BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070052-EI

In the Matter of:

PETITION BY PROGRESS ENERGY FLORIDA, INC. TO RECOVER COSTS OF CRYSTAL RIVER UNIT 3 UPRATE THROUGH FUEL CLAUSE.
_________________________________/

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VOLUME 4

Pages 550 through 634

PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LISA POLAK EDGAR
COMMISSIONER MATTHEW M. CARTER, II
COMMISSIONER KATRINA J. McMURRIAN
COMMISSIONER NANCY ARGENZIANO
COMMISSIONER NATHAN A. SKOP

DATE: Wednesday, August 8, 2007

TIME: Recommenced at 9:40 a.m.
Concluded at 1:15 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

P R O C E E D I N G S

(Transcript follows in sequence from Volume 3.)

CHAIRMAN EDGAR: Okay. We are back on the record from break. Mr. Walls, your witness.

MR. WALLS: Yes. We call Mr. Portuondo back to the stand.

Thereupon,

JAVIER PROTUONDO

was called as a rebuttal witness on behalf of Progress Energy Florida, Inc., and having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. WALLS:

Q. Mr. Portuondo, have you filed prefiled rebuttal testimony in this proceeding?

A. Yes, I have.

Q. And do you have your prefiled rebuttal testimony with you?

A. Yes, I do.

Q. Do you have any changes to make to your prefiled rebuttal testimony?

A. No, I don't.

Q. If I asked you the same questions in your prefiled rebuttal testimony today, would you give the same answers that are reflected in that testimony?

A. Yes, I would.

MR. WALLS: We request that the prefiled rebuttal testimony be moved into evidence as if it was read into the record.

CHAIRMAN EDGAR: The prefiled rebuttal testimony will be entered into the record as though read.

IN RE: PETITION TO RECOVER THE COSTS OF THE CRYSTAL RIVER UNIT 3 UPRATE THROUGH THE FUEL CLAUSE

BY PROGRESS ENERGY FLORIDA

FPSC DOCKET NO. 070052

REBUTTAL TESTIMONY OF

JAVIER PORTUONDO

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is 410 South Wilmington Street, Raleigh, North Carolina, 27601.

Q. Have you previously submitted testimony in this docket?

A. Yes. I filed both direct testimony and amended direct testimony in support of Progress Energy Florida, Inc.'s ("PEF's") request for recovery of the costs of the Crystal River Unit 3 ("CR3") power uprate (the "Uprate Project") through the Fuel and Purchase Power Cost Recovery Clause ("Fuel Clause").

Q. Have any of your duties or responsibilities changed since you filed your amended direct testimony?

A. No.

II. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

Q. Have you reviewed the intervener testimony of Daniel J. Lawton and Patricia W. Merchant, filed on behalf of the Office of Public Counsel ("OPC"), and of Jeffrey Pollock, filed on behalf of the Florida Industrial Power Users Group ("FIPUG")?

A. Yes.

Q. Do you agree with what witnesses Lawton, Merchant, and Pollock have to say in response to PEF's request for recovery of the Uprate Project costs through the Fuel Clause?

A. No, I do not.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the intervener witness arguments and explain why these arguments fail to show that PEF has not met Commission policy establishing that the Uprate Project costs should be recovered through the Fuel Clause. First, I will address the intervener witness arguments that additional tests and definitions should be used for the first time here that are nowhere found in Order 14546. These additional tests and definitions are inconsistent with Order 14546 and the later orders applying the policy established in Order 14546, and if adopted, obliterate Commission policy in Order 14546.

Second, I will address the arguments of some intervener witnesses challenging the application of Commission policy in Order 14546 to PEF's petition. I will demonstrate that PEF's request for cost recovery through the Fuel Clause of the Uprate Costs is consistent with and supported by Order 14546 and the application of the policy in Order 14546 by the Commission in subsequent orders.

Third, I will address the argument of witness Pollock that PEF's petition violates the settlement agreement in PEF's last base rate proceeding and explain that PEF's petition does not violate and is in fact consistent with that agreement.

Fourth, I will address witness Pollock's further argument that the Uprate Project is needed for reliability to maintain PEF reserve margins and, therefore, there will be additional revenues from customer growth or usage to support the Uprate Project costs. Mr. Pollock, quite simply, is wrong. As this Commission determined in Order No. PSC-07-0119-FOF-EI the need for the Uprate Project was economic, based on the demonstrated fuel savings and increased fuel diversity, and not a reliability need.

Finally, I will address the cost allocation issues raised by some of the intervener witnesses and explain that PEF's request in its petition is, again, consistent with Commission application of the policy established in Order 14546.

Q. Please summarize your rebuttal testimony.

A. The Uprate Project benefits PEF's customers. The Uprate Project will provide PEF's customers substantial fuel savings expected to be in excess of $2.6 billion by the end of 2036 with an expected net present value of savings to costs of $320 million. Intervener witnesses agree that it is a beneficial project.

Under well-established Commission policy set forth in item 10 of Order 14546, recovery of the Uprate Project costs through the Fuel Clause is appropriate if the costs (1) were not recognized or anticipated in the costs levels used to determine current base rates and (2) if expended, will result in fuel savings to customers. PEF's Uprate Project satisfies this two-part test and, therefore, PEF's Petition should be granted.

This Commission policy was adopted to encourage utilities to develop and pursue projects and programs that resulted in fuel savings and, thus, lower costs to customers. Intervener witnesses admit this policy provides an incentive for utilities to spend money that they might not otherwise choose to spend to save fuel costs. The policy works. PEF moved forward with the Uprate Project because it was aware of the policy in item 10 of Order 14546. Additionally, utilities have incurred the costs of numerous projects that resulted in fuel savings to customers over the last 20 years because of the Commission policy in item 10 of Order 14546.

Intervener witnesses seek to change this policy. They ask the Commission to consider requirements and definitions that are nowhere found in the Commission's policy expressed in item 10 of Order 14546 and numerous, subsequent Commission orders applying that policy to other utility requests. The requirements and definitions they seek to add to this Commission policy do not merely change it, they obliterate it. If adopted, they will destroy the incentive to incur the costs of projects that result in fuel savings to customers set forth in the clear, straight-forward, two-part test of item 10 of Order 14546.

PEF's request for recovery of the Uprate Project costs is consistent with the application of this policy over the last 20 years in numerous other projects approved for cost recovery under item 10 of Order 14546. PEF seeks only the same treatment for its Uprate Project. This does not harm current or future customers at all. In fact, they receive the benefits of immediate fuel savings beginning in the first year of the Uprate Project and continuing for every year thereafter. These fuel savings pay for the costs of the Uprate Project, the customers do not, and therefore, customers clearly receive fuel savings benefits from the Uprate Project. The Uprate Project should be approved consistent with the Commission's long-standing policy under item 10 of Order 14546.

III. COMMISSION POLICY UNDER ORDER 14546

Q. Under what Commission policy is the request for cost recovery in PEF's Petition made?

A. PEF's cost recovery request in its Petition is based on longstanding Commission policy encouraging utilities to incur the costs of innovative projects or programs that reduce costs to customers. This policy is incorporated in item 10 of Order 14546 establishing the types of costs that prospectively can be recovered by utilities under the Fuel Clause. Under item 10 of Order 14546 a utility is entitled to recover through the Fuel Clause "fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the costs levels used to determine current base rates and which, if expended, will result in fuel savings to customers."

Q. What must a utility demonstrate to be entitled to recover costs through the Fuel Clause under the Commission policy established in Order 14546?

A. Under item 10 of Order 14546 the utility must demonstrate: (1) the expected amount of the project costs; (2) that the expected project costs were not anticipated in current base rates; (3) the amount of projected fuel savings that will be generated if the costs are incurred; and (4) that those fuel savings are expected to exceed the project costs. No other requirements or tests must be met.

Q. Intervener witnesses argue that the costs must be volatile to be recovered under the Fuel Clause, even under item 10 of Order 14546. Do you agree?

A. No. No such requirement appears in item 10 of Order 14546. The Commission was certainly aware that the Fuel Clause was historically used for the recovery of volatile costs when the Commission adopted the policy in item 10 of Order 14546. Yet, nowhere in item 10 or elsewhere in that Order, or in any later Commission Order applying the policy adopted in item 10 of Order 14546, has the Commission ever required a demonstration that the costs sought under item 10 of Order 14546 must be volatile to be recovered through the Fuel Clause. In fact, the Commission expressly recognized in Order 14546 that its policy must be flexible enough to allow recovery through the Fuel Clause of costs *normally* recovered through base rates.

This is the very first part of the test set forth in Item 10, allowing the recovery of fossil fuel-related costs which are *normally recovered through base rates*, if they are not currently recovered in base rates and result in fuel savings.

The Commission policy identified in item 10 of Order 14546 is, therefore, an *exception* to the general rule – as OPC witness Merchant admits (Merchant Test., p. 12, lines 7-9) – providing for the recovery of volatile costs through the Fuel Clause. To read a volatility requirement that does not exist into Item 10 of Order 14546, as Interveners suggest, renders the Commission policy established in item 10 of Order 14546 meaningless. Fossil fuel-related costs "normally recovered through base rates" by definition are not volatile costs and, therefore, they would never be recovered through the Fuel Clause – even when they result in fuel savings and are not currently recovered in base rates – if a "volatility" requirement is added to item 10 of Order 14546. The Commission obviously did not intend a construction of its policy in Order 14546 that obliterates the very policy it adopted. Thus, PEF's Uprate Project costs cannot be rejected because they are not volatile because that is not an appropriate part of the test articulated in Item 10 of Order 14546.

Q. Some intervener witnesses argue that the Uprate Project costs are not fossil fuel-related costs and, therefore, should not be recovered through the Fuel Clause. Do you agree?

A. No. Under their interpretation of fossil fuel-related costs, such costs are limited to only those which are directly related to the delivered price of fossil fuel. No such definition appears in item 10 of Order 14546, elsewhere in Order 14546, or in any Commission order applying the policy adopted in item 10 of Order 14546.

As her support for this argument, Ms. Merchant relies on an example given in Order 14546 to illustrate one type of expense that was appropriately recovered under the Fuel Clause. The Commission acknowledged that the cost of a short-term lease of an oil storage tanker for a utility to take advantage of unanticipated lower oil costs, for example, was recoverable under item 10 through the Fuel Clause. Ms. Merchant claims this example shows that "fossil fuel-related cost" was meant to refer to only those costs "directly related to the delivered cost of fossil fuel to be burned in the boilers to generate electricity." (Merchant Test., p. 12, lines 18-24). The Commission, however, nowhere limited the term "fossil fuel-related costs" in this way in Order 14546. The example provided in Order 14546 was meant to be just that, an example. Indeed, the Commission expressly stated that it intended the policy in Order 14546 to be a flexible one, which negates the narrow "list" of recoverable "fossil fuel-related costs" that Ms. Merchant would use based on the "example" in Order 14546.

As I explained in detail in my amended direct testimony at pages 14-18, the Commission never expressed any intent to give the term "fossil fuel-related costs" in item 10 of Order 14546 the narrow interpretation advocated by intervener witnesses. Such a narrow definition of the term "fossil fuel-related costs" does not make sense because it is inconsistent with the Commission's policy to encourage innovative projects that save fuel costs. Rather, the more logical interpretation consistent with Commission policy is that the term "fossil fuel-related costs" means all costs that result in the reduction or replacement of other, more expensive fossil fuels. This interpretation is confirmed by the Commission's consistent application of its policy in item 10 of Order 14546 in later Commission orders. See Order No. PSC-96-1172-FOF-EI, Docket No. 960001-EI (Sept. 19, 1996); Order No. PSC-95-1089-FOF-EI, Docket No. 950001 (Sept. 5, 1995); Order No. PSC-96-0353-FOF-EI, Docket No. 960001-EI (Mar. 13, 1996); Order No. PSC-97-0359-FOF-EI, Docket No. 970001-EI (Mar. 31, 1997); Order No. PSC-98-0412-FOF-EI, Docket No. 980001-EI (Mar. 20, 1998).

Q. The intervener witnesses apply an "earnings" test to Order 14546, arguing that if part or all of the Uprate Project costs can be absorbed by the Company in current base rates, recovery through the Fuel Clause for the Uprate Project should be denied. Is there an "earnings" test under Order 14546?

A. No, there is not. To summarize the intervener witnesses' argument, they assert that (1) the Uprate Project costs are the types of cost fluctuations that base rates are intended to cover, and (2) PEF's earnings are such that the Uprate Project costs, especially for Phase 1, can be absorbed with only a negligible impact on earnings. In addition, Mr. Lawton argues that the Company in fact may be earning too much if it is allowed to recover the project costs through the fuel clause, if base rates are sufficient to cover the costs. Intervener witnesses, therefore, are applying an abbreviated "earnings" test to Order 14546, comparing only the Uprate Project's future costs against past Company surveillance reports, to conclude there is, in their opinion, a "negligible" impact on PEF earnings as a result of the Uprate Project. There is, however, no such test in Order 14546, and appropriately so.

No "earnings" test of any type is even mentioned in Order 14546. There is no requirement under item 10 of Order 14546 that a utility prove that it is incapable of recovering project costs through base rates without adversely affecting its allowable return on equity. Any requirement to determine if the utility's earnings are affected by a project proposed under item 10 of Order 14546 would necessarily subject the utility to a base rate proceeding inquiry to obtain Fuel Clause recovery of project costs designed to generate fuel savings.

The time and cost that must be invested in a base rate proceeding inquiry defeats the purpose of the Commission policy under item 10 of Order 14546. The Commission set forth a straight-forward, two-part test in item 10 of Order 14546 for Fuel Clause recovery to encourage utilities to pursue projects that would generate fuel savings for customers. Intervener witnesses agree that this was the Commission's purpose in item 10 of Order 14546. This purpose is advanced by providing utilities the opportunity for cost recovery under a simple test in an abbreviated proceeding. Turning that simple test in a Fuel Clause proceeding into a base rate inquiry eliminates the very incentive the Commission intended to establish in item 10 of Order 14546.

PEF specifically considered the Uprate Project because of the fuel savings presented by the Uprate Project and the ability to recover the costs of the Uprate Project through the Fuel Clause under item 10 of Order 14546. The Commission policy represented by item 10 of Order 14546, therefore, was in fact an incentive for the Uprate Project. The Commission's policy to encourage projects that generate fuel savings to reduce customer costs works. The ability to recover the Uprate Project's costs through the Fuel Clause under item 10 of Order 14546 was part of the Company's decision to proceed with the Uprate Project.

None of the Commission's numerous orders applying the Commission's policy under Item 10 of Order 14546 to a utility request for Fuel Clause recovery of project costs that generate fuel savings involved the consideration of the impact of the project costs on the return the utility was earning. For more than twenty years the Commission has applied item 10 of Order 14546 without any "earnings" test. PEF's earnings are, therefore, irrelevant to this proceeding. What is relevant is whether the CR3 Uprate project qualifies under the test set forth in Item 10 of Order 14546. Because it does, PEF's request for Fuel Clause recovery for the Uprate Project costs should be approved.

Q. Intervener witnesses also argue that, if the costs sought through the Fuel Clause under Order 14546 can be recovered in future base rates, they cannot be recovered through the Fuel Clause. Is this argument consistent with the policy established in Order 14546?

A. No. To explain this argument, intervener witnesses Lawton and Merchant both assert that Phases 2 and 3 of the Uprate Project are not appropriate for fuel clause recovery, because, by the time those costs are incurred, PEF will be able to go into a new base rates proceeding and obtain cost recovery through base rates. (Merchant Test., p. 26, lines 5-7; Lawton Test., p. 23, lines 2-9). Ms. Merchant goes on to testify that, given PEF's ability to initiate a new base rates proceeding, there will be no "regulatory lag" in recovering the CR3 Uprate costs, and this is really what Order 14546 was designed to prevent. (Merchant Test., p. 14, lines 7-16).

Intervener witnesses Lawton and Merchant are again reading non-existent requirements into Order 14546. The Commission did not require the utility to show that project costs were not recoverable in *future* base rates to obtain recovery of the project costs through the Fuel Clause under item 10 of Order 14546. Instead, the Commission required the utility to demonstrate that the project costs were not recognized or anticipated in *current* base rates. The intent was to protect against possible double recovery not to eliminate regulatory lag.

Indeed, PEF always has the right to initiate a base rate proceeding to address costs that it believes should be included in base rates to provide an adequate return. Even under the rate case settlement agreement, PEF can initiate a base rate proceeding to include costs in base rates if PEF's return falls below a certain level. A requirement that a utility demonstrate that project costs cannot be recovered in future base rates, again, defeats the purpose of the Commission policy established in Item 10 of Order 14546. And, again, in more than 20 years of applying its policy under item 10 of Order 14546, the Commission has never required the utility to show that the project costs cannot be recovered in future base rates to obtain recovery of those costs through the Fuel Clause.

Q. Intervener witnesses argue that the reference to "case-by-case" consideration of utility requests under item 10 of Order 14546 means that the Commission

should make any issue raised by any party to the proceeding a requirement that must be considered by the Commission in determining whether the relief requested should be granted. Do you agree?

A. No. The Commission intentionally selected a straightforward, two-part test under item 10 of Order 14546 to encourage utilities to pursue projects that generated fuel savings and thus lowered the cost of providing power to customers. The Commission was certainly aware of every issue that the intervener witnesses raise in their testimony at the time the Commission adopted the policy in item 10 of Order 14546, but the Commission decided not to make them requirements of item 10 of Order 14546. As I have explained, the reason the Commission decided not to add the issues raised by the intervener witnesses to the requirements for relief under item 10 of Order 14546 is clear: they are disincentives -- not incentives -- to a policy that encourages investment in projects that result in fuel savings to customers.

Order 14546 resulted from the Commission's direction to investor-owned utilities and other interested parties to consider the types of costs appropriate for fuel clause recovery. The parties did this and in fact "agreed to a policy addressing the appropriate prospective means of recovering such fossil fuel-related expenses." Order 14546 at 1. This policy is reflected in items 1 through 10 of Order 14546, where the Commission states: "As a result of our determinations in this proceeding, *prospectively*, the following charges are properly considered in the computation of the average inventory price of fuel used in the development of fuel expenses in the utilities' fuel cost recovery clauses." Id. at 3. Thus, Order 14546 is a policy of general applicability, which has the force of a rule, because it applies prospectively to all utilities. Intervener witnesses do not dispute that the Commission established a policy of general applicability in Order 14546, including item 10 of that Order.

