Signed:____________________________
Name:_____________________________
(Typed)
Title:______________________________
Date:______________________________

Attachment C

Respondents are requested to respond to the following data requests. All of this information is important to assist FPC in better understanding, among other things, the price and non-price attributes addressed in each alternative generating proposal, including their technical and financial viability, pricing structure, dispatchability, deliverability, water supply, environmental compliance, and performance criteria.

Certain data requirements in this RFP reference "Seasons," which will, for consistency, be defined as:

Winter	[December *through* February]
Summer	[June *through* September]
Shoulder	[Balance of the Months]

Section 1: General Proposal Information

Respondents are requested to provide brief but concise answers to the Data Requests below. If annual escalation is expected or if contract price will vary, include any such rates or indices.

1. Provide documentation of Respondent's previous experience providing the proposed product.

2. Provide the following information for your company:

   a. Annual reports and Form 10-K for the past three years. If these documents are not readily available, then audited financial statements for the past three years will be accepted.

   b. Dunn and Bradstreet identification number credit rating of the Respondent's senior debt securities. Any additional documentation needed to allow FPC to determine the Respondent's financial strength.

   c. Ten year summary of litigation activity related to (1) provision of energy products and services (fuel, power, ancillary services, engineering, on-site services), (2) lease option arrangements for assets, (3) purchases of energy products and services (as above), or (4) industrial construction projects (power plants, industrial plants, cogeneration facilities, etc.).

3. Provide copies of notices to be published, per Section III.D.2 of the RFP.

4. Provide a complete schedule of the proposed contract terms and conditions.

5. Provide a detailed list and summary of contract flexibility attributes included in the proposal as well as discrete cost or fee structures for each of the proposed attributes.

6. Present a detailed description of any security or credit instruments proposed by the Respondent to back its performance obligation.

7. Provide a detailed summary of any liquidated damages provisions included in the proposal and a description of the particular circumstance(s) they are intended to mitigate.

8. Describe whether or not this capacity has been offered in another RFP or is in any other way obligated or may be obligated to others, and under what conditions it would be released to serve this proposed sale.

9. Describe the firmness of the capacity in your offer.

10. Explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the energy after it has been scheduled.)

<u>Section 2: Specific Supply Resource Information</u>

1. For a proposal involving a specific unit(s), provide the following information using the data tables included where appropriate:

    a. (Proposed) Unit name and location.

    b. For new units, provide the schedule for licensing, permitting and construction, including the projected date of commercial operation.

    c. Descriptions (including models and manufacturers) of all of the major components.

    d. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation or other fixed price components. Clearly delineate whether each price component and/or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

    e. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

    f. Seasonal Unit ratings (MW, MVAR, MVA) based on the ambient condition assumptions of Winter (40°F), Summer (90°F), and Shoulder (59°F). If capacity being offered is less than the full capability of the generating unit(s), provide the full capability information for these same ambient conditions. Explain if and how unit performance degradation is accounted for over time. (See Table 3)

g. Generator capability curve.

h. Guaranteed availability. (See Table 4)

i. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation). (See Table 5)

j. For planned maintenance requirements, discuss the means by which FPC will be entitled to schedule the planned maintenance periods. (See Table 6)

k. Detailed Fuel Supply Plan (primary and secondary).

   i. Fuel type, on-site storage capability and inventory management plan, applicable fuel specifications, metering requirements. (See Table 9)

   - Natural Gas: Include interstate pipeline supplier, connection point, lateral length, type and quantity of firm, recallable, and interruptible transportation.
   - Oil: Include type, special specifications, storage tank description, number of hours of full load operation supported by the tank.
   - Other Fuels.

   ii. Any proposed tolling or other fuel procurement arrangements that would involve FPC in the fuel management process.

   iii. Operating limits on either the primary or secondary fuels, if any.

l. Describe any dispatch notice or scheduling requirements for this offer, including, but not limited to:

   i. Minimum run time per dispatch call, if any.

   ii. Minimum down time, if any.

   iii. Start up energy requirements.

   iv. Ramp Rate(s).

