BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition on behalf of Citizens of the State of Florida to require Progress Energy Florida, Inc. to refund to customers $143 million

DOCKET NO. 060658
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DIRECT TESTIMONY OF JOHN BENJAMIN CRISP ON BEHALF OF PROGRESS ENERGY FLORIDA

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IN RE: PETITION ON BEHALF OF CITIZENS OF THE STATE OF FLORIDA TO REQUIRE PROGRESS ENERGY FLORIDA, INC. TO REFUND CUSTOMERS $143 MILLION

FPSC DOCKET NO. 060658

DIRECT TESTIMONY OF

JOHN BENJAMIN CRISP

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is John Benjamin Crisp. My business address is 299-First Avenue North, PEF 121, St. Petersburg, FL 33701.

Q. Please tell us how you are employed and describe your background.

A. I am employed by Progress Energy Florida, Inc. ("PEF" or the "Company") currently serving as the Manager of Energy Efficiency Services. Prior to this role, I was PEF's Director of Generation Planning for Progress Energy Florida, as well as the Director of Generation Planning for both of Progress Energy's regulated utilities. My background includes over 20 years of electric utility experience in generation and fuels planning, load forecasting, generation construction, plant operations, system grid planning and operations, fuels and power trading, and energy efficiency systems. I have a bachelor's degree in Industrial Engineering from Georgia Tech, and have completed post graduate marketing and management programs at Georgia Tech and Duke University.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I am providing an analysis of the total cost to the Company if Crystal River Units 4 and 5 (hereafter "CR4" and "CR5") produced 665 gross MegaWatts ("MW") of electrical energy each year from 1996 to 2005 rather than the net 722MW (winter) and 732MW (winter) of electrical energy we conservatively expected CR4 and CR5, respectively, to produce on average annually from 1996 to 2005 in our Ten Year Site Plans ("TYSPs"). This is a de-rate (or loss of MW energy load) of 57MW for CR4 and 67MW for CR5 for each year or a total annual loss of load of 124MW of electrical capacity and energy. My analysis of the cost to the Company of an annual loss of 124MW during this period of time is based on the testimony of the consultant of the Office of Public Counsel ("OPC") and PEF's outside consultant, Mr. Hatt, in this proceeding.

I understand that OPC's consultant has testified that the Company should have purchased and burned a 50/50 blend of Power River Basin ("PRB") sub-bituminous coal and bituminous coal at CR4 and CR5 from 1996 to 2005 (allowing for a brief period to ramp up to this blend in 1996), because he claims that (1) PRB coals were the cheapest coals for those units during that time period, and (2) the CR4 and CR5 boilers were designed to accommodate a 50/50 blend of PRB coals and bituminous coals. I understand that Mr. Hatt will testify that, if the Company had purchased and burned a 50/50 blend of PRB coals and bituminous coals from 1996 to 2005, the units would have each produced on an average annual basis only 665MW gross, rather than the actual net annual energy production of 722MW (winter) and 732MW (winter) that we expected the units to produce over this time period. I further understand that Mr. Hatt's testimony is supported by the same design documents relied upon by OPC's consultant that demonstrate the design rating of the turbines using a 50/50 blend of PRB and bituminous coals is 665MW. I have, accordingly, determined the cost to the Company to replace 124MW annually from 1996 to 2005, if CR4 and CR5 produced only 665MW gross each rather than the net 712MW (winter) and 732MW (winter) they were expected to produce annually over the 1996 to 2005 time period.

Q. Please describe how your background gives you the technical expertise necessary to support your testimony.

A. For much of the time from 1996 to 2005 it was my job as director of resource planning for PEF to find the most cost-effective alternatives to meet the Company's obligation to serve our customers' short- and long-term needs for electric energy. I oversaw the completion of the Company's TYSPs, which set forth the Company's plans to meet customer load over a ten year period of time, presented and explained many of them in the annual Commission workshops held to evaluate the TYSPs, and further supported them during the Commission's determination of their adequacy, which the Commission by law must determine annually.

To perform these responsibilities, I routinely examined and evaluated both supply-side resources, i.e. additional generation, and demand-side resources to meet the customers' demand for electric energy (or load). In the course of this evaluation I analyzed PEF system load and load service reliability requirements, integrated generation dispatch economics, electric system planning and reserve margin requirements, electric generator costs, construction and associated installation costs, fuel and operating costs, generating unit start-up costs, and market replacement capacity and energy. In other words, it was my responsibility to recommend a course of action to build new generating plants, purchase power on the market, or employ new or expanded demand-side measures to reduce demand during peak periods in order to ensure that the Company adequately met the customers' electrical energy needs in the most cost-effective manner. I am employing the same analysis I performed over the years for PEF to determine the most cost-effective manner to meet customer demand for electric capacity and energy to my analysis in this testimony.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. The following exhibits were prepared by me or under my supervision and control, or they represent business records prepared at or near the time of the events recorded in the records, which records it was a regular practice for me or those who worked with me to keep to perform our responsibilities for the Company:

- Exhibit No. ___ (JBC-1), which are the Babcock & Wilcox Company design documents for the boilers for CR4 and CR5;

- Exhibit No. ___ (JBC-2), which is the Company's 1995 TYSP;
- Exhibit No. ___ (JBC-3); which is a composite exhibit of Schedule 1, Existing Generation Facilities, to the Company's TYSPs for the years 1996 to 2005;
- Exhibit No. ____ (JBC-4), which is PEF's daily total load forecast with the generation;
- Exhibit No. ___ (JBC-5), which is the cost estimate for the two-year "bridge" contract costs and remaining eight-year system costs following the construction of a peaking unit to replace the lost 124MW from the CR4 and CR5 de-rates over the ten-year period of time; and
- Exhibit No. ____ (JBC-6), which is the summary of my calculation of the range of costs the Company would have incurred to replace 124MW of base load capacity over the time frame from 1996 to 2005.

All of these exhibits are true and correct.

Q. Please summarize your testimony.

A. I understand that OPC's consultant has testified that PEF should have purchased and burned a 50/50 blend of PRB sub-bituminous and bituminous coal at CR4 and CR5 from 1996 to 2005. I further understand that PEF's expert, Mr. Rod Hatt, has concluded that, if PEF had converted to a 50/50 PRB/bituminous coal blend in CR4 and CR5 from 1996 to 2005, the units would not have produced the MWs they historically have been expected to produce in our TYSPs from burning bituminous coals in the units. Rather, according to Mr. Hatt, CR4 and CR5 together would have generated 124MW less than the net MW expected from the two units each year in the

TYSPs. This de-rate or loss of load is consistent with the turbine rating (665MW) in the boiler design documents using an equal blend of PRB sub-bituminous and bituminous coals included in Exhibit No. ___ (JBC-1) to my testimony. Based on these conclusions, I have determined that, over the eleven-year period between 1995 and 2005 when this loss of net MW load would have occurred, PEF would have incurred $696.9 million to $966 million to replace the lost energy and capacity associated with this MW loss of base load generating capacity.

III. HISTORICAL RESOURCE PLANS 1996-2005

Q. Let's start at the beginning of this time period, what was PEF's generation supply to meet generation demands in 1995?

A. In 1995, PEF's own generation consisted of a nuclear generation unit, fossil steam generation units, and combustion turbine generation units with 7,400MW of electrical generation capacity. In addition, PEF purchased an additional 1,500MW of generating capacity from other investor owned utilities and qualifying facilities. This is demonstrated by the Company's 1995 TYSP in Exhibit No. ____ (JBC-2) to my testimony.

The Company's generation capacity consisted of base load, intermediate, and peaking generation units. A base load unit is one of the Company's most efficient electrical energy generators and, therefore, they are operated at all times except when they must be taken off line for maintenance or repairs. A base load unit typically has higher relative capital costs and lower fuel costs relative to other types of generating units. Peaking units, on the other hand, have lower capital construction costs but higher fuel costs and, thus, are operated during the periods when the demand for energy on the system is greatest or, in other words, the peak times and, hence, the name "peakers" or "peaking" units. The Company had approximately 2,700MW of natural gas and oil fired peaking generation in 1995.

Intermediate generation units, as the name suggests, are operated more than peakers but less than base load units, typically on a seasonal basis. At this time, approximately 1,600MW of fuel-oil fired steam capability served as the seasonal base load or intermediate generation.

In 1995, approximately 3,100MW of the total electrical generation capacity was base load generation located at the Crystal River site. This includes the nuclear unit and the four coal-fired generation units, including CR4 and CR5. This base load generating capacity provided and continues to provide the backbone of PEF's low-fuel cost, base load generation capability. CR4 and CR5 provided about one-half of this base load generation and, thus, were and are critical to supplying the base load needs of PEF's customers.

PEF also had demand-side management resources ("DSM") that were used to reduce demand during peak time periods by, for example, allowing the Company to turn off participating customers' pool motors and water heaters for a fee or credit on the customers' bills. DSM was a result of the Florida Energy Efficiency and Conservation Act ("FEECA") of 1980. Pursuant to FEECA, PEF employed a robust DSM program, with over 1,500MW of load management and conservation capability.

Accordingly, at the end of 1995, PEF had generation and DSM resources available to it equal to approximately 9,095MW of electric capacity and energy supply. This capacity was needed to meet the projected load for 1996 of 9,007MW. The load is the amount of customer demand for energy on the system, typically measured at the peak time period in the year because of the utility's obligation to supply adequate energy instantaneously at all times to meet energy demand.

Q. You used the terms electric "capacity" and "energy." What do they mean?

A. The term "capacity" refers to the commitment of a particular generation unit output or system of generation unit output to provide service. When a regulated utility builds a generation unit, all of the energy output or "capacity" is committed to the utility to provide electric service to customers. Such a commitment ensures that the customer has reliable electric service. If the capacity of a unit is not committed to the utility for service, which can occur in some contracts for purchase power from other utilities or non-utility generators, then that electric service is less reliable because the purchasing utility has no right to call on that capacity for electric energy at its discretion. Contracts with the generation capacity committed to the purchaser are called "firm" contracts and contracts without such a commitment are called "non-firm" contracts.

All or some of a generation unit's capacity, however, can also be and is sometimes sold on the non-regulated market to generation buyers or between regulated utilities in wholesale transactions. The capacity charge, as a regulated or non-regulated cost, represents the fixed cost portion of the generation unit or energy supply source. This cost represents the depreciation of the asset over time. The capacity charge has typically been booked or represented on a $/kW-month basis.

The term "energy" represents the actual electrical output of a generation unit or system of units. The energy charge would cover all of the variable costs to actually generate electricity, including fuel and operation and maintenance ("O&M") expenses, from the generation unit or system of units. The energy charge is also a component of the cost of service. The energy charge is typically booked or represented on a $/kWH basis.

Capacity and energy are both elements of reliable electrical service to customers and must be accounted for when deciding how to provide reliable electric service to the customer, either through building a new generation unit committed to the customers' service or entering into a contract for such service.

Q. Was customer demand for energy expected to grow between 1996 and 2005?

A. Yes. The State of Florida, including PEF's service territory, was and is an area of growth both in additional residents and, thus customers, and customer energy use. PEF expected to have customer growth and an increase in customer energy use during the entire period of time from 1996 to 2005 when it was planning to meet customer needs.

At that time, in 1995, PEF was planning for up to 10,183MW of generation capacity resources by the end of 2005 to meet an expected load of 11,075MW. The additional generation capacity under construction at the beginning of and planned for this time frame was primarily gas-fired generators of peaking or intermediate capability. The Company also planned additional DSM to reduce peak load. The additional DSM was expected to reduce firm peak load from 11,075MW in 2005 to

8,837MW thus ensuring that there was adequate generation capacity resources (10,183MW) to cover the firm peak demand. This data is provided in tabular form for each winter season from 1996 to 2005 at page 80 of the 1995 TYSP in Exhibit No. ____ (JBC-2).

Q. How does PEF plan to meet increased energy demand on its system?

A. PEF employs a resource planning process that integrates supply-side, generation options with demand-side DSM options into a final, optimal plan designed to deliver reliable, cost-effective power to PEF's customers. This integrated, optimal plan is presented to the Commission each year in the Company's TYSP.

In that plan, the need for additional resources is determined by dual reliability criteria: a minimum Reserve Margin planning criterion and a maximum Loss of Load Probability (LOLP) criterion. This reliability criteria has been used since the early 1990's and is a practice accepted by the Commission. By using both the Reserve Margin and LOLP planning criteria, PEF'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 expected load conditions.

PEF has found that resource additions are typically triggered to meet Reserve Margin thresholds before LOLP becomes a factor. However, PEF still considers LOLP a meaningful supplemental reliability measure, and the Company is committed to adding resources when either one of the criteria would not otherwise be met.

Q. What is a Reserve Margin?

A. Reserve Margins are "energy service that is held in reserve."

Q. Why are reserves of energy service needed?

A. Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. At any given time during the year, some generating units will be out of service and unavailable due to forced outages to repair failed equipment or periodic outages to perform maintenance (or, in the case of the nuclear unit, refueling as well). Adequate reserves must be available to provide sufficient capacity when some generating capacity is unavailable for these reasons and when necessary to meet higher than projected peak demand due to the inherent uncertainties in forecasting load and/or abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

Q. What was PEF's Reserve Margin from 1996 to 2005?

A. PEF's minimum Reserve Margin threshold was 15 percent up until the summer of 2004. Then, pursuant to a Commission-approved joint proposal from the investor-owned utilities in peninsular Florida – PEF, Florida Power & Light Company, and Tampa Electric Company – the Reserve Margin increased to at least 20 percent. Actual and projected Reserve Margins ranged from a high of 25% to a low of 15% from 1996 to 2005.

Q. How does the utility provide reserves to meet or exceed its minimum Reserve Margin criteria?

A. PEF's reserves can be either physical assets, i.e. constructing generation units or purchasing capacity and energy under contracts with utilities with their generation units, or DSM programs that reduce peak load. Either way, the customers' peak demands for energy are satisfied.

At the end of 1995, however, virtually all of PEF's actual and projected reserves for the period from 1996 to 2005 were in the form of DSM programs. Remember, as I pointed out, by 2005 the Company expected DSM to reduce peak load from 11,075MW to 8,837MW. This was acceptable because the peak periods of demand are relatively brief and, thus, customers might find it acceptable to have DSM measures employed to reduce their energy usage for brief periods of time.

PEF's capacity margins, or the available generation capacity from actual physical or contract generation assets above the peak demand, were about 250MW at any point in time during this same time period. This means the actual physical generation reserves to cover outages and extreme weather on peak days was only about 250MW on average. The remainder of the reserves making up the Reserve Margin was DSM.

Q. How were the reserves used by the Company?

A. Typically, outages or extreme conditions would be covered by available excess generation capacity, and then DSM would be used to offset the remaining need. There were no planning criteria, however, that addressed specific requirements for capacity margins at this time, rather, capacity margin reserves and DSM reserves were treated equally under the Reserve Margin criterion. As a result, the common industry operating practice in 1995 and up until the latter part of the relevant time period was to similarly treat generation capacity equal to DSM when it came to reserves such that often the reserves above the firm peak load were primarily DSM.

Q. Did anything else have an impact on the level and type of reserves during this time frame?

A. Yes. During this planning horizon, PEF's firm load was showing growth faster than its planned capacity additions. This increased the reliance on DSM for reserves in this time period such that the reserves in the last seven years of the ten-year planning period in the 1995 TYSP were almost entirely DSM. In fact, the Company projected net negative capacity reserves in the winter and decreasing capacity margins in the summer to the point where DSM provided all or the bulk of the reserves at all times in these years. The last seven years in the 1995 TYSP were the years 1999 to 2005.

PEF was planning capacity additions to meet load and improve its capacity margins during this planning horizon, with three new gas-fired combustion turbines totaling 400MW of peaking generation planned and approximately 1,200MW of additional, intermediate generation planned in the form of one gas-fired, combined cycle unit and three steam repowering projects. These units were planned because they were economically cost effective, easy and quick to build, required less land and thus had a smaller geographic footprint from an environmental perspective, and they were more flexible from an operational standpoint. The first of these additional generation units, however, was not expected in 1995 to come on line until 1998 with a peaker unit located at Intercession City followed by a combined cycle unit in 1999.

Q. Did the Company's planned Reserve Margin during this time period contemplate continuing base load electric energy generating capacity from CR 4 and CR5?

A. Yes. PEF's resource planning process and thus its Reserve Margins assumed that all generation units, including base load units like CR4 and CR5, would continue to produce capacity and energy consistent with the Company's minimum expectations for those units. De-rates, or a loss of generating capacity and energy from the expected production, were not contemplated in the resource planning process.

Q. Would a loss of generating capacity and energy at CR4 and CR5 during this time period have an impact on the Company's resource plan?

A. Absolutely. A loss of 124MW of base load generation would have been a significant event, given the primary reliance on DSM for reserves and the slim capacity margins during this time period. This loss of additional base load generation capacity from de-rates would have reduced by half the average capacity margin available during this time period. The Company would have been required to take immediate action to add generation capacity to provide reliable coverage of the load to ensure that the customers' energy demands were met.

IV. IMPACT OF CR4 AND CR5 DE-RATES ON RESOURCE PLANS

Q. How did you determine the de-rate would have been 124MW annually?

A. I understand that OPC's witness is testifying that the Company should have burned an equal blend of PRB sub-bituminous and bituminous coal in the boilers for CR4 and CR5 from 1996 to 2005. I further understand that, consistent with the boiler design documents for this blend, PEF's consultant is testifying that, had PEF done what OPC's witness suggests from 1996 to 2005 the maximum, reasonable annual gross MW production from the units would have been 665MW each.

In our TYSPs, based on historical experience with the units, we expected and planned our resource needs on the realization on average of a net 722MW from CR4 in the winter and net 732MW from CR5 in the winter. This is actually the net winter planning numbers for 2000, and the range was from 717MW to 735MW during this ten-year time period, but this 2000 planning estimate for the CR4 and CR5 units is about the average for the time period. Attached as Exhibit No. ___ (JBC-3) to my testimony is Schedule 1, containing the Company's expectations for existing generation facilities for planning purposes in the Company's TYSPs for the time period 1996 to 2005. The winter ratings for these units is appropriate to use here because PEF is a winter peaking utility, meaning that PEF's peak load occurs in the winter.

If I could have achieved at best 665MW from CR4 and CR5 annually from 1996 to 2005 when I planned to achieve, based on historical data, a net 722MW and 732MW, respectively, from the units to meet peak load, the Company would have lost 57MW and 67MW from CR4 and CR5, respectively, each year. This is a total annual MW loss of base load capacity and energy of 124MW.

Q. Is this a conservative analysis of the expected loss of base load capacity and energy?

A. Yes, it is. As I have indicated, the average expected MW output from CR4 and CR5 during this ten-year period was a net 722MW and 732MW, respectively. By "net," I mean the available MW from these units for use by Company ratepayers. The units actually demonstrated the gross production capability of between 750MW and 770MW during this same time period. The difference between the "gross" MW output of the units and the "net" MW output of the units is the MW used by the Company to produce the MW from the CR4 and CR5 units and to support the facilities at Crystal River. The 665MW original design capability on a 50/50 blend of PRB and bituminous coals is a gross MW output. Therefore, using this design basis as starting point for comparison to the net MW output expected from CR4 and CR5 for the Company's planning purposes is a conservative estimate of the expected load loss.

Q. What course of action would PEF have likely pursued in order to mitigate the generation capacity and energy losses from a 124MW de-rate at CR4 and CR5?

A. PEF would have to add peaking generation units to offset the 124MW de-rates at CR4 and CR5. Peaking units would have been the quickest types of generation capacity to add. Peaking units require less space than larger generating units, thus, they can be placed at existing PEF generation sites quickly with little to no additional environmental impact that might delay construction. Such units are further readily available on the market from existing vendors. PEF could add up to 124MW of peaking generation capacity in about two years.

Gas-fired, combined cycles are much larger units and require longer lead times due to the added complexity in the construction of the generation units, and the need for more land for their construction (raising environmental issues too). On average, in 1995 PEF could expect to plan, site, and construct a gas-fired combined cycle generation unit in four to five years. Base load coal and nuclear generation units are complex, large generation plants that require very long lead times to adequately plan, site, design, and construct. The only practical solution, then, to replace an immediate loss of 124MW of base load generation, was to build a peaker.

Q. What would PEF have done to replace the loss of 124MW during the two year period of time required to site, design, and construct a peaking unit?

A. PEF would have purchased short-term capacity and energy from market-based suppliers. During the mid-1990s, a fledgling market for electric capacity and energy was emerging, with a supply of firm and non-firm energy contracts available. As I have explained, a firm energy contract is one in which the generation capacity is committed to the purchaser, and a non-firm energy contract is when it is not. So, there is some risk to the purchaser of energy under the contract that the generation capacity might be unavailable when needed. All of these contracts, whether firm or non-firm, carried with them contractual provisions that imposed some level of delivery risk proportional to market fluctuations on the buyer, meaning that the seller might divert the capacity and energy to other buyers when it was more lucrative to do so because of market volatility.

Q. Were these types of market-based capacity and energy supply contracts cost effective?

A. No, not as a long term choice over self-build generation options. The delivery risk and higher costs of such contracts made them unsuitable for reliable use as capacity or reserve margin supplies over the long term.

In many cases, market volatility caused prices for the capacity and energy to rise above the contract penalty for failure to deliver the contracted for capacity and energy to the buyer, and utility buyers simply would not receive the capacity and energy they purchased. The seller could incur the penalty for failing to deliver to the original buyer and still make more money selling the same capacity and energy on the market to another purchaser. Even for contracts where the energy was backed by a specific generation unit, delivery was not guaranteed without a penalty. Price premiums were added to the peak periods under such contracts, forcing the utility buyers to compensate the seller for the opportunities lost in a volatile market when the seller had to remain committed to the original purchaser. Of course, the utility buyer needs the generation capacity and energy the most during such peak periods, when the buyer is at the greatest risk that the seller will not deliver or that price premiums will be imposed on the buyer.

Additionally, the cost of purchasing these firm or non-firm contracts for generation capacity and energy on the market was higher than the regulated utility's cost to construct new generation. Unregulated project developers building generation units to sell capacity and energy on the market generally incurred higher financing costs because there was more risk associated with the developers and/or their projects than with traditional regulated utility projects. For example, the unregulated generation project assets were "unsecured" since, unlike regulated utility projects, their costs were not incorporated in customer rates. Accordingly, the developers of such projects paid a higher interest premium for financing due to the risk of non-payment if all the generation capacity and energy generated over the life of the unit could not be sold. The interest premium alone could add up to five percentage points to the developer's financing costs compared to a regulated utility's weighted average cost of capital. The project developers further required higher returns for investors to compensate them for the additional risk associated with developing projects in the non-regulated energy market, adding additional costs that must be covered by any contract for the sale of capacity and energy from the generation project.

All of these factors, from the added delivery risk to the purchaser under such contracts to the typically higher costs of the contracts compared to the self-build generation option, made these contracts for capacity and energy unsuitable sources of long term, reliable reserves for a utility like PEF that is obligated by law to provide service to its customers.

Q. Why would you use a market-based contract for generation capacity and energy if the contract cost more than and was not as reliable as building your own generation unit?

A. PEF would have had no choice but to purchase such a contract for generation and capacity and energy if it lost 124MW of base load generation due to a de-rate at CR4 and CR5. PEF would need the contract to "bridge" across the time it takes to build a peaking unit to replace the lost generation capacity.

"Bridge" contracts were available during the relevant time period for a "premium" above the self-generation cost to own the rights to a particular generation unit's capacity and energy for short periods of time, generally less than five years. For example, a regulated utility with cost recovery under base customer rates for new generation might pay $3.75 per kW-month for a self-build generation unit. An unregulated generation unit developer, on the other hand, might charge between $4.50 per kW-month and $5.30 per kW-month for a two-year, firm capacity and energy purchase contract because of the developer's higher financing costs, need for a greater return, lost opportunity value in a volatile market, and the added risk that at the end of the two year contract term there is no purchaser available for another contract.

Q. How long a contract would PEF likely need to replace the loss of load from CR4 and CR5?

A. It is likely that a two-year "bridge" contract for generation capacity and energy would cover the time to acquire the turbines and design and construct the peaking unit to replace the loss of load from CR4 and CR5.

Q. So how would you replace the lost capacity and energy caused by the CR4 and CR5 de-rates?

A. The most reliable and cost-effective path would have been to secure a two-year "bridge" contract for capacity and energy on the market and, during that time period, construct appropriate peaking generation units to replace long term the lost MW from the CR4 and CR5 de-rates. In this way, PEF's customers would be exposed to the market premium costs for generation and capacity for only two years after which time the utility would have a self-build generation unit in place at typical utility regulated costs for the remainder of the relevant time period.

Q. Would the costs of the "bridge" contract represent all costs of generation capacity and energy during the two-year period to bring an additional peaker on-line?

A. No. In fact, it would not be cost-effective for PEF and its customers to rely totally on the capacity and energy under the contract for the entire two-year period of time. This is because the capacity and energy being replaced is base load capacity and energy from units with a high capacity factor, on average a conservative 75% annually.

The capacity factor is the measure of how much time during the year the particular generation unit is operating and providing electrical energy. A capacity factor of 75% means that the unit was operating 75% of the total hours for the year. The cost of capacity under available contracts at the time would have been too expensive at a 75% capacity factor level. Rather, the most cost-effective "bridge" capacity and energy contract the Company could have obtained during this time period would have been for a 20% capacity factor for the energy component under the "bridge" contract. This 20% capacity factor, by the way, is the equivalent of a peaking unit capacity factor. The remaining 55% capacity factor and associated energy would have been supplied by other units in the PEF fleet. This would be true as well for the remaining eight years after the peaking unit was built and operational at the end of the first two years. The capacity factor of the peaking unit would be 20%, thus, the remaining 55% capacity factor from the lost base load capacity would have to be supplied by the balance of the fleet.

Exhibit No. ___ (JBC-4) demonstrates why this is the case. It is a chart of the daily load forecast, in this case 2004 which is during the relevant period of time, over the Company's generation resources. The generation resources are added to meet load based on their incremental cost of producing electricity. The cheapest generation resources on an incremental cost basis are at the bottom of the chart (the base load units) and the most expensive are at the top (the peaking units). If 124MW of base load coal capacity is lost for the entire period of time it would be a slice drawn out of the base load coal level that would have to be replaced at all times by other generation (or purchased) capacity. During the peak periods of time on the chart it is clear that all units, from base load nuclear and coal, to intermediate purchases and oil, to peaking gas and oil units, are producing electricity. At these times, up to the 20% capacity factor of the "bridge" contract and later peaking unit, the peaking capacity cost would replace the lost base load generation. At other times, the remaining 55% capacity factor, the lost 124 MW of base load generation must be made up with additional generation from intermediate oil and gas units, at an additional cost to base load generation.

Q. What would it have cost PEF to build a peaker in 1995?

A. Based on my experience, and on costs for similar generation PEF paid during this time period such as the Intercession City peaking unit that went on line in 1998, the estimated cost to bring on-line an additional peaking unit, including direct and indirect construction costs, construction interest (the allowance for funds used during construction or "AFUDC"), start-up, and inventory costs, is \$275/kw or about \$56 million for a 200MW peaking unit. PEF actually paid \$275/kw to construct the Intercession City peaking unit in 1998. This actual cost to PEF to construct a peaking unit demonstrates the reasonableness of my estimate.

Q. Once the peaker was operational, was the cost of the 124MW additional peaking unit to the system equivalent to the cost of the lost 124MW of base load capacity from the CR4 and CR5 de-rates over this period of time?

A. No. The lost 124MW of base load generation from the de-rates at CR4 and CR5 would be much more valuable in the generation system than an additional 124MW of peaking capacity and energy. The base load variable fuel and O&M costs on a per MW basis associated with the lost 124MW is lower than the per MW variable fuel and O&M costs associated with the peaking unit. This is what distinguishes base load from peaking capacity in terms of capacity factor on the system. The generation system itself would have to "backfill" for the value of the lost 124MW of base load capacity, as I have previously explained and as demonstrated in Exhibit No. ___ (JBC-3), at an additional incremental cost to the customer.

This cost for the remaining eight year period of time following the end of the two-year "bridge" contract is conservatively estimated to be $527,823,360. This includes a capacity cost of $45,116,160 and an energy cost of $482,707,200, assuming that the "backfill" was provided by more efficient thus lower heat rate steam driven units at all times, which would not occur in practice.

Rather, the more likely actual results is that the "backfill" from the system for the lost 124MW of base load capacity at times would have been supplied by less efficient, higher heat rate units, such as peakers. Had I used either an average heat rate or the higher heat rate of the peaking units the costs of the "backfill" energy would have been much higher to cover a loss of 124MW base load capacity and energy, ranging from $639,518,592 (the average heat rate) to $774,676,608 (the higher heat rate).

I also assumed that the energy cost would remain flat over the remaining eight years following the two-year bridge capacity and energy contract to replace the lost 124MW of base load capacity and energy generation from 1996 to 2005. This certainly was not the case over this ten-year period of time, rather, the energy cost, like most other costs, rose over this time period.

I have, therefore, conservatively estimated the cost to provide additional capacity and energy to replace the 124MW lost from the de-rates of CR4 and CR5 at $527,823,360. This is demonstrated by Exhibit No. ____ (JBC-5) to my testimony.

Q. Under your recommended resource plan to replace the lost MWs from the CR4 and CR5 de-rates, what incremental costs would PEF and its customers incur?

A. First, PEF would incur the costs of the 20% capacity under the two-year "bridge" contract. This cost is conservatively estimated at $11.9 million for a two-year 124MW purchase contract. The actual range of estimated capacity costs for this two-year bridge contracts was $11.9 million to $14.9 million. The energy cost component in the power purchase contract is conservatively estimated at $44.6 million for 124MW over the course of the two-year "bridge" contract. The range of these estimated costs were from $44.6 million to $63.8 million. The total capacity and energy cost under the "bridge" contract is therefore estimated at $56.5 million, which, again, is the low-end of the total estimated costs that range up to $78.7 million. See Exhibit No. ___ (JBC-5) to my testimony.

Additionally, there would be the incremental generation system charges to provide the remaining 55% capacity factor associated with a loss of 124MW. This would result in additional incremental charges from the remaining generation fleet of about $112.6 million over the course of the two-year "bridge" contract. See Exhibit No. ___ (JBC-5) to my testimony.

Finally, once the peaking unit was operational, there would be an additional cost to the customer to account for the peaking unit and the fact that the additional 124MW of peaking capacity and energy was not equivalent in value to the system to the 124MW of lost base load capacity and energy from the CR4 and CR5 de-rates. Over the remaining eight-year period of time this estimated capacity and energy cost is $527,823,360 for both the necessary capacity and energy. See Exhibit No. ___ (JBC-5) to my testimony.

The total incremental cost to PEF and its customers from a de-rate of 124MW at CR4 and CR5 over the time period from 1996 to 2005 is therefore conservatively estimated at about $697 million. The range of the cost of this de-rate and loss of base load capacity and energy, however, could be up to and just over $966 million. This is summarized in Exhibit No. ___ (JBC-6) to my testimony.