As a policy of general applicability, the Commission should apply item 10 of Order 14546 uniformly and consistently to all utilities, applying the same requirements to all to achieve fairness. Likewise, applying consistent, uniform requirements to all utilities provides certainty to Commission policy and, therefore, promotes that policy. In the case of the policy under item 10 of Order 14546, there is a two-part test for recovery under the Fuel Clause that does not include any of the issues raised by the intervener witnesses. Similarly, the Commission has repeatedly and consistently applied this two-part test for over 20 years, without adding any additional requirements as the intervener witnesses suggest.

To allow the intervener witnesses to add to the requirements of item 10 of Order 14546 now, through their "case-by-case" argument, departs from the clear, express requirements of item 10 and past application of those requirements by the Commission, resulting in an unfair and uncertain application of Commission policy. The result will discourage, not encourage, utility projects in the future that achieve fuel savings to reduce customer costs.

In any event, the reference to the recovery of costs under item 10 of Order 14546 on a "case by case" basis does not mean what intervener witnesses say it means. The full statement is: "Recovery of such costs should be made on a case-by-case basis after Commission approval." Order 14546 at 4. The express recovery of "such costs" refers to the preceding sentence in item 10 setting forth the two-part test for the determination of recoverable costs under this item of Order 14546. The term "case-by-case basis," then, cannot be an open-ended invitation to add requirements to the ability to recover costs under item 10 of Order 14546 because it renders meaningless the express reference to the recovery of "such costs" in the same sentence.

Rather, the term "case-by-case basis after Commission approval" was included in item 10 to differentiate the costs under item 10 from the costs under items 1 through 9 of Order 14546. Costs identified in items 1 through 9, by the terms of Order 14546 itself, can be included by the utility in the development of their fuel expenses in the Fuel Clause without further Commission action. Costs under item 10 of Order 14546, however, cannot automatically be added to the utilities' fuel expenses but must be added only "after Commission approval," which necessarily must be done case-by-case to determine if the two-part test established by the Commission in item 10 of Order 14546 has been met.

Q. Do the intervener witnesses seek to apply the Commission policy in item 10 of Order 14546 or change it?

A. I believe the intervener witnesses seek to change Commission policy under item 10 of Order 14546 rather than apply it to PEF's Petition. Every argument that they assert to add to the requirements set forth under item 10 of Order 14546 – to impose a volatility requirement, to impose an "earnings" test, to narrowly define the term "fossil fuel-related costs", and to impose a requirement that costs cannot be recovered in "future' base rates – can be made with respect to any utility request for cost recovery through the Fuel Clause under item 10 of Order 14546. Their arguments, in fact, fly in the face of years of consistent application by the Commission of the express requirements in item 10 of Order 14546. See Order No. PSC-96-1172-FOF-EI, Docket No. 960001-EI (Sept. 19, 1996); Order No. PSC-95-1089-FOF-EI, Docket No. 950001 (Sept. 5, 1995); Order No. PSC-96-0353-FOF-EI, Docket No. 960001-EI (Mar. 13, 1996); Order No. PSC-97-0359-FOF-EI, Docket No. 970001-EI (Mar. 31, 1997); Order No. PSC-98-0412-FOF-EI, Docket No. 980001-EI (Mar. 20, 1998). They, therefore, seek to change the Commission policy, not apply the existing Commission policy to PEF's current request. If the interveners want to change the policy set forth by the Commission in item 10 of Order 14546, they should do so in a generic docket involving all utilities that would be affected by a change in the policy and other interested parties. Indeed, the policy in item 10 of Order 14546 was adopted in such a generic docket, providing all affected parties and interested persons an opportunity to participate in and comment on the development of that policy.

IV. THE APPLICATION OF COMMISSION POLICY UNDER ORDER 14546

Q. Do the intervener witnesses also challenge the application of Commission policy under item 10 of Order 14546 to PEF's request for cost recovery?

A. Yes, they do. Some intervener witnesses claim PEF has not demonstrated that the Uprate Project costs are not recoverable in current base rates even though they concede PEF has demonstrated that the Uprate Project costs were not recognized in

PEF's minimum filing requirements (MFRs) in its last base rate proceeding. Intervener witnesses also challenge the return on equity and recovery period of the Uprate Costs under PEF's request for cost recovery in its Petition. I will address each of these arguments in turn and explain why PEF's request for recovery of the Uprate Project costs through the Fuel Clause is consistent with the Commission's policy under item 10 of Order 14546 and Commission application of that policy to utility requests over the past 20 years.

Q. Are the Uprate Project costs recognized or anticipated in PEF's current base rates?

A. No, they are not. As I demonstrated in my amended direct testimony, the Uprate Project costs were not anticipated and recognized in PEF's MFRs at the time of PEF's last base rate proceeding and, accordingly, the Uprate Project costs are not recognized or anticipated in PEF's current base rates. Intervener Witness Merchant agrees that the Uprate Project costs are not recognized in PEF's MFRs. (Merchant Test., p. 15, lines 20-23).

Ms. Merchant argues, however, that just because the Uprate Project costs are not recognized in the Company's MFR's it does not mean that the Uprate Project costs could not be anticipated in current base rates. (Merchant Test., pp. 15-16). She essentially contends that base rates are designed to cover all base-rate type expenses, whether anticipated at the time of the utility's MFRs or not, and therefore the Uprate Project costs were implicitly anticipated in current base rates. (Id.).

Ms. Merchant's argument is contrary to the very terms of item 10 of Order 14546 and, if accepted, renders item 10 of Order 14546 meaningless. Under item 10 of Order 14546 a utility is required to show in part that the costs for which recovery is sought are those "normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates." Order 14546 at 4. The reference to the "cost levels used to determine current base rates" obviously refers to the Company's MFRs because that is how utilities demonstrate their "cost levels" to "determine current base rates." Ms. Merchant's argument, then, is inconsistent with the express terms of item 10 and must be rejected.

Additionally, if Ms. Merchant's construction of item 10 of Order 14546 was accepted the policy the Commission adopted in item 10 is again rendered meaningless. Every cost "normally recovered through base rates" that results in fuel savings does not meet the test established by Ms. Merchant, therefore, no such cost would be recoverable through the Fuel Clause under item 10 of Order 14546. The Commission clearly did not intend to adopt a policy in item 10 of Order 14546 that could never be applied.

Ms. Merchant cites no authority to support her novel construction of item 10 of Order 14546. The Commission's application of item 10 of Order 14546, in fact, refutes her construction of item 10. I am not aware of any Commission order applying item 10 of Order 14546 in the way Ms. Merchant does.

Finally, this construction of item 10 by Ms. Merchant is just another way to assert that there should be an additional requirement of an earnings test to item 10 of

Order 14546. She is essentially saying that the costs sought by utilities under item 10 of Order 14546 can and should be absorbed in base rates unless and until the utility determines that its earnings are affected. As I have explained, no such requirement exists under Order 14546 and any such "earnings" requirement undermines and does not advance the policy established by the Commission in item 10 of Order 14546.

Q. Intervener witnesses Lawton and Merchant argue that PEF's request for cost recovery, in particular the return on equity, is inappropriate. Do you agree?

A. No. PEF's request is consistent with the prior Commission orders applying item 10 of Order 14546. For example, the Commission approved FPL's requested return of 9.2897%, which was FPL's then-current weighted average cost of capital, when the Commission permitted FPL to recover the costs of its thermal power uprate at two of its nuclear units through the Fuel Clause under item 10 of Order 14546. See Order No. PSC-96-1172-FOF-EI, Docket No. 960001-EI (Sept. 19, 1996). Likewise, FPC (now PEF) was allowed to recover a return of 8.37%, which was authorized in Docket 91089-EI, PEF's then-last rate case proceeding, when the Commission approved the recovery of the cost of PEF's conversion of its Intercession City combustion turbine units P7 and P9 to burn natural gas through the Fuel Clause under item 10 of Order 14546. See Order No. PSC-95-1089-FOF-EI, Docket No. 950001 (Sept. 5, 1995). PEF's current request is also consistent with other, prior Orders of the Commission under item 10 of Order 14546. See Order No. PSC-96-0353-FOF-EI, Docket No. 960001-EI (Mar. 13, 1996); Order No. PSC-

97-0359-FOF-EI, Docket No. 970001-EI (Mar. 31, 1997); Order No. PSC-98-0412-FOF-EI, Docket No. 980001-EI (Mar. 20, 1998). PEF does not request any different treatment for the Uprate Project costs than how other project costs were treated by the Commission under Order 14546.

It must be remembered that the policy established by item 10 of Order 14546 was intended to encourage utilities to invest in projects that resulted in fuel savings to the benefit of customers. Intervener witnesses agree that this was the intent behind item 10 of Order 14546. (Merchant Test., p. 18, lines 7-9; Lawton Test., top page 9.). Reducing the allowable return on such project costs based on a claimed reduction in the risk, as intervener witnesses assert, would have the effect of discouraging, not encouraging, such projects through the Fuel Clause. That is not what the Commission intended in item 10 of Order 14546.

Q. Intervener witnesses also argue that the recovery of the Uprate Project costs should be spread out over the useful life of the Uprate Project rather than correspond to offsetting fuel savings. Do you agree?

A. No. Again, PEF's request is consistent with the Commission's prior application of its policy under item 10 of Order 14546. In Order No. PSC-96-1172-FOF-EI, for example, FPL's thermal power uprate costs were approved for recovery through the Fuel Clause under Order 14546 over a two-year period of time even though the fuel savings were projected out to 2011, meaning that the capital changes had an expected useful life of at least 15 years. Docket No. 960001-EI (Sept. 19, 1996). In fact, through license extensions Turkey Point Unit 3 is licensed to operate until 2032 and Turkey Point Unit 4 until 2033. That means the expected benefit of those uprates will extend over about 36 years. This illustrates that the practice of providing for an abbreviated amortization period is nothing new for projects being recovered under item 10 of Order 14546.

In Order No. 97-0359-FOF-EI, the Commission approved cost recovery over a five-year period through the Fuel Clause under Order 14546 for the conversion of peaking units to burn natural gas (DeBary 7, Bartow 3 & 4, Suwannee 1). Docket No. 970001-EI (Mar. 31, 1997). In Order No. 98-0412-FOF-EI, the Commission similarly approved cost recovery over a five-year period through the Fuel Clause under Order 14546 for the costs associated with converting Suwannee Unit 3 to be able to burn natural gas. Docket No. 980001-EI (Mar. 20, 1998). Likewise, in Order No. PSC-95-1089-FOF-EI, the Commission approved a five-year recovery through the Fuel Clause under Order 14546 of the costs of converting Intercession City combustion turbine units P7 and P9 to gas. Docket No. 950001 (Sept. 5, 1995). Additionally, in Order No. PSC-96-0353-FOF-EI, the Commission approved FPC's request for the recovery of the costs of converting Intercession City combustion turbine units P8 and P10 through the Fuel Clause under Order 14546 over a five-year period. Docket No. 960001-EI (Mar. 13, 1996). These combustion turbines typically have a depreciable life of around 30 years. Suwannee 1 and 3 were placed in service in 1980, DeBary 7 in 1992, and Intercession City 7 and 9 in 1993. The fact that the Commission saw fit to approve shortened amortization periods for these projects further illustrates that the treatment PEF is requesting in this Petition is nothing new. Rather, PEF's request is consistent with the historic treatment of items recovered under item 10 of Order 14546.

Q. Intervener witnesses Lawton and Merchant testify that PEF's requested cost recovery period violates certain principles of the Uniform System of Accounts ("USOA"). Do you agree?

A. No. When considering the USOA requirements it is important to realize that the Commission has the ability to modify their application. In fact, every time the Commission has approved abbreviated recovery of a capital project through the Fuel Clause in the past it has exercised this authority. Indeed, intervener witnesses Lawton and Merchant agree these requirements can be waived. (See, e.g., Merchant Test., p. 24, lines 4-6). This is, in fact, what the Commission has done time and again in the capital conversion projects and other projects that the Commission has approved pursuant to Item 10 of Order 14546. See Order No. PSC-96-1172-FOF-EI, Docket No. 960001-EI (Sept. 19, 1996); Order No. PSC-95-1089-FOF-EI, Docket No. 950001 (Sept. 5, 1995); Order No. PSC-96-0353-FOF-EI, Docket No. 960001-EI (Mar. 13, 1996); Order No. PSC-97-0359-FOF-EI, Docket No. 970001-EI (Mar. 31, 1997); Order No. PSC-98-0412-FOF-EI, Docket No. 980001-EI (Mar. 20, 1998). A shortened recovery period that corresponds to the period that fuel savings offset the project costs is nothing new and is in fact the typical manner of cost recovery approved under Order 14546. PEF's request for a cost recovery period equal to that of the offsetting fuel savings is just an application of this typical Commission practice.

Q. Intervener witnesses also argue that PEF's requested cost recovery period results in intergeneration inequity and harms PEF's customers. Do you agree?

A. No. First, intergeneration inequity arises when a customer today pays for something that will not produce benefits until some point in the future. With PEF's Uprate Project, however, today's customers will experience fuel savings immediately, in the first year after the Phase 1 of the Uprate, and projected for every year thereafter. In fact, the first year fuel savings are projected to exceed the Uprate Project costs that year. So, PEF's current customers will experience the benefits of the Uprate Project in the form of immediate and continuing fuel savings. Indeed, because PEF will only recover costs to the extent of fuel savings, customers are not paying for Uprate Project costs at all. The Uprate Project costs are being paid for by the fuel savings. Customer bills will remain the same or they will be lower (all other things being equal), so there is no real cost to today's or tomorrow's customers for the Uprate Project.

Second, PEF's requested manner of cost recovery is consistent with every Commission order that has granted cost recovery for utility project costs under item 10 of Order 14546. A similar argument regarding claimed intergeneration inequity can be made with respect to each of those past orders. For example, when the Commission approved the recovery of FPL's nuclear uprate costs through the Fuel Clause under Order 14546 over a two-year period the fuel savings were expected to continue for at least 15 years, resulting in the same alleged intergenerational inequity that intervener witnesses claim exists here. <u>See</u> Order No. PSC-96-1172-

FOF-EI, Docket No. 960001-EI (Sept. 19, 1996). The point is, in that order and in PEF's current request, there is no real intergenerational inequity concern because all customers are receiving fuel savings that through some point in time are simply used to pay for the Uprate Project. Customers should at worst be indifferent to the cost recovery period because the fuel savings are paying for the project costs. This, again, is consistent with the Commission's policy of encouraging utilities to take advantage of projects that result in fuel savings under item 10 of Order 14546.

Finally, intervener witnesses' arguments that PEF's customers are harmed by PEF's request rely almost exclusively on PEF's response to a discovery request (OPC Interrogatory Number 12) requesting revenue requirements information. This spreadsheet, which Mr. Lawton relies on for his exhibit DJL-4, shows that at the end of nine years (2016) the cumulative savings exceed the Uprate Project costs by $19.27 million. Mr. Lawton focuses on the fact that this spreadsheet shows that at the end of year eight (2015) the net savings show a small negative amount. Mr. Lawton then draws the conclusion that PEF's customers are harmed, at least through 2015. Mr. Lawton's reliance on this spreadsheet is misplaced.

PEF developed the spreadsheet showing the revenue requirements as a demonstrative tool to show the cumulative effect of the Uprate Project's fuel savings and to identify an initial cost recovery period whereby cumulative fuel savings exceed the Uprate Project costs. In the spreadsheet that occurs in year nine but PEF proposed an initial ten-year cost recovery period. The actual recovery period will depend, however, on the demonstration of the fuel savings to the costs in each fuel docket proceeding following approval of PEF's petition.

As we have repeatedly said, we intend to recover the Uprate Project costs to the extent that there are fuel savings. If there is an insufficient level of fuel savings in any particular year to cover the Uprate Project costs those costs in excess of the fuel savings that year will be deferred to the next year, and so on, until the costs are paid for by the fuel savings. That is why this particular spreadsheet was not used to support PEF's testimony in this proceeding, it is merely representative of the total fuel savings to costs. PEF's position is consistent with prior Commission precedent. In Order No. PSC-98-0412-FOF-EI, the Commission explained: "If the fuel savings during any annual period are less than the amortization and return costs, [PEF] shall limit cost recovery to actual fuels savings and defer recovery of the difference to future periods." Docket No. 980001-EI (Mar. 20, 1998). This is precisely what PEF proposes to do in this proceeding.

Q. Mr. Lawton argues that "precedent has little value," and so the Commission should not give much weight to its prior decisions. Do you agree?

A. No. All intervener witnesses agree that the Commission established a prospective policy of general application in item 10 of Order 14546. As I have explained, for this policy to have the intended effect there must be clear requirements that are uniformly and consistently applied by the Commission to guide utility actions. As a result, the Commission's prior application of the policy identified in item 10 of Order 14546 is especially important to the advancement of the Commission's policy under that Order. Tellingly, Mr. Lawton cites no authority for his argument that the Commission should completely ignore what it has done with other utilities' requests pursuant to item 10 of Order 14546. He also ignores his own position and attempts to distinguish prior Commission precedent approving FPL's request for cost recovery for its nuclear uprate project under Order 14546.

Q. Do you agree with the distinctions that the intervener witnesses attempt to draw between the FPL uprate (Order 96-1172) and the CR3 Uprate project?

A. No. None of the distinctions that Ms. Merchant (Merchant Test., p. 19) and Mr. Lawton (Lawton Test., p. 22) attempt to draw between FPL's uprate and the CR3 Uprate render reliance on Order 96-1172 inappropriate here.