iv. Start up time from cold start and from hot start.

v. Start up costs from cold start and from hot start.

vi. Quick start capability (less than 10 minutes). (See Table 7)

m. Maximum and minimum operating levels, capacity breakpoints and corresponding net heat rates (in Btu/kWh, on a higher heating value basis). Provide on a seasonal basis, as outlined in the tables. (See Table 8a and 8b)

n. Maximum or minimum energy take per month, season, year, or contract period, if any.

o. A detailed water supply plan, including data requirements. (See Table 10).

p. A thorough description of anticipated environmental impact, environmental permitting requirements, and actions for compliance.

q. A complete description of any cogeneration aspects of the facility(s) including, but not limited to, fuel, steam, water, or power sales and any details related to qualifying facility status, if any.

r. A complete description of any actual or proposed energy or capacity sales, or sales of any other energy-related products (ancillary services, steam, tankage, etc.) to any other parties from this facility(s).

s. Any other limit on use or availability of resource's output, if any.

Section 3: System Supply Resource Information

1. For a system sale or other sales, please provide the following information. It is difficult to anticipate all possible system supply scenarios, but please use the existing tables to the extent that it is practical and provide any additional information needed in separate schedules, tables and/or forms.

   a. Seasonal Capacity (MW, MVAR, MVA) available for use on the FPC System. (See Table 3)

   b. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation, or other fixed price components. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

c. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

d. A description of the system from which the power will be provided, including the name, location, the installed capacity, capacity mix, fuel mix, technology mix, peak hour load, and reserve projections (with and without the proposed capacity sale) during the proposal period. In addition, provide all data requested in the tables. (See Table 11).

e. A detailed history of the system operations for the past five years including, but not limited to fuel mix, power sales and purchases (energy and demand) to native load and to non-native load, emergency power purchase requirements, historical reserve levels, and incidences of firm transmission interruptions. In addition, provide all data requested in the tables. (See Table 11)

f. In conjunction with the information and data provided in b. and c., please provide copies of the 1999 and 2000 EIA-411 filings and the 1999 Ten Year Site Plan for all systems from which power is to be sold under this proposal offering.

g. An explanation of the priority of this proposed transaction relative to all other supply commitments (existing and future) and any criteria under which the supply of system power by the Respondent might be curtailed or interrupted.

h. A description of any dispatch notice or scheduling requirements for this offer.

i. Guaranteed availability. (See Table 4)

j. Maximum or minimum energy take per month, year, contract period, if any.

k. A thorough description of anticipated environmental impact and compliance resulting from these power sales.

l. Any other limit on use or availability of resource, if any.

<u>Section 4: Supplemental Transmission Information</u>

1. Provide all information required in Section IV.B, Transmission Information Requirements,

of this RFP for each Internal or External Resource included in the Respondent's proposal. This data must be included with the Respondent's proposal when it is submitted.

2. If this data has already been supplied to FPC Transmission Planning associated with a current generation interconnection request on the FPC Transmission System, please clearly identify the request, the date of the request and the project(s) associated with the request.

3. Provide a schedule of the costs that the bidder will be responsible for paying for transmission service to deliver power to FPC's Control Area.

4. Describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the FPC Control Area. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.

5. Describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.

Section 5: Data Tables

Respondents are requested to complete the tables in the attached excel file labeled "Data Tables", as represented herein. Once the tables are completed electronically, the respondent is required to print the resulting data tables and include these printed tables in their proposal document. Add rows as necessary for additional years. If annual escalation is expected, include such escalation rates or indices. Please note any additions or modifications made to the tables. Do not leave blanks: write in "N/A" if topic is not applicable, or "0" if the value is zero. Respondents may provide additional tables, as required to better clarify their proposals. Such additional tables should follow the Water Requirements table, and be labeled "Additional Table - (Description)," and include appropriate units.