Q. Do the estimates you have provided account for any fluctuations in these costs over time?

A. Yes, they do. It is true that both the capacity and energy charges can fluctuate depending on the projected use of the generation asset, the amount of fuel consumed, the projected O&M costs, among other factors. Similarly, market prices for capacity and energy can fluctuate in reaction to the costs of equipment, as well as to risks, contract performance requirements, fuel prices, and other cost factors. Accordingly, I have accounted for such fluctuations over this time period in my analysis by coming up with a range in estimated costs for each cost component scenario affected by such variables. The ranges in these scenarios are included in Exhibit Nos. _____ (JBC-5) and _____ (JBC-6) to my testimony. As you can see, in each case with respect to each cost component, I have selected the cost at the lowest end of the range. I therefore believe that my estimate of the total cost impact to the Company for the lost of 124MW of base load generation over the time period from 1996 to 2005 is both reasonable and conservative.

Q. You referenced several power plants being built at or near this time. Why wouldn't you just build bigger plants or speed up the construction plan for those plants? Wouldn't this eliminate the need and associated costs for the replacement 124MW?

A. No, it would not. Regardless of where the capacity and energy come from, the capacity and associated energy will be purely incremental dollars. Speeding up plants or building bigger plants will require relatively similar incremental dollars for construction and fuel, and the impact from construction schedules to build bigger plants will expose the customer to significantly greater purchased power expense. The estimates included in this testimony are reasonable and likely, given the need for immediate replacement capacity and associated energy for the lost 124MW of base load generation from the de-rates at CR4 and CR5.

Q. Does this conclude your testimony?

A. Yes.

Instructions

for the

Care and Operation

of

Babcock & Wilcox Equipment

furnished on Contract

RB-588

for

Florida Power Corporation

Crystal River Plant Unit 4

Progress Energy

9

UNIT DESCRIPTION

PLANT

This unit is installed as Unit No. 4 at the Crystal River Plant located near Crystal River, Florida. Plant elevation is 11 feet above sea level.

The unit supplies steam to a GE turbine rated at 665 MW. The consulting engineer is Black & Veatch, Kansas City, Missouri.

BOILER

This is a semi-indoor, balanced draft Carolina Type Radiant Boiler designed for pulverized coal firing. The unit has 54 Dual-Register burners arranged in three rows of nine burners each on both the front and rear walls. Furnace dimensions are 79 feet wide, 57 feet deep, and 201 feet from the centerline of the lower wall headers to the drum centerline. The steam drum is 72 inches ID.

The maximum continuous rating is 5,239,600 lb/hr of main steam flow at 2640 psig and 1005° F at the superheater outlet with a reheat flow of 4,344,700 lb/hr at 493 psig and 1005° F with a normal feedwater temperature of 546° F. This is a 5% overpressure condition. The full load rating is 4,737,900 lb/hr of main steam flow at 2500 psig and 1005° F with a reheat flow of 3,959,800 lb/hr at 449 psig and 1005° F with a normal feedwater temperature of 535° F. Main steam and reheat steam temperatures are controlled to 1005° F from MCR load down to half load (2,368,900 lb/hr) by a combination of gas recirculation and spray attemperation.

The unit is designed for cycling service and is provided with a full boiler by-pass system. The unit can be operated with either constant or variable turbine throttle pressure from 63% of full load on down.

The design pressures of the boiler, economizer, and reheater are 2975, 3050, and 750 psig respectively.

Steam for boiler soot blowing is taken off the primary superheater outlet header. Steam for air heater soot blowing is taken off the secondary superheater outlet.

SCOPE OF SUPPLY

The major items of equipment supplied by B&W include:

- RBC unit pressure parts including boiler, primary and secondary superheater, economizer, and reheater.
- Fifty-four Dual-Register burners and lighters.
- Six MPS-89GR pulverizers and piping to burners.
- By-pass system including valves and piping.
- Two stages of superheat attemperators (first stage tandem) and one stage of reheat attemperation (2 nozzles); nozzles only, no block or control valves or spray water piping.
- Three Rothemuhle air heaters (one primary and two secondary).
- Ducts from secondary air heaters to windbox.

RB-588 Sept 81

- Primary air system: two TLT centrifugal PA fans and ducts from fans to pulverizers.
- Gas recirculation system: one TLT centrifugal GR fan, one dust collector and flues.
- Six Stock gravimetric coal feeders and drives.
- Bailey burner controls.
- Safety valves and ERV.
- Brickwork, refractory, insulation and lagging (BRIL).
- Seal air piping and fans.
- Erection.
- Recommended spare parts.

RB-588 Sept 81

FUEL

The guarantees for this unit are based on firing a 50/50 blend of Eastern bituminous and Western sub-bituminous coal. The performance coal is classified as high slagging and medium fouling. Performance was also checked on Illinois deep-mined coal which is classified as severe slagging and high fouling. The furnace and convection pass are designed for a severe slagging and severe fouling coal.

Ultimate Analysis: % by Weight

	Performance	Illinois
Ash	7.90	13.00
Sulfur	0.49	4.20
Hydrogen	3.90	4.40
Carbon	58.80	62.00
Chlorine	0.03	0.02
Water	18.50	10.00
Nitrogen	1.10	1.38
Oxygen	9.28	5.00
Total	100.00	100.00
Higher Heating Value	10285 Btu/lb	11000 Btu/lb

Docket No. 060658
Progress Energy Florida
Exhibit No. ____ (JBC-1)
Page 3 of 13

Progress Energy

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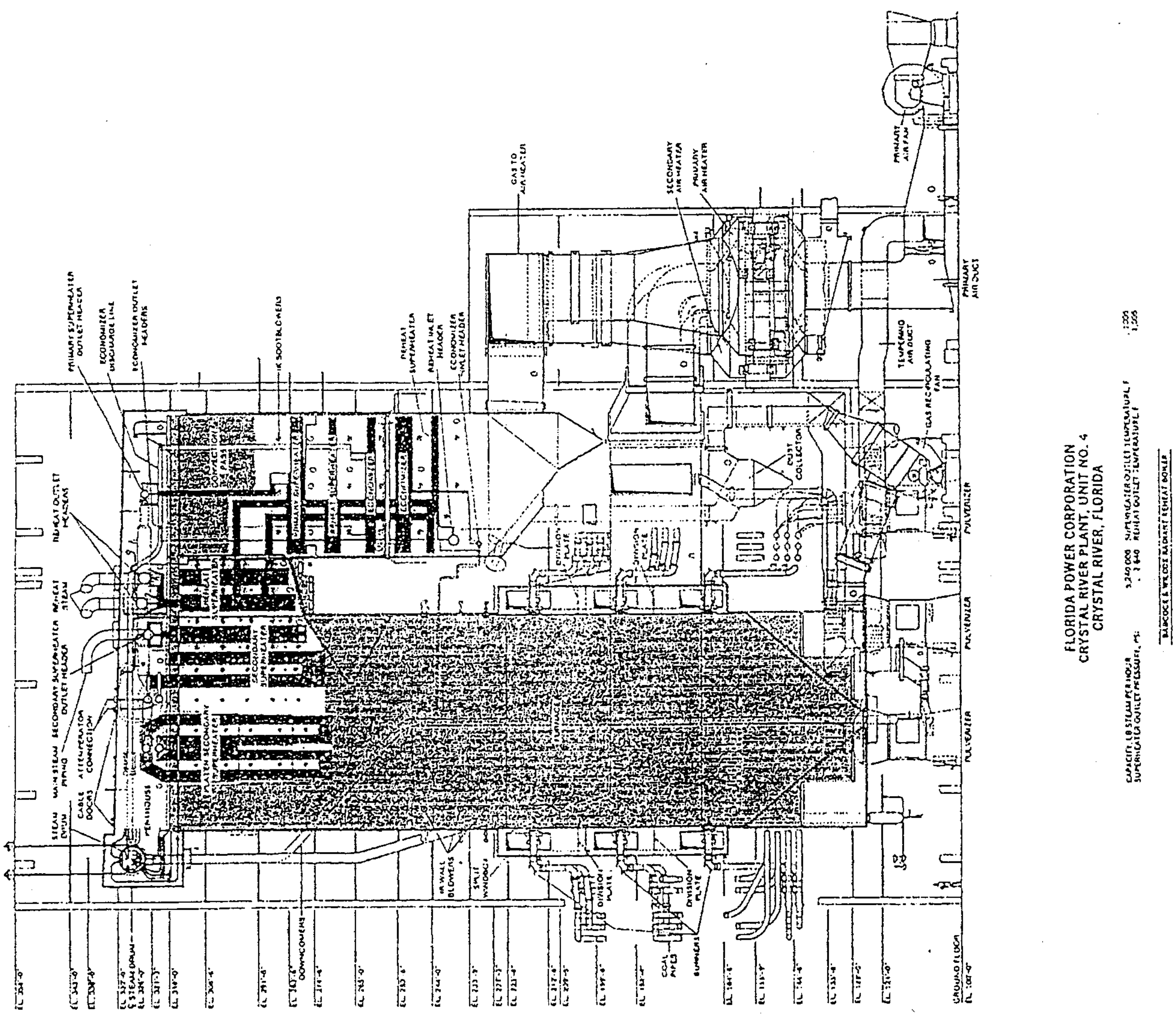
Progress Energy Florida
Exhibit No. ____ (JBC-1)
Page 4 of 13

Progress Energy



PEF-FUEL-002660

Docket No. 060658
Progress Energy Florida
Exhibit No. ____ (JBC-1)
Page 5 of 13

UTILITY BOILER PERFORMANCE SUMMARY

BY RLC APPD. [illegible] DATE

THE BABCOCK & WILCOX COMPANY

P12-4657-16Y0-150

FUEL AS FIRED

SAMPLES				
ANALYSES 50/50 BLEND, EASTERN & WESTERN				
KIND				
ASTM CLASS				
ASTM GROUP				
SOURCE MINE				
SOURCE SEAM				
SOURCE DISTRICT				
SOURCE COUNTY				
SOURCE STATE				
COAL SIZE				
GRINDABILITY				48
SURFACE MOISTURE, %				
				PERF.
ASH SOFT. TEMP., F (REDUCING)				
PROXIMATE MOISTURE, TOTAL				18.5
VOLATILE MATTER				31.0
FIXED CARBON				42.6
ASH				7.9
TOTAL				100.0
FUEL	BIT.	SUB-BIT.		
% BY	WT.	WT.		WT.
ASH	10.0	5.0		7.90
S	0.5	0.48		0.49
H_2	4.4	3.4		3.90
C	69.0	48.5		58.60
CH_4				
C_2H_4				
C_2H_6				
C_3H_8				
C_4H_{10}				
C_5H_{12}				
C_6H_{14}				
CO				
CO_2				
Cl	0.05	0.02		0.03
H_2O	7.0	30.0		18.50
N_2	1.4	0.7		1.10
O_2	7.65	11.1		9.28
TOTAL	100.00	100.00		100.00
BTU/LB	12,450	8,125		10,285
BTU/CU FT AT 60F 30 IN.HG				

*EXCLUDING VALVES AND STATIC HEAD.

PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR	2368.9	4737.9	5239.6
STEAM LEAVING RH¹, M LB/HR	2063.8	3959.8	4344.7
STEAM LEAVING RH², M LB/HR			
TYPE OF FUEL	PC	PC	PC
LOAD CONDITION	CONT.	CONT.	CONT.
EXCESS AIR LEAVING ECON., %	35	20	20
NO. OF BURNERS IN OPERATION	45	54	54
FUEL INPUT, MKB/HR	3348	6053	6581
HEAT AVAIL. MKB/HR (FUEL & HEATED AIR)	3615	6367	6886
QUANTITY, M LB/HR: FUEL (MCFH-NAT. GAS)	325.5	588.6	639.0
FLUE GAS ENTERING AIR HEATER	3728	6051	6579
AIR TO BURNING EQUIPMENT	3327	5419	5891
AIR HEATER LEAKAGE PRI/SEC	107/210	128/272	131/286
PRESSURE, PSIG: STEAM AT SH OUTLET	2425	2500	2640
STEAM AT RH¹ INLET	240	474	520
STEAM AT RH² INLET			
PRESSURE DROP: REHEATER 1	13	25	27
REHEATER 2			
ECONOMIZER *	5	20	25
DRUM TO SH OUTLET	39	155	189
TEMPERATURE, F: STEAM LEAVING SUPERHEATER	1005	1005	1005
LEAVING REHEATER 1	1005	1005	1005
ENTERING REHEATER 1	528	598	604
LEAVING REHEATER 2			
ENTERING REHEATER 2			
GAS: LEAVING ECONOMIZER	630	689	697
LEAVING AH (EXCL. LKG) PRI/SEC	280/260	280/278	280/279
LEAVING AH (INCL. LKG) PRI/SEC	258/249	261/267	262/269
WATER ENTERING ECONOMIZER	459	535	546
AIR: ENTERING UNIT PRI/SEC	85/99	95/82	95/80
LEAVING AIR HEATER PRI/SEC	555/555	575/596	579/601
RESISTANCE, IN. OF WATER, GAS: FURNACE & CONVECTION BANKS	1.7	3.5	3.9
FLUES TO AH OUTLET	0.4	0.9	1.1
AIR HEATER	1.7	3.6	4.1
TOTAL FURN. TO AH OUTLET	3.8	8.0	9.1
AIR: FUEL BURNERS & WINDBOX	1.0	2.5	2.9
DUCTS & FLOW METER	1.2	3.3	3.8
AIR HEATER	1.7	4.0	4.6
TOT. FROM AH INLET TO FURN	3.9	9.8	11.3
HEAT LOSS, %: DRY GAS	4.23	4.34	4.43
H_2 & H_2O IN FUEL	5.80	5.89	5.91
MOISTURE IN AIR	0.11	0.11	0.11
UNBURNED COMBUSTIBLE	0.30	0.30	0.30
RADIATION	0.31	0.17	0.15
UNACC. FOR & MFRS. MARGIN	1.50	1.50	1.50
TOTAL HEAT LOSS	12.25	12.31	12.40
EFFICIENCY OF UNIT, %	87.75	87.69	87.60
PULVERIZERS: NO. IN USE PER BOILER	5	6	5 6
TOTAL POWER, KW HR/TON MOTOR OUTPUT			
% THRU 200 U.S.S. SIEVE	74	69	65 68

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, @ 29.92 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & AN ARRANGEMENT SHOWN ON DRAWING P12-4657-16Y0

EQUIPMENT PER UNIT

TYPE	RADIANT
SIZE	RBC 57 79/HB
DESIGN PRESSURE - 2,975 PSIG	
PRESSURE PART HEATING SURFACE, SQ FT — FURNACE: WATER COOLED SCREEN (CIRCUMFERENTIAL)	
WATER COOLED (PROJECTED)	48,736
SUPERHEATER (CIRCUMFERENTIAL)	
SUPERHEATER (PROJECTED)	46,442
TOTAL FURNACE HEATING SURFACE	95,178
CONVECTION: SATURATED (CIRCUMFERENTIAL)	10,586
SUPERHEATER (CIRCUMFERENTIAL)	243,015
REHEATER 1 (CIRCUMFERENTIAL	333,919
REHEATER 2 (CIRCUMFERENTIAL)	
ECONOMIZER	46,519
TOTAL CONVECTION HEATING SURFACE	634,039
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	729,217
FLAT PROJECTED FURNACE HEATING SURFACE	
TO FACE OF PLATENS (24" CTR)	73,581
TO FACE OF CONVECTION SURFACE	101,501
FURNACE VOLUME, CU FT	734,185
AIR HEATER: TYPE ROTHEMUHLE REGENERATIVE	NO. 1-PRI., 2-SEC.
TOTAL HEATING SURFACE, SQ FT	PRI.-250,522 SEC.-824,850
PRI. SIZE-10.6 Vu 56	
SEC. SIZE-12.5 Vu 68	
FUEL BURNER: TYPE DUAL REGISTER	
NO. 54	
PULVERIZER: TYPE MPS SIZE 89G NO. 6	
CAPACITY OF 5 PULV. IS 5239 M LB STEAM/HR BASED ON 48 GRIND	
10,285 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE	
FOR 1092M LB COAL/PULV.-HR AT 65% THRU 200 U.S.S. SIEVE MIN. GRIND	
IS 42 MAXIMUM TOTAL MOISTURE IS 18% REQUIRING 570 F AIR	
STEAM TEMP. CONTROL: MAIN STEAM BY SPRAY ATTEMPERATION	
REHEAT BY GAS RECIRCULATION	
UNIT CONSTRUCTION FEATURES: MEMBRANE WALLS	
BALANCE DRAFT	

REVISIONS NO.	DESCRIPTION	BY	DATE

FLORIDA POWER CORP.
CRYSTAL RIVER, UNIT #4.

PEF-FUEL-003738

SHEET 6

A — FUEL AS FIRED

SAMPLES
ANALYSES SPECIFIED
50/50 BLEND OF EASTERN & WESTERN

SIZE			
RANK: CLASS			
RANK: GROUP			
SOURCE: MINE			
SOURCE: SEAM			
SOURCE: DISTRICT			
SOURCE: COUNTY			
SOURCE: STATE			
COAL: GRINDABILITY		55	42
SURFACE MOISTURE, %			
		ILLINOIS	PERF. BLEND
ASH SOFT. TEMP., F (REDUCING)		1950	
PROX. ANALYSIS: MOISTURE, TOTAL			18.5
PROX. ANALYSIS: VOLATILE MATTER			31.0
PROX. ANALYSIS: FIXED CARBON			42.6
PROX. ANALYSIS: ASH			7.9
PROX. ANALYSIS: TOTAL			102.0

FUEL	EASTERN	WESTERN	ILLINOIS	BLEND
% BY	WT.	WT.	WT.	WT.
ASH	10.00	5.80	13.00	7.90
S	0.05	0.48	4.20	0.49
H_2	4.90	3.40	4.40	3.90
C	69.00	48.50	62.00	58.80
CH_4				
C_2H_4				
C_2H_6				
C_3H_8				
C_4H_{10}				
C_5H_{12}				
C_6H_{14}				
CO				
CO_2				
Cl	0.05	0.02	0.02	0.03
H_2O	7.00	30.00	10.00	18.50
N_2	1.40	0.7	1.38	1.10
O_2	7.65	11.10	5.00	9.28
TOTAL	100.00	100.00	100.00	100.00
BTU/LB	12450	8175	11000	10235
BTU/CU FT AT 60F 30 IN.HG				

** NOT INCLUDING VALVES & STATIC HEAD.

UTILITY BOILER PERFORMANCE SUMMARY
BY J.H. APPD. RGD DATE 3-25-80
THE BABCOCK & WILCOX COMPANY
P12-4657-1670-350

B — PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR	2369	4738	5240	2369	4738	5240
STEAM LEAVING RH1, M LB/HR	2064	3960	4345	2064	3960	4345
STEAM LEAVING RH2, M LB/HR						
TYPE OF FUEL	ILL	ILL.	ILL.	BLEND	BLEND	BLEND
LOAD CONDITION	CONT-RACL	CONT-GUAR	CONT-MCR	CONT-PRCL	CONT-GUAR	CONT-MCR
EXCESS AIR LEAVING ECON., %	35	20	20	35	20	20
NO. OF BURNERS IN OPERATION	45	54	54	45	54	54
HEAT AVAIL., MKB/HR (FUEL & HEATED AIR)	3493	6295	6845	3481	6295	6849
TOTAL INPUT, MKB/HR (FUEL & HT. CREDITS)						
HEAT CREDITS, MKB/HR						
FUEL INPUT, MKB/HR	3334	6014	6533	3345	6049	6585
QUANTITY M LB/HR: FUEL MLB/HR	303.1	546.7	593.9	325.1	588.1	640.3
QUANTITY M LB/HR: FLUE GAS ENTERING AIR HTRS.	3798	6061	6584	3723	6047	6583
QUANTITY M LB/HR: AIR TO BURNING EQUIPMENT	3381	5493	5967	3323	5414	5895
QUANTITY M LB/HR: AIR HEATER LEAKAGE PRI/SEC	112/239	121/262	125/271	114/238	124/259	127/271
PRESSURE, PSIG: STEAM AT SH OUTLET	2425	2500	2640	2425	2500	2640
PRESSURE, PSIG: STEAM AT RH1 INLET	240	481	520	240	481	520
PRESSURE, PSIG: STEAM AT RH2 INLET						
PRESSURE DROP: REHEATER 1	13	23	28	13	23	28
PRESSURE DROP: REHEATER 2						
PRESSURE DROP: ECONOMIZER **	7	29	39	7	29	39
PRESSURE DROP: DRUM TO SH OUTLET	36	145	176	36	145	176
TEMPERATURE, F: STEAM: LEAVING SUPERHEATER	1005	1005	1005	1005	1005	1005
TEMPERATURE, F: STEAM: LEAVING REHEATER 1	1005	1005	1005	1005	1005	1005
TEMPERATURE, F: STEAM: ENTERING REHEATER 1	529	600	606	529	600	606
TEMPERATURE, F: STEAM: LEAVING REHEATER 2						
TEMPERATURE, F: STEAM: ENTERING REHEATER 2						
TEMPERATURE, F: GAS: LEAVING ECONOMIZER	599	671	678	599	671	677
TEMPERATURE, F: GAS: LEAVING AH (EXCL. LKG) PRI/SEC	281/260	283/278	280/279	279/252	279/271	278/273
TEMPERATURE, F: GAS: LEAVING AH (INCL. LKG) PRI/SEC	253/249	259/268	259/270	257/241	263/262	262/264
TEMPERATURE, F: WATER ENTERING ECONOMIZER	459	535	546	459	535	546
TEMPERATURE, F: AIR: ENTERING UNIT PRI/SEC	94/81	98/83	100/83	96/81	101/83	102/85
TEMPERATURE, F: AIR: LEAVING AIR HEATER PRI/SEC	545/537	416/586	441/588	534/530	529/582	545/564
RESISTANCE, IN. OF WATER: GAS: FURNACE & CONVECTION BANKS	1.8	3.5	3.9	1.8	3.5	3.9
RESISTANCE, IN. OF WATER: GAS: FLUES TO AH OUTLET	0.5	0.9	1.0	0.5	0.9	1.0
RESISTANCE, IN. OF WATER: GAS: AIR HEATER	1.8	4.0	4.5	1.6	3.5	4.1
RESISTANCE, IN. OF WATER: GAS: TOT. FROM FURN TO A.H. OUTLET	4.1	8.4	9.4	3.9	7.9	9.0
RESISTANCE, IN. OF WATER: AIR: FUEL BURNERS & WINDBOX	1.2	3.2	3.7	1.2	3.0	3.4
RESISTANCE, IN. OF WATER: AIR: DUCTS & FLOW METER	1.2	3.5	4.1	1.2	3.2	3.9
RESISTANCE, IN. OF WATER: AIR: AIR HEATER	1.5	3.6	4.2	1.5	3.3	3.9
RESISTANCE, IN. OF WATER: AIR: TOT. FROM AH INLET TO FURN.	3.9	10.3	12.0	3.9	9.5	11.2
HEAT LOSS-EFF., %: DRY GAS	4.50	4.50	4.50	4.13	4.34	4.38
HEAT LOSS-EFF., %: H_2 & H_2O IN FUEL	5.03	5.09	5.09	5.78	5.88	5.88
HEAT LOSS-EFF., %: MOISTURE IN AIR	0.11	0.11	0.11	0.10	0.11	0.11
HEAT LOSS-EFF., %: UNBURNED COMBUSTIBLE	0.30	0.30	0.30	0.3	0.30	0.30
HEAT LOSS-EFF., %: RADIATION	0.30	0.17	0.16	0.3	0.17	0.16
HEAT LOSS-EFF., %: UNACC. FOR & MFRS. MARGIN	1.50	1.50	1.50	1.5	1.50	1.50
HEAT LOSS-EFF., %: TOTAL HEAT LOSS	11.74	11.67	11.66	12.11	12.30	12.33
HEAT LOSS-EFF., %: *GROSS EFFICIENCY OF UNIT, %	88.26	88.33	88.34	87.89	87.70	87.67
HEAT CREDITS ADJUSTMENT, %						
NET EFFICIENCY A.S.M.E. PTC-4.1, %						
FUEL EFFICIENCY, %, (OUTPUT/FUEL INPUT)						
PULVERIZERS: NO. IN USE PER BOILER	5	6/5	6/5	5	6/5	6/5
PULVERIZERS: TOTAL POWER, KW HP/TON MOTOR OUTPUT						
PULVERIZERS: % THRU 200 U.S.S. SIEVE	80	75/71	73/69	74	72/67	69/65

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 29.92 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & BY ARRANGEMENT SHOWN ON DRAWING 4109 J & CONTRACT DRAWINGS

C — EQUIPMENT PER UNIT

TYPE RADIANT CAROLINA
SIZE RBC 57 29/NB
DESIGN PRESSURE = 2975 PSIG (DRUM & SH)
750 PSIG (RH ONLY) 3050 (ECONOMIZER)

PRESSURE PART HEATING SURFACE, SQ FT: FURNACE: WATER COOLED SCREEN (CIRCUMFERENTIAL)	
FURNACE: WATER COOLED (PROJECTED)	48820
FURNACE: SUPERHEATER (CIRCUMFERENTIAL)	
FURNACE: SUPERHEATER (PROJECTED)	45631
TOTAL FURNACE HEATING SURFACE	94451
CONVECTION: SATURATED (CIRCUMFERENTIAL)	10534
CONVECTION: SUPERHEATER (CIRCUMFERENTIAL)	144836
CONVECTION: REHEATER 1 (CIRCUMFERENTIAL)	240472
CONVECTION: REHEATER 2 (CIRCUMFERENTIAL)	
CONVECTION: ECONOMIZER	146570
TOTAL CONVECTION HEATING SURFACE	542412
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	636863
FLAT PROJECTED FURNACE HEATING SURFACE	
TO FACE OF PLATENS (24" CENTERS)	72782
TO FACE OF CONVECTION SURFACE (12" CENTERS)	105963
FURNACE VOLUME, CU FT	729334

AIR HEATER: TYPE ROTHEMUHLE REGENERATIVE NO: 1-PRI. 2-SEC.
TOTAL HEATING SURFACE, SQ FT
PRIMARY - SIZE = 10.6 VI 56 HS = 250522
SECONDARY - SIZE = 12.5 VI 68 HS = 824850

FUEL BURNER: TYPE DUAL REGISTER - PULV. COAL
NO. 54

PULVERIZER: TYPE MPS SIZE 89 G NO. 6
CAPACITY OF 5 PULV. IS 5240M LB STEAM/HR BASED ON 48 GRIND
10285 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE BLEND
FOR 128M LB COAL/PULV.-HR AT 65% THRU 200 U.S.S. SIEVE MIN. GRIND IS 47. MAXIMUM ~~SURFACE~~ TOTAL MOISTURE IS 19 % REQUIRING 565 F AIR

STEAM TEMP. CONTROL:
MAIN STEAM BY ATTEMPERATION
REHEAT STEAM BY GAS RECIRC. & ATTEMPERATION

UNIT CONSTRUCTION FEATURES:
MEMBRANE WALLS
BALANCED DRAFT
COMPLETE BY-PASS SYSTEM

VARIABLE PRESSURE OPERATION POSSIBLE BELOW 63% of GUAR. LOAD.

*CORRESPONDING TO ABB. METHOD PAR. 1.07 A.S.M.E. PTC-4.1

REVISIONS NO.	DESCRIPTION	BY	DATE

FLORIDA POWER CORPORATION
CRYSTAL RIVER UNIT #4

BWFP 31751-3

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

CONTRACT INFORMATION SHEET

A.O.

TURBINE

1 MFG: G.E.

NAME-PLATE RATING: 665,000 KW

HEAT BALANCE — PERFORMANCE DESIGN DATA

3 SPECIFIED BY: ☒ PURCHASER ☒ TURBINE ☐ BOILER DESIGN ☐

	RATING: PERF. AT TERMINALS		GUAR. LOAD	PEAK LOAD ____HRS.	MAX. CONTINUOUS LOAD	LOW LOAD CONTROL	20% O[illegible] Guar.		MAX CONT HEAT INPUT
6	FUEL:		Blend		Blend	Blend	Blend		
	FUEL QUANTITY	MLB/HR							
7	MAIN STEAM FLOW	MLB/HR	4737.9		5239.6	2368.9	947.6		
	OPR. PRESS. @S.H. OUT.	PSIG	2500		2640	2425	2406		
8	STEAM TEMP. @S.H. OUT.	°F	1005		1005	1005	990		
9	1ST REHT. STEAM FLOW	MLB/HR	3959.8		4344.7	2063.8	842.4		
	1ST REHT. ENTR. PRESS.	PSIG	474		520	240	84		
10	1ST REHT. ENTR. TEMP.	°F	598		604	528	410		
	1ST REHT. OUT. PRESS.	PSIG	449		493	227	79		
11	1ST REHT. OUT. TEMP.	°F	1005		1005	1005	950		
	1ST REHT ENTR. ENTH		1298.7		1299.2	1279.3	1232.6		
12	2ND REHT. STEAM FLOW	MLB/HR							
	2ND REHT. ENTR. PRESS.	PSIG							
13	2ND REHT. ENTR. TEMP.	°F							
	2ND REHT. OUT. PRESS.	PSIG							
14	2ND REHT. OUT. TEMP.	°F							
15	FEEDWATER ENTH.	BTU/LB							
	FEEDWATER TEMP.	°F	534.8		546.4	459.4	372.3		
16	FEEDWATER FLOW	M LB/HR	4737.9		5239.6	2368.9	947.6		
	S.H. SPRAY WATER TEMP.	°F	355		362	310	265		
17	PRESS @ SOURCE								
	1ST REHT. SPRAY WATER TEMP.	°F	355		362	310	265		
18	PRESS. @ SOURCE								
	2ND REHT. SPRAY WATER TEMP.	°F							
19	PRESS. @ SOURCE								

20 QTY., TYPE & SIZE CUST. FEED PUMPS:
QTY., TYPE & SIZE CUST. START UP PUMPS:

STEAM TEMPERATURE CONTROL

		METHOD	RANGE	REMARKS
22	MAIN STEAM	Spray Attemperation	2368.9M To 5239.6M	
23	1ST REHT.	Spray Attemperation and Gas Recirculation	2368.9M To 5239.6M	
24	2ND REHT.			

45

SPECIAL PERFORMANCE OR DESIGN REQ'MNTS.

26 ☐ NOT REQD. ☒ REQD.: SEE CIS-14.0

PERF. CURVES & DATA SHEETS

SEE CIS-100 SERIES

REV. NO. AND DATE	CONTRACT NO.	FILE NO.
1 5-25-78 2 6-5-79 3 4-15-80	334-0588	RB-588

UNIT PERFORMANCE DESIGN DATA

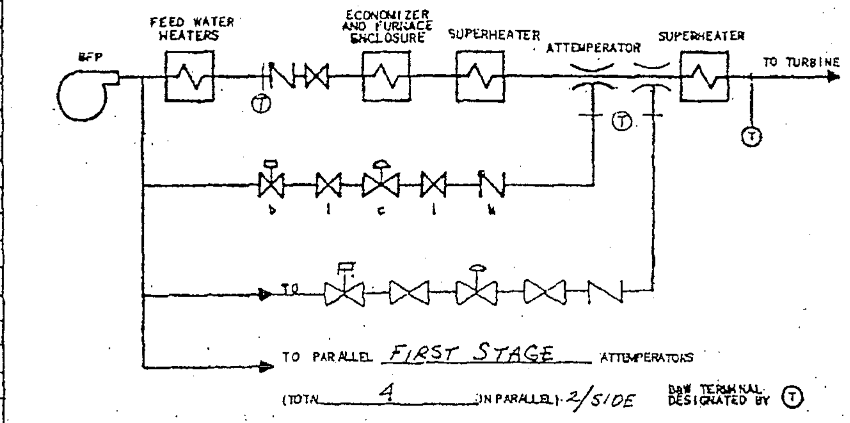
FPGD CIS-13.0 Ω

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

BWFP 33027-3

CONTRACT INFORMATION SHEET

A.O.