Ms. Merchant first contends that the FPL uprate costs were "de minimus" compared to the fuel savings generated. There is no requirement in Item 10 of Order 14546, however, that the fuel savings must outweigh the costs by a certain percentage or by some nominal amount. The only requirement is that the projected fuel savings exceed the costs. Indeed, in FPC's 1998 cost recovery petition for the conversion costs for Suwannee Unit 3 (Order 98-0412), the savings were not much more than the costs of the project. Nevertheless, the Commission approved fuel clause recovery for the costs under Order 14546. Docket No. 980001-EI (Mar. 20, 1998). No prior Commission order has imposed some threshold for the cost to savings to support recovery through the Fuel Clause under Order 14546 and Ms. Merchant suggests none in her testimony. This claimed distinction is irrelevant to PEF's request.

Next, Mr. Lawton claims the lower cost of FPL's uprate, compared to the higher cost of the CR3 Uprate, is a material difference between the two projects.

Again, Order 14546 imposes no ceiling on the amount of project costs that may be passed through the Fuel Clause. The only requirement is that the projected fuel savings exceed the costs. As demonstrated in PEF's amended direct testimony, the projected fuel savings substantially exceed projected costs for the Uprate Project. In fact, the projected fuel savings from the Uprate Project far exceed the projected fuel savings from FPL's nuclear uprate or any other prior project approved under Order 14546.

Finally, intervener witnesses Merchant and Lawton both argue that FPL customers received savings in the first year, unlike what will happen with the CR3 Uprate. They are wrong. PEF's customers will receive fuel savings beginning in year one and continuing for every year throughout the projected twenty-year period.

In sum, witnesses Merchant and Lawton attempt to diminish the importance of the FPL order by pointing to immaterial differences between the FPL nuclear uprate and the CR3 Uprate. When it comes to the application of the Commission's policy in item 10 of Order 14546, there is no reason to treat PEF's request different from the FPL request for cost recovery for its nuclear uprate project.

Q. Intervener witnesses Merchant and Lawton also attack PEF's cost estimates and fuel savings projections for this project. Do you agree with their arguments?

A. No, I do not. Witnesses Merchant and Lawton make various sweeping statements about PEF's cost estimates and fuel savings projections to support their opposition to PEF's Petition. Yet, neither of them have done any independent analysis of

PEF's cost estimates or fuel savings projections nor do they have any reason to believe that PEF has not used the best available methodology and information to estimate the costs and fuel savings. The intervener witnesses offer no evidence to even suggest that PEF's estimates are unreasonable or imprudent in some way. They further agree that prior utility requests for recovery of project costs through the Fuel Clause under item 10 of Order 14546 were similarly based on utility estimates of costs and fuel savings.

PEF's cost and fuel savings estimates are consistent with generally accepted utility estimating tools or methodology and consistent with PEF's past and current cost and fuel savings estimation practice. I believe that our cost and fuel savings estimates are reasonable and prudent and represent the best information that is currently available to the Company.

PEF's petition further requests a determination that the Uprate Project is eligible for cost recovery through the Fuel Clause under item 10 of Order 14546 as applied by the Commission. PEF agrees that it will need to demonstrate that its Uprate Project costs are reasonable and prudent as it seeks recovery of the costs through the Fuel Clause as it has consistently done in all other applications of item 10 of Order 14546.

Q. Witnesses Merchant and Lawton, however, both refer to cost estimates that they claim are different from PEF's cost estimates to suggest that PEF's cost estimates are unreliable. Do you agree?

A. No. Ms. Merchant, for example, claims that PEF's costs are too indefinite because she says they increased by over $68 million in just one month. (Merchant Test., p. 4, lines 3-7). Ms. Merchant, however, is comparing apples to oranges. She is comparing the cost estimates presented in PEF's amended direct testimony, which do not include AFDUC, to the cost estimates presented in my late-filed Exhibit 3, which do include AFDUC. The cost estimates have not increased by $68 million, rather, Ms. Merchant is comparing two different numbers.

Mr. Lawton also claims that the fact that the cost estimates are not final places customers' fuel savings at greater risk (meaning that if costs increase, the fuel savings decrease). Of course, the corollary to that is true as well, if the costs decrease, then fuel savings increase. If that occurred, customers would receive even greater benefits. In addition, there is no risk to customers because PEF is proposing to defer cost recovery to the extent fuel savings materialize each year. So, at worst, the project will pay for itself and customer bills will not increase as a result of the Uprate Project.

V. THE RATE CASE SETTLEMENT AGREEMENT

Q. Mr. Pollock, on pages 5 to 6 of his testimony, argues that the costs of the CR3 Uprate cannot be recovered through the Fuel Clause because such recovery violates the PEF rate case settlement prohibition against "new surcharges." Do you agree with his argument?

A. No, I do not. First, the settlement agreement was not intended to preclude Fuel Clause recovery of costs that properly qualify for such recovery, including costs that qualify under the Commission policy in item 10 of Order 14546. This is also shown by paragraph 14 of the settlement agreement, which contemplates a return on equity for costs recovered through clauses, at exactly the amount that PEF seeks recovery in its Petition.

Second, the settlement agreement does not explicitly prohibit recovery through the Fuel Clause of costs incurred pursuant to the Commission policy in item 10 of Order 14546. The agreement nowhere references Order 14546 at all. Order 14546 was issued in 1985, well before the 2005 settlement agreement was signed. Thus, the parties to the agreement certainly knew about the Commission policy allowing Fuel Clause recovery pursuant to item 10 of Order 14546 at the time of the settlement. If the parties intended to explicitly prohibit the recovery through the Fuel Clause of costs allowed under the Commission policy in item 10 of Order 14546 cost recovery they could and should have said so in the agreement.

Lastly, the Company's proposal cannot be considered a "surcharge" at all, because it will not result in increased customer bills. PEF proposes to recover costs only to the extent of fuel savings, such that in each year the customers will only pay for the costs that are offset by fuel savings. As such, the costs of the CR3 Uprate project will not result in a surcharge, because customer bills will decrease or, in the worst case, remain the same as they would have been without the project. So PEF's proposal is in fact not a surcharge at all and thus could not violate the rate case settlement agreement in any event.

VI. NEED FOR CR3 UPRATE PROJECT

Q. Mr. Pollock argues that the Uprate Project costs will be paid for by additional customer revenue PEF generates with the project. Do you agree with this testimony?

A. No, I do not. Mr. Pollock ignores the fact that the CR3 Uprate was proposed to meet an economic need and not a reliability need. This is clear from Order No. PSC-07-0119-FOF-EI, the order approving the Company's need for the CR3 Uprate. Docket No. 060642-EI (Feb. 8, 2007). There, the Commission clearly stated that the Uprate Project was not needed for reliability, but that the project would generate fuel savings and increase fuel diversity. In other words, the Uprate Project was not needed to maintain its reserve margins to keep up with increasing customer load on the system. Therefore, the Uprate Project costs will not be paid for by revenues from increased customer growth or energy use. Instead, fuel savings will pay for the Uprate Project costs and there will be fuel savings left over for the benefit of PEF's customers.

Q. Does Mr. Pollock make any other arguments regarding PEF's need for the project?

A. Yes, at page 10, lines 5-10 of his testimony, Mr. Pollock argues that the sole need for the CR3 Uprate could not have been the fuel savings, because PEF included the expected megawatt additions into its 2007 Ten Year Site Plan ("TYSP").

Q. Do you agree with this argument?

A. No, I do not. Mr. Pollock's argument again misses the point of the need for the CR3 Project. Order PSC-07-0119-FOF-EI clearly states that the need was an economic need, i.e. to generate expected fuel savings. Indeed, PEF's 2006 TYSP, filed in April 2006 before PEF's CR3 need and fuel cost recovery petition was initially filed, did not include the CR3 Uprate project among the future planned generating units. It was only after the need for the CR3 Uprate was granted, in February 2007, that PEF included the additional megawatts from the CR3 Uprate in the April 2007 TYSP. The additional megawatts from the CR3 Uprate were included in the April 2007 TYSP because PEF cannot ignore megawatts that will be added to the system once they have been approved by the Commission. But the economic need for the Uprate Project remains the same, and Mr. Pollock is simply wrong to assume that the Uprate Project costs are offset by customer sales.

There is an additional benefit to the CR3 Uprate, however, which can be seen by its inclusion in the April 2007 TYSP. This project will have the added benefit of deferring other, fossil fuel generation planned in prior TYSPs.

VII. COST ALLOCATION ISSUES

Q. Mr. Pollock argues that the costs of the Uprate Project should be allocated on the basis of demand rather than energy. Can you address this argument?

A. Mr. Pollock's argument that the CR3 Uprate costs should be treated as a production demand-related cost is based on the erroneous assumption that the capacity of the uprate is needed for PEF to meet its projected peak demands. As I explained, the need for this project was an economic need, not a reliability need. The Uprate Project has nothing to do with how much demand PEF's customers are placing on the system. The genesis of the Uprate Project is the fuel savings that will be generated by displacing more expensive fossil fuels and purchased power with additional nuclear generation.

Furthermore, Order 14546 does not include any requirement that cost allocation between demand and energy customers be considered. Item 10 sets forth a test to consider a utility's request for Fuel Clause recovery, and once the test is satisfied, those costs can be recovered through the Fuel Clause. This is consistent with how the fuel savings will be calculated – the fuel savings will be applied to customers on the basis of energy, not demand. The costs should be similarly allocated, otherwise certain of PEF's customers will be receiving more fuel savings benefits while other customers are paying proportionately more of the costs.

The Commission's prior orders involving requests for cost recovery pursuant to Item 10, Order 14546, also confirm that the Commission has never considered cost allocation issues in connection with these types of requests. Indeed, the Commission approved a similar uprate for FPL's nuclear plant, with no distinction between demand and energy allocation. The issue in these prior proceedings was whether the project was appropriate for *fuel clause* recovery pursuant to Order 14546.

Q. Please comment on Mr. Pollock's arguments regarding recovery of these costs through the Capacity Cost Recovery Clause ("CCRC").

A. Simply put, there is no justification for recovery of the CR3 Uprate costs through the CCRC. The only justification for clause recovery is through the Fuel Clause, pursuant to item 10 of Order 14546. The test set forth in Item 10 of that Order does not address or contemplate CCRC recovery.

On page 18 of his testimony, Mr. Pollock sets forth two reasons to support CCRC recovery. First, he points to the fact that the Commission allowed post-9/11 security measures to be recovered through the CCRC. According to Mr. Pollock, these security costs are allocated in the same manner as all other production base rate costs (through the CCRC), and therefore the Uprate Project costs should be allocated the same way. It makes little sense to compare PEF's CR3 Uprate project to the post-9/11 security costs. Mr. Pollock has given no reason why the Commission's treatment of the security costs is at all relevant to PEF's Petition. Additionally, this argument incorrectly assumes that the Uprate Project costs are base rate costs and should be allocated accordingly. As explained in the Company's Petition and testimony, however, the Uprate Project qualifies for Fuel Clause recovery pursuant to item 10 of Order 14546. How nuclear costs are allocated in base rates, then, is irrelevant to how they are allocated when approved for Fuel Clause recovery.

Second, Mr. Pollock relies on the Commission's recent nuclear cost recovery rule for new nuclear plants as justification for recovery of the Uprate Costs through the CCRC. This rule has no application to PEF's request in this proceeding. The CR3 Uprate is not a new nuclear plant so the rule does not apply. Furthermore, as Mr. Pollock points out, the rule was not even in effect until April 2007, well after PEF filed its petition in this proceeding. Mr. Pollock's argument that the CR3 Uprate costs should be recovered through the CCRC must therefore fail.

Q. Can you comment on Mr. Pollock's argument that fuel savings do not justify fuel clause recovery for nuclear costs?

A. Yes, on page 19 of his testimony, Mr. Pollock argues that the Uprate Project costs cannot be allocated on the basis of fuel savings because FPL and the Commission rejected such allocations in prior proceedings. Both proceedings relied upon by Mr. Pollock, however, were *base rate* proceedings that addressed costs, such as the original construction of CR3, incurred to meet a peak demand need which this Commission has already determined is not the case with the Uprate Project. Thus, they are not relevant to PEF's request for recovery of the Uprate Project costs through the Fuel Clause under a specific Commission policy in item 10 of Order 14546. If PEF meets the test set forth in that order, which it does, PEF is entitled to recover the Uprate Project costs through the Fuel Clause.

VIII. MISCELLANEOUS ISSUES

Q. On pages 20-21 of his testimony, Mr. Pollock states that PEF's cost recovery should be reduced to reflect the joint ownership in CR3. Do you have any comments on this testimony?

A. Yes. PEF's request for cost recovery will not include any costs which CR3's joint owners have agreed to pay. Similarly, the fuel savings will be allocated proportionately among the joint owners based on the percentage of costs each owner bears.

Q. On pages 8-9 of her testimony, Ms. Merchant argues that all special cost recovery clauses have limited purposes and must be limited to prevent double recovery. Can you comment?

A. Yes. Ms. Merchant's argument highlights the fact that her main objection to PEF's request is not with the actual request itself but rather with the policy underlying clause recovery in general. She attacks all cost recovery clauses, not just PEF's specific request for fuel clause recovery. These general policy arguments have no place in PEF's specific request for fuel clause recovery pursuant to Item 10 of Order 14546. If Ms. Merchant and the other intervener witnesses wish for the Commission to address the clause recovery mechanisms in a more general policy setting, then a separate generic docket should be established for that purpose. But this proceeding is for the purpose of determining whether PEF's Uprate Project costs are eligible for recovery through the Fuel Clause pursuant to existing Commission policy in item 10 of Order 14546.

Q. Witness Lawton indicates that ratepayers will suffer a detrimental impact in the form of deferred income taxes, is this true?

A. There may be a deferred income tax impact on the ratepayer. This impact could be favorable, detrimental, or nonexistent. It will depend on the amount of time it takes to recover the costs associated with the Uprate Project under PEF's proposal. If PEF recovers all costs associated with the Uprate Project over ten years because the cumulative fuel savings exceed the cumulative project costs, there will be a mismatch between the tax and book life of the assets. This will always occur when recovery is accomplished over a period shorter or longer than the tax life. As such, there has been an impact in every other cost recovered through the Fuel Clause over a shortened time frame. This is nothing new and it is not a surprise to PEF, the Commission, or interveners. The Commission has consistently recognized that there is a benefit to encouraging projects that are designed to minimize fuel costs to the ratepayer. This is why the Commission has consistently approved recovery of such projects through the Fuel Clause on an abbreviated amortization schedule even though there will be deferred tax implications.

Q. Witness Merchant and Lawton seem confused as to what PEF is proposing to recover through the Fuel Clause associated with this Uprate Project. Can you make it clear what costs you seek Fuel Clause recovery of?

A. Consistent with past Commission precedent and policy, PEF should be authorized to recover through the Fuel Clause the amortization of capital costs and a return on capital at their current pretax weighted average cost of capital (WACC) of the

Uprate Project amortized over a period for which the demonstrated fuel savings exceed the amortization and pretax WACC return of the Uprate Project.

Q. Are you proposing to recover additional O&M costs, deferred taxes, or property taxes through the Fuel Clause?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. WALLS:

Q. Do you have a summary of your prefiled rebuttal testimony?

A. Yes, I do.

Q. Will you please summarize your prefiled rebuttal for the Commission, please?

A. Good afternoon, Commissioners. What intervenor witnesses have tried to do with this simple two-part test in Order 14546 is to add terms and definitions that nowhere appear in the order or in any later order applying that policy. They want to change the Commission's policy and not apply it to the uprate project before you.

Some intervenor witnesses argue that if some of the project costs can be absorbed into the utility's base rates without affecting its return on equity, then those costs should be recovered through base rates. There is no earnings test in the policy established by Order 14546. Had there been, this Commission would have applied it in all past cases that had come before it.

The Commission did not use an earnings test in 14546, because it would have turned a request for fuel clause recovery into a complex base rate inquiry, defeating the Commission's purpose of establishing a straightforward test to encourage projects like the CR3 uprate.

Intervenors also argue that PEF can ask for the cost of most of the uprate costs in future base rate proceedings, so recovery through the fuel clause should not be allowed. Again, there is no requirement that the utility show when its next base rate case will be -- sorry. There's no requirement that the utility show when its next rate case will be taken into consideration under Item 10. In fact, that same argument would apply to all the past decisions that the Commission has made.

The utility always has the right to put costs through base rates. The Commission knew this when it adopted the policy, and the Commission knew this in every case that came before it. It knew that such a requirement would mean that no projects would ever be recovered through the fuel clause, no matter what the net fuel savings were.

Intervenor witnesses further challenge PEF's request because it uses the current weighted average cost of capital. The current weighted average cost of capital has been consistently used by this Commission in pass-through clause proceedings. Typically it's established in a base rate proceeding, and that same rate is approved to be used in all other pass-through dockets.

They argue that there is no risk with fuel clause recovery, so PEF should not be allowed to recover a return on equity, only a cost of debt. PEF's request, though, is consistent with the Commission's application of Item 10, allowing utilities to recover their then-current weighted cost of capital, and that current weighted cost of capital would be the rate applied during the period of recovery. If the Commission was presented with a base rate case where they reviewed evidence and determined that the weighted cost of capital would change, they would in that order also make the change to pass-through clauses. So this current weighted average cost is not a guarantee for the entire recovery period, and I wanted to make that point clear.

Intervenor witnesses challenge the recovery period for capital costs. Again, PEF's request is consistent with the Commission's prior order applying this policy. PEF will recover the costs only to the extent that there are savings to pay for them. This does not harm customers, because the project will pay for itself through fuel savings, and the Commission has been willing to accept some delay in net savings to customers to encourage projects that benefit customers with substantial overall savings. This again is consistent with every petition that has been presented to the Commission. In each and every one of those cases, the costs were recovered over a significantly shorter period than the overall savings to be accrued.

In sum, FPC has met the straightforward test set forth by Item 10 of Order 14546, and the fuel clause recovery for the CR3 uprate project costs is therefore appropriate. Thank you.

MR. WALLS: We tender Mr. Portuondo for cross.

CHAIRMAN EDGAR: Thank you. Mr. McWhirter, any questions?

CROSS-EXAMINATION

BY MR. McWHIRTER:

Q. Mr. Portuondo, your company sought an uprate for CR3 in 2002; is that correct?

A. I'm not familiar with that one, Mr. McWhirter.

Q. You were examining Mr. Pollock's testimony, and Exhibit JP-2 to his testimony was the 100 or so cases where utilities have sought an uprate, and item number 90 was a CR3 uprate that resulted in 24 megawatts of thermal power increase. Do you have no knowledge of that?