Table 1. Fixed Capacity Price Structure- ($/kW-month)

Season	Year: 2003	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2004	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2005	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2006	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2007	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2008	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2009	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2010	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2011	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2012	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					

Season	Year: 2016	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2017	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2018	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2019	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2020	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2021	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2022	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2023	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2024	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2025	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					

Table 2a. Variable Price Structure, Primary Fuel - (units below)

Season	Year: 2003	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2004	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2005	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel:	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2006	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel:	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2007	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2008	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2009	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2010	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units ______)
Winter	Price						
	Escal / Index						

Season	Year: 2016	O&M	Commodity	Emissions		All-In
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2017	O&M	Commodity	Emissions		All-In
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2018	O&M	Commodity	Emissions		All-In
	Fuel:	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2019	O&M	Commodity	Emissions		All-In
	Fuel:	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2020	O&M	Commodity	Emissions		All-In
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2021	O&M	Commodity	Emissions		All-In
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2022	O&M	Commodity	Emissions		All-In
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2023	O&M	Commodity	Emissions		All-In
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)
Winter	Price					
	Escal / Index					

Table 3. Resource Capacity Rating- (units below)							
		40°F		59°F		90°F	
Guaranteed Contract Rating	MW						
	MVAR						
	MVA						
Maximum Unit Rating	MW						
	MVAR						
	MVA						

Table 4. Guaranteed Availability- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 5. Equivalent Forced Outage Rate- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 6. Planned Maintenance Requirements- (Number of Outages/Year, Total Hours/Year)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number year													
Maint Hrs/yr													
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number year													
Maint Hrs/yr													

Table 7. Operational Parameters- (units below)

Minimum run time per dispatch call		Hours
Minimum down time between calls		Hours
Startup Energy		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 proce
Cost of Each Hot Start Beyond Those Included		Dollars
Number of Cold Starts per year		Maximum
Number of Cold Starts per year		Included in bid proce
Cost of Each Cold Start Beyond Those Included		Dollars
Quick Start Capability- Minutes to 1st MW		Minutes
Quick Start Capability- MW in ten minutes		MW
Start up time from cold start		Minutes
Start up cost from cold start		$
Start up time from hot start		Minutes
Start up costs from hot start		$

Table 8a. Capacity States on Primary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 8b. Capacity States on Secondary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

NOTE: Net Heat Rates are to be based on Higher Heating Value (HHV)

Table 9. Fuel Supply Requirements		Units
Primary Fuel Maximum Flow rate		
Primary Fuel Pressure Requirement		
Primary Fuel Metering Requirement		
Primary Fuel Storage Capacity		
Secondary Fuel Maximum Flow rate		
Secondary Fuel Pressure Requirement		
Secondary Fuel Metering Requirement		
Secondary Fuel Storage Capacity		

Table 10. Water Requirements		Units
Cooling		
Consumptive Use		
Other		

Table 11. System Reliability Parameters

	Actual					Forecast				
	1995	1996	1997	1998	1999	2003	2004	2005	2006	2007
Installed Capacity										
Contracted System Firm Capacity Purchases										
Contracted System Firm Capacity Sales										
Load Control Capability										
Seasonal Peak Requirements before Direct Load Control										
Firm Peak Requirements after Direct Load Control										
Capacity Margin before Direct Load Control										
Firm Reserve Margin after Direct Load Control										

Attachment D - Planned Unit Data

The following data represent the planned unit data estimates, which FPC utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on FPC's existing Hines Energy Complex site in Polk County, Florida.

2. Planned Size 530 MW (nominal).

3. Commercial Operation of the facility is proposed to be November 30, 2003.

4. The primary fuel is natural gas. Oil will be used as a backup fuel source.

5. The estimated total direct cost is $197.6 million.

6. The estimated annual levelized revenue requirement is $35.6 million over 25 years.

7. The estimated annual value of deferral of this unit is $48.95/kW-yr (03$).

8. The estimated annual fixed O&M is $2.2 million (03$). The estimated variable O&M is $1.11/MWH (03$).

9. The estimated delivered fuel cost is $2.66/MMBtu (03$), plus fixed transportation at the prevailing rate.

10. The following are estimates for:

Planned outage rate	7, 7, 14, 7, 7, 22 days/year (or 2.92%)
Forced outage rate	3.5 %
Heat rate at maximum capacity	6,975 Btu/kWh
Minimum load	250 MW
Ramp Rate	1 Hr.