PIPING DESIGN CONDITIONS		
LOC.	PRESS	TEMP
ATTEMP	2975	850
SOURCE	*	*

ELEVATIONS	
LOCATION	ELEVATION
ATTEMP NOZ	321'-6"
B&W FEED Ⓣ	225'-9"
SOURCE	*

ATTEMP SYSTEM VALVES			
	VALVE		CIS
c	CONTROL	CUST	
b	BLOCK	"	
i	ISOLATION	"	
k	CHECK	"	

18	FUEL			P.C.			P.C.		
19	MAIN STEAM FLOW		MLB/HR	5240 (MCR)			4738 (GOAR)		
20	AUXILIARY STEAM FLOW		MLB/HR						
21	SPRAY WATER TEMPERATURE		F.	362			355		
22				Installed Capacity		Design	Installed Capacity		Design
23				Min.	Max.	Capacity	Min.	Max.	Capacity
24	TOTAL SPRAY WATER FLOW AT SOURCE		MLB/HR	79.3	432.0	641.6	107.4	530.5	720.0
25	SPRAY WATER FLOW THIS ATTEMPERATOR /NOZZLE		MLB/HR	26.2	108.0	117.4	26.9	132.6	132.6
26	SPRAY WATER PRESS. AT SOURCE (Based on following)		PSIG *						
27	Boiler Press.	DRUM PRESSURE	PSIG	2829	2829	2829	2655	2655	2655
28		ECONOMIZER ΔP (Incl. Static Head)	PSI	71.2	71.2	71.2	63.9	63.9	63.9
29		FEED VALVES AND PIPING ΔP (Incl. Static Head)	PSI	12.7	12.7	12.7	10.1	10.1	10.1
30		EXPECTED PRESS AT B&W FEED INLET TERMINAL	PSIG	2912.9	2912.9	2912.9	2729	2729	2729
31	STEAM PRESSURE AT ATTEMPERATOR		PSIG	2785	2785	2785	2619	2619	2619
32	ΔP THRU WATER NOZZLE NOTE 4		PSI	1	35.8	35.8	2.2	51	41
33	REQ'D SPRAY WATER PRESS AT ATTEMP INLET		PSIG	2786	2820.8	2820.8	2621.2	2670	2660
34	PRESS DROP AVAIL FOR ATTEMP. SYSTEM (26-33)		PSI *						
35	STATIC HEAD, SOURCE TO ATTEMP. NOZZLE.		PSI *						
36	PRESS DROP AVAIL FOR PIPING AND VALVES (34-35)		PSI *						
37	Piping	ΔP B&W PIPING	PSI	0	0	0	0	0	0
38		ΔP CUST PIPING	PSI *						
39		TOTAL PIPING LOSS	PSI *						
40	PRESS DROP AVAIL FOR VALVES (36-39)		PSI *						
41	Valves	ΔP B&W VALVES (Excluding control valve)	PSI	0	0	0	0	0	0
42		ΔP CUST VALVES (Excluding control valve)	PSI *						
43		TOTAL VALVE LOSS (Excluding control valve)	PSI *						
44	PRESS DIFF. ACROSS CONTROL VALVE (40-43)		PSI *						
45	MIN. REQ'D PRESS DROP ACROSS CONTROL VALVE → SUGGESTED CONTROL VALVE ΔP		PSI	40	155	195	40	242	242

46–51 Notes
1. * Indicates information to be completed by customer.
2. Piping and valves to be sized for design capacity.
3. Control valve internals may be sized for "Installed maximum capacity" provided internals suitable for design capacity may be installed in the control valve body.
4. DESIGN CAPACITY NOZZLE PRESSURE DROP IS BASED ON REDRILLING ORIFICE TO SIZE SHOWN ON CIS 37.00

54 ATTEMPERATOR TYPE: ☐ SINGLE STAGE ☒ TANDEM FIRST STAGE ☐ TWO STAGE

55–56 ATTEMPERATOR IDENTIFICATION: ☐ DOWNSTREAM (1st in Control) ☐ UPSTREAM (2nd in Control) ☒ FIRST STAGE (~~1st in Control~~) ☐ SECOND STAGE (2nd in Control)

REL. NO. AND DATE	CODE NO.	COMP. NO.	FILE NO.
4(3-19-80) 5(4-24-80)	334-0588		RB-588

SUPERHEATER ATTEMPERATOR SYSTEM DATA SHEET FPGD CIS-38.0 0

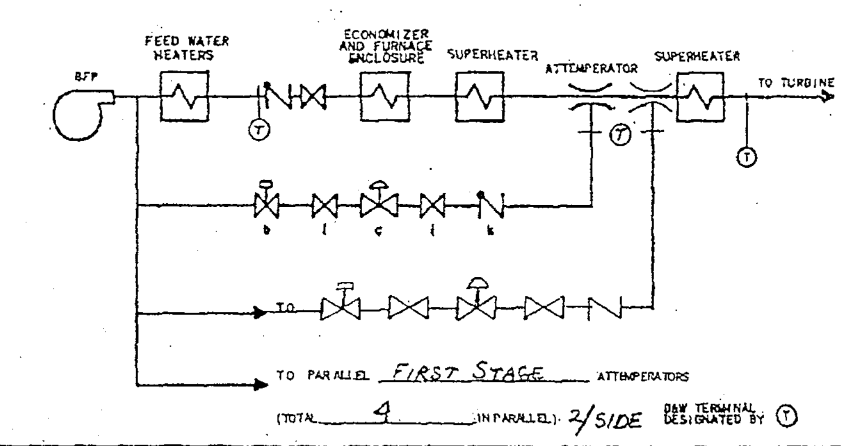
(FIRST STAGE ATTEMPERATOR)

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

BWFP 33027-3

CONTRACT INFORMATION SHEET

A.C.



PIPING DESIGN CONDITIONS		
LOC.	PRESS	TEMP
ATTEMP	2975	850
SOURCE	*	*

ELEVATIONS	
LOCATION	ELEVATION
ATTEMP NOZ	321'-6"
B&W FEED Ⓣ	225'-9"
SOURCE	*

ATTEMP SYSTEM VALVES			
	VALVE	BY	CIS
c	CONTROL	CUST	
b	BLOCK	//	
i	ISOLATION	//	
k	CHECK	//	

18	FUEL		P.C.			P.C.		
19	MAIN STEAM FLOW	MLB/HR	2369 (RHCL)			2369 (RHCL-V.P)		
20	AUXILIARY STEAM FLOW	MLB/HR						
21	SPRAY WATER TEMPERATURE	F	310			310		
22			Installed Capacity		Design	Installed Capacity		Design
23			Min.	Max.	Capacity	Min.	Max.	Capacity
24	TOTAL SPRAY WATER FLOW AT SOURCE	MLB/HR	239.8	398.5	493.2	312.9	466.8	561.6
25	SPRAY WATER FLOW THIS ATTEMPERATOR /NOZZLE	MLB/HR	59.9	97.6	99.2	75.5	98.1	99.1
26	SPRAY WATER PRESS. AT SOURCE (Based on following)	PSIG *						
27	Boiler Press. DRUM PRESSURE	PSIG	2446	2446	2446	1960	1960	1960
28	ECONOMIZER ΔP (Incl. Static Head)	PSI	40.3	40.3	40.3	40.3	40.3	40.3
29	FEED VALVES AND PIPING ΔP (Incl. Static Head)	PSI	2.4	2.4	2.9	2.4	2.4	2.9
30	EXPECTED PRESS AT B&W FEED INLET TERMINAL	PSIG	2488.7	2488.7	2488.7	2002.7	2002.7	2002.7
31	STEAM PRESSURE AT ATTEMPERATOR	PSIG	2955	2455	2455	1973	1973	1973
32	ΔP THRU WATER NOZZLE NOTE 4	PSI	10.6	28.3	24.0	16.4	28.3	24.0
33	REQ'D SPRAY WATER PRESS AT ATTEMP INLET	PSIG	2965.6	2483.3	2479	1989.9	2001.3	199.7
34	PRESS DROP AVAIL FOR ATTEMP. SYSTEM (26-33)	PSI *						
35	STATIC HEAD, SOURCE TO ATTEMP. NOZZLE	PSI *						
36	PRESS DROP AVAIL FOR PIPING AND VALVES (34-35)	PSI *						
37	Piping ΔP B&W PIPING	PSI	0	0	0	0	0	0
38	ΔP CUST PIPING	PSI *						
39	TOTAL PIPING LOSS	PSI *						
40	PRESS DROP AVAIL FOR VALVES (36-39)	PSI *						
41	Valves ΔP B&W VALVES (Excluding control valve)	PSI	0	0	0	0	0	0
42	ΔP CUST VALVES (Excluding control valve)	PSI *						
43	TOTAL VALVE LOSS (Excluding control valve)	PSI *						
44	PRESS DIFF. ACROSS CONTROL VALVE (40-43)	PSI *						
45	MIN. REQ'D PRESS DROP ACROSS CONTROL VALVE	PSI	50	140	141	75	140	141

Notes

1. * Indicates information to be completed by customer. → SUGGESTED CONTROL VALVE ΔP
2. Piping and valves to be sized for design capacity.
3. Control valve internals may be sized for "Installed maximum capacity" provided internals suitable for design capacity may be installed in the control valve body.
4. DESIGN CAPACITY NOZZLE PRESSURE DROP IS BASED ON REDRILLING ORIFICE TO SIZE SHOWN ON CIS 37.00

54 ATTEMPERATOR TYPE: ☐ SINGLE STAGE ☒ TANDEM FIRST STAGE ☐ TWO STAGE

55–56 ATTEMPERATOR IDENTIFICATION: ☐ DOWNSTREAM (1st in Control) ☐ UPSTREAM (2nd in Control) ☒ FIRST STAGE ~~(1st in Control)~~ ☐ SECOND STAGE (2nd in Control)

REL. NO. AND DATE	CODE NO.	COMP. NO.	FILE NO.
4 (3-19-80)	334-0588		RB-588

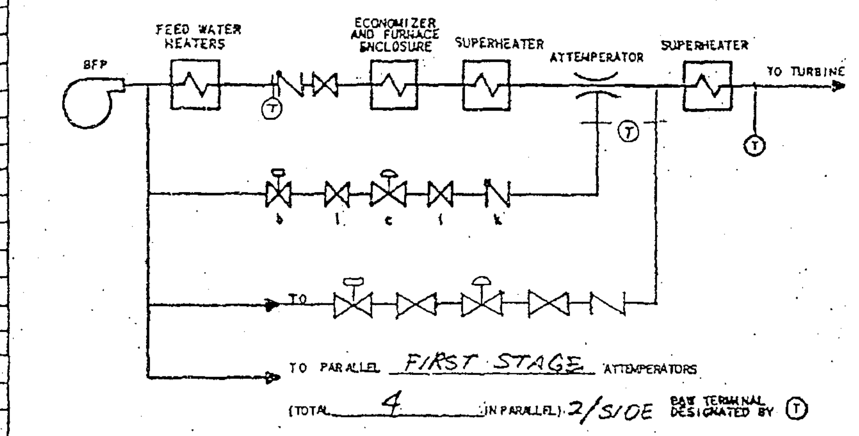
SUPERHEATER ATTEMPERATOR SYSTEM DATA SHEET — FPGD CIS-38.0 1
(FIRST STAGE ATTEMPERATOR)

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

BWFP 33027-3

CONTRACT INFORMATION SHEET

A.O.



PIPING DESIGN CONDITIONS		
LOC.	PRESS	TEMP
ATTEMP	2975	850
SOURCE	*	*

ELEVATIONS	
LOCATION	ELEVATION
ATTEMP NOZ	321'-6"
B&W FEED T	225'-9"
SOURCE	*

ATTEMP SYSTEM VALVES			
	VALVE	[illegible]	CIS
c	CONTROL	CUST	
b	BLOCK	"	
i	ISOLATION	"	
k	CHECK	"	

18	FUEL		P.C.					
19	MAIN STEAM FLOW	MLB/HR	1310 (25% - V.P.)					
20	AUXILIARY STEAM FLOW	MLB/HR						
21	SPRAY WATER TEMPERATURE	F	275					
22			Installed Capacity		Design	Installed Capacity		Design
23			Min.	Max.	Capacity	Min.	Max.	Capacity
24	TOTAL SPRAY WATER FLOW AT SOURCE	MLB/HR	159.1	262.9	315.3			
25	SPRAY WATER FLOW THIS ATTEMPERATOR/NOZZLE	MLB/HR	79.5	106.4	120.1			
26	SPRAY WATER PRESS. AT SOURCE (Based on following)	PSIG *						
27	Boiler Press. DRUM PRESSURE	PSIG	1117	1117	1117			
28	ECONOMIZER ΔP (Incl. Static Head)	PSI	36.3	36.3	36.3			
29	FEED VALVES AND PIPING ΔP (Incl. Static Head)	PSI	0.7	0.7	0.7			
30	EXPECTED PRESS AT B&W FEED INLET TERMINAL	PSIG	1154	1154	1154			
31	STEAM PRESSURE AT ATTEMPERATOR	PSIG	1109	1109	1109			
32	ΔP THRU WATER NOZZLE NOTE 4	PSI	18.2	32.1	33.2			
33	REQ'D SPRAY WATER PRESS AT ATTEMP INLET	PSIG	1127.2	1141.1	1142.2			
34	PRESS DROP AVAIL FOR ATTEMP. SYSTEM (26-33)	PSI *						
35	STATIC HEAD, SOURCE TO ATTEMP. NOZZLE	PSI *						
36	PRESS DROP AVAIL FOR PIPING AND VALVES (34-35)	PSI *						
37	Piping ΔP B&W PIPING	PSI	0	0	0			
38	ΔP CUST PIPING	PSI *						
39	TOTAL PIPING LOSS	PSI *						
40	PRESS DROP AVAIL FOR VALVES (36-39)	PSI *						
41	Valves ΔP B&W VALVES (Excluding control valve)	PSI	0	0	0			
42	ΔP CUST VALVES (Excluding control valve)	PSI *						
43	TOTAL VALVE LOSS (Excluding control valve)	PSI *						
44	PRESS DIFF. ACROSS CONTROL VALVE (40-43)	PSI *						
45	MIN. REQ'D PRESS DROP ACROSS CONTROL VALVE	PSI	85	150	192			

Notes:
1. * Indicates information to be completed by customer. SUGGESTED CONTROL VALVE ΔP
2. Piping and valves to be sized for design capacity.
3. Control valve internals may be sized for "Installed maximum capacity" provided internals suitable for design capacity may be installed in the control valve body.
4 DESIGN CAPACITY NOZZLE PRESSURE DROP IS BASED ON REDRILLING ORIFICES TO SIZE SHOWN ON CIS 37.00

54 ATTEMPERATOR TYPE: ☐ SINGLE STAGE ☒ TANDEM FIRST STAGE ☐ TWO STAGE

55–56 ATTEMPERATOR IDENTIFICATION: ☐ DOWNSTREAM (1st in Control) ☐ UPSTREAM (2nd in Control) ☒ FIRST STAGE ~~(Not in Control)~~ ☐ SECOND STAGE (2nd in Control)

REL. NO. AND DATE	CODE NO.	COMP. NO.	FILE NO.
4 (3-19-80)	334-0588		RB-588

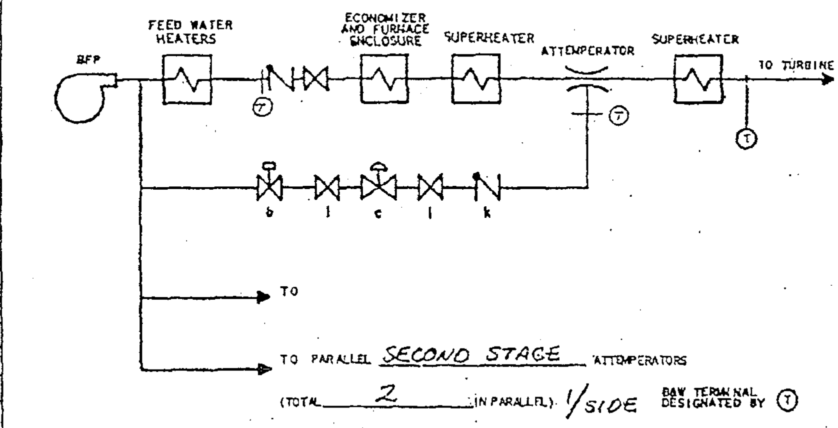
SUPERHEATER ATTEMPERATOR SYSTEM DATA SHEET FPGD CIS-38.02
(FIRST STAGE ATTEMPERATOR)

PEF-FUEL-003743

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

BWFP 33027-3

CONTRACT INFORMATION SHEET



PIPING DESIGN CONDITIONS		
LOC.	PRESS	TEMP
ATTEMP	2975	850
SOURCE	*	*

ELEVATIONS	
LOCATION	ELEVATION
ATTEMP NOZ	321'-6"
B&W FEED T	225'-9"
SOURCE	*

ATTEMP SYSTEM VALVES			
	VALVE		CIS
c	CONTROL	CUST	
b	BLOCK	//	
i	ISOLATION	//	
k	CHECK	//	

18	FUEL		P.C.			P.C.		
19	MAIN STEAM FLOW	MLB/HR	5290 (MCR)			4738 (GUAR)		
20	AUXILIARY STEAM FLOW	MLB/HR						
21	SPRAY WATER TEMPERATURE	F	362			355		
22			Installed Capacity		Design	Installed Capacity		Design
23			Min.	Max.	Capacity	Min.	Max.	Capacity
24	TOTAL SPRAY WATER FLOW AT SOURCE	MLB/HR	79.3	432.0	641.6	107.4	530.5	720.0
25	SPRAY WATER FLOW THIS ATTEMPERATOR /NOZZLE	MLB/HR	13.1	153.9	153.9	16.4	185.4	185.4
26	SPRAY WATER PRESS. AT SOURCE (Based on following)	PSIG *						
27	Boiler Press. DRUM PRESSURE	PSIG	2829	2829	2829	2655	2655	2655
28	ECONOMIZER ΔP (Incl. Static Head)	PSI	71.2	71.2	71.2	63.9	63.9	63.9
29	FEED VALVES AND PIPING ΔP (Incl. Static Head)	PSI	12.7	12.7	12.7	10.1	10.1	10.1
30	EXPECTED PRESS AT B&W FEED INLET TERMINAL	PSIG	2912.9	2912.9	2912.9	2729	2729	2729
31	STEAM PRESSURE AT ATTEMPERATOR	PSIG	2725	2725	2725	2570	2570	2570
32	ΔP THRU WATER NOZZLE	PSI	1	42.6	42.6	1	63.3	63.3
33	REQ'D SPRAY WATER PRESS AT ATTEMP INLET	PSIG	2726	2767.6	2767.6	2571	2633.3	2633.3
34	PRESS DROP AVAIL FOR ATTEMP. SYSTEM (26-33)	PSI *						
35	STATIC HEAD, SOURCE TO ATTEMP. NOZZLE.	PSI *						
36	PRESS DROP AVAIL FOR PIPING AND VALVES (34-35)	PSI *						
37	Piping ΔP B&W PIPING	PSI	0	0	0	0	0	0
38	ΔP CUST PIPING	PSI *						
39	TOTAL PIPING LOSS	PSI *						
40	PRESS DROP AVAIL FOR VALVES (36-39)	PSI *						
41	Valves ΔP B&W VALVES (Excluding control valve)	PSI	0	0	0	0	0	0
42	ΔP CUST VALVES (Excluding control valve)	PSI *						
43	TOTAL VALVE LOSS (Excluding control valve)	PSI *						
44	PRESS DIFF. ACROSS CONTROL VALVE (40-43)	PSI *						
45	MIN. REQ'D PRESS DROP ACROSS CONTROL VALVE	PSI	40	350	350	40	470	470

→ SUGGESTED CONTROL VALVE ΔP

Notes:
1. * Indicates information to be completed by customer.
2. Piping and valves to be sized for design capacity.
3. Control valve internals may be sized for "Installed maximum capacity" provided internals suitable for design capacity may be installed in the control valve body.

ATTEMPERATOR TYPE: ☐ SINGLE STAGE ☐ TANDEM ☒ TWO STAGE

ATTEMPERATOR IDENTIFICATION: ☐ DOWNSTREAM (1st in Control) ☐ UPSTREAM (2nd in Control) ☐ FIRST STAGE (1st in Control) ☒ SECOND STAGE ~~(2nd in Control)~~

REL. NO. AND DATE	CODE NO.	COMP. NO.	FILE NO.
4 (3-19-80)	334-0588		RB-588

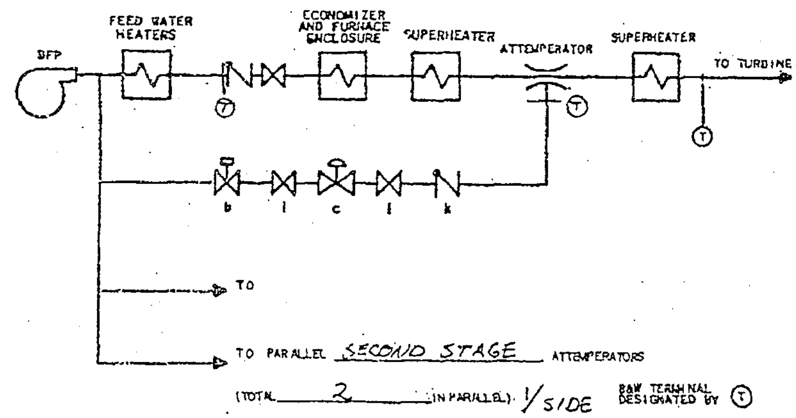
SUPERHEATER ATTEMPERATOR SYSTEM DATA SHEET FPGD CIS-38.0 3
(SECOND STAGE ATTEMPERATOR)

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

UWFP 33027-3

CONTRACT INFORMATION SHEET

A.O.



PIPING DESIGN CONDITIONS		
LOC.	PRESS	TEMP
ATTEMP	2975	850
SOURCE	*	*

ELEVATIONS	
LOCATION	ELEVATION
ATTEMP NOZ.	321'-6"
B&W FEED (T)	225'-9"
SOURCE	*

ATTEMP SYSTEM VALVES			
	VALVE	[illegible]	CIS
c	CONTROL	CUST.	
b	BLOCK	"	
i	ISOLATION	"	
k	CHECK	"	

18	FUEL		P.C.			P.C		
19	MAIN STEAM FLOW	MLB/HR	2369 (RHCL)			2369 (RHCL-V.P.)		
20	AUXILIARY STEAM FLOW	MLB/HR						
21	SPRAY WATER TEMPERATURE	F	310			310		
22			Installed Capacity		Design	Installed Capacity		Design
23			Min.	Max.	Capacity	Min.	Max.	Capacity
24	TOTAL SPRAY WATER FLOW AT SOURCE	MLB/HR	239.8	398.5	493.2	312.4	466.8	561.6
25	SPRAY WATER FLOW THIS ATTEMPERATOR /NOZZLE	MLB/HR	6.5	97.9	97.9	30.7	125.3	125.3
26	SPRAY WATER PRESS. AT SOURCE (Based on following)	PSIG *						
27	Boiler Press. — DRUM PRESSURE	PSIG	2446	2446	2446	1960	1960	1960
28	Boiler Press. — ECONOMIZER ΔP (Incl. Static Head)	PSI	40.3	40.3	40.3	40.3	40.3	40.3
29	Boiler Press. — FEED VALVES AND PIPING ΔP (Incl. Static Head)	PSI	2.4	2.4	2.4	2.4	2.4	2.4
30	Boiler Press. — EXPECTED PRESS AT B&W FEED INLET TERMINAL	PSIG	2488.7	2488.7	2488.7	2002.7	2002.7	2002.7
31	STEAM PRESSURE AT ATTEMPERATOR	PSIG	2443	2443	2443	1956	1956	1956
32	ΔP THRU WATER NOZZLE	PSI	1	18	18	1.7	29.4	29.4
33	REQ'D SPRAY WATER PRESS AT ATTEMP INLET	PSIG	2444	2461	2461	1957.7	1985.4	1985.4
34	PRESS DROP AVAIL FOR ATTEMP. SYSTEM (26-33)	PSI *						
35	STATIC HEAD, SOURCE TO ATTEMP. NOZZLE.	PSI *						
36	PRESS DROP AVAIL FOR PIPING AND VALVES (34-35)	PSI *						
37	Piping — ΔP B&W PIPING	PSI	0	0	0	0	0	0
38	Piping — ΔP CUST PIPING	PSI *						
39	Piping — TOTAL PIPING LOSS	PSI *						
40	PRESS DROP AVAIL FOR VALVES (36-39)	PSI *						
41	Valves — ΔP B&W VALVES (Excluding control valve)	PSI	0	0	0	0	0	0
42	Valves — ΔP CUST VALVES (Excluding control valve)	PSI *						
43	Valves — TOTAL VALVE LOSS (Excluding control valve)	PSI *						
44	PRESS DIFF. ACROSS CONTROL VALVE (40-43)	PSI *						
45	MIN. REQ'D PRESS DROP ACROSS CONTROL VALVE	PSI	40	180	180	40	250	250

Notes

1. * Indicates information to be completed by customer.
2. Piping and valves to be sized for design capacity.
3. Control valve internals may be sized for "Installed maximum capacity" provided internals suitable for design capacity may be installed in the control valve body.

ATTEMPERATOR TYPE: ☐ SINGLE STAGE ☐ TANDEM ☐ TWO STAGE

ATTEMPERATOR IDENTIFICATION: ☐ DOWNSTREAM (1st in Control) ☐ UPSTREAM (2nd in Control) ☐ FIRST STAGE (1st in Control) ☐ SECOND STAGE (2nd in Control)

REL. NO. AND DATE	CODE NO.	COMP. NO.	FILE NO.
3(3-19-80) 4(4-24-80)	334-0588		RB-588

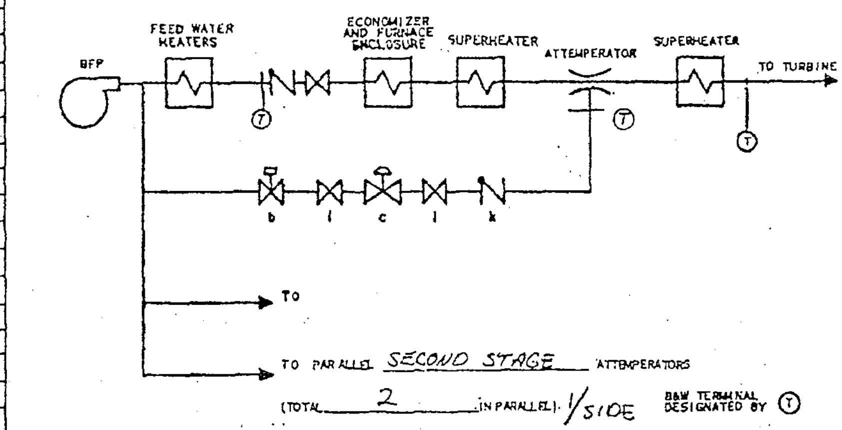
SUPERHEATER ATTEMPERATOR SYSTEM DATA SHEET   FPGD CIS-38.0 4

THE BABCOCK & WILCOX COMPANY
FOSSIL POWER GENERATION DIVISION

BWFP 33027-3

CONTRACT INFORMATION SHEET

A.O.



PIPING DESIGN CONDITIONS

LOC.	PRESS	TEMP
ATTEMP	2975	850
SOURCE	*	*

ELEVATIONS

LOCATION	ELEVATION
ATTEMP NOZ	321'-6"
B&W FEED Ⓣ	225'-9"
SOURCE	*

ATTEMP SYSTEM VALVES

	VALVE	[illegible]	CIS
c	CONTROL	CUST	
b	BLOCK	"	
i	ISOLATION	"	
k	CHECK	"	

18	FUEL		P.C.					
19	MAIN STEAM FLOW	MLB/HR	1310 (25% V.P.)					
20	AUXILIARY STEAM FLOW	MLB/HR						
21	SPRAY WATER TEMPERATURE	F	275					
22			Installed Capacity		Design	Installed Capacity		Design
23			Min.	Max.	Capacity	Min.	Max.	Capacity
24	TOTAL SPRAY WATER FLOW AT SOURCE	MLB/HR	159.1	262.9	315.3			
25	SPRAY WATER FLOW THIS ATTEMPERATOR /NOZZLE	MLB/HR	11.9	67.6	67.6			
26	SPRAY WATER PRESS. AT SOURCE (Based on following)	PSIG *						
27	Boiler Press. — DRUM PRESSURE	PSIG	1117	1117	1117			
28	Boiler Press. — ECONOMIZER ΔP (Incl. Static Head)	PSI	36.3	36.3	36.3			
29	Boiler Press. — FEED VALVES AND PIPING ΔP (Incl. Static Head)	PSI	.7	.7	.7			
30	Boiler Press. — EXPECTED PRESS AT B&W FEED INLET TERMINAL	PSIG	1154	1154	1154			
31	STEAM PRESSURE AT ATTEMPERATOR	PSIG	1099	1099	1099			
32	ΔP THRU WATER NOZZLE	PSI	1.1	34.2	34.2			
33	REQ'D SPRAY WATER PRESS AT ATTEMP INLET	PSIG	1100.1	1133.2	1133.2			
34	PRESS DROP AVAIL FOR ATTEMP. SYSTEM (26-33)	PSI *						
35	STATIC HEAD, SOURCE TO ATTEMP. NOZZLE.	PSI *						
36	PRESS DROP AVAIL FOR PIPING AND VALVES (34-35)	PSI *						
37	Piping — ΔP B&W PIPING	PSI	0	0	0			
38	Piping — ΔP CUST PIPING	PSI *						
39	Piping — TOTAL PIPING LOSS	PSI *						
40	PRESS DROP AVAIL FOR VALVES (36-39)	PSI *						
41	Valves — ΔP B&W VALVES (Excluding control valve)	PSI	0	0	0			
42	Valves — ΔP CUST VALVES (Excluding control valve)	PSI *						
43	Valves — TOTAL VALVE LOSS (Excluding control valve)	PSI *						
44	PRESS DIFF. ACROSS CONTROL VALVE (40-43)	PSI *						
45	MIN. REQ'D PRESS DROP ACROSS CONTROL VALVE	PSI	40	75	75			

Notes

1. * Indicates information to be completed by customer. → SUGGESTED CONTROL VALVE ΔP
2. Piping and valves to be sized for design capacity.
3. Control valve internals may be sized for "Installed maximum capacity" provided internals suitable for design capacity may be installed in the control valve body.