A. In the context of the applicability of that uprate to Item 10, it's my recollection that that uprate did not meet the savings test, which is part 2, that the overall costs could be -- or the overall savings could be measured and quantified in order to demonstrate that the savings were sufficient to offset the costs.

Q. And as a result, you absorbed it in base rates?

A. Yes, sir, because it would not have complied with Item 10.

MR. McWHIRTER: I have no further questions.

CHAIRMAN EDGAR: Mr. Brew, any questions? No questions. Thank you.

Mr. Twomey?

MR. TWOMEY: Can we -- (gesturing).

CHAIRMAN EDGAR: We can do that. Mr. McGlothlin.

CROSS-EXAMINATION

BY MR. McGLOTHLIN:

Q. Mr. Portuondo, I was trying to listen to your summary, and during one part of the summary, you said the 11.75 percent is not a guarantee because, as I understand it, it's possible that the Commission may authorize a different overall cost of capital at some point subsequent to that; is that correct?

A. That is correct, just like what happened in 2005 when the last rate case was approved by the Commission and the 11.75 was authorized. It too was authorized to be put in place for all pass-through clauses.

Q. I was trying to find the point in your rebuttal testimony where you make that point. Can you direct me to it?

A. I don't believe I made it explicitly.

Q. Did you make it implicitly?

A. I believe it was implied in the fact that it would be run through a clause recovery mechanism.

Q. You understand, of course, that Mr. Lawton's point about a guaranteed return related not to the view that the 11.75 would not change, but rather to the fact that in the fuel cost recovery mechanism, there's a feature that we call a true-up mechanism and that he called a reconciliation; is that correct?

A. That is correct.

Q. And your point about the overall average cost of capital perhaps being changed by another overall average cost of capital is really a separate point, is it not?

A. It's the point to address the appropriateness of the weighted average cost of capital.

Q. And the weighted average cost of capital includes a return on equity that is higher than the risk-free cost of debt that he assumed for purposes of his testimony; correct?

A. He assumed an all-debt financing, which is not realistic for a project of this nature. And it is not consistent with the other capital projects being recovered through other clauses, which earn the current weighted average cost of capital.

Q. You say he assumed an all-debt cost of capital, but didn't he assume a return on equity that reflected the reduced risk that flows from the availability of a true-up proceeding to ensure that the targeted return would be realized?

A. He applied a debt rate as an equity cost rate, which I personally don't believe is realistic.

Q. But that's very different than saying that the company would finance with 100 percent debt, is it not?

A. It is different. But ultimately, the ability to secure equity capital at that cost rate would probably be unlikely.

Q. Would you agree that as compared to depreciation over the normal useful life of an asset, accelerated depreciation such as the ten-year period that is being requested by the company has the effect of generating increased cash flow?

A. Absolutely, and that is one of the shareholder benefits or incentives created by Item 10.

Q. As I understand it, with the exception of the -- and I don't know if it's more correct to say M-U-R or MUR. I don't know how one pronounces the acronym. But with the exception of the first phase, the balance of the project will be constructed prior to and during the refueling outage of 2009; is that correct?

A. With respect to --

Q. I'm sorry. Let me correct that. Phase 2 through 2009 and Phase 3 through 2011.

A. Correct. We've allocated time in those two outages that were already scheduled to accomplish the second and third phases of the project.

Q. So between this point in time and the point in time -- let me just ask another question first. Do I understand correctly that the company will recognize the incurrence of the costs associated with the projects at the point in time when they enter commercial service?

A. That is correct.

Q. And prior to that time, the amounts spent will be accumulated and capitalized and reflected in the plant account at the appropriate time?

A. That is correct.

Q. Do I also understand correctly that necessarily then the company will finance the construction of those assets prior to the point in time when they enter commercial service?

A. That is correct.

Q. And is it true that the calculation of the costs of the project that is being used in the comparison of costs versus fuel savings reflects or assumes the same capital structure that results in the overall average cost of capital that is being employed, in other words, both debt and equity?

A. If your question is does our calculation use the weighted average cost of capital throughout the recovery period that exists today, the answer is yes.

Q. So does that reflect the assumption that both equity and debt will be used to finance the construction of the project?

A. Yes. We would attempt to use all sources of capital to finance this project, like we do other capital projects.

Q. And bearing in mind that the recognition of the costs and the recovery of those costs will not occur until the point of commercial service, whether the Commission says do it through fuel recovery or whether it says do it through base rates, the company would have to finance the construction of that project in either event?

A. Correct. If the company elects to pursue the project, yes, we would have to finance it in any event.

MR. McGLOTHLIN: Those are all my questions.

CHAIRMAN EDGAR: Mr. Wright.

MR. WRIGHT: No questions, Madam Chairman. Thank you.

CHAIRMAN EDGAR: Mr. Twomey.

MR. TWOMEY: Yes, Madam Chair. Thank you. Just a couple.

CROSS-EXAMINATION

BY MR. TWOMEY:

Q. Good afternoon, sir.

A. Good afternoon.

Q. On page 3 of your rebuttal testimony, you again discuss the $2.6 billion of benefits to be achieved to the benefit of your customers; right?

A. Correct.

Q. And you say the project will result in fuel savings and lower costs; correct?

A. Could you point me to where you are?

Q. I think it's on page 4, or maybe you just say the policy of Item 10 is to result in fuel savings and lower costs; is that correct?

A. Again, where are you pointing? Where are you?

COMMISSIONER McMURRIAN: Mr. Twomey, is it line 10?

MR. TWOMEY: Pardon?

COMMISSIONER McMURRIAN: I think it may be lines 9 and 10 on page 4.

MR. TWOMEY: Commissioner, it sure is. I just wrote it down in my notes, and I didn't have it underlined.

BY MR. TWOMEY:

Q. She's right. Will you look at lines 9 and 10?

A. Yes, I see it.

Q. Is that your testimony?

A. Yes, it is. That is the intent of the policy, is that those fuel savings will result in lower costs to customers.

Q. And I understand the thrust of your testimony in this case is that this project is consistent with the intent of the policy; right?

A. Yes, sir.

Q. If you go ahead and undertake it?

A. Correct.

Q. Would you say that if you undertake the project and you achieve fuel savings and lower costs, that you are providing your customers with more efficient service than if you didn't undertake the project and had higher fuel costs and higher costs, operating costs? Does this --

A. I don't look at this project as efficiency.

It's more in terms of, you know, lowest cost to our customer. I see efficiency more, you know, are the lights flickering, or am I interrupting the customer frequently. I see that as the efficiency of our operations to provide service to the customer. I guess I have a different view of efficiency.

Q. You would just say -- because you recognize, don't you, that you have an obligation to provide your customers with efficient service, don't you?

A. Efficient, reliable service, yes, I agree with that.

Q. So you're saying that you see efficient as making the lights not flicker and avoiding operation -- discontinuation of service?

A. Yes, sir.

Q. But you don't want to include achieving lower costs and fuel savings in the definition of efficient?

A. I don't personally look at it that way. I see our role as a regulated utility to provide safe, reliable, efficient service to our customer at the least cost possible. The least cost is -- this component that we're talking about here today is how can I be innovative and do something, whatever that may be, to find an opportunity to lower costs to our customers.

Q. So you're saying you do recognize that you have an obligation to provide least cost service?

A. Oh, absolutely. I think in every single petition that has come before the Commission, that fundamental premise has existed.

Q. Okay. Now, I want to be clear on your answer to this. Again, my understanding of your testimony is that the lower fuel costs -- the fuel savings and the lower costs would still be attainable to the benefit of the customers as long as you undertook and completed this uprate project, irrespective of the method of capital and cost recovery; is that correct?

A. Correct.

Q. So to the extent that anybody in this room was concerned that the fuel savings and the lower costs ascribed to the project can't happen except if you get your petition approved, that's not necessarily true, is it?

A. No. I don't think we've ever said that that wasn't true. I think what we've said is that this order provided the incentive for the companies to bring before the Commission projects that would create fuel savings, but allow a timely recovery of their costs absent the need for a base rate proceeding.

In your example where the project is done in base rates, the economics of the project, the total net savings may not be as large over the life of the project as it is presented in our petition. The reason for that is, just like with a home loan or a mortgage, if you pay it off in 30 years, that's going to cost you more than paying it off in 15 years or in 10 years. So that same concept would have to be applied, and the net fuel savings would be different. That's not to say that they're going to go away, but they are different.

Q. Well, using that argument -- so you're saying that thesis benefits customers. Did I hear you correctly?

A. It benefits customers, and it benefits the company through increased cash flow in order to redeploy resources to meet other projects.

Q. Your company here in Florida has announced that it intends to build at least one, perhaps two new nuclear generating units in Levy County; correct?

A. Correct.

Q. Those plants are projected to cost what, 5, 6 billion apiece?

A. I don't have those numbers.

Q. Do you have a ballpark figure?

A. No.

Q. Let's say they cost only $4 billion. Would it be your thesis that customers would be better off paying off the capital costs of the plant in ten years as opposed to the expected operating lives of the plants because they would pay less interest? That would be consistent with what you just said here; right?

A. That's correct. If you shorten the recovery period, you reduce the amount of carrying costs that the customer pays.

Q. But you don't expect that if you build that plant and put it in rates that it's going to be recovered under any other scenario but over the projected operating life of the plant, do you?

A. Oh, correct. No, I would never propose such a thing for a base load capacity need, absolutely not.

Q. Okay. With the limitations, I think, of what Mr. McGlothlin asked you about a second ago, the fact of the matter is, to the advantage of the company, that if you get your petition approved, you will essentially have a guaranteed return at some level, presumably starting at 11.75; isn't that correct?

A. To the extent that the costs are deemed prudent by this Commission, that is correct.

Q. And isn't it true as well that that guarantee, at whatever level, is superior, in terms of providing shareholder value, to having the mere opportunity of earning whatever your authorized rate of return is through base rate recovery? Do you understand the question?

A. I guess I wouldn't say it's superior because, again, given the range of reasonableness, base rates also provides me the opportunity to earn more than the 11.75.

Q. What is your most recent reported return on equity in your last surveillance report?

A. The December was 11 percent. The latest was, I think, 10.8. I think 10.8. I don't have it committed to memory. I do have the December committed to memory.

Q. That's a good enough answer. Thank you.

I want to skip for a minute and go to the page 32 area. You don't need to refer to it. I think you'll understand. It's the part of your testimony that deals with cost allocation issues, and you were asked some questions on this yesterday. But it's clear from your statement there that since you ascribe the construction and planning of this plant uprate to fuel savings, you believe equitably it should be -- the costs should be recovered through the fuel clause as well, not the capacity clause; correct?

A. Right. I think that's an appropriate matching of the cost assignment to the clause which is giving rise to the savings.

Q. And I think I heard you say that that methodology of recovery through the fuel clause would be more equitable to residential customers of yours, including most of my clients, than going through the capacity clause; correct? Or isn't that the result?

A. I guess the way I would phrase it is that the opposite would be inequitable, because the savings are accruing based on energy, and it would be inequitable to charge the costs on a different basis which would put a larger burden on your residential customers.

Q. Fair enough. Let me go back to the -- help me have a clearer understanding of the distinctions between how the customers are treated and the company is treated as between the fuel clause treatment sought in your petition versus rate base recovery. The fuel savings, if your petition is approved, when do the net fuel savings again start accruing to the benefit of your customers?

A. You said the net fuel savings?

Q. Yes. I ask that because -- help me on this. My understanding is that the fuel savings would be used to pay down -- to the extent they exist, they would be used to pay down the capital costs of the project.

A. Correct. And I think the first year in which customers actually see a benefit is in 2008, with the installation of the MUR. I believe that the savings in that year surpass the $6 million worth of costs, so it would be -- in 2008 would be the first year.

Q. And when would they -- when would the fuel savings first occur to the benefit of the customers if the recovery was through base rates?

A. 2008.

Q. Okay. And if you know, what would the relative magnitude of the savings be for the two?

A. It would be the -- well, they would get 100 percent of the savings through fuel in 2008, and the costs would be absorbed into current base rates.

Q. Base rates?

A. Correct.

MR. TWOMEY: Okay. Thank you. That's all I have. Thank you.

CHAIRMAN EDGAR: Commissioners. Commissioner Carter.

COMMISSIONER CARTER: Thank you, Madam Chairman.

Mr. Portuondo, I'm trying to get my head around this issue here. You heard my questions this morning regarding Paragraph 10. Yesterday you were asked a line of questioning by Commissioner Argenziano, and also this morning you heard the line of questions by

Commissioner Skop in the context of -- and if I got it wrong, I'm sure you'll let me know. In Phase 1, I think you said there would be like 12 megawatts, and in Phase 2 there would be like 40 megawatts.

In light of Exhibit 28 which was presented to you yesterday, wouldn't that be more in line with the actual applications, the prior applications of Item 10 more so than what you're presenting now? Wouldn't it fall within that -- I mean, you're talking about 40 megawatts, plus you're talking about substantially less than $400 million; correct?

THE WITNESS: Yes and no. Yes and no, sir. If you're simply comparing costs, yes, the first phase is more in line with the costs that were presented in previous proceedings, 6 million. The savings are based on smaller megawatts, so again, probably very comparable.

Again, but I think all of the phases that we're presenting in this proceeding are identical to the fundamental principles that were used to approve those smaller cost, smaller savings type projects, since the goal is, are you in essence holding the customer harmless because you're able to fund the recovery of the project costs with achieved fuel savings. And the Commission is allowing the recovery over whatever period those savings are sufficient to cover the costs so that it's collected as quickly as possible and the full 100 percent of the savings can accrue to customers as quickly as possible.

COMMISSIONER CARTER: Madam Chair.

But we're talking about a significantly less amount of money in this process here, though; right? I'm kind of zeroing in on this Phase 1 and 2 in terms of the megawatts that would be provided and the savings. Do you understand what I'm trying to get here?

THE WITNESS: Yes.

COMMISSIONER CARTER: It seems inconsistent -- excuse me for a moment. Let me just kind of finish my thought pattern here. It seems more consistent with -- particularly as we look at Exhibit 28, it seems more consistent with the projects that were within the confines from prior orders or the prior applications of this Item 10 than the proposal as it's currently iterated.

THE WITNESS: Well, I don't agree. I think that -- let's look at the circumstances in each of those cases as compared to ours. It was a capital investment that was being made in a generating facility. It was a capital investment that had a useful life far longer than the recovery period awarded. It was a capital investment whose -- it was a capital investment that, if undertaken, would create savings, fossil fuel savings far superior to -- far greater than the costs that would be necessary to achieve those savings.

In each of those previous cases, the utilities were being monitored from an earnings surveillance perspective, so the Commission, the staff, and the intervenors all knew what the range of reasonableness was. So that's the same.

The utilities would have known that these projects were being contemplated and would have to schedule them accordingly, especially St. Lucie. You would have to plan for an outage. So in that case, they could have planned for a base rate proceeding if that was the intent of the Commission.

So every single one of those factors that existed for every one of those cases exists here today with this case.

COMMISSIONER CARTER: Are you saying this is identical to the other cases? Because I don't read it that way.

THE WITNESS: I certainly do.

COMMISSIONER CARTER: No further questions.

CHAIRMAN EDGAR: Commissioner McMurrian, and then Commissioner Skop.

COMMISSIONER McMURRIAN: Thank you. Mr. Portuondo, in your opening statement or your summary, you mentioned that you wanted to make clear something about the weighted average cost of capital, and the way I have it is that the current average cost is not a guarantee over the entire recovery period. And I didn't quite get all of that, so could you elaborate on that for me?

THE WITNESS: I sure can. Typically what's done is, the Commission will take testimony in a base rate proceeding, and they will establish the common equity cost rate. And the cost rate authorized in that proceeding is then applied prospectively to any pass-through clause where capital investments are being recovered. So it becomes applicable to your environmental clause, your energy efficiency cost recovery clause, and the fuel clause or capacity clause to the extent you have a return that's being recovered in those clauses.

The next time the Commission changes the reasonable weighted average cost of capital in the next base rate proceeding or show cause proceeding, then I would expect the same thing to occur, given history.

COMMISSIONER McMURRIAN: Okay. Thank you. I did have a couple others. In cross by Mr. Twomey, there was discussion about when customers see benefits with respect to your project, and I remember that earlier when we were talking to Mr. Lawton, there was a discussion about that the customers would get the benefits after the first ten years. And I may be confusing something, but I wonder if you can help me sort of get that straight.

THE WITNESS: Sure. Because we are accomplishing this total uprate in three phases because of the three outages that are already scheduled, the first outage is this fall in 2007, where the MUR project will go in. So that asset will become commercial, as Mr. Twomey indicated, in the November-December time frame of '07. So the benefits of those 12 megawatts begin to accrue in 2008 and beyond.

The costs to recover that MUR, given the small nature, as Commissioner Carter indicated, is not greater than the expected savings in that one year from the 12 megawatts. So customers will see a reduction in their -- all other things being equal, in their factor for fuel in 2008 because there are more savings than there are costs being recovered.

COMMISSIONER TEW: I know I should have probably asked this of Mr. Lawton, and we're through with Mr. Lawton, but can you help me remember why he might say that after the first ten years is when the customers would see the benefit?

THE WITNESS: Sure, and I can. It has to do with Phase 2 and Phase 3. The savings for Phase 2 and Phase 3 are not sufficient to pay for the costs and still leave savings available to customers until the -- what we hope to be the ten-year period. Once that ten-year period is complete, then they get 100 percent of the savings.

Now, having said that, even within that ten-year period, there could be two, three, four years where you get some savings, but not huge like you will get following that ten-year period.

COMMISSIONER McMURRIAN: And that would depend on the actual amount of costs that are put through the clause in any given year, and then the savings on the fuel side?

THE WITNESS: Exactly.

COMMISSIONER McMURRIAN: So is it correct to say that in 2008 there might be savings, but then there may be a gap of possibly up to ten years where there wouldn't be savings to customers in those given years, and then the savings would pick up again? Is that where the ten years --

THE WITNESS: Correct. That could be an

outcome. Another outcome could be that they get a small amount of savings in every year. It will all depend on the projected savings, the cost of oil, the cost of gas.