11. The estimated transmission and interconnection costs for this unit are $5.6 million.

12. Supplemental site certification as well as amendment to related environmental permits will be required for this unit. It is FPC's plan to comply with all environmental standards of Local, Regional, State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.5 % per year
General escalation:	3.1 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.3 %
	55 % equity @ 12.0 %

Attachment E

Florida Power Corporation
Generation Interconnection Study
Data Request Form

INSTRUCTIONS

(*) denotes items that are required for both a Generation Interconnection Feasibility Study and a Generation Interconnection Study and must be completed and included in Respondent's proposal. All items on this form are required prior to the start of engineering design.

If a data item is unavailable, please provide an estimate and indicate it as an estimate. Please note that a restudy could be required if data assumptions change while the study is in progress.

Please fill out and attach a copy of Section II for each generator on the site.

Please use this form to supply the requested data. Submittal of manufacturer data sheets, other than generator characteristic curves, is not an acceptable alternative to completing this form.

SECTION I - Generation Site Data

A) **Contact Person** - Provide name and address of person completing this form

(*)1. Name: ____________________

(*)2. Address: ____________________

(*)3. City/State/Zip: ____________________

(*)4. Telephone: ____________________

(*)5. Date: ____________________

B) Site Location

(*)1. County: ____________________

(*)2. Section / Township / Range: ______________________________

(*)3. Site Drawing: Include a site drawing indicating county, section, township, and range. In addition, for a Generation Interconnection Study, a preliminary equipment layout on the site, suitable for site plan permitting, is required.

C) Proposed Load Requirements for Site

(*)1. Required Date: ______________________________

(*)2. Nature of Load (Station Service, Start-up Power, Etc.) ____________________

(*)3. Connected kVA Load: ________________

(*)4. Peak Demand kVA Load: ________________

(*)5. Expected Power Factor: ________________

(*)6. Service Voltage: ________________

(*)7. Anticipated Future Load Requirements (please describe): ________________

____

____

____

D) Other Site Information

(*)1. Net Generation Output (MVA) for Site @ 59°F Outdoor Ambient: __________

(*)2. Net Generation Output (MVA) for Site @ 90°F Outdoor Ambient: __________

(*)3. Proposed Interconnections with Other Systems (please describe):

____

____

E) In-Service Dates

(*)1. Required connection to grid for generator testing: ____________

(*)2. Commercial in-service date: ____________

SECTION II – Individual Generator Data

A) Unit Identification

(*) 1. Plant Name and Unit Number ____________

2. Manufacturer ____________

3. Generator Serial Number ____________

4. Turbine Serial Number ____________

B) Ratings and Capabilities

1. Nameplate kV Rating (nominal design voltage) ____________

2. MVA Rating

	MVA Rating	@ Hydrogen Pressure
a.	______	______
b.	______	______
c.	______	______
d.	______	______