ATTEMPERATOR TYPE: ☐ SINGLE STAGE ☐ TANDEM ☒ TWO STAGE

ATTEMPERATOR IDENTIFICATION: ☐ DOWNSTREAM (1st in Control) ☐ UPSTREAM (2nd in Control) ☐ FIRST STAGE (1st in Control) ☒ SECOND STAGE ~~(2nd in Control)~~

REL. NO. AND DATE	CODE NO.	COMP. NO.	FILE NO.
3(3-19-80)	334-0588		RB-588

SUPERHEATER ATTEMPERATOR SYSTEM DATA SHEET FPGD CIS-38.05

(SECOND STAGE ATTEMPERATOR)

Florida Power
CORPORATION

Ten-Year Site Plan

DETAIL AS OF DECEMBER 31, 1995

Florida Power
CORPORATION

Ten-Year Site Plan

1996-2005

Submitted To :

State of Florida
Public Service Commission

DETAIL AS OF DECEMBER 31, 1995

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

LIST OF ILLUSTRATIONS
REQUIRED FORMS & CHARTS

FLORIDA POWER CORPORATION
CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - 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

Air Pollution Control Strategy

CSCF - Controlled Sulfur Content of Fuel
EP - Electrostatic Precipitator
LNB - Low NOx Burners
N - None

Cooling Method

OTF - Once-through, fresh
OTS - Once-through, saline
NDS - Natural Draft Cooling Towers (saline), closed cycle cooling system
HCT - Helper Cooling Towers

Future Generating Unit Status

A - 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

CHAPTER 1

Description of EXISTING FACILITIES

CHAPTER 1 Description of EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Florida Power Corporation (FPC) is an investor-owned electric utility with 508 preferred shareholders. The company's common stock is held by Florida Progress Corporation which has 40,523 registered common shareholders, 13,523 of whom 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 32 Florida counties. The area of service is divided into three geographical regions which are subdivided into 34 business offices. The company supplies electricity at retail to approximately 356 communities and at wholesale to 11 municipalities. Wholesale supplemental electric service also is supplied to Seminole Electric Cooperative, Inc. (SECI), Florida Municipal Power Agency (FMPA), and Walt Disney World.

INTERCONNECTIONS

The company is part of a nationwide interconnected power network that enables power to be exchanged between utilities.

TRANSMISSION (See Transmission System Map)

Circuit miles of transmission lines		4,557
Transmission & plant substations		83

DISTRIBUTION

Circuit miles of distribution lines		23,527
Overhead	17,499	
Underground	6,028	
Distribution substations		262

ENERGY MANAGEMENT

Florida Power customers participating in the company's Energy Management program are managing future growth and costs. As of December 31, 1995, 520,610 customers received $39,803,548 in credits during the year. This excellent participation level provides over 951,000 KW of peak shaving capacity for use during high load periods. This program is a leader in the electric utility industry and directly benefits our environment.

TOTAL CAPACITY RESOURCE

Florida Power has a total capacity resource of 8,850 MW. This capacity resource includes utility and non-utility purchased power, peaking facilities, and nuclear and fossil steam plants. Additional information is shown on the following table "Power Plants, Peaking Units and Purchased Power."

POWER PLANTS, PEAKING UNITS AND PURCHASED POWER

Plants	Number Of Units	Net Dependable Capability KW Winter
Nuclear Steam Plant		
Crystal River	1	755,000*
Fossil Steam Plants		
Crystal River	4	2,276,000
Anclote	2	1,034,000
Paul L. Bartow	3	449,000
Suwannee River	3	147,000
Total Fossil	12	3,906,000
Total Steam (Nuclear & Fossil)	13	4,661,000
Peaking Units		
DeBary	10	786,000
Intercession City	10	750,000
Bayboro	4	232,000
Bartow	4	217,000
Suwannee	3	201,000
Turner	4	200,000
Higgins	4	158,000
Avon Park	2	64,000
University of Florida	1	42,000
Port St. Joe	1	18,000
Rio Pinar	1	18,000
Total Peaking	44	2,686,000
Total Units	57	
Total Net Generating Capability		**7,347,000**
** Adjusted for sale of 9.6% total capacity*		
Purchased Power		
Qualifying Facilities	16	1,044,000
Investor Owned Utilities	2	459,000
Total Capacity Resource		**8,850,000**

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Docket No. 060658
Progress Energy Florida
Exhibit No. ____ (JBC-2)
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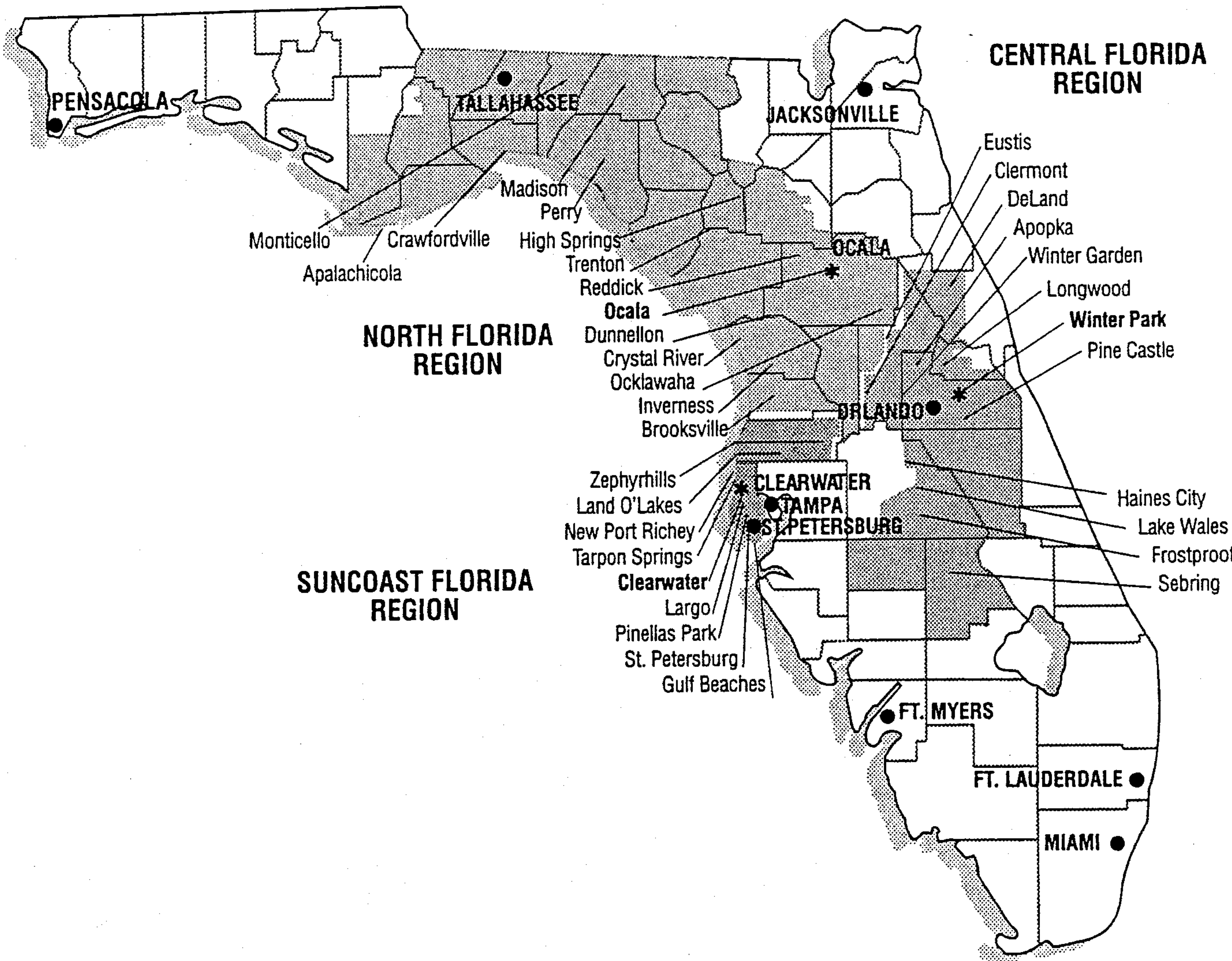
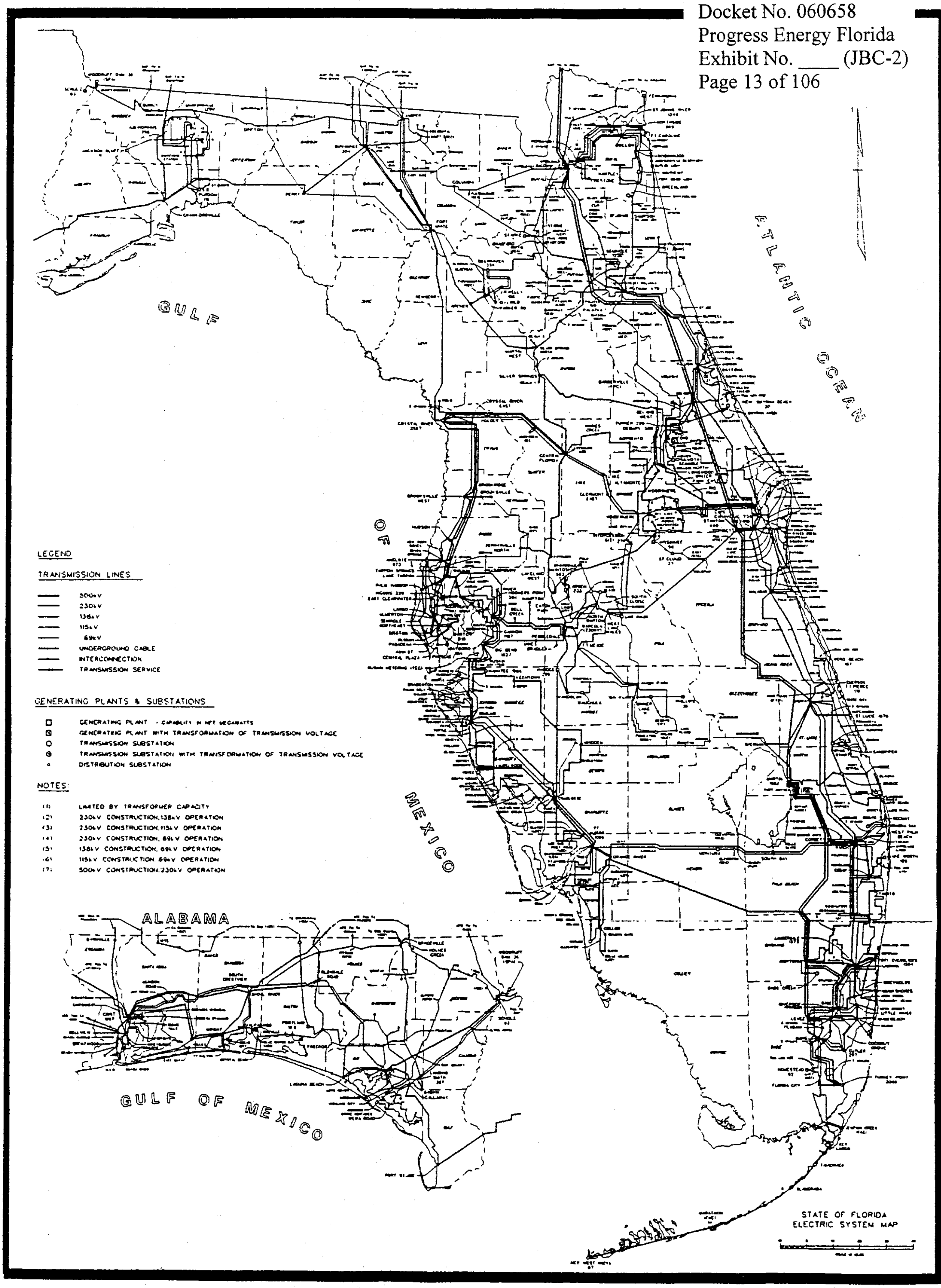
Florida Power
CORPORATION

Florida Power Corporation • Area of Service



✱ Administrative Offices


ATLANTIC OCEAN
GULF OF MEXICO
ALABAMA
GULF OF MEXICO
LEGEND
TRANSMISSION LINES
500kV
230kV
138kV
115kV
69kV
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
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
STATE OF FLORIDA
ELECTRIC SYSTEM MAP

Additional information on FPC's existing assets are shown on the following forms:

Existing Generating Facilities are shown on Form 1A.

Existing Generating Facilities - Land Use and Investment are shown on Form 1B.

Existing Generating Facilities - Environmental Considerations are shown on Form 1C.

FLORIDA POWER CORPORATION

EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
				PRIMARY FUEL		ALTERNATE FUEL					NET CAPABILITY MW	
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	COMMERCIAL IN-SERVICE (MO/YR)	EXPECTED RETIREMENT (MO/YR)	GENERATOR MAXIMUM NAMEPLATE KW	SUMMER	WINTER
											1,006	1,034
ANCLOTE	1	PASCO CO.	ST	F06	PL			10/1974		556,200	503	517
	2	SECT.33,34	ST	F06	PL			10/1978		556,200	503	517
		T26S,R15E										
											58	64
AVON PARK	P1-2	HIGHLANDS CO.	GT	F02	TK	NG	PL	12/1968	12/2004	67,580	58	64
											627	666
BARTOW	1	PINELLAS CO.	ST	F06	WA			09/1958		127,500	115	117
	2	SECT.20,21,22	ST	F06	WA			08/1961		127,500	117	119
	3	T30S,R16E	ST	F06	WA	NG	PL	07/1963		239,360	208	213
	P1-3		GT	F02	WA			06/1972		167,100	138	159
	P4		GT	F02	WA			06/1972		55,700	49	58
											188	232
BAYBORO	P1-4	PINELLAS CO.	GT	F02	WA			04/1973	12/2004	226,800	188	232
		SECT. 30										
		T31S,R17E										
											2,961	[illegible]031
CRYSTAL RIVER	1	CITRUS CO.	ST	BIT	WA,RR			10/1966		440,550	369	3[illegible]
	2	SECT.33	ST	BIT	WA,RR			11/1969		523,800	464	469
	3 *	T17S,R16E	NP	UR				03/1977		890,460	734	755
	4		ST	BIT	WA,RR			12/1982		739,260	697	717
	5		ST	BIT	WA,RR			10/1984		739,260	697	717
											656	786
DEBARY	P1-6	VOLUSIA CO.	GT	F02	TK,RR			04/1976		401,220	324	390
	P7-10	SECT.16,19-21, 28-30,T18S,R30E	GT	F02	TK,RR			11/1992		460,000	332	396
											128	158
HIGGINS	P1-2	PINELLAS CO.	GT	F02	TK	NG	PL	04/1969	12/2003	67,580	58	74
	P3-4	SECT. 35,36	GT	F02	TK	NG	PL	12/1970	12/2003	85,850	70	84
		T25S,R16E										
											614	750
INTERCESSION CITY	P1-6	OSCEOLA CO.	GT	F02	PL			05/1974		340,200	282	354
	P7-10	SECT. 31	GT	F02	PL	NG	PL	11/1993		460,000	332	396
		T25S,R28E										
											15	18
PORT ST. JOE	P1	GULF CO.	GT	F02	TK			12/1970	12/2003	19,300	15	18
											15	18
RIO PINAR	P1	ORANGE CO.	GT	F02	TK			11/1970	12/2003	19,290	15	18
											307	348
SUWANNEE RIVER	1	SUWANNEE CO.	ST	F06	TK	NG	PL	11/1953		34,500	33	34
	2	SECT. 26,	ST	F06	TK	NG	PL	11/1954		37,500	32	33
	3	T1S,R11E	ST	F06	TK	NG	PL	10/1956		75,000	80	80
	P1-3		GT	F02	TK			11/1980		183,600	162	201
											160	[illegible]0
TURNER	P1-2	VOLUSIA CO.	GT	F02	TK,WA			10/1970	12/2004	38,580	30	36
	P3-4	SECT. 1,	GT	F02	TK,WA			08/1974		142,400	130	164
		T19S,R30E										
											36	42
UNIV. OF FLA.	P1	ALACHUA CO.	GT	NG	PL			01/1994		43,000	36	42
											6,771	7,347

* REPRESENTS 90.4473 % FPC OWNERSHIP OF UNIT

FLORIDA POWER CORPORATION

EXISTING GENERATING FACILITIES
LAND USE AND INVESTMENT *
AS OF DECEMBER 31, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	LAND AREA		PLANT CAPITAL INVESTMENT ($000)			
PLANT NAME	TOTAL ACRES	IN USE ACRES	LAND	SITE IMPROVEMENT	BUILDINGS & EQUIPMENT	TOTAL
ANCLOTE	454.34	425.56	1,869	3,940	230,498	236,307
AVON PARK	36.70	36.70	67	72	7,290	7,429
BARTOW	1,347.99	1,325.41	1,894	7,341	123,084	132,319
BAYBORO	4.52	4.52	0	325	18,877	19,202
CRYSTAL RIVER (FOSSIL)	5,527.67	4,334.51	2,415	48,681	1,166,331	1,217,427
CRYSTAL RIVER (NUCLEAR)	—	10.00	41	11,697	642,758	654,496 **
DEBARY	2,192.92	950.16	1,984	4,670	134,122	140,776
HIGGINS	141.82	117.37	184	1,474	28,416	30,074
INTERCESSION CITY	125.04	95.36	294	5,903	120,262	126,459
POLK COUNTY	8,110.53	8,110.53	11,013	0	0	11,013
PORT ST. JOE	—	—	0	6	2,382	2,388
RIO PINAR	—	—	0	13	2,287	2,300
SUWANNEE RIVER	647.47	647.47	22	1,105	55,914	57,041
TURNER	134.97	127.27	825	1,397	35,717	37,939
UNIVERSITY OF FLORIDA	—	—	—	—	886	886
BARTOW / ANCLOTE PIPELINE	—	—	242	449	12,849	13,540

* INCLUDES CLOSING TO PLANT IN SERVICE, HELD FOR FUTURE USE & OTHER UTILITY PROPERTY; DOES NOT INCLUDE CLOSINGS TO ELECTRIC PLANT UNCLASSIFIED OR UNRECOVERED PLANT.

** FPC OWNERSHIP ONLY

FLORIDA POWER CORPORATION

EXISTING GENERATING FACILITIES
ENVIRONMENTAL CONSIDERATIONS FOR STEAM GENERATING UNITS
AS OF DECEMBER 31, 1995

(1)	(2)	(3)	(4)	(5)	(6)
		FLUE GAS CLEANING			
PLANT NAME	UNIT	PARTICULATE	SO2	NOx	COOLING TYPE
ANCLOTE	1	N	CSCF	N	OTS,HCT
	2	N	CSCF	N	OTS,HCT
BARTOW	1	EP	CSCF	N	OTS
	2	N	CSCF	N	OTS
	3	N	CSCF	N	OTS
CRYSTAL RIVER	1	EP	CSCF	N	OTS,HCT
	2	EP	CSCF	N	OTS,HCT
	3	N/A	N/A	N/A	OTS,HCT
	4	EP	CSCF	LNB	NDS
	5	EP	CSCF	LNB	NDS
SUWANNEE RIVER	1	N	CSCF	N	OTF
	2	N	CSCF	N	OTF
	3	N	CSCF	N	OTF

CHAPTER 2

Forecast of ELECTRIC POWER DEMAND

CHAPTER 2 Forecast of ELECTRIC POWER DEMAND

ELECTRIC ENERGY AND FUEL REQUIREMENTS

Florida Power Corporation's 1995 actual and projected energy requirements, in GWH, are shown by fuel type on Form 3A. FPC's 1995 actual and projected nuclear, coal, oil, and gas requirements are shown on Form 3B. FPC's energy and fuel requirements indicate that FPC has a diverse fuel supply 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.

FLORIDA POWER CORPORATION

Docket No. 090988
Progress Energy Florida
Exhibit No. ____ (JBC-2)
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NET ELECTRICAL ENERGY REQUIREMENTS

	ENERGY REQUIREMENTS			-ACTUAL- 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
(1)	INTERCHANGE 1 /		GWH	-115	139	176	142	128	159	171	186	165	173	171
(2)	NUCLEAR		GWH	6,544	5,570	6,289	5,620	6,289	5,638	6,289	5,620	6,289	5,638	6,289
(3)	COAL		GWH	13,596	15,052	14,778	14,582	14,320	14,807	15,187	15,439	15,281	15,524	16,094
(4)	RESIDUAL	TOTAL	GWH	3,772	3,070	2,866	3,467	2,671	3,202	3,297	3,373	3,584	3,641	2,831
(5)		STEAM	GWH	3,772	3,070	2,866	3,467	2,671	3,202	3,297	3,373	3,584	3,641	2,831
(6)		CC	GWH	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
(8)		DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWH	383	312	355	491	433	575	950	1,084	1,254	1,207	809
(10)		STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	383	312	355	491	433	575	950	1,084	1,254	1,207	809
(13)		DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWH	1,415	1,034	1,356	2,431	5,154	4,998	4,947	4,670	4,898	6,182	7,469
(15)		STEAM	GWH	1,085	567	853	1,086	754	753	829	846	852	838	611
(16)		CC	GWH	0	0	0	696	3,935	3,703	3,742	3,530	3,795	4,846	6,475
(17)		CT	GWH	330	467	503	649	465	542	376	294	251	498	383
(18)		DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0
(19)	OTHER INTERCHANGE 2 /													
	QF PURCHASES		GWH	6,847	7,277	7,740	7,740	7,806	7,827	7,806	7,806	7,806	7,827	7,806
	IMPORT FROM OUT OF STATE		GWH	1,462	1,413	1,458	1,872	1,354	2,135	1,878	2,345	2,205	2,414	2,274
	EXPORT TO OUT OF STATE		GWH	-237	0	0	0	0	0	0	0	0	0	0
(20)	NET ENERGY FOR LOAD 3 /		GWH	33,667	33,867	35,018	36,345	38,155	39,341	40,525	40,523	41,482	42,606	43,743

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

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

3 / SHOULD EQUAL COLUMN 10 ON FORM 4C, PAGE 1.

FLORIDA POWER CORPORATION

FUEL REQUIREMENTS

	FUEL REQUIREMENTS			-ACTUAL- 1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
(1)	NUCLEAR		TRILLION BTU	68	59	67	60	67	60	67	60	67	60	67
(2)	COAL		1,000 TON	5,138	5,627	5,517	5,436	5,353	5,552	5,678	5,774	5,716	5,775	5,991
(3)	RESIDUAL	TOTAL	1,000 BBL	6,140	4,748	4,464	5,361	4,206	4,962	5,116	5,223	5,546	5,658	4,461
(4)		STEAM	1,000 BBL	6,140	4,748	4,464	5,361	4,206	4,962	5,116	5,223	5,546	5,658	4,461
(5)		CC	1,000 BBL	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
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	1,025	1,037	1,143	1,420	1,298	1,597	2,363	2,623	2,990	2,892	2,057
(9)		STEAM	1,000 BBL	141	388	404	397	399	402	387	378	396	394	387
(10)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	884	649	739	1,023	899	1,195	1,976	2,245	2,594	2,498	1,670
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	14,414	11,036	14,169	23,370	39,109	38,543	37,579	35,113	36,448	45,769	53,750
(14)		STEAM	1,000 MCF	10,272	5,870	8,658	11,171	7,885	7,817	8,566	8,547	8,579	8,438	6,280
(15)		CC	1,000 MCF	0	0	0	4,553	25,828	24,358	24,635	23,258	25,026	32,198	43,412
(16)		CT	1,000 MCF	4,142	5,166	5,511	7,646	5,396	6,368	4,378	3,308	2,843	5,133	4,058
(17)		DIESEL	1,000 MCF	0	0	0	0	0	0	0	0	0	0	0

FORECAST OF ELECTRIC DEMAND CHARTS AND TABLES

FPC's History and Forecast of Energy Consumption is shown on Chart 1. Related information on energy consumption and customer class is shown on Form 2.

FPC's Summer Peak Demand and Generating Capacity is shown on Chart 2 and includes historical and forecasted information. Additional data is shown on Form 4A to support Chart 2.

FPC's Winter Peak Demand and Generating Capacity is shown on Chart 3 and includes historical and forecasted information. Additional data is shown on Form 4B to support Chart 3.

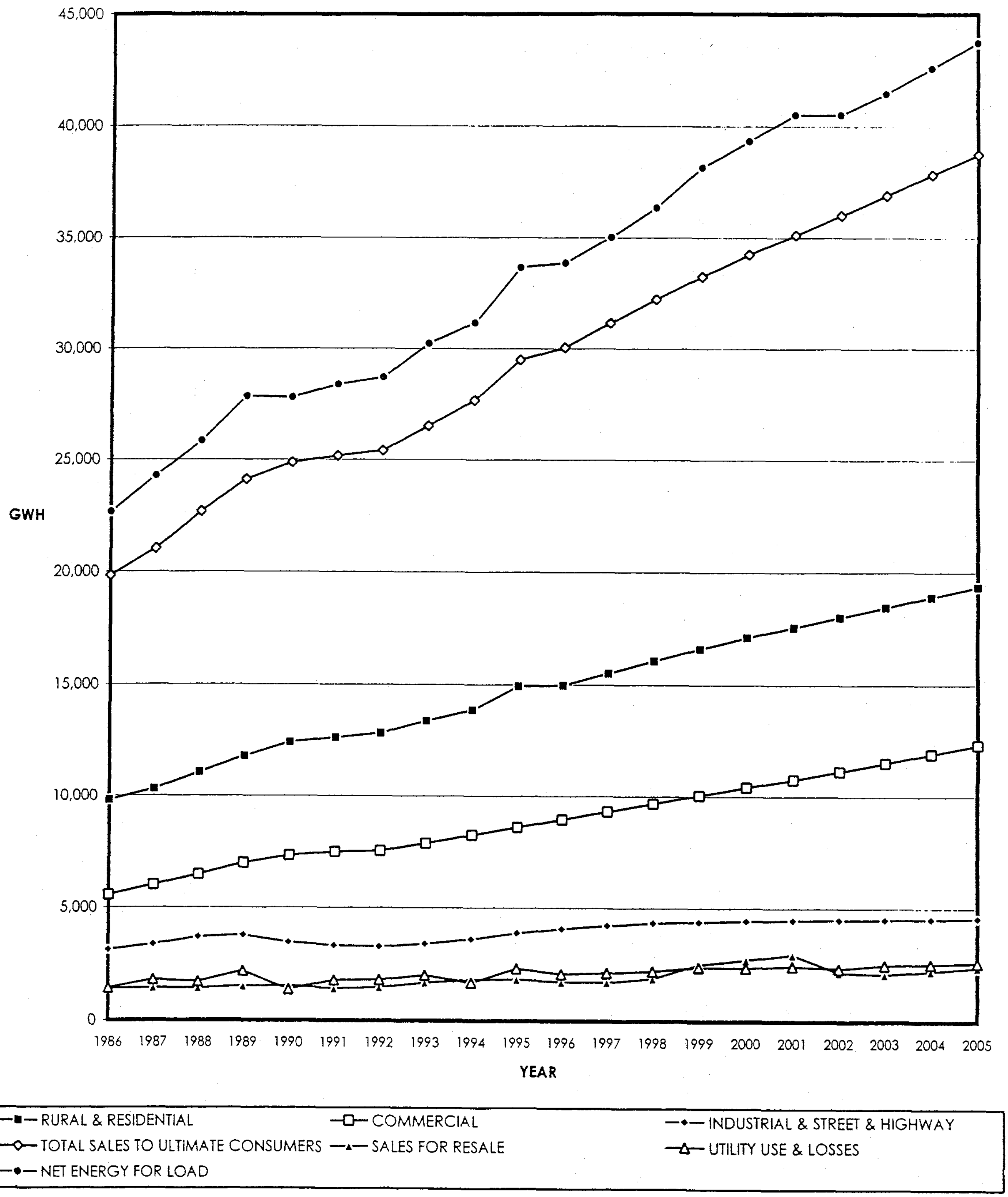
FPC's History and Forecast of Base, High, and Low Demand and Energy requirements are shown on Form 4C. Additional information on the methodology, models and high and low scenarios are discussed in the following write-up on forecasting.

FPC's Previous Year Actual and Two-Year Forecast of Peak Demand and Energy by Month is shown on Form 5.