COMMISSIONER McMURRIAN: And I did have one more, Chairman. Earlier when Mr. McWhirter was asking you a question about Table 2 under Mr. Pollock's Exhibit, JP-2, and he asked you about the Crystal River 3 uprate, I guess in 2002, and you said that it didn't comply with Item 10. And I just wanted to ask you why didn't it apply with Item 10.

THE WITNESS: Well, one of the things that the Commission requires under Item 10 is that you prove up the fuel savings. As I was asked yesterday in direct, we will present to the Commission a schedule, an exhibit and testimony showing the savings, and we will be running the models to quantify those savings.

My recollection of the type of modification that was being made in that particular uprate was not conducive to being able to present that kind of evidence to the Commission. So my recommendation to management was that it did not meet the tests under Item 10, because I could not demonstrate the savings to offset the costs.

COMMISSIONER McMURRIAN: Thank you.

CHAIRMAN EDGAR: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair. Again, I have some questions along the lines that Mr. McWhirter brought on cross-examination. Again, he raised a point that escaped my attention, and Commissioner McMurrian also brought that point home a little bit. But I would like to draw your attention also to the prior uprate that was done on CR3. And I just want to make sure for my own knowledge -- and again, I'm having trouble at times hearing all the way down here on the end. But that uprate was performed in 2003; is that correct?

THE WITNESS: Yes.

COMMISSIONER SKOP: And I noticed that in that table, page 7 of JP-2 -- and I don't know if you have that before you.

THE WITNESS: This is of my rebuttal testimony?

COMMISSIONER SKOP: No, it's JP-2. It's another table that was referenced in Mr. Pollock's. And I can speak to the point without reference to the exhibit, because it was for a different witness's testimony. But that uprate in that exhibit was identified as a stretch uprate, and it was basically .9 percent with 24 megawatts of increased generation.

And I'm curious for two points, one of which was raised by Mr. McWhirter, and the other one raised by Commissioner McMurrian. Having been identified as a stretch uprate, which is basically what the Turkey Point one was, it just seems -- I don't know what went into that uprate. But again, out of all the uprates on those three pages, for a stretch or a MUR, that's the lowest percent uprate of any of those, so I'm kind of wondering what made it a stretch uprate, given the fact that the percentage was the smallest of any that I see on that paper. Do you have any explanation as to that, of what was done with that uprate?

THE WITNESS: No, sir, I do not. I don't know how the NR -- I'm assuming this is an NRC document.

COMMISSIONER SKOP: Yes, sir.

THE WITNESS: And how they evaluate something being stretch versus not a stretch, no.

COMMISSIONER SKOP: Okay. Moving on to that point where you mentioned that this project was recovered through the base rates, you mentioned in response to Commissioner McMurrian it was because you didn't feel that it qualified under Item 10 to the extent that you could not quantify the fuel cost savings associated with that. Is that correct?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: But I think you admit that any additional nuclear generation would displace fuel savings; correct?

THE WITNESS: Yes, but I have to be able to bring that evidence to the Commission. I just -- take my word for it, I don't think it's going to fly.

COMMISSIONER SKOP: So how in the instant case are you able to identify that when in the past you weren't able to do that for an uprate, which is an uprate, which is an uprate?

THE WITNESS: The -- my understanding was that the modeling for that 24 megawatts, we were not able for some reason -- and again, I take what's presented to me. My first question to them is, "Prove it up to me." And what I was being told was that there was a problem with being able to model those savings, and therefore I rejected it.

Here in the instant case, I was presented by Mr. Waters the analysis, the runs of the PROSYM model that supports this savings calculation. So in this case I said, "Okay. I do have evidence. I can show the models."

For some reason, running of the models was not capturing that uprate differential. I don't know why.

COMMISSIONER SKOP: So as a follow-up, you can't quantify the avoided cost of fuel savings based on

24 additional megawatts of nuclear under an uprate as opposed to what you would have to otherwise generate via a fossil fuel?

THE WITNESS: You know, I wish I knew all the particulars, but I don't. You know, we're able to quantify the MUR, which is 12 megawatts. They presented that to us. This particular case, you know, I regret I don't have the particulars of why they couldn't do it. I just know that if they can't bring it to me, I reject it.

COMMISSIONER SKOP: Okay. And finally, with respect to that uprate that was performed -- again, I think we've belabored the point between how can you quantify an MUR of 12 megawatts and come forward versus having 24 megawatts previously and not being able to do the same thing, but I won't belabor that point.

With respect to the uprate that was performed in 2002, which again escaped my diligent reading until it was brought forth, is any part of that stretch uprate -- and I assume they only have one reactor there. It's not like Turkey Point where they have two, and it's not like Port St. Lucie where they have two or three, or actually two. Is any part of that uprate redundant to what's being proposed now in terms of what has been granted under the need determination?

THE WITNESS: No, sir.

COMMISSIONER SKOP: And did that uprate of the 24 megawatts, is that reflected in the 900 megawatts that's shown for the premodification of the existing reactor plant?

THE WITNESS: Yes, sir.

COMMISSIONER SKOP: Okay. Thank you.

CHAIRMAN EDGAR: Commissioners, any other questions at this time? No. Are there questions from staff?

MS. BENNETT: Yes, Madam Chair. Thank you.

CROSS-EXAMINATION

BY MS. BENNETT:

Q. Mr. Portuondo, we discussed earlier that the project, the useful life of the project will be until 2036, but the savings, the costs will be collected from the customers in the first ten years, approximately; is that correct?

A. Yes, ma'am.

Q. I need to talk a little bit about the federal tax period and deferred taxes. The federal tax period for recovery of all the assets associated with the CR3 uprate project is 15 years; is that correct?

A. Yes, it is.

Q. So PEF's proposed recovery period of ten years or less for the investment in the CR3 uprate project is less than the tax life of these assets; is that correct?

A. That is correct, and it is consistent with all past approved projects under Item 10.

Q. Mr. Young is going to hand you a document entitled "Deferred Tax Impact of Different Recovery Periods," which was Late-filed Exhibit Number 2, and that would be identified as Hearing I.D. No. 24.

(Exhibit 24 was marked for identification.)

BY MS. BENNETT:

Q. And do you recognize this schedule?

A. Yes, I do.

Q. Did you or someone under your supervision prepare this schedule in response to a question during your July 24th deposition?

A. Yes.

Q. To your knowledge, is this schedule true and accurate?

A. Yes.

Q. Are there any changes that you're aware of that need to be made to this schedule?

A. Not that I'm aware of.

Q. To the extent that the recoverable life of an asset is less than the tax life of the asset, would you agree that there would be a detrimental impact on deferred taxes?

A. Detrimental impact on the weighted average cost of capital, yes.

Q. Okay. Yes. And did PEF attempt to quantify the impact on deferred taxes if its proposal for recovery periods is accepted by the Commission?

A. No, we did not.

Q. If PEF's recovery of the investment in the CR3 uprate project is spread over the expected useful life of the uprate assets, such treatment would preserve the value of the deferred taxes for the benefit of the ratepayers; is this correct?

A. If I could restate that, if the recoverable life is greater than the tax life, it would create a benefit to rate base through a lower weighted average cost of capital.

Q. Okay. And if PEF's recovery of the investment in the CR3 uprate project is spread over the expected useful life of the uprate assets, that will leave more savings that will lower the fuel factor to customers; is that correct?

A. Could you repeat that?

Q. Sure. If PEF's recovery of the investment in the CR3 uprate project is spread over the expected useful life of the uprate assets, that will leave more savings that will lower the fuel factor to customers; is this correct?

A. That is correct. On an annual basis, that is correct. Over the long term or over the useful life, because of the carrying charges on the uncollected balance, it would be no different than in base rates. They would end up paying more than what we've presented here today.

Q. Yesterday you were in the room when Mr. Waters testified, and he deferred some questions to you; is that correct?

A. Yes.

Q. I remember those questions. Do you recall Mr. Waters talking about the recovery method of the Bartow repowering project?

A. Yes.

Q. Would you agree that the recovery of the investment in the Bartow repowering will be through base rates?

A. Absolutely.

Q. Hines Unit 4 is expected to come online in December of this year; is that correct?

A. Yes.

Q. When Hines Unit 4 comes online later this year, would you agree that recovery of the investment in

Hines Unit 4 will be through base rates?

A. That is correct. Both of those power plants were constructed to meet a capacity need, and the difference between those and the project before you today is that the fuel savings that those projects may provide to the system in no way are greater than the cost of those projects, so that's test 2 of Item 10, do the fuel savings -- are the fuel savings greater than the costs expended to achieve.

Q. Okay. Would you turn to page 29 of your rebuttal testimony? And I want to refer you to lines 3 through 6.

A. Yes, ma'am.

Q. On lines 3 through 6, you discuss the cost estimate of the CR3 uprate project with and without AFUDC; is that correct?

A. That's correct.

Q. And AFUDC stands for?

A. Allowance for funds used during construction.

Q. Also in this passage, you mention a Late-filed Deposition Exhibit 3; is this correct?

A. Yes.

Q. And Late-filed Deposition Exhibit 3 was filed in response to an OPC inquiry during your May 23rd deposition; is that correct?

A. Correct.

MS. BENNETT: I'm having an exhibit Mr. Young is passing out that is the late-filed exhibit. And, Madam Chairman, could we have that marked as Exhibit 29?

CHAIRMAN EDGAR: We will mark as Exhibit 29, and can you give me a description?

MS. BENNETT: Besides the long sheet, it is the Excel spreadsheet showing AFUDC, Late-filed Exhibit 3. And as a note, Madam Chair, this exhibit will take care of the problem I talked with you about at the break.

CHAIRMAN EDGAR: All right. That will work.

(Exhibit 29 was marked for identification.)

BY MS. BENNETT:

Q. Mr. Portuondo, do you recognize this schedule?

A. Yes, I do.

Q. Would you turn to the second page?

A. Yes.

Q. Does this schedule show the amount of return PEF projects it will earn on the CR3 uprate project if it is allowed to recover the investment through the fuel cost recovery clause?

A. It does. There's a section called "Return," and it shows the annual return expected through the recovery period.

Q. And what is the total amount of the return PEF projects to earn on the CR3 uprate project if it's allowed to recover the investment through the fuel cost recovery clause?

A. I've got to add it up.

The total return, debt and equity, is 291 million.

Q. Thank you. And then one final line of questioning. It's my understanding that Progress Energy is releasing its second quarter earnings results today; is that correct?

A. Today is the 9th. Yes.

Q. And Bob McGehee is the chairman and chief executive officer of Progress Energy; is that correct?

A. Yes, he is.

Q. And when Mr. McGehee mentions core businesses with respect to Progress Energy, he is referring to its utilities, Progress Energy Florida and Progress Energy Carolinas; is that correct?

A. That is correct.

MS. BENNETT: Mr. Young is passing out an exhibit. I would like that marked as Exhibit 30, and let's call it Progress Energy Second Quarter Results.

(Exhibit 30 was marked for identification.)

BY MS. BENNETT:

Q. Mr. Portuondo, are you aware that Progress Energy posts company-related press releases on its website?

A. Yes, I am.

Q. Okay. And have you seen this press release regarding Progress Energy's second quarter earnings?

A. Not this one.

Q. The page that was just handed to you was printed from Progress Energy's website this morning. Do you see the third paragraph on this page that begins, the quote, "Our core businesses continue to perform well"?

A. Yes, I do.

Q. Would you read that paragraph aloud into the record?

A. "'Our core businesses continued to perform well in the second quarter,' said Bob McGehee, chairman and chief executive officer of Progress Energy. 'With the sale of our energy contracts with the Georgia cooperatives we have completed the last major step in our plan to focus our capital and our attention on meeting the needs of our two growing utilities. We have completed this transition ahead of schedule. More important, the results of this initiative have produced a stronger balance sheet, enhanced credit ratings, and have contributed to strong ongoing earnings growth. We believe these actions firmly support our investment objective of offering a reasonable total return with low volatility.'"

Q. Thank you. When Mr. McGehee states that the company has completed the last major step in our plan, he's referring to Progress Energy's initiative to divest its nonregulated businesses; is that correct?

A. That is correct.

Q. Would you agree with Mr. McGehee's remarks that after having successfully divested its nonregulated businesses, Progress Energy is now a better position to fund capital projects of its regulated utilities, including Progress Energy Florida?

A. Yes. It has helped in funding the upcoming capital initiatives of the two utilities.

MS. BENNETT: Thank you. I have no further questions.

CHAIRMAN EDGAR: Mr. Walls, redirect?

MR. WALLS: Yes, very briefly.

REDIRECT EXAMINATION

BY MR. WALLS:

Q. Mr. Portuondo, if you would turn back to JP Exhibit -- this JP being Jeff Pollock, not Javier Portuondo. And that's JP Exhibit 2.

A. JP-2, page --

Q. Yes. If you look at page 7 of 8, where the Crystal River 3 uprate was identified in item 90.

A. Yes, sir.

Q. And you see in the second column it had 24?

A. Yes, sir.

Q. And if you look back to page 4 of 8, that second column is entitled "MWT." Do you see that?

A. I do.

Q. If you go to the first page of the document, page 1 of 8, the second sentence says, "The NRC has completed 102 such reviews to date, resulting in a gain of approximately 12,615 MWT (megawatts thermal) or 4,216 MWE (megawatts electric) at existing plants." Do you see that?

A. I do.

Q. So if we look back at the uprate for CR3 on page 8 at 90, item 90, where it says 24 MWT, how many megawatts electric is that?

A. Rounded, 8 megawatts.

MR. WALLS: Thank you. No further questions.

CHAIRMAN EDGAR: Okay. Let's take up the exhibits. I have 24, 29, and 30 offered by staff.

MS. BENNETT: Yes, Chairman. We would offer 24, 29, and 30 into the record.

CHAIRMAN EDGAR: Any objections?

MR. WALLS: No objections.

CHAIRMAN EDGAR: No objections? Seeing none, we will enter Exhibits 24, 29, and 30.

(Exhibits 24, 29, and 30 were admitted into the record.)

CHAIRMAN EDGAR: Any other matters for this witness? Seeing none, the witness is excused. Thank you, Mr. Portuondo.

THE WITNESS: Thank you.

CHAIRMAN EDGAR: Okay. As noted earlier, Mr. Portuondo is our last witness. Are there any other matters that we should address while we are all gathered here together before we adjourn?

Ms. Bennett.

MS. BENNETT: I would note for the record that the critical dates for the remainder of this docket are that the hearing transcript will be due August 14th, the briefs August the 28th. And the briefs, according to the Prehearing Order, are not to exceed 40 pages, summaries not to exceed 100 words for each position. The recommendation by staff will be September 27th, and the post-hearing agenda October the 9th.

CHAIRMAN EDGAR: Any questions about the dates that Ms. Bennett has relayed to us? No questions.

Okay. Any other matters?

Seeing none, Ms. Bennett, let me confirm, on my exhibit list, Exhibit 25.

MS. BENNETT: Exhibit 25 we did not enter into the record, nor did we enter Exhibit 23 into the record.

CHAIRMAN EDGAR: Okay. That's what I had, but I wanted to make sure.

Okay. Commissioner Argenziano.

COMMISSIONER ARGENZIANO: I don't know if this is appropriate, but I found out during our meeting that President Ken Pruitt's son died last night, and I just wanted to express my condolences, and maybe that we all just think about his family today.

CHAIRMAN EDGAR: Absolutely. Thank you, Commissioner. All of our, I know, thoughts go out to Senator Pruitt, President Pruitt and his family and friends. Thank you.

And with that, we are adjourned.

(Proceedings concluded at 1:15 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 550 through 633 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 14th day of August, 2007.

Mary Allen Neel

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
Staff				
1		Exhibit List- 1	Comprehensive Exhibit List	
Testimony Exhibit List				
PEF				
2	Daniel L. Roderick	DLR-1	Aerial view of Crystal River Complex, including CR3.	
3	Daniel L. Roderick	DLR-2	Photo of primary plant configuration for pressurized water reactor nuclear plant at CR3 that shows major components of nuclear reactor and primary coolant system.	
4	Daniel L. Roderick	DLR-3	Schematic of major components in primary system and balance of nuclear plant that shows major components in secondary systems, including main turbine and main generator.	
5	Samuel S. Waters	SSW-1 (Amended)	Amended Summary of Annual Fuel Savings of Proposed Power Upgrade to CR3.	
6	Samuel S. Waters	SSW-2	Summary of Overall Cost Effectiveness of the Proposed Power Upgrade to CR3 to the retail customer.	
7	Javier Portuondo	JP-1	Excerpt of Schedule B-13 of Minimum Filing Requirement submitted in Docket No. 050078-EI.	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 1
COMPANY FL Public Service Comm. Staff
WITNESS Exhibit List 1
DATE 08/07+08/07

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
8	Javier Portuondo	JP-2	Excerpt of Schedule B-2 of Minimum Filing Requirement submitted in Docket No. 050078-EI.	
9	Javier Portuondo	JP-3	Excerpt of Schedule B-1 of Minimum Filing Requirement submitted in Docket No. 050078-EI.	
OPC				
10	Patricia W. Merchant	PWM-1	Resume.	
11	Daniel J. Lawton	DJL-1	Resume and Case Listing.	
12	Daniel J. Lawton	DJL-2	Deferred Tax Impact.	
13	Daniel J. Lawton	DJL-3	Net Savings at 7.5% ROR.	
14	Daniel J. Lawton	DJL-4	Cash Flow Comparison.	
15	Daniel J. Lawton	DJL-5	PEF's Proposed Timing.	
FIPUG				
16	Jeffry Pollock	JP-1	PEF 2006 Surveillance Report.	
17	Jeffry Pollock	JP-2	USNRC Power Uprates.	
18	Jeffry Pollock	JP-3	Impact of Sales Growth.	
19	Jeffry Pollock	JP-4	CCCR vs. Fuel Clause.	
20			Review of 2006 Ten Year Site Plans dated December 2006.	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
21		________	Progress Energy Florida Ten Year Site Plans filed on or about April 1 in the years 2005, 2006 and 2007.	
Staff				
22		________	Progress Energy Florida's response to staff Interrogatory (No. 5) in Docket Number 060642 – EI -Crystal River Unit 3 Uprate Need Determination.	
23		________	Progress Energy Florida's response to Office of Public Counsel Interrogatory (No. 12) in Docket Number 070052.	
24		________	Late Filed Exhibit (No. 2) of July 24, 2007 deposition of Javier Portuondo in Docket Number 070052.	
25		________	Staff prepared summary entitled "Prior Application of Item 10 Under Order 14546."	