(*) 3. Gross MW Rating @ 59°F Outdoor Ambient ____________

(*) 4. Net MW Rating @ 59°F Outdoor Ambient ____________

(*) 5. Gross MW Rating @ 90°F Outdoor Ambient ____________

(*) 6. Net MW Rating @ 90°F Outdoor Ambient ______________________

7. Rated Power Factor ______________________

8. Rated Speed ______________________

9. Rated Turbine Capability ______________________

10. Field Voltage at Rated Load ______________________

11.. Field Current at Rated Load ______________________

12. No-load Field Voltage at Generator Rated Voltage ______________________

13. Air Gap Field Voltage at Generator Rated Voltage ______________________

14. Field Resistance ____ohms @ __________ °C

C) **Inertia**

(*) 1. WR^2 for Generator and Exciter ______________________lb-ft^2

(*) 2. WR^2 for Turbine ______________________lb-ft^2

(*) 3. Calculated H Constant ____________sec. @ ____________ MVA

D) **Losses and Efficiency**

1. Open circuit core loss ______________________ kW

2. Windage loss ______________________ kW

3. H_2 seal and exciter friction loss ______________________ kW

4. Stator I^2R Loss at rated power and voltage __________°C ______________ kW

5. Rotor I^2R Loss at rated power and voltage __________°C ______________ kW

6. Stray Load loss ______________________ kW

7. Excitation losses ______________________kW

E) Generator Time Constants

1. T'_{do} (Direct axis open circuit transient time constant) ______________ sec
2. T''_{do} (Direct axis open circuit subtransient time constant) ______________ sec
3. T'_{qo} (Quadature axis open circuit transient time constant) ______________ sec
4. T''_{qo} (Quadature axis open circuit subtransient time constant) ______________ sec
5. T_{a3} (Short circuit time constant) ______________ sec

F) Generator Impedances

(*) 1. MVA base for all impedance data ______________ MVA

(*) 2. kV base for all impedance data ______________ kV

Parameter	Description	p.u. value
(*) 3. X_d	Direct axis synchronous reactance (unsaturated)	____________
4. X_q	Quadrature axis synchronous reactance (unsaturated)	____________
(*) 5. X'_d	Direct axis transient reactance (unsaturated)	____________
6. X'_{ds}	Direct axis transient reactance (saturated)	____________
7. X'_q	Quadrature axis transient reactance (unsaturated)	______
8. X'_{qs}	Quadrature axis transient reactance (saturated)	____________
(*) 9. X''_d	Direct axis subtransient reactance (unsaturated)	____________
10. X''_q	Quadrature axis subtransient reactance (unsaturated)	____________
11. X_L	Armature leakage reactance	____________
12. R_1	Positive sequence armature resistance at 75° C	____________
13. R_2	Negative sequence armature resistance at 75° C	____________
14. X_2	Negative sequence armature reactance at rated voltage	____________

15. X_0 Positive sequence armature resistance at 75° C ____________

16. R_{dc} Direct current armature resistance at 75° C ____________

17. Generator neutral grounding resistance ________ ohms

(*)18. Generator neutral grounding reactance ________ ohms

G) Required Characteristic Curves and Diagrams

(*) 1. Real and reactive power capability curves **(Maximum var capability, lagging and leading, is sufficient for Feasibility Study)**

2. Saturation curve, full load and no-load

3. "V" curves

4. Governor overspeed response curve

5. One-Line diagram showing generator and substation equipment connections

H) Excitation System Data

1. Excitation system type ______________________________

2. Voltage regulator model name______________________________

3. Excitation system model, supply block diagram and model parameters in IEEE[1] or PSS/E format

4. Voltage compensation, supply block diagram and settings if used

5. Voltage regulator overexcitation limiters, supply block diagram and model parameters in IEEE[2] format.

6. Power System Stabilizer (if used), supply Power System Stabilizer block diagram and model parameters in IEEE or PSS/E format

I) Turbine Governor Data

1. Speed/Load governor model name ______________________________

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[1] IEEE Standard 421.5-1992 "IEEE Recommended Practice for Excitation System Models for Power System Stability Studies"

[2] IEEE Committee Report, "Recommended Models for Overexcitation Limiting Devices," IEEE Transactions on Energy Conversion, Vol. 10, No. 4, December 1995

2. Governor model, supply block diagram and model parameters in IEEE[3,4] or PSS/E format

J) **Generator Step-up Transformer Data**

1. Manufacturer ______________________________

2. Model Type ______________________________

3. Serial Number ______________________________

(*) 4. Rating ______________________________MVA

(*) 5. High voltage winding, nominal voltage ____________________ kV

(*) 6. High voltage winding connection (wye/delta)____________________

(*) 7. Low voltage winding, nominal voltage ____________________ kV

(*) 8. Low voltage winding connection (wye/delta) ____________________

9. Transformer resistance ____________________ p.u.

(*)10. Transformer reactance ____________________ p.u.