CHART 1

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF ENERGY CONSUMPTION



FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND NUMBER OF CUSTOMERS BY CUSTOMER CLASS
AS OF DECEMBER 31, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	FPC POPULATION	MEMBERS PER HOUSEHOLD	GWH	AVERAGE # OF CUST	AVERAGE KWH/ CUST	GWH	AVERAGE # OF CUST	AVERAGE KWH/ CUST
1986	2,162,572	2.48	9,819	872,441	11,255	5,573	96,843	57,547
1987	2,236,354	2.46	10,319	908,640	11,357	6,016	102,657	58,603
1988	2,302,453	2.45	11,066	941,440	11,754	6,479	106,899	60,609
1989	2,404,525	2.46	11,787	977,448	12,059	6,990	111,079	62,928
1990	2,492,186	2.47	12,416	1,007,806	12,320	7,329	113,595	64,519
1991	2,537,012	2.46	12,624	1,029,901	12,257	7,489	114,657	65,318
1992	2,588,540	2.47	12,826	1,050,077	12,214	7,544	116,727	64,630
1993	2,653,485	2.46	13,373	1,076,657	12,420	7,885	119,811	65,810
1994	2,720,931	2.47	13,863	1,100,537	12,597	8,252	122,987	67,097
1995	2,780,048	2.47	14,938	1,124,679	13,282	8,612	126,189	68,248
1996	2,830,076	2.47	14,977	1,145,203	13,078	8,960	128,513	69,721
1997	2,888,173	2.47	15,526	1,169,503	13,276	9,326	131,576	70,879
1998	2,947,724	2.47	16,075	1,194,896	13,453	9,686	134,856	71,825
1999	3,008,143	2.46	16,617	1,221,139	13,608	10,058	138,246	[illegible]4
2000	3,066,360	2.46	17,127	1,246,982	13,735	10,432	141,584	7[illegible]81
2001	3,123,758	2.46	17,579	1,272,342	13,816	10,770	144,859	74,348
2002	3,177,118	2.45	18,023	1,296,471	13,902	11,135	147,976	75,249
2003	3,227,173	2.45	18,467	1,319,593	13,994	11,523	150,963	76,330
2004	3,275,138	2.44	18,919	1,342,129	14,096	11,918	153,875	77,452
2005	3,321,177	2.43	19,359	1,364,071	14,192	12,326	156,709	78,655

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND NUMBER OF CUSTOMERS BY CUSTOMER CLASS
AS OF DECEMBER 31, 1995

(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
	INDUSTRIAL					OTHER SALES TO ULTIMATE CONSUMERS GWH	TOTAL SALES TO ULTIMATE CONSUMERS GWH
YEAR	GWH	AVERAGE # OF CUST	AVERAGE KWH/ CUST	OTHER CLASSIFICATION (SPECIFY):	STREET & HIGHWAY GWH		
1986	3,122	2,705	1,154,159		16	1,301	19,831
1987	3,349	2,877	1,164,060		19	1,336	21,039
1988	3,681	2,942	1,251,190		19	1,447	22,692
1989	3,766	3,021	1,246,607		19	1,561	24,123
1990	3,456	3,115	1,109,470		21	1,658	24,880
1991	3,303	3,124	1,057,288		23	1,740	25,179
1992	3,254	3,137	1,037,445		24	1,765	25,414
1993	3,381	3,107	1,088,123		25	1,865	26,528
1994	3,580	3,186	1,123,539		26	1,954	27,675
1995	3,864	3,143	1,229,532		27	2,058	29,499
1996	4,049	3,248	1,246,613		29	2,042	30,057
1997	4,196	3,281	1,278,878		31	2,079	31,158
1998	4,320	3,314	1,303,561		32	2,132	32,245
1999	4,359	3,347	1,302,360		34	2,187	33,255
2000	4,414	3,380	1,305,917		36	2,243	34,252
2001	4,438	3,413	1,300,322		37	2,293	35,117
2002	4,457	3,446	1,293,384		39	2,344	35,998
2003	4,471	3,479	1,285,139		40	2,397	36,898
2004	4,489	3,512	1,278,189		41	2,450	37,817
2005	4,512	3,545	1,272,779		43	2,504	38,744

FLORIDA POWER CORPORATION

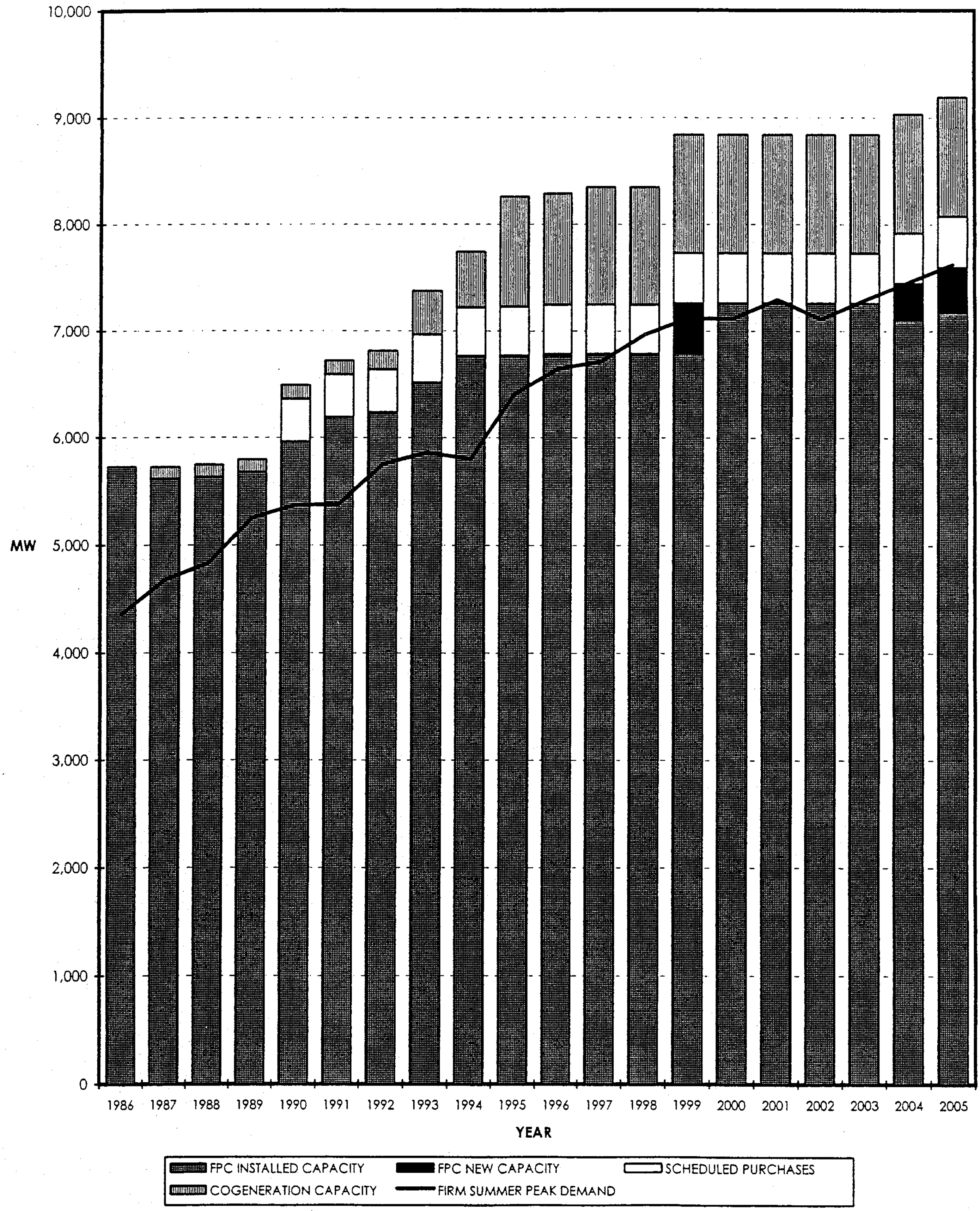
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND NUMBER OF CUSTOMERS BY CUSTOMER CLASS
AS OF DECEMBER 31, 1995

(18) YEAR	(19) SALES FOR RESALE GWH	(20) UTILITY USE & LOSSES GWH	(21) NET ENERGY FOR LOAD GWH	(22) OTHER CUSTOMERS (AVERAGE NO.)	(23) TOTAL NO. OF CUSTOMERS
1986	1,408	1,446	22,685	8,438	980,427
1987	1,441	1,812	24,292	9,047	1,023,221
1988	1,432	1,724	25,848	9,691	1,060,972
1989	1,529	2,195	27,847	10,269	1,101,817
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	19,484	1,273,495
1996	1,728	2,082	33,867	18,391	1,295,355
1997	1,722	2,138	35,018	18,979	1,323,339
1998	1,885	2,215	36,345	19,564	1,352,630
1999	2,505	2,395	38,155	20,147	1,382,87'
2000	2,718	2,371	39,341	20,737	1,412,683
2001	2,965	2,443	40,525	21,322	1,441,936
2002	2,172	2,353	40,523	21,908	1,469,801
2003	2,092	2,492	41,482	22,494	1,496,529
2004	2,241	2,548	42,606	23,082	1,522,598
2005	2,396	2,603	43,743	23,668	1,547,993

CHART 2

FLORIDA POWER CORPORATION
HISTORY AND FORECAST OF

SUMMER PEAK DEMAND & GENERATING CAPACITY



FLORIDA POWER CORPORATION

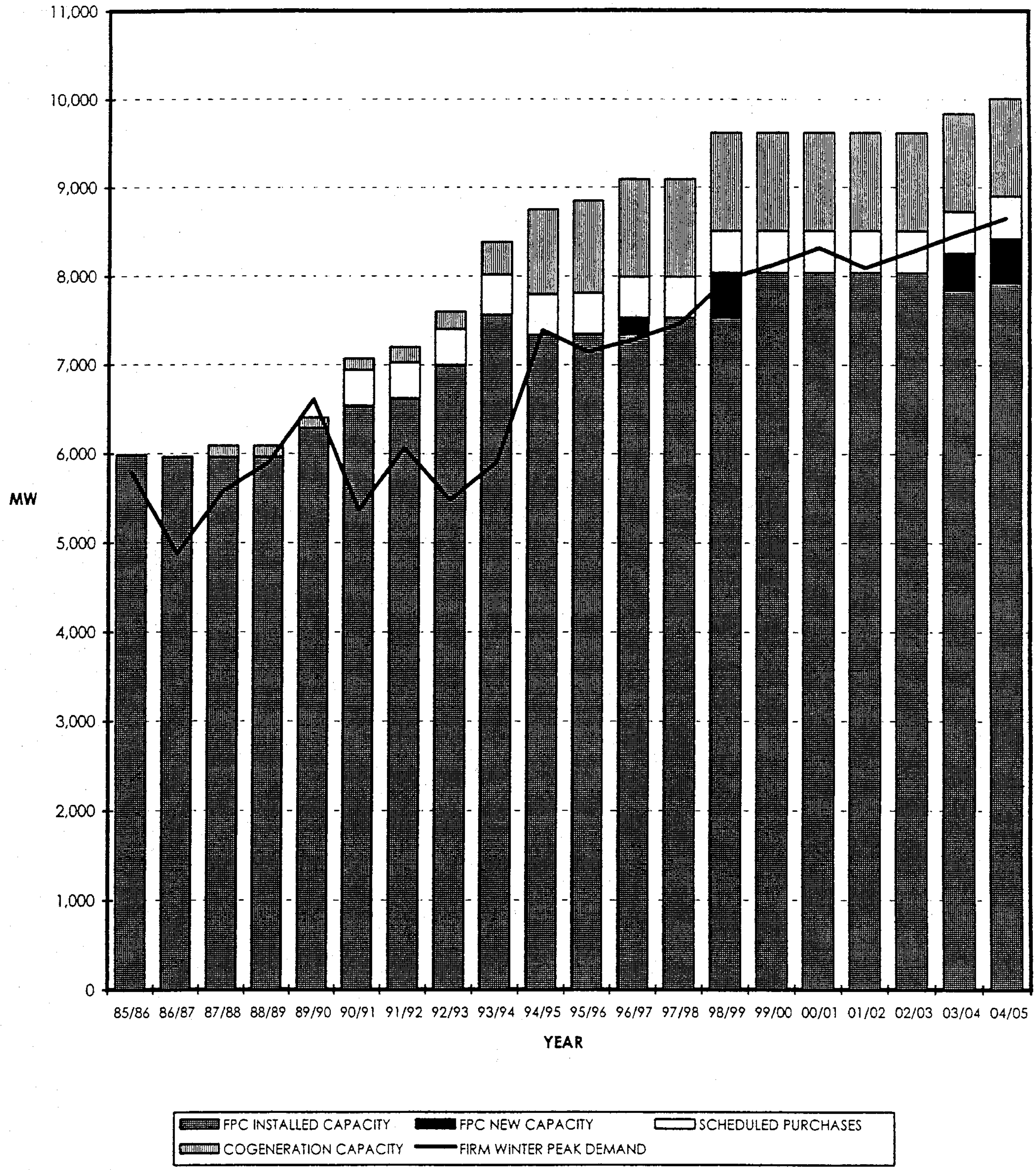
HISTORY AND FORECAST OF
SUMMER PEAK DEMAND & GENERATING CAPACITY

YEAR	FPC INSTALLED CAPACITY	FPC NEW CAPACITY	FIRM SCHEDULED PURCHASES	FIRM COGENERATION CAPACITY	FIRM SUMMER PEAK DEMAND
1986	5,731	0	0	0	4,357
1987	5,617	0	0	111	4,680
1988	5,633	0	0	117	4,837
1989	5,678	0	0	121	5,256
1990	5,963	0	400	131	5,374
1991	6,192	0	400	134	5,383
1992	6,240	0	400	177	5,754
1993	6,516	0	450	412	5,864
1994	6,767	0	452	527	5,804
1995	6,771	0	457	1,034	6,408
1996	6,771	17	459	1,044	6,644
1997	6,788	0	459	1,105	6,714
1998	6,788	0	459	1,105	6,966
1999	6,788	474	469	1,115	7,121
2000	7,262	0	469	1,115	7,116
2001	7,262	0	469	1,115	7,297
2002	7,262	0	469	1,115	7,113
2003	7,262	0	469	1,115	7,290
2004	7,104	347	469	1,115	7,458
2005	7,175	424	479	1,115	7,628

NOTE: FPC INSTALLED CAPACITY COLUMN INCLUDES
EXTENDED COLD SHUTDOWN AND RETIRED CAPACITY.

FLORIDA POWER CORPORATION
HISTORY AND FORECAST OF

WINTER PEAK DEMAND & GENERATING CAPACITY



FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF
WINTER PEAK DEMAND & GENERATING CAPACITY

YEAR	FPC INSTALLED CAPACITY	FPC NEW CAPACITY	FIRM SCHEDULED PURCHASES	FIRM COGENERATION CAPACITY	FIRM WINTER PEAK DEMAND
85/86	5,989	0	0	0	5,792
86/87	5,966	0	0	0	4,881
87/88	5,961	0	0	132	5,582
88/89	5,966	0	0	127	5,900
89/90	6,289	0	0	121	6,614
90/91	6,543	0	400	131	5,370
91/92	6,627	0	400	177	6,068
92/93	7,002	0	400	200	5,484
93/94	7,563	0	452	373	5,905
94/95	7,337	0	457	960	7,392
95/96	7,347	0	459	1,044	7,148
96/97	7,347	184	459	1,105	7,288
97/98	7,531	0	459	1,105	7,466
98/99	7,531	507	469	1,115	7,961
99/00	8,038	0	469	1,115	8,122
00/01	8,038	0	469	1,115	8,317
01/02	8,038	0	469	1,115	8,092
02/03	8,038	0	469	1,115	8,276
03/04	7,844	414	469	1,115	8,472
04/05	7,926	498	479	1,115	8,657

NOTE: FPC INSTALLED CAPACITY COLUMN INCLUDES
EXTENDED COLD SHUTDOWN AND RETIRED CAPACITY.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD
AS OF DECEMBER 31, 1995

Docket No. 090988
Progress Energy Florida
Exhibit No. ____ (JBC-2)
Page 31 of 106

(BASE CASE)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	SUMMER PEAK DEMAND (MW)						ANNUAL NET ENERGY FOR LOAD			
	FIRM						GWH			LOAD FACTOR
YEAR	RETAIL	WHOLESALE	TOTAL	LOAD MGT. *	INTERRUPT	TOTAL	RETAIL	WHOLESALE	TOTAL	(%)
1986	4,038	319	4,357	110	177	4,644	21,277	1,408	22,685	43.3
1987	4,233	447	4,680	250	266	5,196	22,851	1,441	24,292	54.5
1988	4,337	500	4,837	250	222	5,309	24,416	1,432	25,848	47.6
1989	4,633	623	5,256	300	276	5,832	26,318	1,529	27,847	51.8
1990	4,733	641	5,374	342	230	5,946	26,257	1,548	27,805	46.6
1991	4,699	684	5,383	335	207	5,925	26,978	1,411	28,389	53.5
1992	4,927	827	5,754	417	186	6,357	27,231	1,471	28,702	46.8
1993	5,016	848	5,864	591	274	6,729	28,548	1,695	30,243	55.5
1994	5,003	801	5,804	615	262	6,681	29,355	1,819	31,174	51.2
1995	5,522	886	6,408	436	284	7,128	31,821	1,846	33,667	49.8
1996	5,359	1,285	6,644	0	314	6,958	32,139	1,728	33,867	51.7
1997	5,492	1,222	6,714	0	317	7,031	33,296	1,722	35,018	52.6
1998	5,632	1,334	6,966	0	327	7,293	34,460	1,885	36,345	53.2
1999	5,735	1,386	7,121	0	370	7,491	35,650	2,505	38,155	52.3
2000	5,873	1,243	7,116	0	373	7,489	36,623	2,718	39,341	52.7
2001	6,009	1,288	7,297	0	376	7,673	37,560	2,965	40,525	53.2
2002	6,177	936	7,113	0	340	7,453	38,351	2,172	40,523	54.9
2003	6,305	985	7,290	0	343	7,633	39,390	2,092	41,482	54.9
2004	6,422	1,036	7,458	0	346	7,804	40,365	2,241	42,606	55.0
2005	6,540	1,088	7,628	0	350	7,978	41,347	2,396	43,743	55.4

* LOAD MANAGEMENT THAT WAS AVAILABLE BUT NOT EXERCISED.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD
AS OF DECEMBER 31, 1995

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(BASE CASE)

(12)	(13)	(14)	(15)	(16)	(17)	(18)
	WINTER PEAK DEMAND (MW)					
	FIRM					
YEAR	RETAIL	WHOLESALE	TOTAL	LOAD MGT. *	INTERRUPT	TOTAL
1985-86	5,082	710	5,792	0	185	5,977
1986-87	4,378	503	4,881	0	206	5,087
1987-88	4,869	713	5,582	377	229	6,188
1988-89	5,261	639	5,900	0	237	6,137
1989-90	5,656	958	6,614	203	0	6,817
1990-91	4,574	796	5,370	490	196	6,056
1991-92	5,063	1,005	6,068	704	210	6,982
1992-93	4,608	876	5,484	585	150	6,219
1993-94	4,901	1,004	5,905	851	199	6,955
1994-95	6,223	1,169	7,392	50	280	7,722
1995-96 **	5,898	1,250	7,148	0	314	7,462
1996-97	6,023	1,265	7,288	0	317	7,605
1997-98	6,145	1,321	7,466	0	327	7,793
1998-99	6,239	1,722	7,961	0	369	8,330
1999-00	6,367	1,755	8,122	0	373	8,495
2000-01	6,494	1,823	8,317	0	376	8,693
2001-02	6,655	1,437	8,092	0	340	8,432
2002-03	6,770	1,506	8,276	0	343	8,619
2003-04	6,893	1,579	8,472	0	346	8,818
2004-05	7,001	1,656	8,657	0	349	9,006
2005-06	7,105	1,732	8,837	0	352	9,189

* LOAD MANAGEMENT THAT WAS AVAILABLE BUT NOT EXERCISED.

** FORECAST ESTIMATE.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD
AS OF DECEMBER 31, 1995

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(HIGH LOAD FORECAST)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	SUMMER PEAK DEMAND (MW)						ANNUAL NET ENERGY FOR LOAD			
	FIRM						GWH			LOAD FACTOR
YEAR	RETAIL	WHOLESALE	TOTAL	LOAD MGT. *	INTERRUPT	TOTAL	RETAIL	WHOLESALE	TOTAL	(%)
1986	4,038	319	4,357	110	177	4,644	21,277	1,408	22,685	43.3
1987	4,233	447	4,680	250	266	5,196	22,851	1,441	24,292	54.5
1988	4,337	500	4,837	250	222	5,309	24,416	1,432	25,848	47.6
1989	4,633	623	5,256	300	276	5,832	26,318	1,529	27,847	51.8
1990	4,733	641	5,374	342	230	5,946	26,257	1,548	27,805	46.6
1991	4,699	684	5,383	335	207	5,925	26,978	1,411	28,389	53.5
1992	4,927	827	5,754	417	186	6,357	27,231	1,471	28,702	46.8
1993	5,016	848	5,864	591	274	6,729	28,548	1,695	30,243	55.5
1994	5,003	801	5,804	615	262	6,681	29,355	1,819	31,174	51.2
1995	5,522	886	6,408	436	284	7,128	31,821	1,846	33,667	49.8
1996	5,523	1,285	6,808	0	314	7,122	32,783	1,728	34,511	52.7
1997	5,667	1,222	6,889	0	317	7,206	34,198	1,722	35,920	52.5
1998	5,885	1,334	7,219	0	327	7,546	35,610	1,885	37,495	53.0
1999	6,031	1,386	7,417	0	370	7,787	37,036	2,505	39,541	52.0
2000	6,273	1,243	7,516	0	373	7,889	38,432	2,718	41,150	52.2
2001	6,423	1,288	7,711	0	376	8,087	39,667	2,965	42,632	53.0
2002	6,641	936	7,577	0	340	7,917	40,642	2,172	42,814	54.4
2003	6,853	985	7,838	0	343	8,181	42,088	2,092	44,180	54.4
2004	7,042	1,036	8,078	0	346	8,424	43,318	2,241	45,559	54.3
2005	7,204	1,088	8,292	0	350	8,642	44,772	2,396	47,168	55.0

* LOAD MANAGEMENT THAT WAS AVAILABLE BUT NOT EXERCISED.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD
AS OF DECEMBER 31, 1995

Docket No. 090988
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(HIGH LOAD FORECAST)

(12)	(13)	(14)	(15)	(16)	(17)	(18)
	WINTER PEAK DEMAND (MW)					
	FIRM					
YEAR	RETAIL	WHOLESALE	TOTAL	LOAD MGT. *	INTERRUPT	TOTAL
1985-86	5,082	710	5,792	0	185	5,977
1986-87	4,378	503	4,881	0	206	5,087
1987-88	4,869	713	5,582	377	229	6,188
1988-89	5,261	639	5,900	0	237	6,137
1989-90	5,656	958	6,614	203	0	6,817
1990-91	4,574	796	5,370	490	196	6,056
1991-92	5,063	1,005	6,068	704	210	6,982
1992-93	4,608	876	5,484	585	150	6,219
1993-94	4,901	1,004	5,905	851	199	6,955
1994-95	6,223	1,169	7,392	50	280	7,722
1995-96 **	5,898	1,250	7,148	0	314	7,462
1996-97	6,222	1,265	7,487	0	317	7,804
1997-98	6,429	1,321	7,750	0	327	8,077
1998-99	6,582	1,722	8,304	0	369	8,673
1999-00	6,840	1,755	8,595	0	373	8,968
2000-01	6,982	1,823	8,805	0	376	9,181
2001-02	7,202	1,437	8,639	0	340	8,979
2002-03	7,418	1,506	8,924	0	343	9,267
2003-04	7,626	1,579	9,205	0	346	9,551
2004-05	7,783	1,656	9,439	0	349	9,788
2005-06	8,006	1,732	9,738	0	352	10,090

* LOAD MANAGEMENT THAT WAS AVAILABLE BUT NOT EXERCISED.

** FORECAST ESTIMATE.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD
AS OF DECEMBER 31, 1995

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(LOW LOAD FORECAST)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	SUMMER PEAK DEMAND (MW)						ANNUAL NET ENERGY FOR LOAD			
	FIRM						GWH			LOAD FACTOR
YEAR	RETAIL	WHOLESALE	TOTAL	LOAD MGT. *	INTERRUPT	TOTAL	RETAIL	WHOLESALE	TOTAL	(%)
1986	4,038	319	4,357	110	177	4,644	21,277	1,408	22,685	43.3
1987	4,233	447	4,680	250	266	5,196	22,851	1,441	24,292	54.5
1988	4,337	500	4,837	250	222	5,309	24,416	1,432	25,848	47.6
1989	4,633	623	5,256	300	276	5,832	26,318	1,529	27,847	51.8
1990	4,733	641	5,374	342	230	5,946	26,257	1,548	27,805	46.6
1991	4,699	684	5,383	335	207	5,925	26,978	1,411	28,389	53.5
1992	4,927	827	5,754	417	186	6,357	27,231	1,471	28,702	46.8
1993	5,016	848	5,864	591	274	6,729	28,548	1,695	30,243	55.5
1994	5,003	801	5,804	615	262	6,681	29,355	1,819	31,174	51.2
1995	5,522	886	6,408	436	284	7,128	31,821	1,846	33,667	49.8
1996	5,227	1,285	6,512	0	314	6,826	31,455	1,728	33,183	50.6
1997	5,280	1,222	6,502	0	317	6,685	32,419	1,722	34,141	52.9
1998	5,379	1,334	6,713	0	327	7,040	33,296	1,885	35,181	53.5
1999	5,424	1,386	6,810	0	370	7,180	34,195	2,505	36,700	52.6
2000	5,534	1,243	6,777	0	373	7,150	34,901	2,718	37,619	52.9
2001	5,575	1,288	6,863	0	376	7,239	35,570	2,965	38,535	53.8
2002	5,720	936	6,656	0	340	6,996	36,094	2,172	38,266	55.4
2003	5,798	985	6,783	0	343	7,126	36,883	2,092	38,975	55.5
2004	5,852	1,036	6,888	0	346	7,234	37,441	2,241	39,682	55.5
2005	5,882	1,088	6,970	0	350	7,320	38,184	2,396	40,580	56.3

* LOAD MANAGEMENT THAT WAS AVAILABLE BUT NOT EXERCISED.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD
AS OF DECEMBER 31, 1995

(LOW LOAD FORECAST)

(12)	(13)	(14)	(15)	(16)	(17)	(18)
	WINTER PEAK DEMAND (MW)					
	FIRM			LOAD		
YEAR	RETAIL	WHOLESALE	TOTAL	MGT. *	INTERRUPT	TOTAL
1985-86	5,082	710	5,792	0	185	5,977
1986-87	4,378	503	4,881	0	206	5,087
1987-88	4,869	713	5,582	377	229	6,188
1988-89	5,261	639	5,900	0	237	6,137
1989-90	5,656	958	6,614	203	0	6,817
1990-91	4,574	796	5,370	490	196	6,056
1991-92	5,063	1,005	6,068	704	210	6,982
1992-93	4,608	876	5,484	585	150	6,219
1993-94	4,901	1,004	5,905	851	199	6,955
1994-95	6,223	1,169	7,392	50	280	7,722
1995-96 **	5,898	1,250	7,148	0	314	7,462
1996-97	5,783	1,265	7,048	0	317	7,365
1997-98	5,861	1,321	7,182	0	327	7,509
1998-99	5,877	1,722	7,599	0	369	7,968
1999-00	5,966	1,755	7,721	0	373	8,094
2000-01	5,979	1,823	7,802	0	376	8,178
2001-02	6,112	1,437	7,549	0	340	7,889
2002-03	6,170	1,506	7,676	0	343	8,019
2003-04	6,219	1,579	7,798	0	346	8,144
2004-05	6,221	1,656	7,877	0	349	8,226
2005-06	6,294	1,732	8,026	0	352	8,378

* LOAD MANAGEMENT THAT WAS AVAILABLE BUT NOT EXERCISED.

** FORECAST ESTIMATE.

FLORIDA POWER CORPORATION

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH
AS OF DECEMBER 31, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST			
	1995		1996		1997	
MONTH	PEAK DEMAND (MW)	NEL (GWH)	PEAK DEMAND (MW)	NEL (GWH)	PEAK DEMAND (MW)	NEL (GWH)
JAN	7,081	2,611	7,148	2,596	7,288	2,700
FEB	7,722	2,350	6,410	2,319	6,552	2,410
MAR	5,064	2,251	5,319	2,474	5,424	2,568
APR	5,487	2,357	4,507	2,377	4,599	2,464
MAY	6,851	3,213	5,205	2,887	5,314	2,984
JUN	6,814	3,015	6,314	3,195	6,389	3,292
JUL	6,840	3,364	6,490	3,466	6,566	3,575
AUG	7,128	3,442	6,644	3,486	6,714	3,600
SEP	6,654	3,167	6,242	3,275	6,319	3,380
OCT	6,108	2,801	5,134	2,746	5,250	2,836
NOV	5,553	2,340	4,974	2,411	5,071	2,490
DEC	6,977	2,756	6,229	2,635	6,344	2,719
TOTAL		33,667		33,867		35,018

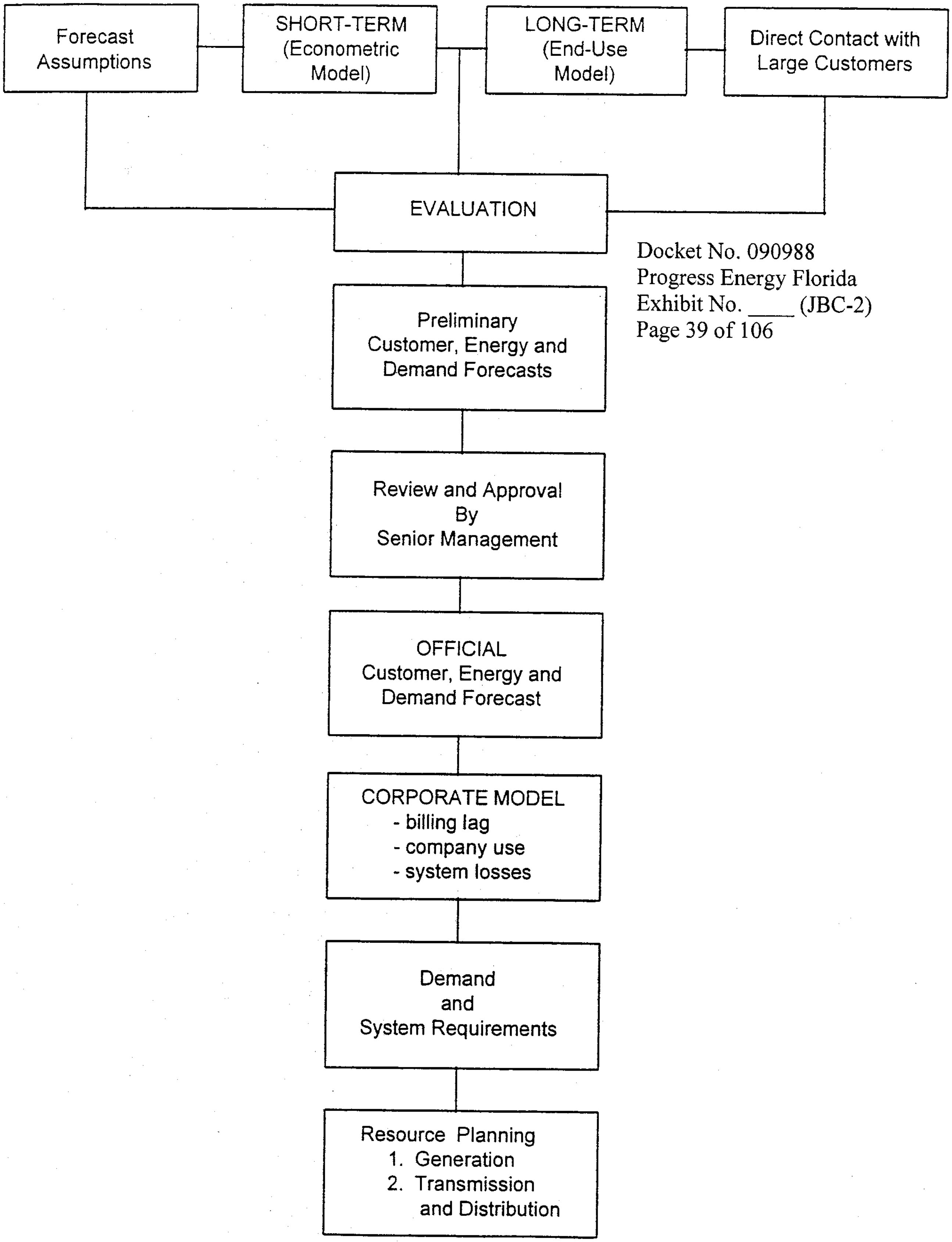
FORECASTING METHODOLOGY

INTRODUCTION

The need for accurate forecasts of long-range electric energy consumption, customer growth, peak demand and system load shape is an important planning function for any electric utility. Risks involved with being in an over-or-under capacity situation can have a significant financial impact on a utility operating in either a competitive marketplace or the regulatory arena. Accurate projections of a utility's future growth require forecasting methodologies with the ability to account for a variety of factors influencing electric energy usage in both the short-term and long-term planning horizons. Florida Power Corporation's forecasting system 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 in 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 the 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 set of assumptions. Add to this some direct contact with large customers and the forecaster has the tools to mold a most likely scenario of the future.

CUSTOMER, ENERGY AND DEMAND FORECAST



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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 Business Planning 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 is based on a ten-year average of service-area-weighted degree days in order to project kilowatt-hour sales. Similarly, a ten-year average of service area weighted temperature at hour of system peak is used to forecast 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 uses "Population Studies," Bulletin No. 111, February 1995.

3. FPC's largest electric consumers, its phosphate mining customers, have experienced a significant improvement of late. Improved market conditions for phosphate rock have firmed market prices and allowed for expansion of operations at some mining sites. New mining operations with scheduled openings in the 1995-1996 period include Mobil Chemical Company in South Ft. Meade and C.F. Industries in Ft. Green. As a result, a significant increase in phosphate energy consumption is assumed in this forecast over the next few years. Beyond this time period, a trend level of production is assumed.

4. Florida Power Corporation supplies capacity and energy service to wholesale customers on a full and partial requirements basis. Full requirements customers' demand and energy are assumed to grow at rates dictated by projected population levels as well as projected economic activity. Partial requirements customers' load is assumed to reflect the current contractual obligations received by FPC as of June 1, 1995. The forecast of energy and demand from partial requirements customers reflect their ability to receive dispatched energy from the Florida broker system any time it is more economical to do so. FPC's arrangement with Seminole Electric Cooperative, Incorporated is to serve "supplemental" service over and above annual levels of self-generation and firm purchase contracts. SECI's projection of their system's supplemental demand and energy requirements has been

incorporated into this forecast. This forecast also includes three wholesale bulk power contracts. The first is a multi-part contract with SECI to serve 455 MW for three years beginning in 1999 and ending in 2001. An option to extend this load for an additional seven years exists, but is not assumed in the forecast. A second piece of the SECI contract involves 150 MW of stratified intermediate demand that is assumed to be served throughout the forecast horizon. The other two bulk power contracts are summer firm contract sales at varying annual capacity levels with Georgia Power Company and Oglethorpe Power Corporation for the 1996-1999 and 1997-1998 periods, respectively.