HEARING EXHIBITS				
Exhibit #	**Witness**	**Counsel**	**Description**	**Moved In/Due Date of Late Filed**
26				
27				
28				
29				
30				
31				
32				
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34				
35				

HEARING EXHIBITS				
Exhibit #	**Witness**	**Counsel**	**Description**	**Moved In/Due Date of Late Filed**
36				
37				
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HEARING EXHIBITS				
Exhibit #	**Witness**	**Counsel**	**Description**	**Moved In/Due Date of Late Filed**
46				
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HEARING EXHIBITS				
Exhibit #	**Witness**	**Counsel**	**Description**	**Moved In/Due Date of Late Filed**
56				
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HEARING EXHIBITS				
Exhibit #	**Witness**	**Counsel**	**Description**	**Moved In/Due Date of Late Filed**
66				
67				
68				
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72				
73				
74				
75				

EXHIBITS

NUMBER:		ID.	ADMTD.
1	Comprehensive Exhibit List	8	8
2	DLR-1	122	122
3	DLR-2	122	122
4	DLR-3	122	122

EXHIBITS

NUMBER:		ID.	ADMTD.
5	SSW-1		216
6	SSW-2		216
7	JP-1 (Portuondo)		336
8	JP-2 (Portuondo)		336
9	JP-3 (Portuondo)		336
16	JP-1 (Pollock)		379
17	JP-2 (Pollock)		379
18	JP-3 (Pollock)		379
19	JP-4 (Pollock)		379
21	Extracts from 2005, 2006, and 2007 Ten-Year Site Plans		217
22	PEF Response to Staff Interrogatory No. 5, Docket 060642-EI	190	221
26	2006 Ten-Year Site Plan	194	221
27	2007 Ten-Year Site Plan	194	221
28	Prior Application of Item 10 Under Order 14546	293	336

EXHIBITS

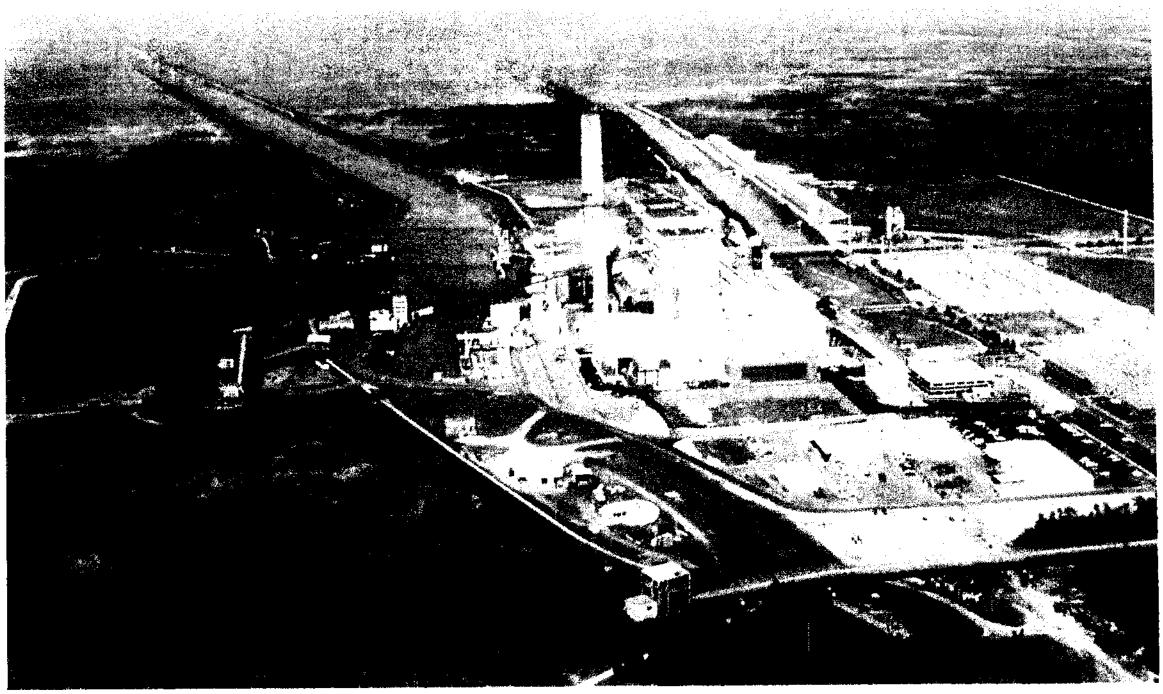
NUMBER:		ID.	ADMTD.
10	PWM-1		445
11	DLJ-1		548
12	DLJ-2		548
13	DLJ-3		548
14	DLJ-4		548
15	DLJ-5		548

EXHIBITS

NUMBER:		ID.	ADMTD.
24	Deferred Tax Impact of Different Recovery Periods	623	632
29	Excel Spreadsheet Showing AFUDC	627	632
30	Progress Energy Second Quarter Results	628	632

Docket No. 070052
Progress Energy Florida
Exhibit No. ___ (DLR-1)
Page 1 of 1

Exhibit 1
General Site Layout

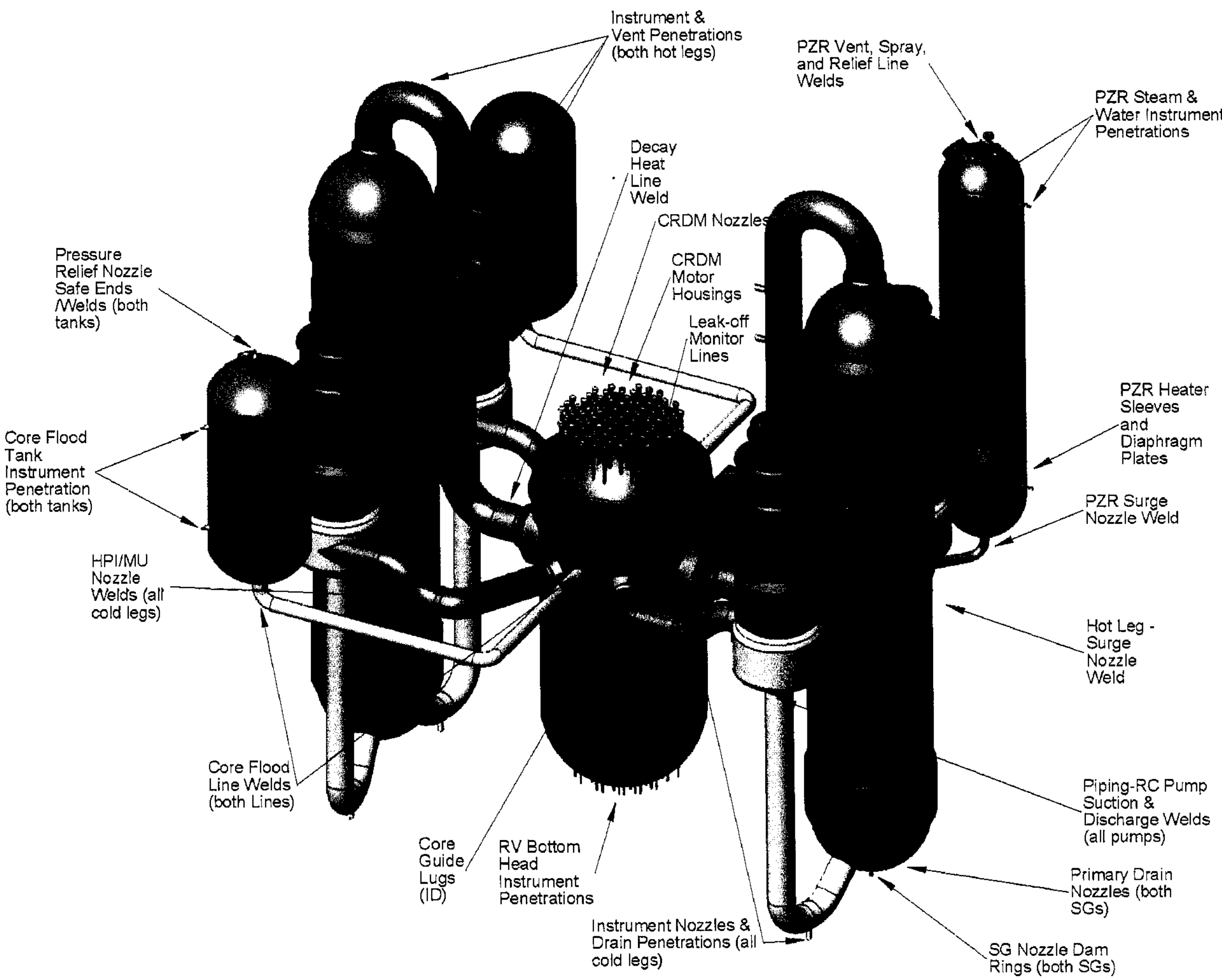


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 2
COMPANY PEF
WITNESS Daniel L. Roderick (DLR-1)
DATE 08/07+08/07

Docket No. 070052
Progress Energy Florida
Exhibit No. ___ (DLR-2)
Page 1 of 1

Exhibit 2

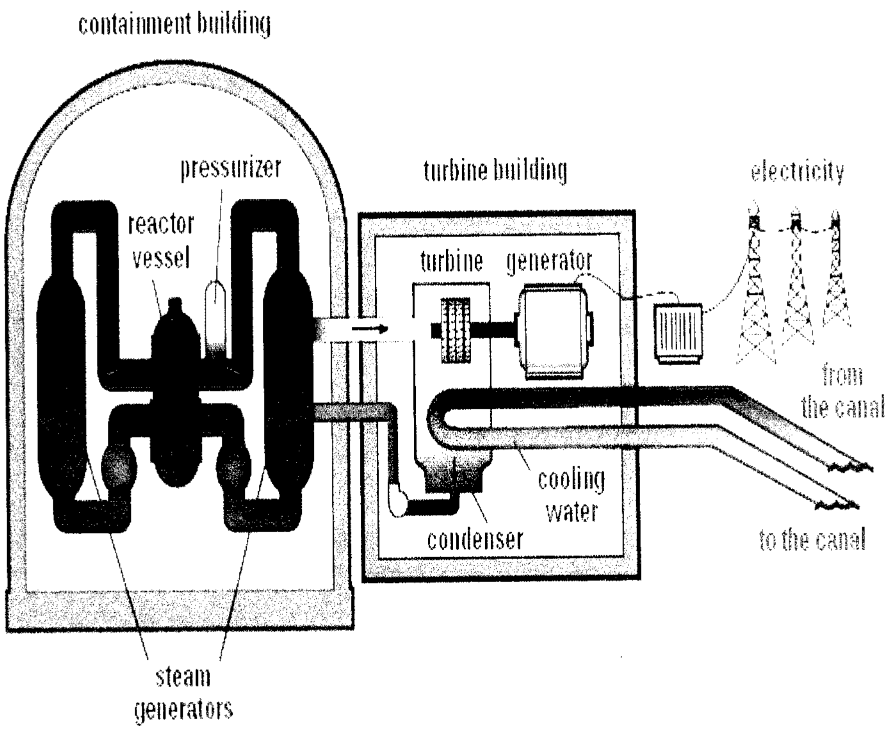
Primary Plant Configuration



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 3
COMPANY PEF
WITNESS Daniel L. Roderick (DLR-2)
DATE 08/07-08/07

Docket No. 070052
Progress Energy Florida
Exhibit No. ___ (DLR-3)
Page 1 of 1

Exhibit 3
Secondary Plant Interface



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 4
COMPANY PEF
WITNESS Daniel L. Roderick (DLR-3)
DATE 08/07 + 08/07

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Progress Energy Florida, Inc.)
To recover costs of Crystal Rive Unit 3) Docket No.: 070052
Uprate through fuel clause)
_______________________________________) Submitted for Filing: June 29, 2007

PROGRESS ENERGY FLORIDA, INC.'s
NOTICE OF FILING

Progress Energy Florida, Inc. hereby gives notice of filing Amended Exhibit No. ___ (SSW-1) to the Amended Testimony of Samuel S. Waters filed May 3, 2007.

Respectfully submitted this 29th day of June, 2007.

Dianne M. Triplett

R. Alexander Glenn
Deputy General Counsel
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St. Petersburg, FL 33733-4042
Telephone: (727) 820-5587
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James Michael Walls
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 5
COMPANY PEF
WITNESS Samuel S. Waters (SSW-1)
DATE 08/07-08/07

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished to all counsel of record and interested parties as listed below via electronic mail and U.S. Mail this 29th day of June, 2007.

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Amended Exhibit No. ___ (SSW-1)
Summary of Expected Annual Fuel Savings Due to the Proposed Uprate to Crystal River Unit 3 (System Basis)

PRODUCTION COST - NO UPRATE
July 2006 Generation & Fuel Forecast - Florida

Annual

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Fuel									
Steam-Coal	458,471,678	452,201,421	458,714,726	482,372,702	471,866,842	576,148,977	644,328,435	691,646,114	813,291,855
Steam-Oil	566,845,330	424,501,058	257,438,849	277,297,035	298,800,706	258,796,788	275,506,509	282,512,322	288,667,035
Steam-CC	956,271,147	1,243,813,724	1,092,757,781	1,351,350,740	1,521,014,994	1,440,502,994	1,338,315,975	1,429,907,508	1,356,063,581
CT	266,758,091	276,741,152	218,947,290	256,269,410	261,387,920	259,492,600	256,847,996	277,072,241	276,799,602
Nuclear	31,190,495	24,003,315	35,402,007	32,965,672	37,139,235	34,468,628	38,607,030	35,938,746	40,352,868
Fuel Sub-Total	2,279,536,741	2,421,260,671	2,063,260,653	2,400,255,559	2,590,209,697	2,569,409,987	2,553,605,944	2,717,076,931	2,775,174,942
NH3	1,276,691	3,611,243	4,066,308	4,119,150	3,939,519	5,181,268	5,948,184	6,396,978	8,024,030
CaCO3	-	1,097,713	10,389,108	10,958,897	10,859,563	14,461,986	16,913,466	18,491,855	23,392,313
Pur Pwr									
Cogen	452,354,399	450,187,054	504,884,151	522,987,867	539,522,120	542,486,721	490,959,375	504,594,212	519,650,142
Tran-Purc	352,457,985	337,972,117	328,132,018	261,802,331	267,735,792	247,069,404	241,173,165	258,526,016	211,465,363
Pur Pwr Sub-Total	804,812,384	788,159,171	833,016,168	784,790,197	807,257,912	789,556,125	732,132,540	763,120,228	731,115,505
TOTAL EXPECTED FUEL COST W/OUT UPRATE	**3,085,625,815**	**3,214,128,798**	**2,918,732,237**	**3,200,123,804**	**3,412,266,890**	**3,378,609,365**	**3,308,600,134**	**3,505,085,992**	**3,537,706,790**

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Fuel									
Steam-Coal	823,475,802	806,295,425	829,380,939	854,267,444	886,415,940	832,096,525	880,853,792	917,358,012	944,336,299
Steam-Oil	326,770,949	318,469,059	346,929,421	378,108,213	398,859,322	349,089,708	378,282,017	378,723,604	413,387,117
Steam-CC	1,516,665,004	1,271,842,434	1,482,015,247	1,597,923,456	1,695,354,913	1,393,886,781	1,500,834,205	1,570,892,532	1,744,775,169
CT	311,394,055	308,473,037	319,002,643	350,381,164	356,816,625	341,290,088	350,121,511	358,844,909	378,243,328
Nuclear	41,472,893	96,903,525	94,406,433	101,307,516	103,129,570	163,291,949	161,316,722	170,707,904	168,267,039
Fuel Sub-Total	3,019,778,703	2,801,983,480	3,071,734,683	3,281,987,792	3,440,576,370	3,079,655,050	3,271,408,249	3,396,526,962	3,649,008,953
NH3	7,894,221	7,783,016	7,764,748	7,854,788	8,153,742	7,441,142	7,656,641	7,916,296	7,875,546
CaCO3	23,389,627	23,429,143	23,711,725	24,406,957	25,738,676	23,828,422	24,893,599	26,157,611	26,407,342
Pur Pwr									
Cogen	539,602,740	546,562,196	568,909,689	588,879,617	609,925,477	620,138,388	647,973,969	595,031,554	483,202,534
Tran-Purc	232,653,443	113,827,016	116,980,833	124,009,563	125,812,887	113,739,446	116,041,938	117,718,827	121,838,242
Pur Pwr Sub-Total	772,256,182	660,389,212	685,890,522	712,889,180	735,738,364	733,877,833	764,015,907	712,750,381	605,040,776
TOTAL EXPECTED FUEL COST W/OUT UPRATE	**3,823,318,734**	**3,493,584,851**	**3,789,101,678**	**4,027,138,717**	**4,210,207,152**	**3,844,802,448**	**4,067,973,396**	**4,143,351,250**	**4,288,332,616**

PRODUCTION COST - 180MW CR3 UPRATE
Based on July 2006 Generation & Fuel Forecast - Florida