(*)11. Transformer impedance base values __________ MVA ______ kV

12. Available tap settings

HV taps ______________________________ kV

LV taps ______________________________ kV

13. Expected tap settings

HV taps ______________________________ kV

LV taps ______________________________ kV

[3] IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbine Control Models for System Dynamic Studies," IEEE transactions on Power Apparatus and Systems, Vol. PAS-92, November, 1973
[4] W.I. Rowen, "simplified Mathematical Representations of Heavy Duty Gas Turbines," Transactions of ASME, Vol.105(1), 1983

Table 1 Fixed Capacity Price Structure ($/kW-month)

Season	Year 2003	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2016	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2004	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2017	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2005	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2018	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2006	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2019	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2007	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2020	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2008	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2021	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2009	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2022	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2010	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2023	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2011	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2024	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2012	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2025	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2013	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2026	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					
Season	Year 2014	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year 2027	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	[illegible]							Escal / Index					
Season	Year [illegible]	Capacity	O & M	Other	All-In	Fuel Transportation	Season	Year [illegible]	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price						Winter	Price					
	Escal / Index							Escal / Index					
Shoulder	Price						Shoulder	Price					
	Escal / Index							Escal / Index					
Summer	Price						Summer	Price					
	Escal / Index							Escal / Index					

Table 2a. Variable Price Structure, Primary Fuel (units below)

Season	Year 2003	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2004	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2005	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2006	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2007	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2008	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2009	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2010	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2011	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2012	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2013	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2014	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year [illegible]	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summe	Price						
	Escal. Index						

Season	Year 2016	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2017	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2018	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2019	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2020	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2021	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2022	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2023	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2024	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2025	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2026	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year 2027	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Season	Year [illegible]	O&M	Commodity	Emissions		All-In	Fuel Transportation
	Fuel	($/MWh)	(¢/MMBtu)	SO2 ($/ton)	Other ($/MWh)	Price ($/MWh)	(units)
Winter	Price						
	Escal. Index						
Shoulde	Price						
	Escal. Index						
Summer	Price						
	Escal. Index						

Table 3. Resource Capacity Rating- (units below)

		40°F		59°F		90°F	
Guaranteed Contract Rating	MW						
	MVAR						
	MVA						
Maximum Unit Rating	MW						
	MVAR						
	MVA						

Table 4. Guaranteed Availability- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 5. Equivalent Forced Outage Rate- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 6. Planned Maintenance Requirements- (Number of Outages/Year, Total Hours/Year)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number/year													
Maint Hrs/yr													

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number/year													
Maint Hrs/yr													

Table 7. Operational Parameters- (units below)

Minimum run time per dispatch call		Hours
Minimum down time between calls		Hours
Startup Energy		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 proce
Cost of Each Hot Start Beyond Those Included		Dollars
Number of Cold Starts per year		Maximum
Number of Cold Starts per year		Included in bid proce
Cost of Each Cold Start Beyond Those Included		Dollars
Quick Start Capability- Minutes to 1st MW		Minutes
Quick Start Capability- MW in ten minutes		MW
Start up time from cold start		Minutes
Start up cost from cold start		$
Start up time from hot start		Minutes
Start up costs from hot start		$

Table 8a. Capacity States on Primary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 8b. Capacity States on Secondary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 9. Fuel Supply Requirements

		Units
Primary Fuel Maximum Flow rate		
Primary Fuel Pressure Requirement		
Primary Fuel Metering Requirement		
Primary Fuel Storage Capacity		
Secondary Fuel Maximum Flow rate		
Secondary Fuel Pressure Requirement		
Secondary Fuel Metering Requirement		
Secondary Fuel Storage Capacity		

Table 10. Water Requirements

		Units
Cooling		
Consumptive Use		
Other		

Table 11. System Reliability Parameters

	Actual					Forecast				
	1995	1996	1997	1998	1999	2003	2004	2005	2006	2007
Installed Capacity										
Contracted System Firm Capacity Purchases										
Contracted System Firm Capacity Sales										
Load Control Capability										
Seasonal Peak Requirements before Direct Load Control										
Firm Peak Requirements after Direct Load Control										
Capacity Margin before Direct Load Control										
Firm Reserve Margin after Direct Load Control										