5. This forecast incorporated all cost effective amounts of demand and energy reductions from FPC'S dispatchable and non-dispatchable DSM programs as approved by the Florida Public Service Commission.

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. This forecast assumes an increase of 6 MW of self-service capacity by a large phosphate customer. Supplemental load is defined as the cogeneration customers' total load 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.

7. The economic outlook for this 20 year forecast attempts to describe 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

The basis for the customer, energy, and demand forecasts during the first five years of this twenty year forecast reflects a soft landing from the strong growth in economic activity experienced in 1993 and 1994. During those years seven consecutive interest rate hikes by the Federal Reserve Board (FED) began to constrain growth in the national economy in a bid to restrain inflationary pressures. Recent declines in interest rates have been influenced by slackening growth in the national economy, which slowed significantly during the first half of

1995. The FED has been trying to attain a natural rate of Gross Domestic Product (GDP) growth of 2.5 percent -- far lower than the torrid rate experienced in 1994. It is assumed that interest rates have peaked for the current business cycle and will remain at the lower second quarter of 1995 level for the remainder of 1995 and 1996. No economic recession is predicted for the short-term forecast horizon, but growth will be lower than that experienced in 1993-1994. Federal government efforts to balance the federal budget will place downward pressure on interest rates in the next few years. A streamlined Federal government will lessen the demand for credit in the marketplace, thereby reducing the so called "crowding-out" effect. This is expected to aid home building as well as other capital intensive industries.

Personal income growth is expected to continue to increase, but not at the pace experienced in recent years. As interest rates fall, so will the return on interest-bearing accounts, and, correspondingly, income levels of Florida retirees. Employment growth will moderate from the strong pace experienced over the past two years, resulting in reduced growth in total wages. The strong employment growth in the service sector will continue. Export-related job growth is also expected to fare well in the year ahead. The weak dollar will encourage American exports, as well as attract more foreign tourists to Florida.

The cost of electricity is projected to decline in real dollar terms, which will result in greater average use by retail customers. Also contributing to this trend, according to home builders' surveys, is the demand for larger living quarters and increased median square footage in new construction of homes and apartments. Bigger areas mean greater central air conditioning use, and this, along with increased use of washers and dryers in multi-family dwellings, will boost average electricity consumption per customer.

LONG-TERM

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 1990s 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 moving to Florida. Second, the enormous growth in population and corresponding development of the 1980s made portions of Florida less desirable for retirement living. This diminished quality of retiree life, along with increasing competition from neighboring states for the retirement population, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

- o 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. Coupling this with two other events of the 1980s -- airline deregulation that lowered airfares, thereby increasing accessibility to Florida, and a recession in the oil-producing states that historically pulled a percentage of their labor pools from Florida -- one begins to realize that these conditions will not recur in the foreseeable future. In fact, slower population in-migration to Florida can be expected as the baby boom generation enters the 40's and 50's age bracket. This age group has been significantly characterized as immobile when studies concerning interstate population flows or job changes are conducted.

Economic Growth Trends

- o Florida's rapid population growth of the 1980s created a period of strong job creation, especially in the service sector industries of the state economy. While the service-oriented economy expanded to support the 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. Of long-term concern, however, is the passage of the North American Free Trade Agreement (NAFTA). At risk here is the by-passing 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 prices. 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 per capita personal incomes are assumed to increase throughout the forecast period and thereby boost 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 cost of electricity, consumer ability to make additional purchases of electricity will improve.

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 long-term forecast.

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), Blue Chip Economic Indicators, and the University of Florida's Bureau of Economic and Business Research. 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 short-term energy 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 each sales month. This equation significantly captures short-term movements in customer usage. Projections of KWh usage per customer combined with the customer forecast provides 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 population projections are developed by the University of Florida's BEBR.

Commercial Sector

Short-term commercial KWh use per customer is forecast based on commercial (non-agricultural, non-manufacturing and non-governmental) employment, the average number of billing days each 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 dissimilar behavior patterns 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 the industrial energy use, 32 percent in 1995, 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 68 percent of total industrial class sales. Both groups are impacted by changes in short-term economic activity. However, adequately explaining this behavior 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 which lacks a significant automotive manufacturing sector.

The industrial phosphate energy sales sub-sector is modeled using phosphate mining employment and the real industrial price of electricity. Since this sub-sector is comprised of only five customers, model results are heavily supplemented with information received from direct customer contact. FPC industrial customer representatives provide 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 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, 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. Monthly government employment has been determined to be the best indicator of the level of government services provided. This variable, along with heating and cooling degree days 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 months of January, July and August.

Sales For Resale Sector

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

Seminole Electric Cooperative, Incorporated is a wholesale, or sales for resale, customer of FPC on a supplemental contract basis. FPC provides service within a contractual framework for those energy requirements above the level of generation capacity served by SECI's own facilities or firm purchase obligations. SECI provides FPC with a forecast of monthly supplemental 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 resources. Beyond supplemental service, FPC has signed a bulk power agreement with SECI for intermediate and peaking generation. From the forecaster's standpoint, this contract has two pieces that impact the load and energy forecast directly. First, a 455 MW structured capacity contract beginning in 1999 and ending in 2001 is incorporated in the forecast. An option to extend this sale for seven additional years beginning in 2002 (upon proper notification) exists in the contract, but is not assumed in this forecast. Second, the remaining 150 MW piece of the contract involves the sale of intermediate capacity on a long-term basis that is assumed to be served throughout the forecast horizon. Monthly projections of demand and energy were supplied to FPC by SECI.

A second bulk power contract customer is Oglethorpe Power Corporation (OPC). This customer has contracted with FPC to supplement its summer demand by 50 MW in 1997 and 275 MW in 1998.

Using information provided by the customer, it is projected that the full contracted MW amount will be required on-peak, but it will have a low load factor since this energy will be primarily used to help OPC meet summer peaking conditions. A four year contract demand agreement with Georgia Power Company (GPC) is also included in the forecast. This contract is for FPC to supply GPC summer peaking capacity of 400 MW in 1996, 300 MW in 1997, and 150 MW in both 1998 and 1999. The full amount of demand contracted is expected to be used by the customer, but with a low load factor.

The municipal sales for resale class includes a number of customer types divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each category is modeled separately in order to accurately reflect the individual profiles. The majority of customers in this class are municipalities whose full energy requirements are met by FPC. The eight full requirements 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 requirements service to three municipalities (New Smyrna Beach, Kissimmee and St. Cloud), a power authority (Florida Municipal Power Agency), a utility district (Reedy Creek Improvement District) and an investor-owned utility (Georgia Power Company). 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 forecasts for the partial requirement wholesale customers are derived using their historical coincident demand to contract demand relationship (including transmission delivery losses). The demand projections for the Florida Municipal Power Agency also include a "losses service" MW amount to account for the transmission losses FPC incurs when "wheeling" power to their service area from other suppliers.

The methodology for projecting MWh energy usage for the partial requirement (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 MWs nominated by FMPA. Average monthly to annual energy ratios are applied to the forecast in order to obtain monthly profiles.

The remaining municipal PR customers are comprised of the Reedy Creek Improvement District (RCID) and the cities of New Smyrna Beach, Kissimmee and St. Cloud. Recent growth trends and historic load factor calculations are utilized to provide the expected level of MWh sales to these cities based on the MW level and stratification (base, intermediate, peaking) of power contracted as well as the individual profile of each contract. Again, these cities 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 by FPC's Marketing and Demand-Side Management Department 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 Generation Planning Department's production costing models. These models determine the most cost-effective means to meet system requirements.

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's 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. SHAPES-PC has the capability to forecast hourly demand values for "typical" days in the year and then compute annual projections of MWh by summing the appropriate demand values.

Residential Sector

The electricity consuming units in the residential sector are major household appliances. A total of seventeen major household appliances is 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, appliance features and technologies 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 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 dis-aggregated 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 index for the 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. Future commercial electricity consumption is determined by multiplying the floor space in each of these ten building categories times the energy intensities 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. 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 comprise 98.3 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. To determine future residential customer growth or change, a regression is performed against historic growth in residential customers. 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-series 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 dis-aggregated 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 dis-aggregation technique that separates 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 peak demand (excluding interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of FPC's Load Management (LM) program. The historical values of this series are constructed to show the size of FPC's retail 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 in the service area to total system customer levels and coincident weather conditions without the impacts of year-to-year variation in load control amounts.

Demand-Side Management and load control estimates are provided by both FPC's Marketing and Demand-Side Management Department and the Generation Planning Department, and include FPC's DSM programs that have been approved by the Florida Public Service Commission. 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 and energy projection is based on their projection of demand and energy that they expect FPC to serve. For the partial requirements customers demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels. The full requirement 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 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 dis-aggregated 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 MWh energy forecast in aggregate. This model accounts for variation in Gross Domestic Product, service area population and electric price. The base forecasts for these variables were developed based on input from Data Resources Inc., the Bureau of Economic and Business Research at the University of Florida and internal company sources. 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. In addition, qualitative variables accounting for shifts in wholesale load and the total number of degree days (weather) were also incorporated into the model. The DSM forecast utilized in the high and low scenarios is assumed to be identical to the DSM forecast used in the base case.

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 scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate occurrence probability of .10. The high scenario similarly represents a bandwidth forecast with an approximate occurrence probability 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

In June 1994, FPC participated in FPSC hearings in Docket No. 930549-EG. A final order, PSC-94-1313-FOF-EG, was issued on October 25, 1994. Pursuant to this order, the FPSC approved the following DSM goals for FPC, and required that FPC submit for approval a DSM plan designed to meet the goals:

Residential Conservation Goals

Year	Cumulative Summer MW Goal	Cumulative Winter MW Goal	Cumulative GWh Goal
1994	11	43	12
1995	30	86	24
1996	50	133	38
1997	71	184	60
1998	93	236	78
1999	116	290	100
2000	140	343	127
2001	164	395	145
2002	188	445	169
2003	209	483	184

Commercial/Industrial Conservation Goals

Year	Cumulative Summer MW Goal	Cumulative Winter MW Goal	Cumulative GWh Goal
1994	0.3	0.05	2
1995	3	3	19
1996	8	7	40
1997	15	13	71
1998	24	20	110
1999	35	29	155
2000	48	39	207
2001	61	48	255
2002	74	56	299
2003	84	64	336

FPC's DSM plan was submitted to the FPSC on February 22, 1995, and approved on November 1, 1995. This plan was designed to efficiently acquire all cost-effective DSM resources necessary to meet the Commission-established goals. The DSM plan consists of four residential programs, nine commercial and industrial programs, and one research and development program. These programs were designed using the end-use measures identified during FPC's Integrated Resource Planning process. 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 community on energy efficient building design and construction, pays for the cost of duct testing on model homes, provides financial incentives for energy efficient equipment, provides an FPC "seal-of-approval" on qualifying energy efficient homes, and provides cooperative advertising to the more energy efficient developers and builders.

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.

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 lighting, 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 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. Incentives will be provided for high efficiency HVAC equipment, motors, heat recovery units, and duct leakage testing and repair.

Energy Monitor Program

This program will assist customers in managing their energy use by providing services to improve the operation and maintenance (O&M) of building and process systems. FPC will provide four types of O&M services -- energy accounting, load monitoring, commissioning assistance, and energy project assistance -- each with its own fee schedule for services.

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 (Rate Schedule GSLM-2)

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 (Rate Schedule IS-1)

This direct load control program 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 qualified non-residential customer who is willing to have their power interrupted. FPC will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. Customers participating in the Interruptible Service program receive a monthly interruptible demand credit based on their billing demand.

Curtailable Service (Rate Schedule CS-1)

This direct load control program 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 qualified non-residential customer who is willing to curtail the greater of 25 KW or 25 percent of their average annual billing demand. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit based on their curtailable demand amount.

Research and Development Program

Technology Development Program

The 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 Administrative Code). FPC will undertake certain development and demonstration projects which 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.

Low Income Pilot

FPC will pilot and evaluate a customized DSM program targeted toward the low income market segment as one of the first projects to be implemented under the Technology Development Program. The low income pilot will be initiated in early 1996 as FPC begins working with the Florida Department of Community Affairs (DCA) and local weatherization providers to develop an integrated delivery of weatherization and Rate Impact Measure (RIM) cost-effective DSM services by weatherization providers.

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CHAPTER 3

Forecast of FACILITIES REQUIREMENTS

CHAPTER 3 Forecast of FACILITIES REQUIREMENTS

INTEGRATED RESOURCE PLANNING OVERVIEW

Florida Power Corporation employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of generation and Demand-Side Management programs that will reliably satisfy our customer's future energy needs as required by the Energy Policy Act of 1992 (EPACT).

FPC's IRP process incorporates state-of-the-art computer hardware and models to evaluate future generation alternatives and cost-effective conservation and dispatchable demand-side management programs on a consistent and integrated basis. Integrated resource planning involves a wide diversity of departments and company resources. A full range of generation and demand side alternatives are considered for incorporation into the company's resource mix. The IRP process is carried out in full or in part every few years. This allows the company the flexibility to re-evaluate resources that are in the current plan prior to their construction or implementation, and to evaluate the addition of new resources not previously examined.

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 is 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 that meets the company's reliability criteria. This is called the Integrated Optimal Plan. This plan is then evaluated within the company's financial model to determine its effect on the overall financial health of the corporation. The current 1996 Ten-Year Site Plan involves a modified IRP process which incorporates the DSM Goals established in the 1994 Conservation Goals Hearings prior to supply-side evaluations. This process is discussed further in the section titled 1996 Ten-Year Site Plan Modified IRP Process.

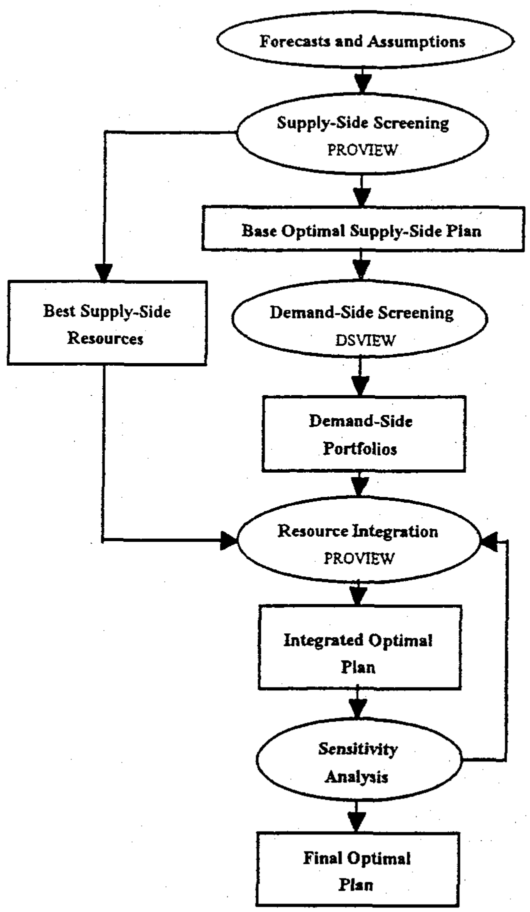


Figure 1

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 and begin 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.

FPC plans its resources to meet dual reliability criteria of 15 percent reserve margin over forecasted firm peak demand and 0.1 days per year 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. The 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.

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. Resource options are "pre-screened" to set aside those that do not warrant a detailed costeffectiveness 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 combinations of future resource additions which meet system reliability criteria and other system constraints. All resource plans are then ranked by system revenue requirements. Multiple optimization runs may be required to screen a large selection of future resource additions. The screening process proceeds until all of the alternatives that are left can be evaluated in a single optimization run. The final optimization run then produces an optimal supply-side resource plan which is called the "Base Optimal Supply-Side Plan."

Demand-Side Screening:

Like supply-side resources, data about large numbers of potential demand-side resources is collected. These resources are "pre-screened" to eliminate those alternatives that are still in research and development, addressed by other regulation (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 as the basis for screening future demand-side resources. The future supply-side alternatives that are selected for the base optimal supply-side plan are the stream of avoidable units that future demand-side programs are screened against. Each future demand-side alternative is individually added to the base optimal supply-side plan and the amount of generation in the plan is reduced to equalize the reliability between the cases. The system is then re-dispatched over the ten year planning period. Comparison of this case, with the demand-side program included, to the base optimal supply-side plan is used 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 into portfolios. Portfolios of DSM programs are considered together, rather than individually, in the integration process that follows. This is necessary to reduce the number of possible future scenarios and make the optimization solvable with the computing resources available.

Resource Integration and Final Optimal Plan:

The cost-effective generation alternatives as determined by the supply-side screening and the demand-side portfolios developed in the demand-side screening process are optimized together to formulate an integrated optimal plan. The optimization program considers all possible future mixes of supply-side and demand-side alternatives that meet the company's reliability criteria in each year over a ten year period. The economic operation of each future scenario is additionally evaluated over forty years. The program will again consider many tens or hundreds of thousands of combinations, and report those that provide the lowest rates to FPC's ratepayers.

The plan that provides the lowest rates is further tested using sensitivity analysis. The economics of the plan are evaluated under high and low forecast scenarios to ensure that the plan does not unduly burden the company or the ratepayers if the future unfolds in a way very different from the base forecast. If the plan is judged robust under sensitivity analysis, it becomes the final optimal plan.

The final optimal plan passes from the optimization process to the company financial model. It is evaluated to ensure that the company can finance it adequately and that it will not have a detrimental impact on the company's stock or bond rating. A plan that has a detrimental impact on the company's financial health will be returned to the integration process. At this point, it may be necessary to re-assess part of the screening process, or it may only be necessary to repeat the integration and sensitivity analyses with appropriate constraints included.

1996 TEN-YEAR SITE PLAN MODIFIED IRP PROCESS

FPC's 1996 Ten-Year Site Plan Demand-Side Management projections are consistent with the late 1994 results of the FPSC Conservation Goals Hearing. FPC's DSM goals projections were integrated as a group prior to determining the supply-side expansion plan. The DSM Goals and the supply-side plan were then combined to form the optimal plan. The 1996 IRP process was modified slightly by projecting the DSM expansion plan prior to supply-side evaluations to ensure consistency with FPC's DSM goals. This process will be reviewed periodically to balance the impacts of the DSM goals on the IRP process and future resources.

1996 IRP RESULTS

Future DSM requirements were projected based on the DSM goals for residential and commercial/industrial customers as established in the 1994 Conservation Goals Hearings. Future DSM requirements are summarized in the following tables.

Residential Conservation Goals

Year	Cumulative Summer MW Goal	Cumulative Winter MW Goal	Cumulative GWh Goal
1994	11	43	12
1995	30	86	24
1996	50	133	38
1997	71	184	60
1998	93	236	78
1999	116	290	100
2000	140	343	127
2001	164	395	145
2002	188	445	169
2003	209	483	184

Commercial/Industrial Conservation Goals

Year	Cumulative Summer MW Goal	Cumulative Winter MW Goal	Cumulative GWh Goal
1994	0.3	0.05	2
1995	3	3	19
1996	8	7	40
1997	15	13	71
1998	24	20	110
1999	35	29	155
2000	48	39	207
2001	61	48	255
2002	74	56	299
2003	84	64	336

FPC's DSM programs include load management and interruptible loads to defer new capacity additions. These resources are shown on Forms 7A and 7B.

FPC has made a substantial commitment to include cogeneration into its resource mix. The company has contracted for over 1,100 MW of capacity provided by Qualifying Facilities (QF), which represents a significant portion of the state-wide QF capacity available. The following table shows FPC's contracts for firm capacity provided by QFs.

FLORIDA POWER CORPORATION
QUALIFYING FACILITY GENERATION CONTRACTS
AS OF DECEMBER 31, 1995

FACILITY NAME	LOCATION (COUNTY)	TYPE	FUEL TYPE	CONTRACT START DATE (MO/YR)	FIRM CAPACITY - MW
BAY COUNTY RES. RECOV.	BAY	SPP	MSW	04/1988	11.0
CARGILL	POLK	COG	WH	10/1992	15.0
CFR-BIOGEN	POLK	COG	NG	06/1995	74.0
DADE COUNTY RES. RECOV.	DADE	SPP	MSW	11/1991	43.0
ECOPEAT	POLK	COG	NG	07/1995	40.2
EL DORADO	POLK	COG	NG	07/1994	114.2
GENERAL PEAT 1	POLK	COG	NG	01/1995	57.2
GENERAL PEAT 2	POLK	COG	NG	01/1995	57.2
GENERAL PEAT 3	POLK	COG	NG	01/1995	57.2
LAKE COGEN	LAKE	COG	NG	07/1993	110.0
LAKE COUNTY RES. RECOV.	LAKE	SPP	MSW	01/1995	12.8
LFC JEFFERSON	POLK	COG	NG	01/1995	8.5
LFC MADISON	POLK	COG	NG	01/1995	8.5
MULBERRY	POLK	COG	NG	07/1994	79.2
ORLANDO COGEN	ORANGE	COG	NG	10/1993	79.2
* PANDA KATHLEEN	POLK	COG	NG	01/1997	74.9
PASCO COGEN	PASCO	COG	NG	07/1993	109.0
PASCO COUNTY RES. RECOV.	PASCO	SPP	MSW	01/1995	23.0
PINELLAS COUNTY RES. RECOV. 1	PINELLAS	SPP	MSW	01/1995	40.0
PINELLAS COUNTY RES. RECOV. 2	PINELLAS	SPP	MSW	01/1995	15.8
PINELLAS COUNTY RES. RECOV. 3	PINELLAS	SPP	MSW	01/1999	40.0
RIDGE GENERATING STATION	POLK	SPP	BIO	05/1994	39.6
ROYSTER	POLK	COG	NG	07/1994	30.8
TIMBER ENERGY 1	LIBERTY	SPP	BIO	04/1992	12.8
TIMBER ENERGY 2	POLK	COG	NG	01/1995	6.0
US AGRICHEM	POLK	COG	WH	01/1997	5.1

* DISPUTES EXIST WITH PANDA KATHLEEN WHICH MAKE THE TIMING OF THIS PROJECT UNCERTAIN.

FPC has long-term contracts for approximately 460 MW of firm purchased power with other utilities, including a contract with Southern Company for approximately 400 MW of purchased power through 2010. The remaining firm purchased power is from Tampa Electric Company and will be supplied through 2011.

Changes in FPC's existing resources (shown on Form 6, page 1) include a 19 MW upgrade of capacity at Crystal River 3, peaking gas conversions at Intercession City P8 and P10, and plant retirements consistent with FPC's latest plant Depreciation and Dismantlement filing. This plant Depreciation and Dismantlement filing includes 158 MW and 276 MW of combustion turbine retirements in years 2003 and 2004, respectively. Consideration for potential life extensions of these facilities will be included in future Depreciation and Dismantlement and IRP studies.

FPC capacity additions currently under construction include a 165 MW combustion turbine at the Intercession City (IC) site which is scheduled to be in-service by September 1996 and a 470 MW combined cycle plant at the Polk County site scheduled for November 1998. These two units are included on Form 6, page 2. The combustion turbine unit at IC incorporates a unique ownership arrangement between FPC and Georgia Power. FPC owns two-thirds of the unit and Georgia Power one-third. The output of the unit will be available to FPC from October through May of each year, and to Georgia Power June through September. Thus, the ratepayers of both companies will derive the maximum benefit from the unit's capacity, since it is available to each company at their time of highest need. Combined cycle generation will be added at the Polk County site in 1998 and will be owned by FPC. This generation will be a high efficiency combined cycle plant of approximately 470 MW fueled by natural gas with distillate oil back-up. The in-service date of this plant is scheduled for November of 1998. The Polk County unit will be one of the most efficient combined cycle plants in the nation.

The remaining resources shown on Form 6, page 2, are considered to be planned supply-side resource additions. Included in the planned supply-side resource additions are combined cycles (CC) fueled by natural gas and combustion turbines fueled by interruptible gas and distillate oil. The combined cycle plants are repowering projects at FPC's Turner and Higgins sites. Capacity additions proposed for 2003 are a 165 MW combustion turbine (with interruptible gas) and a 249 MW CC repowering of Turner Unit 3. Capacity additions proposed for 2004 include a 249 MW CC repowering of Turner Unit 4 and a 249 MW CC repowering of the Higgins plant. The final capacity addition is a 165 MW combustion turbine (fueled by distillate) in 2005. FPC's expansion plan over the next ten years meets or exceeds FPC's reliability criteria and complies with the 1990 Clean Air Act Amendments. FPC's Forecast of Demand and Capacity for the summer and winter peaks are shown on Forms 7A and 7B, respectively.

FPC's proposed future bulk transmission line additions are shown below.

FLORIDA POWER CORPORATION
LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS
1996-2005

LINE OWNERSHIP	TERMINALS	TERMINALS	LINE LENGTH CKT. MILES	COMMERCIAL IN-SERVICE DATE (MO/YR)	NOMINAL OPERATING VOLTAGE
FPC	BARCOLA #1	POLK GEN	3	12/1997	230
FPC	FORT MEADE	POLK GEN	6	12/1997	230
FPC	POLK GEN	TIGER BAY	4	12/1997	230
FPC	FORT MEADE	TIGER BAY	2	12/1997	230
FPC	SILVER SPRINGS NORTH	SILVER SPRINGS #3	6	06/1998	230
FPC	LAKE BRYAN	INTERCESSION CITY	10	05/2000	230
FPC	CENTRAL FLORIDA	SILVER SPRINGS	3	05/2002	230
FPC	TAYLOR CREEK	HOLOPAW	1	11/2002	230
FPC	TURNER	DEBARY	3	12/2003	230
FPC	TURNER	LAKE EMMA	3	12/2003	230
FPC	WINDERMERE	LAKE BRYAN	10	12/2003	230
FPC	INTERCESSION CITY	GIFFORD	12	11/2004	230
FPC	ULMERTON	HIGGINS	10	05/2005	230

FLORIDA POWER CORPORATION

EXISTING GENERATING CAPABILITY CHANGES AND REMOVALS

(JANUARY 1, 1996 THROUGH DECEMBER 31, 2005)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRIMARY FUEL		ALTERNATE FUEL			GENERATOR	NET CAPABILITY MW			
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	COMMERCIAL IN-SERVICE (MO/YR)	MAXIMUM NAMEPLATE KW	SUMMER	WINTER	STATUS	NOTES
CRYSTAL RIVER	3	CITRUS CO.	NP	UR				05/1996		17	19	A	
INTER. CITY	P8	OSCEOLA CO.	GT	F02	PL	NG	PL	05/1996				FC	1
INTER. CITY	P10	OSCEOLA CO.	GT	F02	PL	NG	PL	05/1996				FC	1
HIGGINS	P1-4	PINELLAS CO.	GT	F02	TK	NG	PL	(12/2003)		(128)	(158)	RE	2
PORT ST. JOE	P1	GULF CO.	GT	F02	TK			(12/2003)		(15)	(18)	RE	2
RIO PINAR	P1	ORANGE CO.	GT	F02	TK			(12/2003)		(15)	(18)	RE	2
AVON PARK	P1-2	HIGHLANDS CO.	GT	F02	TK	NG	PL	(12/2004)		(58)	(64)	RE	2
BAYBORO	P1-4	PINELLAS CO.	GT	F02	WA			(12/2004)		(188)	(232)	RE	2
TURNER	P1-2	VOLUSIA CO.	GT	F02	TK,WA			(12/2004)		(30)	(36)	RE	2

NOTES :

1 / FUEL CONVERSION TO NATURAL GAS

2 / RETIREMENT DATES AND CAPACITIES ARE IN PARENTHESES AND ARE CONSISTENT WITH THE LATEST PLANT DEPRECIATION AND DISMANTLEMENT FILING. CONSIDERATION FOR POTENTIAL LIFE EXTENSIONS OF THESE FACILITIES WILL BE INCLUDED IN FUTURE DEPRECIATION AND DISMANTLEMENT AND IRP STUDIES.

FLORIDA POWER CORPORATION

FUTURE GENERATING CAPABILITY UNDER CONSTRUCTION AND PLANNED

(JANUARY 1, 1996 THROUGH DECEMBER 31, 2005)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				PRIMARY FUEL		ALTERNATE FUEL			GENERATOR	NET CAPABILITY MW			
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	FUEL TYPE	TRANSP. METHOD	FUEL TYPE	TRANSP. METHOD	COMMERCIAL IN-SERVICE (MO/YR)	MAXIMUM NAMEPLATE KW	SUMMER	WINTER	STATUS	NOTES
INTER. CITY	P11	OSCEOLA CO.	GT	F02	PL			08/1996		135	165	V	1,2
POLK COUNTY	1	POLK CO.	CC	NG	PL	F02	TK	11/1998		474	507	U	1
COMB. TURBINE	P1	UNKNOWN	GT	F02	UN	NG	PL	11/2003		135	165	P	
TURNER	3	VOLUSIA CO.	CC	NG	PL	F02	TK,WA	11/2003		212	249	RP	
TURNER	4	VOLUSIA CO.	CC	NG	PL	F02	TK,WA	11/2004		212	249	RP	
HIGGINS	1-3	PINELLAS CO.	CC	NG	PL	F02	WA	11/2004		212	249	RP	
COMB. TURBINE	P2	UNKNOWN	GT	F02	UN			11/2005		135	165	P	

NOTES :

1 / UNDER CONSTRUCTION

2 / SUMMER CAPABILITY OWNED BY GEORGIA POWER COMPANY.

FLORIDA POWER CORPORATION

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
TOTAL PEAK DEMAND	7,837	7,945	8,244	8,481	8,519	8,742	8,558	8,770	8,980	9,186
INTERRUPTIBLE LOAD	314	317	328	370	373	376	340	343	346	350
LOAD MANAGEMENT *	639	659	679	699	719	741	761	778	801	815
QF LOAD SERVED BY QF GEN	72	72	72	72	72	72	72	72	72	72
CONSERVATION	168	183	199	218	238	255	271	287	303	320
FIRM PEAK DEMAND	6,644	6,714	6,966	7,122	7,117	7,298	7,114	7,290	7,458	7,629
GENERATION CAPACITY	6,788	6,788	6,788	7,262	7,262	7,262	7,262	7,262	7,451	7,599
QF CAPACITY PURCHASE	1,044	1,105	1,105	1,115	1,115	1,115	1,115	1,115	1,115	1,115
FIRM PURCHASE POWER (INTER-STATE)	409	409	409	409	409	409	409	409	409	409
FIRM PURCHASE POWER (INTRA-STATE)	50	50	50	60	60	60	60	60	60	70
TOTAL CAPACITY RESOURCE	8,291	8,352	8,352	8,846	8,846	8,846	8,846	8,846	9,035	9,193
RESERVE MARGIN BEFORE MAINT. (MW)	1,647	1,638	1,386	1,724	1,729	1,548	1,732	1,556	1,577	1,564
RESERVE MARGIN BEFORE MAINT. (%)	25%	24%	20%	24%	24%	21%	24%	21%	21%	21%
SCHEDULED MAINTENANCE	0	0	0	0	0	0	0	0	0	0
NET CAPACITY RESOURCE	8,291	8,352	8,352	8,846	8,846	8,846	8,846	8,846	9,035	9,193
RESERVE MARGIN AFTER MAINT. (MW)	1,647	1,638	1,386	1,724	1,729	1,548	1,732	1,556	1,577	1,564
RESERVE MARGIN AFTER MAINT. (%)	25%	24%	20%	24%	24%	21%	24%	21%	21%	21%

* LOAD MANAGEMENT = TOTAL OF LOAD CONTROL PROGRAMS : LOAD MANAGEMENT, HEATWORKS & VOLTAGE REDUCTION.