Annual

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Fuel									
Steam-Coal	457,700,683	451,867,549	457,668,230	481,424,948	466,134,327	569,051,047	633,872,055	681,200,156	802,055,798
Steam-Oil	564,825,772	423,125,575	254,783,678	275,267,515	280,334,402	250,026,430	263,746,701	274,715,992	280,875,947
Steam-CC	951,815,337	1,239,938,348	1,077,834,349	1,330,424,989	1,459,426,672	1,377,177,151	1,276,682,273	1,371,129,674	1,283,274,674
CT	266,293,813	276,165,291	218,213,679	255,400,695	256,166,674	256,767,127	253,082,921	272,426,180	273,812,528
Nuclear	31,669,833	24,413,908	37,215,459	35,215,195	45,699,896	42,417,150	47,506,290	44,225,294	49,654,377
Fuel Sub-Total	2,272,305,438	2,415,510,670	2,045,715,395	2,377,733,342	2,507,761,970	2,495,438,905	2,474,890,240	2,643,697,296	2,689,673,323
NH3	1,274,970	3,609,694	4,061,887	4,114,563	3,908,812	5,138,649	5,870,269	6,323,730	7,929,345
CaCO3	-	1,097,855	10,377,818	10,946,699	10,774,899	14,342,015	16,690,853	18,279,043	23,114,322
Pur Pwr	-	-	-	-	-	-	-	-	-
Cogen	452,403,906	450,016,314	504,658,513	522,896,958	538,401,433	541,699,297	489,194,592	502,613,440	517,702,537
Tran-Purc	351,735,190	337,582,570	325,680,792	258,561,354	254,789,569	236,519,700	233,415,403	249,912,115	202,975,747
Pur Pwr Sub-Total	804,139,096	787,598,884	830,339,305	781,458,312	793,191,002	778,218,997	722,609,996	752,525,554	720,678,284
TOTAL EXPECTED FUEL COST W/ UPRATE	**3,077,719,504**	**3,207,817,103**	**2,890,494,404**	**3,174,252,917**	**3,315,636,682**	**3,293,138,566**	**3,220,061,358**	**3,420,825,623**	**3,441,395,275**
EXPECTED FUEL SAVINGS DUE TO UPRATE	**$7,906,311**	**$6,311,695**	**$20,237,833**	**$25,870,887**	**$96,630,008**	**$85,470,799**	**$88,538,776**	**$84,260,369**	**$96,311,515**

	2017	2018	2019	2020	2021	2022	2023	2024	2025
Fuel									
Steam-Coal	812,123,154	791,060,131	817,351,459	840,899,768	871,081,965	816,704,054	866,959,318	900,631,510	930,805,555
Steam-Oil	316,843,042	311,569,856	338,906,849	368,239,597	382,085,755	342,562,616	371,742,166	370,473,847	403,806,640
Steam-CC	1,451,623,410	1,195,455,319	1,403,795,615	1,509,116,136	1,626,893,737	1,305,328,649	1,419,207,273	1,484,201,558	1,658,747,286
CT	305,374,296	305,702,842	315,489,838	344,843,797	349,792,045	339,210,506	346,282,162	355,257,086	372,142,506
Nuclear	50,019,714	106,328,566	103,228,769	111,235,980	112,327,638	173,301,168	170,607,278	181,161,671	178,071,918
Fuel Sub-Total	2,935,983,616	2,710,116,713	2,978,772,529	3,174,335,278	3,342,981,140	2,977,106,992	3,174,798,196	3,291,725,671	3,543,573,906
NH3	7,800,660	7,648,082	7,661,578	7,743,897	8,023,139	7,316,458	7,544,761	7,782,571	7,771,744
CaCO3	23,109,758	23,022,330	23,396,563	24,061,842	25,325,239	23,428,717	24,532,297	25,715,791	26,058,857
Pur Pwr	-	-	-	-	-	-	-	-	-
Cogen	538,083,299	543,306,979	566,386,801	586,427,989	606,856,275	616,570,178	645,162,313	590,076,265	478,917,073
Tran-Purc	224,566,047	112,628,600	113,893,254	120,418,415	122,152,784	111,960,535	113,673,604	114,981,480	117,944,397
Pur Pwr Sub-Total	762,649,346	655,935,578	680,280,055	706,846,403	729,009,059	728,530,713	758,835,917	705,057,745	596,861,471
TOTAL EXPECTED FUEL COST W/ UPRATE	**3,729,543,380**	**3,396,722,703**	**3,690,110,725**	**3,912,987,421**	**4,105,338,577**	**3,736,382,879**	**3,965,711,172**	**4,030,281,777**	**4,174,265,978**
EXPECTED FUEL SAVINGS DUE TO UPRATE	**$93,775,354**	**$96,862,148**	**$98,990,953**	**$114,151,296**	**$104,868,576**	**$108,419,569**	**$102,262,224**	**$113,069,473**	**$114,066,638**

TOTAL GROSS SAVINGS THROUGH 2025	**$1,458,004,422**
TOTAL GROSS SAVINGS THROUGH 2036	**$2,677,797,560**

Exhibit No.___(SSW-2)

Summary of Overall Cost Effectiveness of the Proposed Upgrade to Crystal River Unit 3 to the Retail Customer

NPV Costs, (000's) in 2006 $'s	$320,369
NPV Benefits, (000's) in 2006 $'s	$639,844
Net Benefit to Retail Customers, (000's) in 2006 $'s	$319,475

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 6
COMPANY PEF
WITNESS Samuel S. Waters (SSW-2)
DATE 08/07 + 08/07

DOCKET NO. 070052
PROGRESS ENERGY FLORIDA
EXHIBIT NO. ____ (JP-1)
PAGE 1 OF 1

SCHEDULE B-13

CONSTRUCTION WORK IN PROGRESS

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: For each major construction project whose cost of completion exceeds exceeds 0.2 percent (.002) of gross plant, and for smaller projects within each category shown taken as a group, provide the requested data concerning projects for the test year.

Type of Data Shown:
XX Projected Test Year Ended 12/312006
__ Prior Year Ended 12/312005
__ Historical Test Year Ended 12/312004
Witness: Portuondo / Williams / Young / McDonald / DeSouza / Slusser

Line No.	(A) Project No	(B) Project Description	(C) Year End CWIP Balance	(D) Estimated Additional Project Costs	(E) Total Cost of Completion	(F) Initial Project Budget Per Construction Bid	(G) Date Construction Started	(H) Expected Completion Date	(I) Percent Complete (C)/(E)	(J) Amount of AFUDC Charged	(K) 13 Month Average Balance	(L) Jurisdictional Factor	(M) Jurisdictional Amount
1													
2		STEAM PRODUCTION											
3		Major Projects:											
4		Crystal River Coal Yard Upgrade	34,252	51,418	85,670	85,670	Mar-05	Dec-07	40.0%	0	16,142		
5													
6		Minor Projects:	12,471								11,251		
7		Total Steam Projects	46,723	51,418	85,670	85,670				-	27,393		
8													
9		NUCLEAR PRODUCTION											
10		Major Projects:											
11		CR3 Steam Generator Replacement	57,986	172,364	230,350	170,000				0	47,117		
12													
13		Minor Projects:	3,168								3,367		
14		Total Nuclear Projects	61,155	172,364	230,350	170,000				-	50,484		
15													
16		HYDRAULIC PRODUCTION											
17		none											
18													
19		OTHER PRODUCTION											
20													
21		Hines unit 3	597	-	247,500	226,500	Jan-02	Dec-05	100.0%	-	524		
22		Hines unit 4	145,190	76,310	221,500	221,500	Jun-04	Dec-07	65.5%	7,667	98,266		
23		Subtotal Major Projects	145,787	76,310	469,000	448,000				7,667	98,790		
24													
25		Minor Projects:	8,903								7,848		
26		Total Other Projects	154,690	76,310	469,000	448,000				7,667	106,638		
27													

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 7
COMPANY PEF
WITNESS Javier Portuondo (JP-1)
DATE 08/07+08/07

R:\2005 Rate Case\MFRs\MFRs - 2005 RATE CASE\Submitted B-13 4/20/2005 1:31 PM

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 8
COMPANY PEF
WITNESS Javier Portuondo (JP-2)
DATE 08/07 - 08/07

DOCKET NO. 070052
PROGRESS ENERGY FLORIDA
EXHIBIT NO. ____ (JP-2)
PAGE 1 OF 1

SCHEDULE B-2

RATE BASE ADJUSTMENTS

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: List and explain all proposed adjustments to the 13-month average rate base for the test year, the prior year and the most recent historical year. List the adjustments included in the last case that are not proposed in the current case that are not proposed in the current case and the reasons for excluding them.

Type of Data Shown:

X Projected Test Year Ended 12/31/2006
_ Prior Year Ended 12/31/2005
_ Historical Test Year Ended 12/31/2004
Witness: Portuondo / Slusser

Line No.	(A) Adjustment Title	(B) Reason for Adjustment or Omission (provide supporting schedule)	(C) Adjustment Amount (000)	(D) Jurisdictional Factor	(E) Jurisdictional Amount of Adjustment (1) x (2) (000)
1	**Adjustments to System Per Books:**				
2	Remove ARO	(1)	$352,555	N/A	
3	Remove ECCR	(2)	7,749	N/A	
4	Remove ECRC	(3)	(19,265)	N/A	
5	Remove Fuel	(4)	(44,574)	N/A	
6	Remove SCRC	(5)	(139,000)	N/A	
7	Remove NUP	(6)	(9,094)	N/A	
8	Remove Above Market Affiliate Transfer	(7)	(23,361)	N/A	
9	Remove Job Orders	(8)	26,567	N/A	
10	Remove Sebring	(9)	(3,684)	N/A	
11	Remove Nucl Decom Trust Unreal Gains	(10)	83,101	N/A	
12	Remove A/D Nuc Decom-Funded	(11)	61,897	N/A	
13	Remove Other Special Funds (126)	(12)	(476,913)	N/A	
14	Misc Adjustment	(13)	(34)	N/A	
15			($159,058)		
16	**Company/FPSC Adjustments:**				
17	Company Adjustment - Distrib Enhancement Projects	(14)	55,521	0.99757	53,509
18	Company Adjustment - Transm Enhancement Projects	(15)	7,439	0.71418	5,313
19	Company Adjustment - End of Life Nuclear M&S	(16)	409	1.00000	409
20	Company Adjustment - Charging Practices	(17)	(51,468)	0.99760	(51,345)
21	Company Adjustment - Fossil Dismantlement	(18)	(5,936)	0.83972	(4,986)
22	Company Adjustment - Last Core Nuclear Fuel	(19)	168	1.00000	166
23	Company Adjustment - Mobile Meter Reading	(20)	55,554	1.00000	55,554
24	Company Adjustment - Organization Realignment	(21)	(51,174)	0.92422	(47,296)
25	Company Adjustment - Progress Fuels Corp	(22)	28,387	0.91126	25,868
26	Company Adjustment - Rate Case	(23)	2,250	1.00000	2,250
27	Company Adjustment - Storm Reserve	(24)	(22,000)	0.96945	(21,328)
28	CWIP - AFUDC	(25)	(145,815)	0.92471	(134,837)
29	Gain/loss on sale of plant	(26)	(127)	0.93176	(118)
30	Nuc. Decom. Unfunded - Wholesale	(27)	2,286	1.00000	2,286
31	RTO Start-up Costs	(28)	(4,173)	0.90943	(3,791)
32	Section 1341 Income Tax Adj	(29)	1,407	0.92577	1,303
33			($173,942)		($162,051)
34	*Note: Differences are due to rounding*				

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 9
COMPANY PEF
WITNESS Javier Portuondo (JP-2)
DATE 08/07 + 08/07

SCHEDULE B-1

ADJUSTED RATE BASE

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No. 050078-EI

Explanation: Provide a schedule of the 13-month average adjusted rate base for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule B-2.

Type of Data Shown:

X Projected Test Year Ended 12/31/2006
__ Prior Year Ended 12/31/2005
__ Historical Test Year Ended 12/31/2004
Witness: Portuondo / Slusser

Line No		(A) Plant in Service	(B) Accumulated Provision for Depreciation & Amortization	(C) Net Plant in Service (A-B)	(D) CWIP - No AFUDC	(E) Plant Held for Future Use	(F) Nuclear Fuel - No AFUDC (Net)	(G) Net Utility Plant	(H) Working Capital Allowance	(I) Other Rate Base Items	(J) Total Rate Base
1	System Per Books (B-3)	$9,197,606	$4,490,733	$4,706,873	$244,471	$7,921	$63,933	$5,023,198	$443,248		$5,466,446
2	Adjustments to System Per Books:										
3	Remove ARO	(77,065)	(43,697)	(33,368)				(33,368)	385,922		352,555
4	Remove ECCR	(403)	(13)	(395)				(395)	8,144		7,749
5	Remove ECRC	(2,372)	(151)	(2,221)				(2,221)	(17,044)		(19,265)
6	Remove Fuel	(1,032)	0	(1,032)				(1,032)	(43,542)		(44,574)
7	Remove SCRC	0	0	0				0	(139,000)		(139,000)
8	Remove NUP	(19,042)	(10,948)	(8,094)				(8,094)			(8,094)
9	Remove Above Market Affiliate Transfer	(23,361)		(23,361)				(23,361)			(23,361)
10	Remove Job Orders			0				0	26,567		26,567
11	Remove Sebring			0				0	(9,664)		(9,664)
12	Remove Nucl Decom Trust Unreal Gains			0				0	83,101		83,101
13	Remove A/D Nuc Decom-Funded		(61,897)	61,897				61,897			61,897
14	Remove Other Special Funds (128)			0				0	(476,913)		(476,913)
15	Misc Adjustment			0				0	(34)		(34)
16	Adjusted System per Books	9,074,325	4,374,026	4,700,299	244,471	7,921	63,933	5,016,624	260,764	0	5,277,387
17	Jurisdictional Factors	0.92671	0.93960	0.91472	0.88897	0.76430	0.89802	0.91301	0.85238		0.91002
18	Jurisdictional Per Books	8,409,264	4,109,825	4,299,439	217,327	6,054	57,413	4,580,233	222,270	0	4,802,503
19	Jurisdictional Company/FPSC Adjustments:										
20	Company Adjustment - Distrib Enhancement Projects	7,281	105	7,176	1,324	0	0	8,500	0		8,500
21	Company Adjustment - Transm Enhancement Projects	4,533	44	4,489	824	0	0	5,313	0		5,313
22	Company Adjustment - End of Life Nuclear M&S	0	0	0	0	0	0	0	409		409
23	Company Adjustment - Charging Practices	(50,601)	(1,789)	(48,812)	(2,533)	0	0	(51,345)	0		(51,345)
24	Company Adjustment - Fossil Dismantlement	0	4,988	(4,988)	0	0	0	(4,988)	0		(4,988)
25	Company Adjustment - Last Core Nuclear Fuel	0	0	0	0	0	0	0	168		168
26	Company Adjustment - Mobile Meter Reading	(3,386)	(58,940)	55,554	0	0	0	55,554	0		55,554
27	Company Adjustment - Organization Realignment	(3,858)	0	(3,858)	0	0	0	(3,858)	(43,438)		(47,296)
28	Company Adjustment - Progress Fuels Corp	0	0	0	0	0	0	0	25,668		25,668
29	Company Adjustment - Rate Case	0	0	0	0	0	0	0	2,250		2,250
30	Company Adjustment - Storm Reserve	0	0	0	0	0	0	0	(21,328)		(21,328)
31	CWIP - AFUDC	0	0	0	(134,837)	0	0	(134,837)	0		(134,837)
32	Gain/loss on sale of plant	0	0	0	0	0	0	0	(118)		(118)
33	Nuc. Decom. Unfunded - Wholesale	0	(2,286)	2,286	0	0	0	2,286	0		2,286
34	RTO Start-up Costs	0	0	0	0	0	0	0	(3,791)		(3,791)
35	Section 1341 Income Tax Adj	0	0	0	0	0	0	0	1,303		1,303
36	Total Adjustments	(46,031)	(57,379)	11,848	(135,222)	0	0	(123,374)	(33,677)	0	(162,051)
37	Jurisdictional Adjusted Rate Base	$8,363,233	$4,051,946	$4,311,287	$82,105	$6,054	$57,413	$4,456,859	$188,593	$0	$4,640,452

38 Note: Differences are due to rounding

Supporting Schedules:

Recap Schedules:

Resume

PATRICIA W. MERCHANT, CPA

Office of Public Counsel
Room 812, 111 West Madison Street
Tallahassee, Florida 32399-1400

Phone: 850-487-8245
Fax: 850-488-4491
E-mail: merchant.tricia@leg.state.fl.us

Professional Experience:

March, 2005 to Present

Office of Public Counsel – Senior Legislative Analyst

In my current position, I perform financial and accounting analysis and reviews, and provide testimony, as required, involving utility filings before the Florida Public Service Commission on behalf of the Citizens of the State of Florida.

1981 to February, 2005 - Florida Public Service Commission

2000 to February, 2005

Public Utilities Supervisor – File and Suspend Rate Case Section, Bureau of Rate Filings, Division of Economic Regulation

In this capacity I supervised 5 to 8 regulatory professionals. This section performed financial, accounting, engineering and rate review and evaluation of rate proceedings for large water and wastewater utilities, as well as electric and gas utilities regulated by the Commission. The types of cases included file and suspend rate cases, limited proceedings, overearning investigations, annual report reviews, service availability and tariff filings, rulemaking, and customer complaints. The section reviewed utility filings, requested and reviewed Commission staff audits, and generated and analyzed discovery requests. I coordinated and prepared staff recommendations to the Commission for agenda conferences. I reviewed the analyses and written documentation of all analysts in this section for proper regulatory theory, grammar and accuracy. I also made presentations to customer groups at Commission staff customer meetings for the rate proceedings to which I was assigned. We presented recommendations at agenda conferences, providing responses to comments and questions by other parties and Commissioners. I also prepared and presented testimony, and assisted in the preparation of cross-examination questions for depositions and formal hearings. Additionally, I provided training in regulatory theory for new staff and provided training on regulatory and accounting issues for other analysts at the Commission.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 10
COMPANY OPC
WITNESS Patricia W. Merchant (PWM-1)
DATE 08/07+08/07

1989 – 2000

Regulatory Analyst Supervisor, Accounting Section, Bureau of Economic Regulation, Division of Water and Wastewater

I supervised 5-7 regulatory accounting analysts. This section performed the same job activities as above specifically for the larger Commission regulated Class A and B water and wastewater companies.

1983 – 1989
Regulatory Analyst – Accounting Bureau, Division of Water and Wastewater

As an accounting analyst, I performed the same job activities as described above for water and wastewater companies in a non-supervisory role.

1981 – 1983

Public Utilities Auditor, Division of Auditing and Financial Analysis

As an auditor in the Tallahassee district of the Commission, I performed financial and accounting audits of electric, gas, telephone, water and wastewater utilities under the Commission's jurisdiction.