FLORIDA POWER CORPORATION

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF WINTER PEAK

	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/0
TOTAL PEAK DEMAND	9,007	9,249	9,841	10,065	10,321	10,116	10,357	10,597	10,838	11,07
INTERRUPTIBLE LOAD	317	328	370	373	376	340	343	346	350	35
LOAD MANAGEMENT *	1,116	1,151	1,183	1,220	1,257	1,293	1,327	1,350	1,381	1,41
QF LOAD SERVED BY QF GEN	72	72	72	72	72	72	72	72	72	7
CONSERVATION	214	232	255	278	299	319	339	357	378	40
FIRM PEAK DEMAND	7,288	7,466	7,961	8,122	8,317	8,092	8,276	8,472	8,657	8,837
GENERATION CAPACITY	7,531	7,531	8,038	8,038	8,038	8,038	8,038	8,258	8,424	8,589
QF CAPACITY PURCHASE	1,105	1,105	1,115	1,115	1,115	1,115	1,115	1,115	1,115	1,115
FIRM PURCHASE POWER (INTER-STATE)	409	409	409	409	409	409	409	409	409	409
FIRM PURCHASE POWER (INTRA-STATE)	50	50	60	60	60	60	60	60	70	70
TOTAL CAPACITY RESOURCE	9,095	9,095	9,622	9,622	9,622	9,622	9,622	9,842	10,018	10,183
RESERVE MARGIN BEFORE MAINT. (MW)	1,807	1,629	1,661	1,500	1,305	1,530	1,346	1,370	1,361	1,346
RESERVE MARGIN BEFORE MAINT. (%)	25%	22%	21%	18%	16%	19%	16%	16%	16%	15%
SCHEDULED MAINTENANCE	0	0	0	0	0	0	0	0	0	0
NET CAPACITY RESOURCE	9,095	9,095	9,622	9,622	9,622	9,622	9,622	9,842	10,018	10,183
RESERVE MARGIN AFTER MAINT. (MW)	1,807	1,629	1,661	1,500	1,305	1,530	1,346	1,370	1,361	1,346
RESERVE MARGIN AFTER MAINT. (%)	25%	22%	21%	18%	16%	19%	16%	16%	16%	15%

* LOAD MANAGEMENT = TOTAL OF LOAD CONTROL PROGRAMS : LOAD MANAGEMENT, HEATWORKS & VOLTAGE REDUCTION.

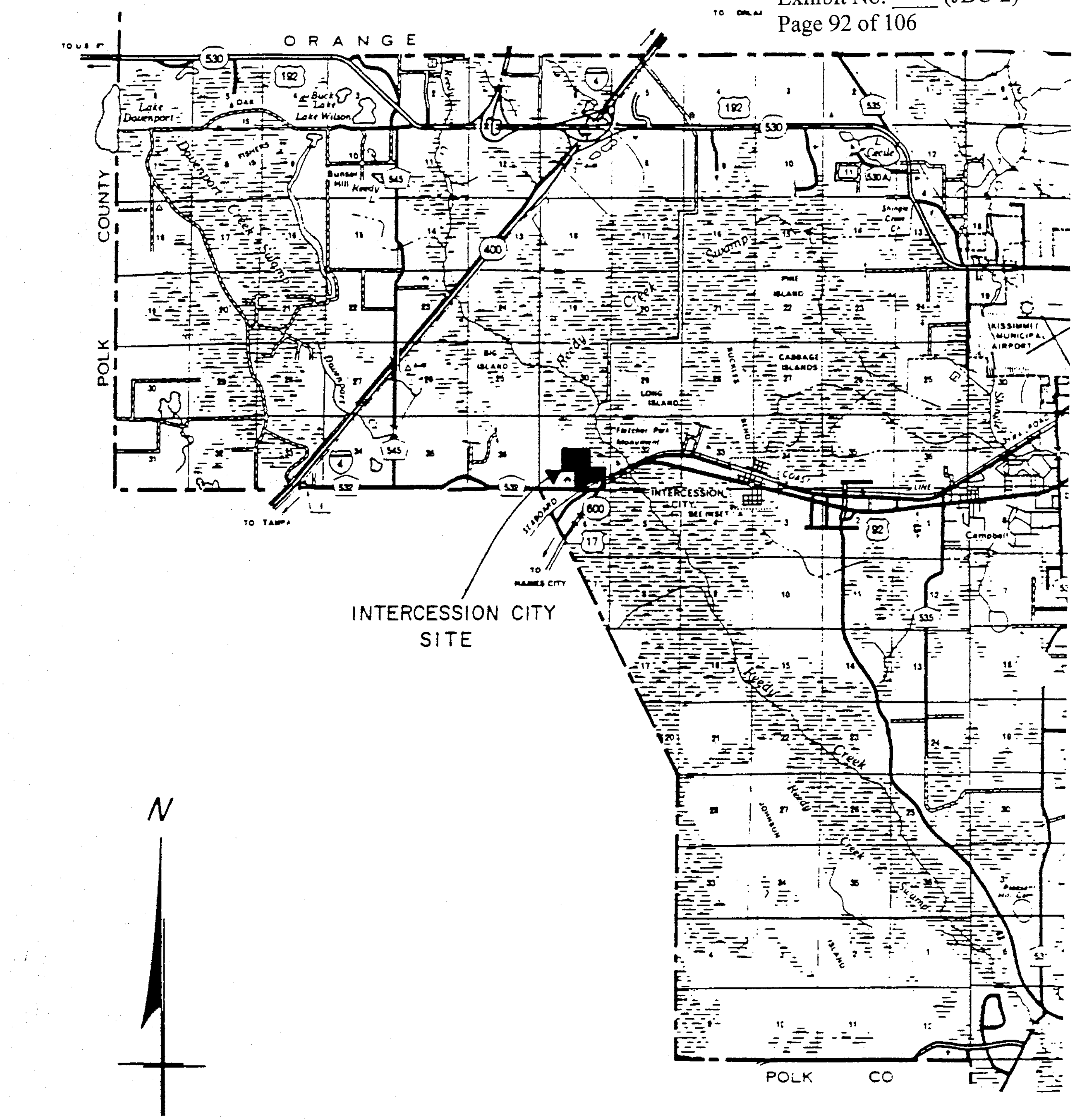
CHAPTER 4

Description and Impact Analysis of SITE AND FACILITY

CHAPTER 4 Description and Impact Analysis of SITE AND FACILITY

INTERCESSION CITY SITE:

Intercession City was chosen as the primary site for installation of a combustion turbine peaking unit addition by September 1996. The seasonal ratings for the Intercession City capacity addition are projected to be 135 MW summer (dedicated to service for Georgia Power) and 165 MW winter (dedicated to service for FPC). 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 grid will accommodate this combustion turbine addition. A status report for specifications of proposed generating facilities is shown on Form 8A, page 1 for Intercession City Peaking Unit #11.



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	BY	DATE

POLK COUNTY SITE:

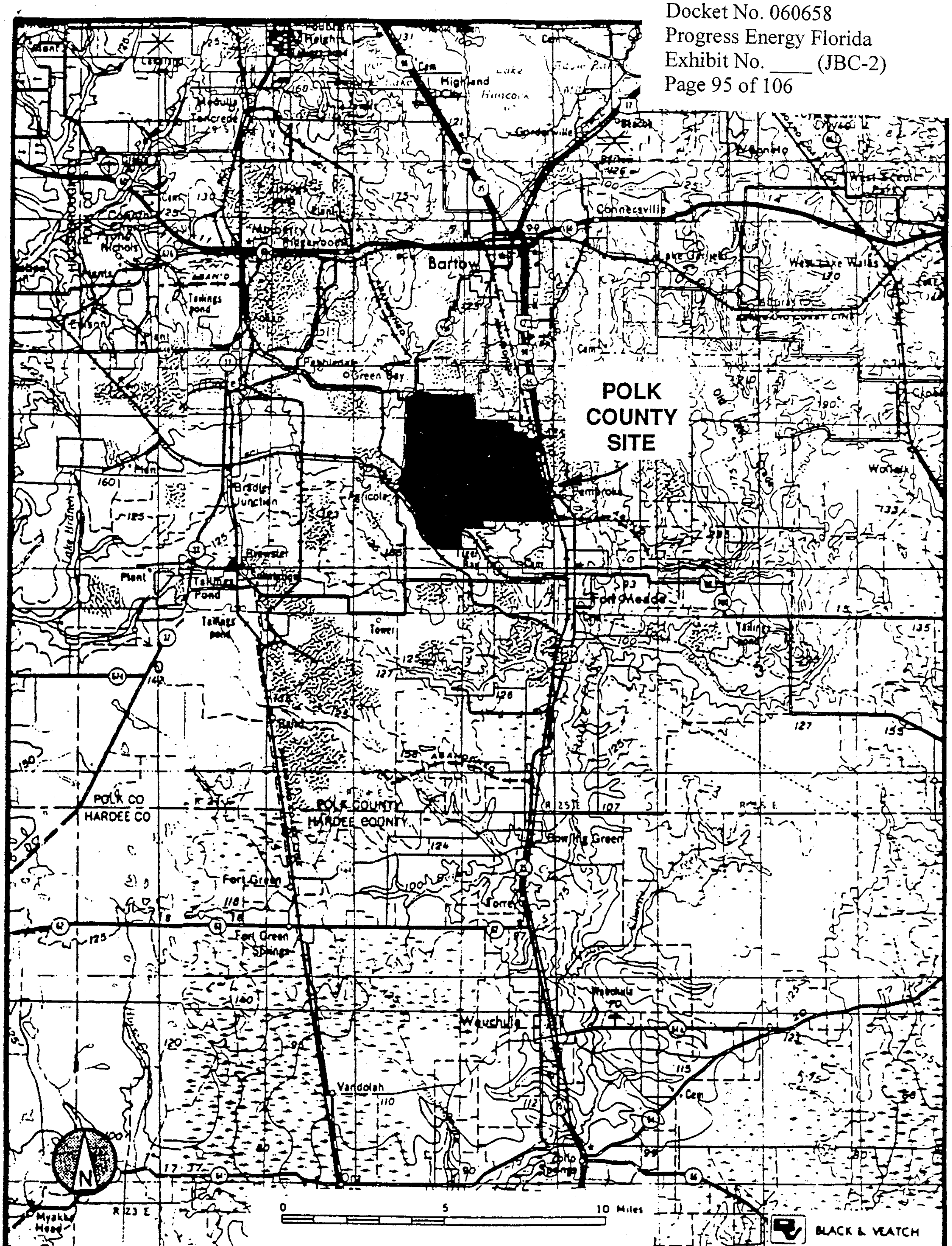
In 1990, FPC completed a state-wide search for a new 3,000 MW coal capable power plant site. As a result of this work, a large tract of mined out phosphate land in south-central Polk County was selected as the primary alternative. This 8,200 acre site is located near the cities of Fort Meade and Homeland,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

Site certification was approved by the governor and cabinet 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 generation units are added, the extensive 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. The site is serviced by an industrial rail network and an adequate road system.

Construction of site improvements began in October 1994. The first combined cycle unit, with a capacity of 470 MW, is scheduled for commercial operation by November 1998. A status report for specifications of proposed generating facilities is shown on Form 8A, page 2 for Polk County Unit #1.

The transmission improvements associated with the first unit at this site are the rebuilding of the existing 230/115 kV double circuit Barcola - Ft. Meade line by increasing the conductor sizes and converting the line to double circuit 230 kV operation. The new lines will be relocated on the plant site to clear plant facilities, and looped into the plant substation. (Form 8B, pages 1 and 2.)



POLK COUNTY SITE

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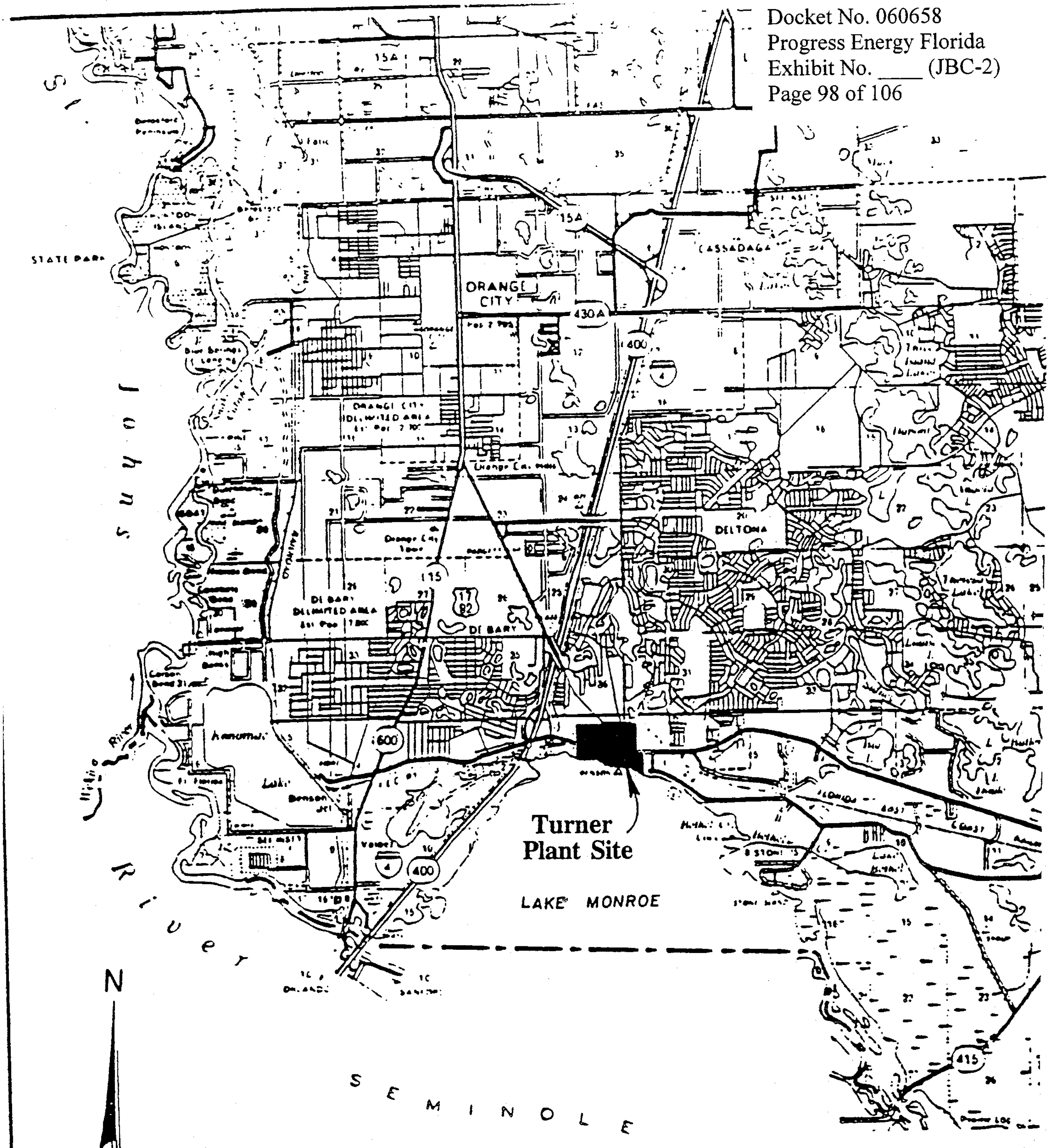
TURNER PLANT SITE:

The Turner Plant Site consists of approximately 117 acres in Deltona (on Lake Monroe) in Volusia County (reference DWG IV-3). The George E. Turner Fossil Steam Plant is currently in extended cold shutdown.

FPC expects to repower this facility using natural gas as the primary fuel. Turner has an existing metering station and is connected to the Florida Gas Transmission system. No. 2 Fuel Oil, for which there is already delivery and storage equipment at Turner, will serve as the backup fuel. The planned repowering at Turner will use two combustion turbine/HRSG trains to feed steam to the existing steam turbines for units 3 and 4. The resulting total net dependable capability is expected to be approximately 498 MW.

Environmental permits for Turner Plant will be maintained. The Florida Department of Environmental Protection air rules currently list Turner Plant in an area designated as attainment. FPC will coordinate closely with regulatory agencies to ensure compliance with all applicable environmental regulations. (Individual permits will be obtained and/or modified as necessary.)

The transmission improvement associated with the Turner repowering is a loop of the 230 kV DeBary - Lake Emma line into Turner Plant. (Form 8B, page 3.)



PRODUCTION ENGINEERING DEPARTMEN

PARTIAL AREA MAP
VOLUSIA CO. FL.

DRAWN BY B.Whiteside	DATE 2-21-86	SCALE
CHECKED BY	DATE	DISCIPLINE
APPROVED BY	DATE	PLANT/UNIT
DATA PROCESS NO.		SHEET
DWG. NO. III - 3		

Florida Power Corporation

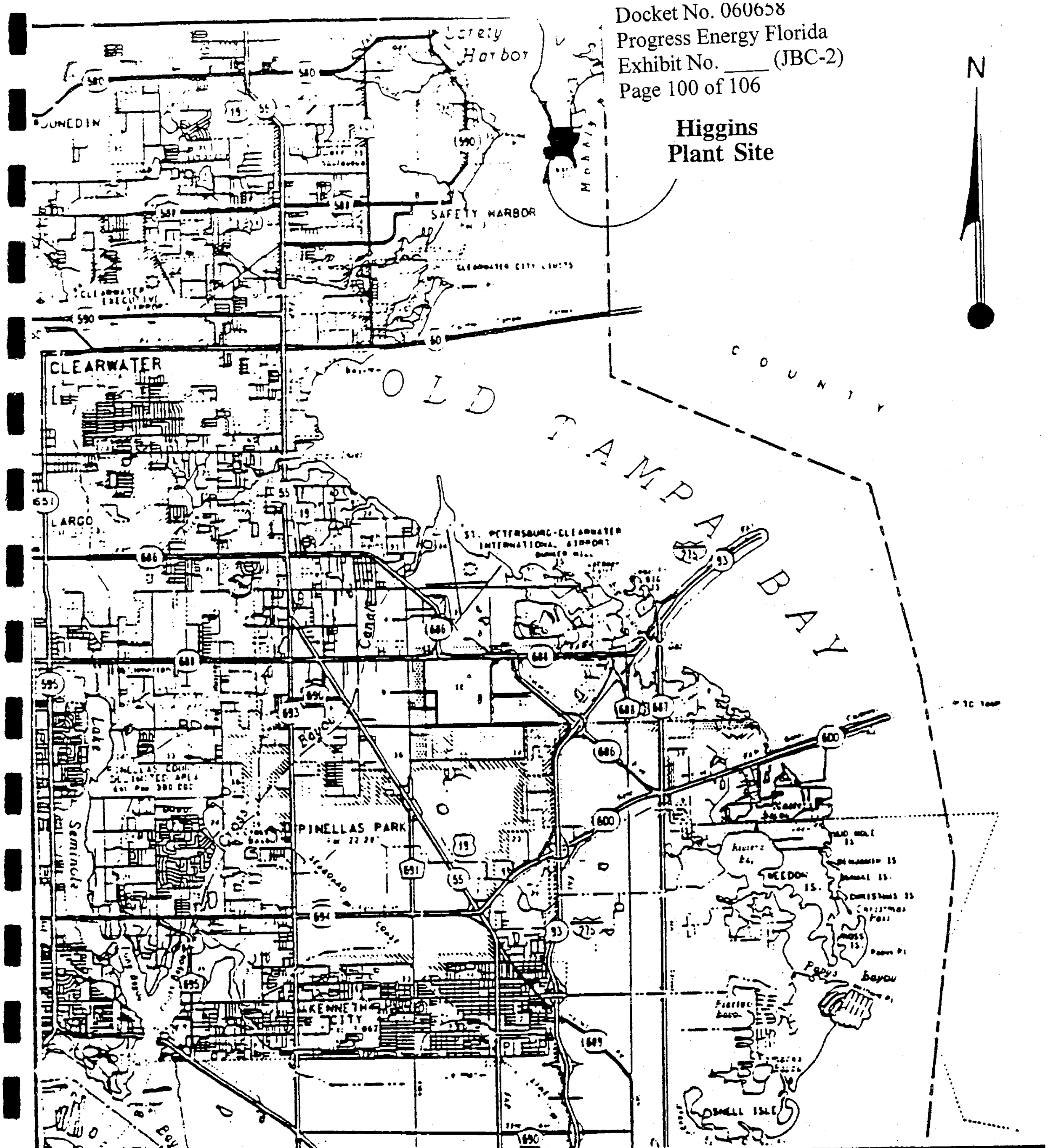
HIGGINS PLANT SITE:

The Higgins Plant Site consists of approximately 142 acres in Oldsmar (on Tampa Bay) in Pinellas County (reference DWG IV-2). The A. W. Higgins Fossil Steam Plant is currently in extended cold shutdown.

FPC expects to repower this facility using natural gas as the primary fuel. Higgins has an existing metering station and is connected to the Florida Gas Transmission system. No. 2 Fuel Oil, for which there is already delivery and storage equipment at Higgins, will serve as the backup fuel. The planned repowering at Higgins will be accomplished utilizing two of the existing three steam turbines. The repowering will utilize one combustion turbine/Heat Recovery Steam Generator (HRSG) combination to feed steam to two of the existing three steam turbines. The third steam turbine may be utilized as an operational or standby spare turbine. The resulting total net dependable capability is expected to be approximately 249 MW.

Environmental permits for Higgins Plant will be maintained. The Florida Department of Environmental Protection (DEP) air rules currently list Higgins Plant in an area designated as non-attainment for ozone, but is expected to be redesignated as attainment. DEP will develop a maintenance plan once this happens. FPC will coordinate closely with regulatory agencies to ensure compliance with all applicable environmental regulations. (Individual permits will be obtained and/or modified as necessary.) The existing 230/115 kV grid can accommodate the Higgins repowering.

Docket No. 060658
Progress Energy Florida
Exhibit No. ____ (JBC-2)
Page 100 of 106



PRODUCTION ENGINEERING DEPARTMEN

PARTIAL AREA MAP
PINELLAS CO. FL.

DRAWN BY	DATE	SCALE
B. Whiteside	2/25/86	
CHECKED BY	DATE	DISCIPLINE
APPROVED BY	DATE	PLANT/UNIT
DATA PROCESS NO.		SHEET
DWG. NO.		

Florida Power Corporation

SITE AND FACILITY FORMS

The Intercession City Peaking Unit #11 is projected to be in-service by September 1996. A status report for this unit is shown on Form 8A, page 1. FPC's Polk County Unit #1 is projected to be in-service by November 1998. A status report for this unit is shown on Form 8A, page 2. Directly associated transmission lines with Polk County are shown on Form 8B, pages 1 and 2. Directly associated transmission lines with Turner Plant are shown on Form 8B, page 3.

Form 8A
Page 1 of 2

FLORIDA POWER CORPORATION

STATUS REPORT
SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	Plant Name & Unit	Intercession City P11
(2)	Status	Under Construction
(3)	Anticipated Construction Timing	Construction Start Date 10/94 Expected Commercial In-Service Date by 9/96
(4)	Capacity	Summer 135 MW (Owned by Georgia Power) Winter 165 MW
(5)	Type	Combustion Turbine
(6)	Primary and Alternate Fuel	Primary - Distillate Oil
(7)	Air Pollution Control Strategy	Water Injection
(8)	Cooling Method	Air
(9)	Total Site Area	165 Acres
(10)	Anticipated Capital Investment	$40,000,000
(11)	Certification Status	Filed 6/94 Received 7/94
(12)	Status with Federal Agencies	Environmental Protection Agency Approval Obtained 8/92

FLORIDA POWER CORPORATION

STATUS REPORT
SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	Plant Name & Unit	Polk County Unit #1
(2)	Status	Under Construction
(3)	Anticipated Construction Timing	Construction Start Date 8/95 (Cooling Pond Dams) Expected Commercial In-Service Date 11/98
(4)	Capacity	Summer 474 MW Winter 507 MW
(5)	Type	Combined Cycle
(6)	Primary and Alternate Fuel	Primary - Natural Gas Alternate - Distillate Oil
(7)	Air Pollution Control Strategy	Dry Low NO_x Combustion
(8)	Cooling Method	Cooling Ponds
(9)	Total Site Area	8,200 Acres
(10)	Anticipated Capital Investment	$300,000,000
(11)	Certification Status	Filed 8/92 Received 2/94 (DEP/EPA)
(12)	Status with Federal Agencies	Department of Environmental Protection Air Permit Approval Obtained 2/94

FLORIDA POWER CORPORATION

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

POLK COUNTY SITE

(1) Point of Origin and Termination	Polk Power Plant - Barcola Substation
(2) Number of Lines	1 (Double Circuit Construction)
(3) Right-of-Way	Existing Transmission Line & Polk Plant Site
(4) Line Length	Approximately 3 miles
(5) Voltage	230 kV
(6) Anticipated Construction Timing	Late 1997 in-service, start construction late 1996
(7) Anticipated Capital Investment	$1,800,000
(8) Substations	N/A
(9) Participation	N/A

FLORIDA POWER CORPORATION

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

TURNER PLANT SITE

(1) Point of Origin and Termination	Turner Plant to the point along the DeBary - Lake Emma 230 kV line adjacent to the DeBary - Altamonte 230 kV line structure DA-31
(2) Number of Lines	2 (230 kV loop into Turner Plant)
(3) Right-of-Way	Existing 115 kV transmission corridor
(4) Line Length	3 miles x 2 circuits
(5) Voltage	230 kV
(6) Anticipated Construction Timing	Late 2003 in-service, start construction late 2002
(7) Anticipated Capital Investment	$2,000,000 (230 kV loop into Turner Plant)
(8) Substations	Turner Plant Substation Expansion
(9) Participation	N/A

FLORIDA POWER CORPORATION

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

POLK COUNTY SITE

(1) Point of Origin and Termination	Polk Power Plant - Ft. Meade Substation
(2) Number of Lines	2
(3) Right-of-Way	Existing Transmission Line & Polk Plant Site
(4) Line Length	Approximately 6 miles
(5) Voltage	230 kV
(6) Anticipated Construction Timing	Late 1997 in-service, start construction late 1996
(7) Anticipated Capital Investment	$5,300,000
(8) Substations	N/A
(9) Participation	N/A

FLORIDA POWER CORPORATION

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1996

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				FUEL		FUEL TRANSPORT.		ALT. FUEL				NET CAPABILITY	
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALT.	PRIMARY	ALT.	DAYS USE	COMMERCIAL IN-SERVICE MONTH/YEAR	EXPECTED RETIREMENT MONTH/YEAR	GEN. MAX. NAMEPLATE KW	SUMMER MW	WINTER MW
												1,006	1,034
ANCLOTE	1	PASCO CO.	ST	F06		PL			10/1974		556,200	503	517
	2	SECT.33,34	ST	F06		PL			10/1978		556,200	503	517
		T26S,R15E											
												58	64
AVON PARK	P1	HIGHLANDS CO.	GT	F02	NG	TK	PL		12/1968	12/2004	33,790	29	32
	P2		GT	F02		TK			12/1968	12/2004	33,790	29	32
												627	666
BARTOW	1	PINELLAS CO.	ST	F06		WA			09/1958		127,500	115	117
	2	SECT.20,21,22	ST	F06		WA			08/1961		127,500	117	119
	3	T30S,R16E	ST	F06	NG	WA	PL		07/1963		239,360	208	213
	P1-4		GT	F02		WA			06/1972		222,800	187	217
												188	232
BAYBORO	P1-4	PINELLAS CO.	GT	F02		WA,TK			04/1973	12/2004	226,800	188	232
		SECT. 30											
		T31S,R17E											
												2,961	3,031
CRYSTAL	1	CITRUS CO.	ST	BIT		WA,RR			10/1966		440,550	369	373
RIVER	2	SECT.33	ST	BIT		WA,RR			11/1969		523,800	464	469
	3 *	T17S,R16E	NP	UR					03/1977		890,460	734	755
	4		ST	BIT		WA,RR			12/1982		739,260	697	717
	5		ST	BIT		WA,RR			10/1984		739,260	697	717
												656	786
DEBARY	P1-6	VOLUSIA CO.	GT	F02		TK,RR			04/1976		401,220	324	390
	P7-10	SECT.16,19-21,	GT	F02		TK,RR			11/1992		460,000	332	396
		28-30,T18S,R30E											
												128	158
HIGGINS	P1-2	PINELLAS CO.	GT	F02	NG	TK	PL		04/1969	12/2003	67,580	58	74
	P3-4	T25S,R16E	GT	F02	NG	TK	PL		12/1970	12/2003	85,850	70	84
												614	744
INTERCESSION	P1-6	OSCEOLA CO.	GT	F02		PL,TK			05/1974		340,200	282	348
CITY	P7-10	SECT. 31	GT	F02	NG	PL,TK	PL		11/1993		460,000	332	396
		T25S,R28E											
												15	18
PORT ST. JOE	P1	GULF CO.	GT	F02		TK			12/1970	12/2003	19,300	15	18
												15	18
RIO PINAR	P1	ORANGE CO.	GT	F02		TK			11/1970	12/2003	19,290	15	18
												307	348
SUWANNEE	1	SUWANNEE CO.	ST	F06	NG	TK	PL		11/1953	12/1998	34,500	33	34
RIVER	2	SECT. 26,	ST	F06	NG	TK	PL		11/1954	12/1998	37,500	32	33
	3	T1S,R11E	ST	F06	NG	TK	PL		10/1956	12/1998	75,000	80	80
	P1-3		GT	F02		TK			11/1980		183,600	162	201
												160	200
TURNER	P1-2	VOLUSIA CO.	GT	F02		TK			10/1970	12/2004	38,580	30	36
	P3-4	SECT. 1,	GT	F02		TK			08/1974		142,400	130	164
		T19S,R30E											
												36	42
UNIV. OF FLA.	P1	ALACHUA CO.	GT	NG		PL			01/1994		43,000	36	42
												6,771	7,341

* REPRESENTS 90.4 % FPC OWNERSHIP OF UNIT

FLORIDA POWER CORPORATION

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				FUEL		FUEL TRANSPORT.		ALT. FUEL DAYS				NET CAPABILITY	
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALT.	PRIMARY	ALT.	USE	COMMERCIAL IN-SERVICE MONTH/YEAR	EXPECTED RETIREMENT MONTH/YEAR	GEN. MAX. NAMEPLATE KW	SUMMER MW	WINTER MW
												1,006	1,034
ANCLOTE	1	PASCO CO.	ST	F06		PL			10/1974		556,200	503	517
	2	SECT.33,34	ST	F06		PL			10/1978		556,200	503	517
		T26S,R15E											
												58	64
AVON PARK	P1	HIGHLANDS CO.	GT	F02	NG	TK	PL		12/1968	12/2004	33,790	29	32
	P2		GT	F02		TK			12/1968	12/2004	33,790	29	32
												627	666
BARTOW	1	PINELLAS CO.	ST	F06		WA			09/1958		127,500	115	117
	2	SECT.20,21,22	ST	F06		WA			08/1961		127,500	117	119
	3	T30S,R16E	ST	F06	NG	WA	PL		07/1963		239,360	208	213
	P1, P3		GT	F02		WA			06/1972		111,400	92	106
	P2, P4		GT	F02	NG	WA	PL		06/1972		111,400	95	111
												188	232
BAYBORO	P1-P4	PINELLAS CO.	GT	F02		WA,TK			04/1973		226,800	188	232
		SECT. 30											
		T31S,R17E											
												2,961	3,031
CRYSTAL	1	CITRUS CO.	ST	BIT		WA,RR			10/1966		440,550	369	373
RIVER	2	SECT.33	ST	BIT		WA,RR			11/1969		523,800	464	469
	3 *	T17S,R16E	NP	UR		TK			03/1977		890,460	734	755
	4		ST	BIT		WA,RR			12/1982		739,260	697	717
	5		ST	BIT		WA,RR			10/1984		739,260	697	717
												656	786
DEBARY	P1-P6	VOLUSIA CO.	GT	F02		TK,RR			04/1976		401,220	324	390
	P7, P9	SECT.16,19-21,	GT	F02	NG	TK,RR	PL		11/1992		230,000	166	198
	P8, P10	28-30,T18S,R30E	GT	F02		TK,RR			11/1992		230,000	166	198
												128	148
HIGGINS	P1-P2	PINELLAS CO.	GT	F02	NG	TK	PL		04/1969	12/2003	67,580	58	64
	P3-P4	T25S,R16E	GT	F02	NG	TK	PL		12/1970	12/2003	85,850	70	84
												757	912
INTERCESSION	P1-P6	OSCEOLA CO.	GT	F02		PL,TK			05/1974		340,200	282	348
CITY	P7-P10	SECT. 31	GT	F02	NG	PL,TK	PL		11/1993		460,000	332	396
	P11	T25S,R28E	GT	F02		PL,TK			01/1997		165,000	143	168
												15	18
RIO PINAR	P1	ORANGE CO.	GT	F02		TK			11/1970	12/2003	19,290	15	18
												307	348
SUWANNEE	1	SUWANNEE CO.	ST	F06	NG	TK	PL		11/1953	04/2000	34,500	33	34
RIVER	2	SECT. 26,	ST	F06	NG	TK	PL		11/1954	04/2000	37,500	32	33
	3	T1S,R11E	ST	F06	NG	TK	PL		10/1956	04/2000	75,000	80	80
	P1		GT	F02	NG	TK	PL		11/1980		61,200	54	67
	P2, P3		GT	F02		TK			11/1980		122,400	108	134
												206	236
TIGER BAY	1	POLK CO.	CC	NG		PL			08/1997		233,000	206	236
												160	200
TURNER	P1-P2	VOLUSIA CO.	GT	F02		TK			10/1970	12/2004	38,580	30	36
	P3-P4	SECT. 1,	GT	F02		TK			08/1974		142,400	130	164
		T19S,R30E											
												36	42
U OF FLA.	P1	ALACHUA CO.	GT	NG		PL			01/1994		43,000	36	42
												7,105	7,717

* EPRESENTS 90.4 % FPC OWNERSHIP OF UNIT

FLORIDA POWER CORPORATION

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1998

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				FUEL		FUEL TRANSPORT.		ALT. FUEL				NET CAPABILITY	
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALT.	PRIMARY	ALT.	DAYS USE	COMMERCIAL IN-SERVICE MONTH/YEAR	EXPECTED RETIREMENT MONTH/YEAR	GEN. MAX. NAMEPLATE KW	SUMMER MW	WINTER MW
												1,006	1,034
ANCLOTE	1	PASCO CO.	ST	F06		PL			10/1974		556,200	503	517
	2	SECT.33,34	ST	F06	NG	PL	PL		10/1978		556,200	503	517
		T26S,R15E											
												58	64
AVON PARK	P1	HIGHLANDS CO.	GT	NG	F02	PL	TK		12/1968	12/2004	33,790	29	32
	P2		GT	F02		TK			12/1968	12/2004	33,790	29	32
												627	666
BARTOW	1	PINELLAS CO.	ST	F06		WA			09/1958		127,500	115	117
	2	SECT.20,21,22	ST	F06		WA			08/1961		127,500	117	119
	3	T30S,R16E	ST	NG	F06	PL	WA		07/1963		239,360	208	213
	P1, P3		GT	F02		WA			06/1972		111,400	92	106
	P2, P4		GT	NG	F02	PL	WA		06/1972		111,400	95	111
												188	232
BAYBORO	P1-P4	PINELLAS CO.	GT	F02		WA,TK			04/1973		226,800	188	232
		SECT. 30											
		T31S,R17E											
												2,961	3,031
CRYSTAL	1	CITRUS CO.	ST	BIT		WA,RR			10/1966		440,550	369	373
RIVER	2	SECT.33	ST	BIT		WA,RR			11/1969		523,800	464	469
	3 *	T17S,R16E	NP	UR		TK			03/1977		890,460	734	755
	4		ST	BIT		WA,RR			12/1982		739,260	697	717
	5		ST	BIT		WA,RR			10/1984		739,260	697	717
												656	786
DEBARY	P1-P6	VOLUSIA CO.	GT	F02		TK,RR			04/1976		401,220	324	390
	P7, P9	SECT.16,19-21,	GT	NG	F02	PL	TK,RR		11/1992		230,000	166	198
	P8, P10	28-30,T18S,R30E	GT	F02		TK,RR			11/1992		230,000	166	198
												128	148
HIGGINS	P1-P2	PINELLAS CO.	GT	NG	F02	PL	TK		04/1969	12/2003	67,580	58	64
	P3-P4	T25S,R16E	GT	NG	F02	PL	TK		12/1970	12/2003	85,850	70	84
												757	912
INTERCESSION	P1-P6	OSCEOLA CO.	GT	F02		PL,TK			05/1974		340,200	282	348
CITY	P7-P10	SECT. 31	GT	NG	F02	PL	PL,TK		11/1993		460,000	332	396
	P11	T25S,R28E	GT	F02		PL,TK			01/1997		165,000	143	168
												15	18
RIO PINAR	P1	ORANGE CO.	GT	F02		TK			11/1970	12/2003	19,290	15	18
												307	348
SUWANNEE	1	SUWANNEE CO.	ST	NG	F06	PL	TK		11/1953	12/2001	34,500	33	34
RIVER	2	SECT. 26,	ST	NG	F06	PL	TK		11/1954	12/2001	37,500	32	33
	3	T1S,R11E	ST	NG	F06	PL	TK		10/1956	12/2001	75,000	80	80
	P1, P3		GT	NG	F02	PL	TK		11/1980		122,400	108	134
	P2		GT	F02		TK			11/1980		61,200	54	67
												206	246
TIGER BAY	1	POLK CO.	CC	NG		PL			08/1997		233,000	206	246
												160	200
TURNER	P1-P2	VOLUSIA CO.	GT	F02		TK			10/1970	12/2004	38,580	30	36
	P3-P4	SECT. 1,	GT	F02		TK			08/1974		142,400	130	164
		T19S,R30E											
												36	42
NIV. OF FLA.	P1	ALACHUA CO.	GT	NG		PL			01/1994		43,000	36	42
												7,105	7,727

* REPRESENTS 90.4 % FPC OWNERSHIP OF UNIT

FLORIDA POWER CORPORATION

SCHEDULE 1
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. FUEL DAYS	COMMERCIAL IN-SERVICE	EXPECTED RETIREMENT	GEN. MAX. NAMEPLATE	NET CAPABILITY	
PLANT NAME	UNIT NO.	LOCATION	UNIT TYPE	PRIMARY	ALT.	PRIMARY	ALT.	USE	MONTH/YEAR	MONTH/YEAR	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 T26S,R15E	ST	F06	NG	PL	PL		10/1978		556,200	495	522
												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. SECT. 30 T31S,R17E	CT	F02		WA,TK			04/1973		226,800	184	232
												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
												7,659	8,267

* REPRESENTS 91.8 % FPC OWNERSHIP OF UNIT

FLORIDA POWER CORPORATION

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								ALT. FUEL	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		DAYS	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	USE	MO./YEAR	MO./YEAR	KW	MW	MW
												993	1,044
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/1974		556,200	498	522
	2		ST	RFO	NG	PL	PL		10/1978		556,200	495	522
												52	64
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3	12/1968	12/2006	33,790	26	32
	P2		GT	DFO		TK			12/1968	12/2006	33,790	26	32
												631	671
BARTOW	1	PINELLAS	ST	RFO		WA			09/1958		127,500	121	123
	2		ST	RFO		WA			08/1961		127,500	119	121
	3		ST	RFO	NG	WA	PL		07/1963		239,360	204	208
	P1, P3		GT	DFO		WA			06/1972		111,400	92	106
	P2		GT	NG	DFO	PL	WA	8	06/1972		55,700	46	53
	P4		GT	NG	DFO	PL	WA	8	06/1972		55,700	49	60
												184	232
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA,TK			04/1973		226,800	184	232
												3,067	3,123
CRYSTAL	1	CITRUS	ST	BIT		WA,RR			10/1966		440,550	379	383
RIVER	2		ST	BIT		WA,RR			11/1969		523,800	486	491
	3 *		ST	NUC		TK			03/1977		890,460	765	782
	4		ST	BIT		WA,RR			12/1982		739,260	720	735
	5		ST	BIT		WA,RR			10/1984		739,260	717	732
												667	762
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK,RR			04/1976		401,220	324	390
	P7-P9		GT	NG	DFO	PL	TK,RR	8	11/1992		345,000	258	279
	P10		GT	DFO		TK,RR			11/1992		115,000	85	93
												122	134
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK	1	04/1969	12/2005	67,580	54	64
	P3-P4		GT	NG	DFO	PL	TK	1	12/1970	12/2005	85,850	68	70
												482	529
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	6	04/1999		546,550	482	529
												1,029	1,194
INTERCESSION	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/1974		340,200	294	366
CITY	P7-P10		GT	NG	DFO	PL	PL,TK	5	11/1993		460,000	352	376
	P11 **		GT	DFO		PL,TK			01/1997		165,000	143	170
	P12-P14		GT	NG	DFO	PL	PL,TK	5	12/2000		345,000	240	282
												13	16
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/1970	12/2005	19,290	13	16
												307	347
SUWANNEE	1	SUWANNEE	ST	RFO	NG	TK	PL		11/1953	12/2003	34,500	32	33
RIVER	2		ST	RFO	NG	TK	PL		11/1954	12/2003	37,500	31	32
	3		ST	RFO	NG	TK	PL		10/1956	12/2003	75,000	80	81
	P1, P3		GT	NG	DFO	PL	TK	10	11/1980		122,400	110	134
	P2		GT	DFO		TK			11/1980		61,200	54	67
												207	223
TIGER BAY	1	POLK	CC	NG		PL			08/1997		278,223	207	223
												154	194
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/1970	12/2006	38,580	26	32
	P3		GT	DFO		TK			08/1974		71,200	65	82
	P4		GT	DFO		TK			08/1974		71,200	63	80
												35	41
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/1994		43,000	35	41
												7,943	8,574

* REPRESENTS 91.8% FPC OWNERSHIP OF UNIT
** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

FLORIDA POWER

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								ALT. FUEL	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		DAYS	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	USE	MO/YEAR	MO/YEAR	KW	MW	MW
												993	1,044
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/1974		556,200	498	522
	2		ST	RFO	NG	PL	PL		10/1978		556,200	495	522
												52	64
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3	12/1968		33,790	26	32
	P2		GT	DFO		TK			12/1968		33,790	26	32
												631	671
BARTOW	1	PINELLAS	ST	RFO		WA			09/1958		127,500	121	123
	2		ST	RFO		WA			08/1961		127,500	119	121
	3		ST	RFO	NG	WA	PL		07/1963		239,360	204	208
	P1, P3		GT	DFO		WA			06/1972		111,400	92	106
	P2		GT	NG	DFO	PL	WA	8	06/1972		55,700	46	53
	P4		GT	NG	DFO	PL	WA	8	06/1972		55,700	49	60
												184	232
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA,TK			04/1973		226,800	184	232
												3,067	3,123
CRYSTAL RIVER	1	CITRUS	ST	BIT		WA,RR			10/1966		440,550	379	383
	2		ST	BIT		WA,RR			11/1969		523,800	486	491
	3 *		ST	NUC		TK			03/1977		890,460	765	782
	4		ST	BIT		WA,RR			12/1982		739,260	720	735
	5		ST	BIT		WA,RR			10/1984		739,260	717	732
												667	762
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK,RR			04/1976		401,220	324	390
	P7-P9		GT	NG	DFO	PL	TK,RR	8	11/1992		345,000	258	279
	P10		GT	DFO		TK,RR			11/1992		115,000	85	93
												122	134
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK	1	04/1969		67,580	54	64
	P3-P4		GT	NG	DFO	PL	TK	1	12/1970		85,850	68	70
												482	529
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	6	04/1999		546,550	482	529
												1,039	1,194
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/1974		340,200	294	366
	P7-P10		GT	NG	DFO	PL	PL,TK	5	11/1993		460,000	352	376
	P11 **		GT	DFO		PL,TK			01/1997		165,000	143	170
	P12-P14		GT	NG	DFO	PL	PL,TK	5	12/2000		345,000	240	282
												13	16
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/1970		19,290	13	16
												307	347
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK	PL		11/1953	12/2005	34,500	32	33
	2		ST	RFO	NG	TK	PL		11/1954	12/2005	37,500	31	32
	3		ST	RFO	NG	TK	PL		10/1956	12/2005	75,000	80	81
	P1, P3		GT	NG	DFO	PL	TK	10	11/1980		122,400	110	134
	P2		GT	DFO		TK			11/1980		61,200	54	67
												207	223
TIGER BAY	1	POLK	CC	NG		PL			08/1997		278,223	207	223
												154	194
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/1970		38,580	26	32
	P3		GT	DFO		TK			08/1974		71,200	65	82
	P4		GT	DFO		TK			08/1974		71,200	63	80
												35	41
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/1994		43,000	35	41
												7,543	8,574

* REPRESENTS 91.78% FLORIDA POWER OWNERSHIP OF UNIT

** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

Docket No. 090988
Progress Energy Florida
Exhibit No. _____ (JBC-3)
Page 7 of 10

April 2003

PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								ALT. FUEL	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		DAYS	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	USE	MO/YEAR	MO/YEAR	KW	MW	MW
												993	1,044
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/1974		556,200	498	522
	2		ST	RFO	NG	PL	PL		10/1978		556,200	495	522
												52	64
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3	12/1958		33,790	26	32
	P2		GT	DFO		TK			12/1968		33,790	26	32
												631	671
BARTOW	1	PINELLAS	ST	RFO		WA			09/1958		127,500	121	123
	2		ST	RFO		WA			08/1961		127,500	119	121
	3		ST	RFO	NG	WA	PL		07/1963		239,360	204	208
	P1, P3		GT	DFO		WA			06/1972		111,400	92	106
	P2		GT	NG	DFO	PL	WA	8	06/1972		55,700	46	53
	P4		GT	NG	DFO	PL	WA	8	06/1972		55,700	49	60
												184	232
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA,TK			04/1973		226,800	184	232
												3,067	3,123
CRYSTAL RIVER	1	CITRUS	ST	BIT		WA,RR			10/1966		440,550	379	383
	2		ST	BIT		WA,RR			11/1969		523,800	486	491
	3 *		ST	NUC		TK			03/1977		890,460	765	782
	4		ST	BIT		WA,RR			12/1982		739,260	720	735
	5		ST	BIT		WA,RR			10/1984		739,260	717	732
												667	762
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK,RR			04/1976		401,220	324	390
	P7-P9		GT	NG	DFO	PL	TK,RR	8	11/1992		345,000	258	279
	P10		GT	DFO		TK,RR			11/1992		115,000	85	93
												122	134
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK	1	04/1969		67,580	54	64
	P3-P4		GT	NG	DFO	PL	TK	1	12/1970		85,850	68	70
												482	529
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	6	04/1999		548,550	482	529
												1,041	1,206
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/1974		340,200	284	386
	P7-P10		GT	NG	DFO	PL	PL,TK	5	11/1993		460,000	352	376
	P11 **		GT	DFO		PL,TK			01/1997		165,000	143	170
	P12-P14		GT	NG	DFO	PL	PL,TK	5	12/2000		345,000	252	284
												13	18
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/1970		19,290	13	16
												307	347
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK	PL		11/1953		34,500	32	33
	2		ST	RFO	NG	TK	PL		11/1954		37,500	31	32
	3		ST	RFO	NG	TK	PL		10/1956		75,000	80	81
	P1, P3		GT	NG	DFO	PL	TK	10	11/1980		122,400	110	134
	P2		GT	DFO		TK			11/1980		61,200	54	67
												207	223
TIGER BAY	1	POLK	CC	NG		PL			08/1997		278,223	207	223
												154	194
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/1970		38,580	26	32
	P3		GT	DFO		TK			08/1974		71,200	65	82
	P4		GT	DFO		TK			08/1974		71,200	63	80
												35	41
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/1994		43,000	35	41
												7,955	8,586

* REPRESENTS 91.78% PEF OWNERSHIP OF UNIT

** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

April
2004

Docket No. 090988
Progress Energy Florida
Exhibit No. ____ (JBC-3)
Page 8 of 10

PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2003

(1) PLANT NAME	(2) UNIT NO.	(3) LOCATION (COUNTY)	(4) UNIT TYPE	(5) FUEL PRI.	(6) FUEL ALT.	(7) FUEL TRANSPORT PRI.	(8) FUEL TRANSPORT ALT.	(9) ALT. FUEL DAYS USE	(10) COM'L IN-SERVICE MO./YEAR	(11) EXPECTED RETIREMENT MO./YEAR	(12) GEN. MAX. NAMEPLATE KW	(13) NET CAPABILITY SUMMER MW	(14) NET CAPABILITY WINTER MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/74		556,200	498	522
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL		10/78		556,200	495	522
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	123
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	121
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	208
CRYSTAL RIVER	1	CITRUS	ST	BIT		WA,RR			10/66		440,550	379	383
CRYSTAL RIVER	2	CITRUS	ST	BIT		WA,RR			11/69		523,800	486	491
CRYSTAL RIVER	3 *	CITRUS	ST	NUC		TK			03/77		890,460	769	788
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA,RR			12/82		739,260	720	735
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA,RR			10/84		739,260	717	732
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK	PL		11/53		34,500	32	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO	NG	TK	PL		11/54		37,500	31	32
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK	PL		10/56		75,000	80	81
												4,651	4,771
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	6	04/99		546,550	482	529
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	6	12/03		598,000	516	582
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,223	207	223
												1,205	1,334
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3	12/68		33,790	26	32
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	26	32
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			5/72-6/72		111,400	92	106
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	53
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	49	60
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA,TK			04/73		226,800	184	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK,RR			12/75-04/76		401,220	324	390
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK,RR	8	10/92		345,000	258	279
DEBARY	P10	VOLUSIA	GT	DFO		TK,RR			10/92		115,000	85	93
HIGGINS	P1-P2	PINELLAS	GT	DFO		TK			03/69-04/69		67,580	54	64
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70-01/71		85,850	68	70
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	294	366
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	352	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	170
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	252	294
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/70		19,290	13	16
SUWANNEE RIVER	P1	SUWANNEE	GT	NG	DFO	PL	TK	10	10/80		61,200	55	67
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	54	67
SUWANNEE RIVER	P3	SUWANNEE	GT	NG	DFO	PL	TK	10	11/80		61,200	55	67
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	26	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	65	82
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	63	80
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	35	41
												2,619	3,069
											TOTAL RESOURCES (MW)	8,475	9,174

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT
** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

April 2005

PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/74		556,200	498	522
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL		10/78		556,200	495	522
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	123
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	121
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	208
CRYSTAL RIVER	1	CITRUS	ST	BIT		WA,RR			10/66		440,550	379	383
CRYSTAL RIVER	2	CITRUS	ST	BIT		WA,RR			11/69		523,800	486	491
CRYSTAL RIVER	3 *	CITRUS	ST	NUC		TK			03/77		890,460	769	788
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA,RR			12/82		739,260	720	735
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA,RR			10/84		739,260	717	732
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK	PL		11/53		34,500	32	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO		TK			11/54		37,500	31	32
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK	PL		10/56		75,000	80	81
												4,651	4,771
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	6	04/99		546,550	482	529
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	6	12/03		598,000	516	582
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,223	207	223
												1,205	1,334
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3	12/68		33,790	26	32
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	26	32
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			5/72-6/72		111,400	92	106
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	53
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	49	60
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA,TK			04/73		226,800	184	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK			12/75-04/76		401,220	324	390
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	8	10/92		345,000	258	279
DEBARY	P10	VOLUSIA	GT	DFO		TK			10/92		115,000	85	93
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK		03/69-04/69		67,580	54	64
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70-01/71		85,850	68	70
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	294	366
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	352	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	170
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	252	294
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/70		19,290	13	16
SUWANNEE RIVER	P1	SUWANNEE	GT	NG	DFO	PL	TK	10	10/80		61,200	55	67
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	54	67
SUWANNEE RIVER	P3	SUWANNEE	GT	NG	DFO	PL	TK	10	11/80		61,200	55	67
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	26	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	65	82
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	63	80
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	35	41
												2,619	3,069
											TOTAL RESOURCES (MW)	8,475	9,174

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT
** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

PROGRESS ENERGY FLORIDA

SCHEDULE 1

EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2005

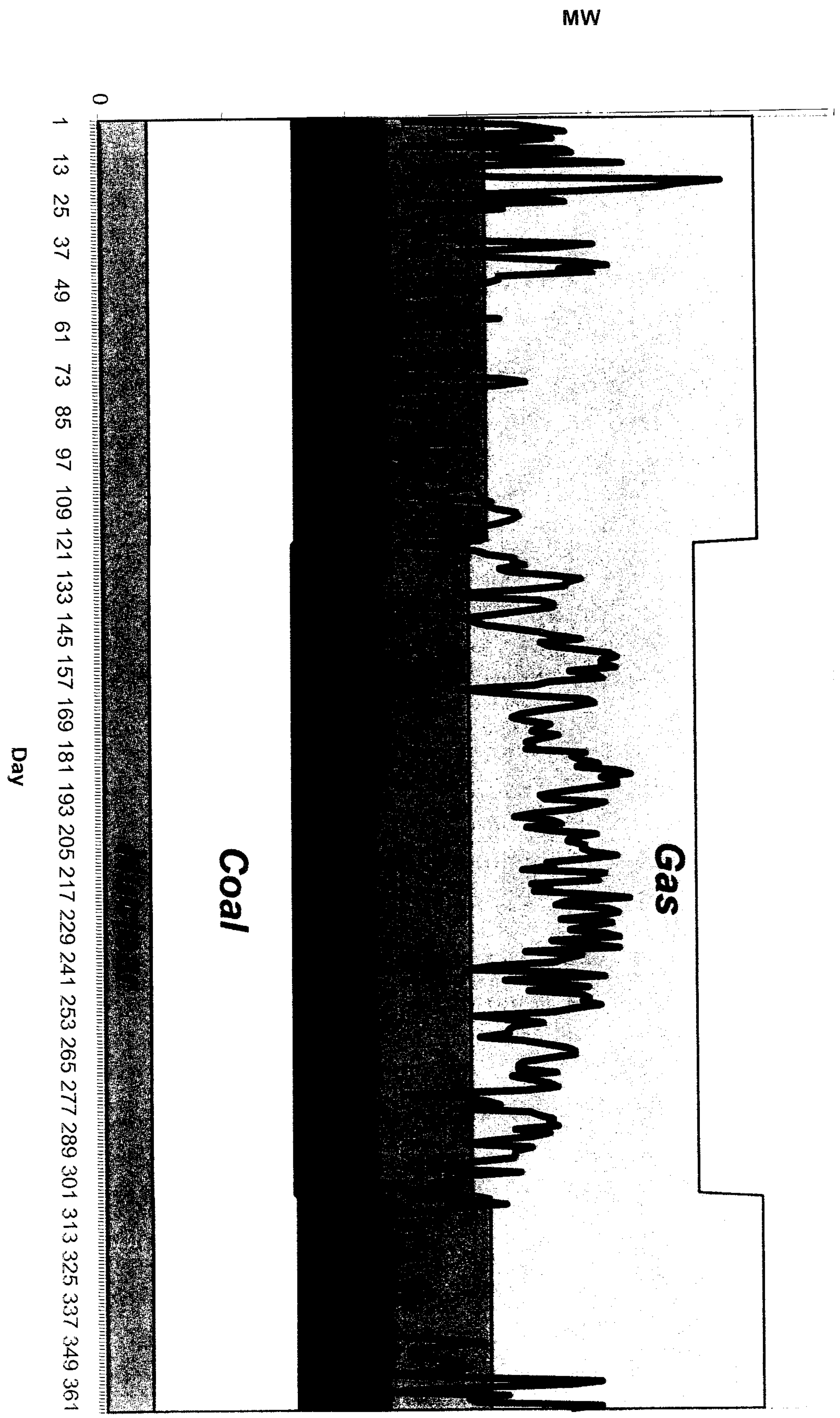
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/74		556,200	498	522
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL		10/78		556,200	495	522
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	123
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	121
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	208
CRYSTAL RIVER	1	CITRUS	ST	BIT		WA			10/66		440,550	379	383
CRYSTAL RIVER	2	CITRUS	ST	BIT		WA			11/69		523,800	486	491
CRYSTAL RIVER	3 *	CITRUS	ST	NUC		TK			03/77		890,460	769	788
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA			12/82		739,260	720	735
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA			10/84		739,260	717	732
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/53		34,500	32	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/54		37,500	31	32
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK/RR	PL		10/56		75,000	80	81
												4,651	4,771
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	2***	04/99		546,550	482	529
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK		12/03		598,000	516	582
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK		11/05		589,900	501	576
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,223	207	223
												1,706	1,910
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3***	12/68		33,790	26	32
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	26	32
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			05/72, 06/72		111,400	92	106
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	53
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	49	60
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA			04/73		226,800	184	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK			12/75-04/76		401,220	324	390
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	8	10/92		345,000	258	279
DEBARY	P10	VOLUSIA	GT	DFO		TK			10/92		115,000	85	93
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK		03/69, 04/69		67,580	54	64
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70, 01/71		85,850	68	70
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	294	366
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	352	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	170
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	252	294
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/70		19,290	13	16
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	PL	TK	9***	10/80, 11/80		122,400	110	134
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	54	67
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	26	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	65	82
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	63	80
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	35	41
												2,619	3,069
											TOTAL RESOURCES (MW)	8,976	9,750

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT

** SUMMER CAPABILITY (JUNE THROUGH SEPTEMBER) OWNED BY GEORGIA POWER COMPANY

*** FOR ENTIRE PLANT

2004 PEF Daily Total Load Forecast
Generation Illustrated with No Outage



Scenario 1 — **Two Year Bridge Cost - Low Capacity cost, Low heat rate, actual fuel, TAG O&M, no esc**

Capacity kW	Term (Mo)	Cap. Cost ($/ kw-mo)	Total Cap cost	Energy MW	Unit Cap Factor	hours per year	heat rate	NG Fuel ($/mmbtu)	Var. O&M ($/MWH)	Fixed O&M ($/kW-mo)	Energy cost / yr	Energy cost for 2 years	Bridge Cap and Energy
124000	24	4	$11,904,000	124	0.2	8760	11	3	5.4	1.5	$22,305,715	$44,611,430	$56,515,430

Scenario 2 — **Two Year Bridge Cost - Mid Capacity cost, Realized heat rate, actual fuel, TAG O&M, no esc**

Capacity kW	Term (Mo)	Cap. Cost ($/ kw-mo)	Total Cap cost	Energy MW	Unit Cap Factor	hours per year	heat rate	NG Fuel ($/mmbtu)	Var. O&M ($/MWH)	Fixed O&M ($/kW-mo)	Energy cost / yr	Energy cost for 2 years	Bridge Cap and Energy
124000	24	4.5	$13,392,000	124	0.2	8760	13	3	5.4	1.5	$25,955,482	$51,910,963	$65,302,963

Scenario 3 — **Two Year Bridge Cost - Capacity prem, Realized heat rate, volatility premium (fuel & O&M)**

Capacity kW	Term (Mo)	Cap. Cost ($/ kw-mo)	Total Cap cost	Energy MW	Unit Cap Factor	hours per year	heat rate	NG Fuel ($/mmbtu)	Var. O&M ($/MWH)	Fixed O&M ($/kW-mo)	Energy cost / yr	Energy cost for 2 years	Bridge Cap and Energy
124000	24	5	$14,880,000	124	0.2	8760	13	4.5	5.75	2	$31,924,296	$63,848,592	$78,728,592

Balance of Energy Costs provided by Fleet @ medium backfill heatrate (steam efficiency driven)

Capacity kW	Term (Mo)	Cap. Cost ($/ kw-mo)	Total Cap cost	Energy MW	Unit Cap Factor	hours per year	heat rate	NG Fuel ($/mmbtu)	Var. O&M ($/MWH)	Fixed O&M ($/kW-mo)	Energy cost / yr	Energy cost for 2 years
124000	24			124	0.55	8760	11.5	3	4.2	4.6	$56,312,170	$112,624,339

Scenario A — **Eight Year Self Build Capacity plus fleet energy back-fill, low back-fill heat rate (remaining fleet average, steam efficiency driven)**

Capacity kW	Term (Mo)	Cap. Cost ($/ kw-mo)	Total Cap cost	Energy MW	Fleet Cap Factor	hours per year	heat rate	NG Fuel ($/mmbtu)	Var. O&M ($/MWH)	Fixed O&M ($/kW-mo)	Energy cost / yr	Energy cost for 8 years	Fleet Cap and Energy
124000	96	3.79	$45,116,160	124	0.75	8760	10	3	3	7.7	$60,338,400	$482,707,200	$527,823,360

Scenario B — **Eight Year Self Build Capacity plus fleet energy back-fill, medium back-fill heat rate, balanced back-fill heat rate (average of units)**

Capacity kW	Term (Mo)	Cap. Cost ($/ kw-mo)	Total Cap cost	Energy MW	Fleet Cap Factor	hours per year	heat rate	NG Fuel ($/mmbtu)	Var. O&M ($/MWH)	Fixed O&M ($/kW-mo)	Energy cost / yr	Energy cost for 8 years	Fleet Cap and Energy
124000	96	3.79	$45,116,160	124	0.75	8760	11.5	3	4.2	4.6	$74,300,304	$594,402,432	$639,518,592

Scenario C — **Eight Year Self Build Capacity plus fleet energy back-fill, high back-fill heat rate (peaking unit heat rate)**

Capacity kW	Term (Mo)	Cap. Cost ($/ kw-mo)	Total Cap cost	Energy MW	Fleet Cap Factor	hours per year	heat rate	NG Fuel ($/mmbtu)	Var. O&M ($/MWH)	Fixed O&M ($/kW-mo)	Energy cost / yr	Energy cost for 8 years	Fleet Cap and Energy
124000	96	3.79	$45,116,160	124	0.75	8760	13	3	5.4	1.5	$91,195,056	$729,560,448	$774,676,608

		Scenario 1-A	Scenario 2-B	Scenario 3-C
124 MW	2 yr Bridge cap	$11,904,000	$13,392,000	$14,880,000
	20% energy	$44,611,430	$51,910,963	$63,848,592
	55% energy	$112,624,339	$112,624,339	$112,624,339
	8 yr fleet cap	$45,116,160	$45,116,160	$45,116,160
	8 yr fleet energy	$482,707,200	$594,402,432	$729,560,448
	Total	$696,963,130	$817,445,894	$966,029,539