Education and Professional Licenses

1981 Bachelor of Science with a major in accounting from Florida State University

1983 Received a Certified Public Accountant license in Florida

List of Cases in which Testimony was Submitted

Dockets Before the Florida Public Service Commission:

060162-EI – Petition by Progress Energy Florida, Inc. to recover modular cooling tower costs through the Environmental Cost recovery clause. (filed testimony stipulated into record)

050958-EI – Petition for approval of new environmental program for cost recovery through Environmental Cost Recovery Clause by Tampa Electric Company. (testified at hearing)

060658-EI - Petition on Behalf of Citizens of the State of Florida to require Progress Energy Florida, Inc. to Refund Customers $143 million. (filed testimony stipulated into record)

060362-EI - Petition to Recover Natural Gas Storage Project Costs through Fuel Cost Recovery Clause, by Florida Power & Light Company. (testified at hearing)

050045-EI - Petition for Rate Increase by Florida Power & Light Company. (filed testimony, deposed, case settled prior to hearing)

991643-SU - Application for Increase in Wastewater Rates in Seven Springs System in Pasco County by Aloha Utilities, Inc. (testified at hearing)

971663-WS - Application of Florida Cities Water Company, Inc. for a limited proceeding to recover environmental litigation costs. (all testimony and exhibits stipulated into record without hearing)

940847-WS - Application of Ortega Utility Company for increased water and wastewater rates. (testified at hearing)

911082-WS - Water and Wastewater Rule Revisions to Chapter 25-30, Florida Administrative Code. (testified at hearing)

881030-WU - Investigation of Sunshine Utilities of Central Florida rates for possible over earnings. (testified at hearing)

850151-WS - Application of Marco Island Utilities, Inc. for increased water and wastewater rates. (testified at hearing)

850031-WS - Application of Orange/Osceola Utilities, Inc. for increased water and wastewater rates in Osceola County (testified at hearing)

840047-WS - Application of Poinciana Utilities, Inc. for increased water and wastewater rates (testified at hearing)

Cases Before the Division of Administrative Hearings:

97-2485RU - Aloha Utilities, Inc., and Florida Waterworks Association, Inc., Petitioners, vs. Public Service Commission, Respondents, and Citizens of the State of Florida, Office of Public Counsel, Intervenors (deposed and testified at hearing)

DANIEL J. LAWTON

PRINCIPAL, DIVERSIFIED UTILITY CONSULTANTS, INC.
B.A. ECONOMICS, MERRIMACK COLLEGE
M.A. ECONOMICS, TUFTS UNIVERSITY

Prior to beginning his own consulting practice, Diversified Utility Consultants, Inc., in 1986, Mr. Lawton had been in the utility consulting business with a national engineering and consulting firm. In addition, Mr. Lawton has been employed as a senior analyst and statistical analyst with the Department of Public Service of Minnesota. Prior to Mr. Lawton's involvement in utility regulation and consulting he taught economics, econometrics, statistics and computer science at Doane College.

Mr. Lawton has conducted numerous financial and cost of capital studies on electric, gas and telephone utilities for various interveners before local, state and federal regulatory bodies. In addition, Mr. Lawton has provided studies, analyses, and expert testimony on statistics, econometrics, accounting, fore-casting, and cost of service issues. Other projects in which Mr. Lawton has been involved include rate design and analyses for electric, gas and telephone utilities. Mr. Lawton has developed software systems, databases and manage-ment systems for cost of service analyses.

In addition, Mr. Lawton has developed and reviewed numerous forecasts of energy and demand used for utility generation expansion studies as well as municipal financing. Mr. Lawton has represented numerous municipalities as a negotiator in utility related matters. Such negotiations ranged from the settle-ment of electric rate cases to the negotiation of provisions in purchase power contracts.

A list of cases in which Mr. Lawton has provided testimony is attached.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 11
COMPANY OPC
WITNESS Daniel J. Lawton (DJL-1)
DATE 08/07 + 08/07

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY DANIEL J. LAWTON

JURISDICTION/COMPANY	DOCKET NO.	TESTIMONY TOPIC
ALASKA REGULATORY COMMISSION		
Beluga Pipe Line Company	P-04-81	Cost of Capital
FEDERAL ENERGY REGULATORY COMMISSION		
Alabama Power Company	ER83-369-000	Cost of Capital
Arizona Public Service Company	ER84-450-000	Cost of Capital
Florida Power & Light	EL83-24-000	Cost Allocation, Rate Design
Florida Power & Light	ER84-379-000	Cost of Capital, Rate Design, Cost of Service
Southern California Edison	ER82-427-000	Forecasting
LOUISIANA PUBLIC SERVICE COMMISSION		
Louisiana Power & Light	U-15684	Cost of Capital, Depreciation
Louisiana Power & Light	U-16518	Interim Rate Relief
Louisiana Power & Light	U-16945	Nuclear Prudence, Cost of Service
MINNESOTA PUBLIC UTILITIES COMMISSION		
Continental Telephone	P407/GR-81-700	Cost of Capital
Interstate Power Co.	E001/GR-81-345	Financial
Montana Dakota Utilities	G009/GR-81-448	Financial, Cost of Capital
New ULM Telephone Company	P419/GR81767	Financial
Norman County Telephone	P420/GR-81-230	Rate Design, Cost of Capital
Northern States Power	G002/GR80556	Statistical Forecasting, Cost of Capital
Northwestern Bell	P421/GR80911	Rate Design, Forecasting

NORTH CAROLINA UTILITIES COMMISSION		
North Carolina Natural Gas	G-21, Sub 235	Forecasting, Cost of Capital, Cost of Service
OKLAHOMA PUBLIC SERVICE COMMISSION		
Arkansas Oklahoma Gas Corporation	200300088	Cost of Capital
Public Service Company of Oklahoma	200600285	Cost of Capital
PUBLIC SERVICE COMMISSION OF INDIANA		
Kokomo Gas & Fuel Company	38096	Cost of Capital
PUBLIC UTILITY COMMISSION OF NEVADA		
Nevada Bell	99-9017	Cost of Capital
Nevada Power Company	99-4005	Cost of Capital
Sierra Pacific Power Company	99-4002	Cost of Capital
PUBLIC SERVICE COMMISSION OF UTAH		
PacifiCorp	04-035-42	Cost of Capital
SOUTH CAROLINA PUBLIC SERVICE COMMISSION		
Piedmont Municipal Power	82-352-E	Forecasting
PUBLIC UTILITY COMMISSION OF TEXAS		
Central Power & Light Company	6375	Cost of Capital, Financial Integrity
Central Power & Light Company	9561	Cost of Capital, Revenue Requirements
Central Power & Light Company	7560	Deferred Accounting
Central Power & Light Company	8646	Rate Design, Excess Capacity
Central Power & Light Company	12820	STP Adj. Cost of Capital, Post Test-year adjustments, Rate Case Expenses
Central Power & Light Company	14965	Salary & Wage Exp., Self-Ins. Reserve, Plant Held for Future use, Post Test Year Adjustments, Demand Side Management, Rate Case Exp.
Central Power & Light Company	21528	Securitization of Regulatory Assets
El Paso Electric Company	9945	Cost of Capital, Revenue Requirements, Decommissioning Funding
El Paso Electric Company	12700	Cost of Capital, Rate Moderation Plan, CWIP, Rate Case Expenses

Entergy Gulf States Incorporated	16705	Cost of Service, Rate Base, Revenues, Cost of Capital, Quality of Service
Entergy Gulf States Incorporated	21111	Cost Allocation
Entergy Gulf States Incorporated	21984	Unbundling
Entergy Gulf States Incorporated	22344	Capital Structure
Entergy Gulf States Incorporated	22356	Unbundling
Entergy Gulf States Incorporated	24336	Price to Beat
Gulf States Utilities Company	5560	Cost of Service
Gulf States Utilities Company	6525	Cost of Capital, Financial Integrity
Gulf States Utilities Company	6755/7195	Cost of Service, Cost of Capital, Excess Capacity
Gulf States Utilities Company	8702	Deferred Accounting, Cost of Capital, Cost of Service
Gulf States Utilities Company	10894	Affiliate Transaction
Gulf States Utilities Company	11793	Section 63, Affiliate Transaction
Gulf States Utilities Company	12852	Deferred acctng., self-Ins. reserve, contra AFUDC adj., River Bend Plant specifically assignable to Louisiana, River Bend Decomm., Cost of Capital, Financial Integrity, Cost of Service, Rate Case Expenses
GTE Southwest, Inc.	15332	Rate Case Expenses
Houston Lighting & Power	6765	Forecasting
Houston Lighting & Power	18465	Stranded costs
Lower Colorado River Authority	8400	Debt Service Coverage, Rate Design
Southwestern Electric Power Company	5301	Cost of Service
Southwestern Electric Power Company	4628	Rate Design, Financial Forecasting
Southwestern Electric Power Company	24449	Price to Beat Fuel Factor
Southwestern Bell Telephone Company	8585	Yellow Pages
Southwestern Bell Telephone	18509	Rate Group Re-Classification

Company		
Southwestern Public Service Company	13456	Interruptible Rates
Southwestern Public Service Company	11520	Cost of Capital
Southwestern Public Service Company	14174	Fuel Reconciliation
Southwestern Public Service Company	14499	TUCO Acquisition
Southwestern Public Service Company	19512	Fuel Reconciliation
Texas-New Mexico Power Company	9491	Cost of Capital, Revenue Requirements, Prudence
Texas-New Mexico Power Company	10200	Prudence
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	21112	Acquisition risks/merger benefits
Texas Utilities Electric Company	9300	Cost of Service, Cost of Capital
Texas Utilities Electric Company	11735	Revenue Requirements
TXU Electric Company	21527	Securitization of Regulatory Assets
West Texas Utilities Company	7510	Cost of Capital, Cost of Service
West Texas Utilities Company	13369	Rate Design
RAILROAD COMMISSION OF TEXAS		
Energas Company	5793	Cost of Capital
Energas Company	8205	Cost of Capital
Energas Company	9002-9135	Cost of Capital, Revenues, Allocation
Lone Star Gas Company	8664	Rate Design, Cost of Capital, Accumulated Depr. & DFIT, Rate Case Exp.
Lone Star Gas Company-Transmission	8935	Implementation of Billing Cycle Adjustment
Southern Union Gas Company	6968	Rate Relief
Southern Union Gas Company	8878	Test Year Revenues, Joint and Common Costs
Texas Gas Service Company	9465	Cost of Capital, Cost of Service, Allocation
TXU Lone Star Pipeline	8976	Cost of Capital, Capital Structure
TXU-Gas Distribution	9145-9151	Cost of Capital, Transport Fee, Cost Allocation, Adjustment Clause
TXU-Gas Distribution	9400	Cost of Service, Allocation, Rate Base, Cost of Capital, Rate Design

Westar Transmission Company	4892/5168	Cost of Capital, Cost of Service
Westar Transmission Company	5787	Cost of Capital, Revenue Requirement
TEXAS WATER COMMISSION		
Southern Utilities Company	7371-R	Cost of Capital, Cost of Service
SCOTSBLUFF, NEBRASKA CITY COUNCIL		
K. N. Energy, Inc.		Cost of Capital
HOUSTON CITY COUNCIL		
Houston Lighting & Power Company		Forecasting
PUBLIC UTILITY REGULATION BOARD OF EL PASO, TEXAS		
Southern Union Gas Company		Cost of Capital
DISTRICT COURT CAMERON COUNTY, TEXAS		
City of San Benito, et. al. vs. PGE Gas Transmission et. al.	96-12-7404	Fairness Hearing
DISTRICT COURT HARRIS COUNTY, TEXAS		
City of Wharton, et al vs. Houston Lighting & Power	96-016613	Franchise fees
DISTRICT COURT TRAVIS COUNTY, TEXAS		
City of Round Rock, et al vs. Railroad Commission of Texas et al	GV 304,700	Mandamus

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 12
COMPANY OPC
WITNESS Daniel J. Lawton (DJL-2)
DATE 08/07 + 08/07

OPC'S QUANTIFICATION OF DEFERRED INCOME TAXES AND REVENUE REQUIREMENTS OF DEFERRED INCOME TAXES DUE TO CORRECTION OF DEPRECIATION TIMING THROUGH 2036
(Millions of Dollars)

Year	PEF Proposed Deferred Tax (a)	Corrected Deferred Tax (b)	PEF Proposed Revenue Req. (c)	Corrected Revenue Req. (d)
2006	$0.00	$0.00	$0.00	$0.00
2007	$0.00	$0.00	$0.00	$0.00
2008	$2.39	-$0.04	$0.32	-$0.01
2009	-$1.66	-$1.76	-$0.22	-$0.23
2010	-$0.04	-$2.11	-$0.01	-$0.28
2011	-$3.54	-$6.99	-$0.47	-$0.92
2012	$2.68	-$7.70	$0.35	-$1.02
2013	$4.03	-$6.35	$0.53	-$0.84
2014	$5.24	-$5.14	$0.69	-$0.68
2015	$6.22	-$4.16	$0.82	-$0.55
2016	$7.02	-$3.36	$0.93	-$0.44
2017	$7.51	-$2.87	$0.99	-$0.38
2018	$7.73	-$2.65	$1.02	-$0.35
2019	$7.49	-$2.61	$0.99	-$0.34
2020	$4.35	-$2.61	$0.57	-$0.34
2021	$2.05	-$2.61	$0.27	-$0.34
2022	-$9.44	-$2.61	-$1.24	-$0.34
2023	-$9.36	-$2.54	-$1.24	-$0.33
2024	-$8.28	-$1.45	-$1.09	-$0.19
2025	-$7.27	-$0.44	-$0.96	-$0.06
2026	-$4.98	$1.85	-$0.66	$0.24
2027	-$2.70	$4.13	-$0.36	$0.55
2028	-$2.70	$4.13	-$0.36	$0.55
2029	-$2.70	$4.13	-$0.36	$0.55
2030	-$2.70	$4.13	-$0.36	$0.55
2031	-$1.35	$5.48	-$0.18	$0.72
2032	$0.00	$6.83	$0.00	$0.90
2033	$0.00	$6.83	$0.00	$0.90
2034	$0.00	$6.83	$0.00	$0.90
2035	$0.00	$6.83	$0.00	$0.90
2036	$0.00	$6.83	$0.00	$0.90
Total	$0.00	$0.00	$0.00	$0.00
NPV	$9.68	-$19.83	$1.28	-$2.62
Difference		-$29.50		-$3.89

SOURCES AND REFERENCES

Column (a) : PEF's response to OPC Interrogatory 12 spreadsheet line 95.
Columns (b, d) : OPC's corrected depreciation through 2036.
Column (c) : PEF's response to OPC Interrogatory 12 spreadsheet line 96.
NPV : NPV based on 8.1% as proposed by PEF.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 13
COMPANY OPC
WITNESS Daniel J. Lawton (DJL-3)
DATE 08/07-08/07

OPC'S QUANTIFICATION OF IMPACT ON NET SAVINGS
DUE TO A REDUCED 7.5% OVERALL COST OF CAPITAL
(Millions of Dollars)

		PEF's Proposed		Based On 7.5% ROR	
Year	Fuel Savings	Revenue Requirements	Net Savings	Revenue Requirements	Net Savings
	(a)	(b)	(c)	(d)	(e)
2006	$0.00	$0.00	$0.00	$0.00	$0.00
2007	$0.00	$0.00	$0.00	$0.00	$0.00
2008	$7.91	$7.20	$0.71	$6.87	$1.03
2009	$6.31	$1.47	$4.84	$1.15	$5.16
2010	$20.24	$19.68	$0.56	$19.68	$0.55
2011	$25.87	$31.60	-$5.73	$31.81	-$5.94
2012	$96.63	$97.85	-$1.22	$75.21	$21.42
2013	$85.47	$92.11	-$6.64	$71.90	$13.57
2014	$88.54	$86.44	$2.10	$68.68	$19.86
2015	$84.26	$80.82	$3.44	$65.51	$18.75
2016	$96.31	$75.10	$21.21	$62.26	$34.05
2017	$93.78	$69.43	$24.35	$59.07	$34.70
2018	$96.86	$63.65	$33.22	$55.79	$41.07
2019	$98.99	$57.21	$41.78	$51.86	$47.13
2020	$114.15	$43.69	$70.46	$40.76	$73.39
2021	$104.87	$33.29	$71.58	$32.34	$72.53
2022	$108.42	$0.29	$108.13	$0.83	$107.59
2023	$102.26	$0.30	$101.96	$0.84	$101.43
2024	$113.07	$0.52	$112.55	$0.99	$112.08
2025	$114.07	$0.79	$113.28	$1.20	$112.86
2026	$108.31	$1.04	$107.27	$1.33	$106.98
2027	$108.92	$1.39	$107.53	$1.55	$107.37
2028	$109.49	$1.76	$107.73	$1.59	$107.89
2029	$110.02	$1.48	$108.54	$1.64	$108.38
2030	$110.53	$1.53	$109.00	$1.69	$108.84
2031	$111.01	$1.76	$109.25	$1.83	$109.18
2032	$111.47	$1.98	$109.48	$1.98	$109.48
2033	$111.90	$2.03	$109.87	$2.03	$109.87
2034	$112.32	$2.08	$110.24	$2.08	$110.24
2035	$112.72	$2.13	$110.59	$2.13	$110.59
2036	$113.10	$2.18	$110.92	$2.18	$110.92
Total	$2,677.80	$780.79	$1,897.00	$666.78	$2,011.02
Difference - Nominal					-$114.01
NPV Total	$706.23	$353.61	$352.62	$298.68	$407.55
Difference - NPV					-$54.93

SOURCE AND REFERENCES

Columns (a-c) : PEF's response to OPC Interrogatory 12 spreadsheet.
Column (d & e) : PEF's response to OPC Interrogatory 12 spreadsheet modified to reflect a 7.5% rate of return.
NPV : NPV based on 8.1% as proposed by PEF.

DOCKET NO. 070052-EI
Cash Flow Comparison
Exhibit _____(DJL-4)
Page 1 of 1

CUSTOMER/SHAREHOLDER CASH FLOW
BENEFITS OF UPRATE PROPOSAL
FOR THE PERIOD THROUGH 2016

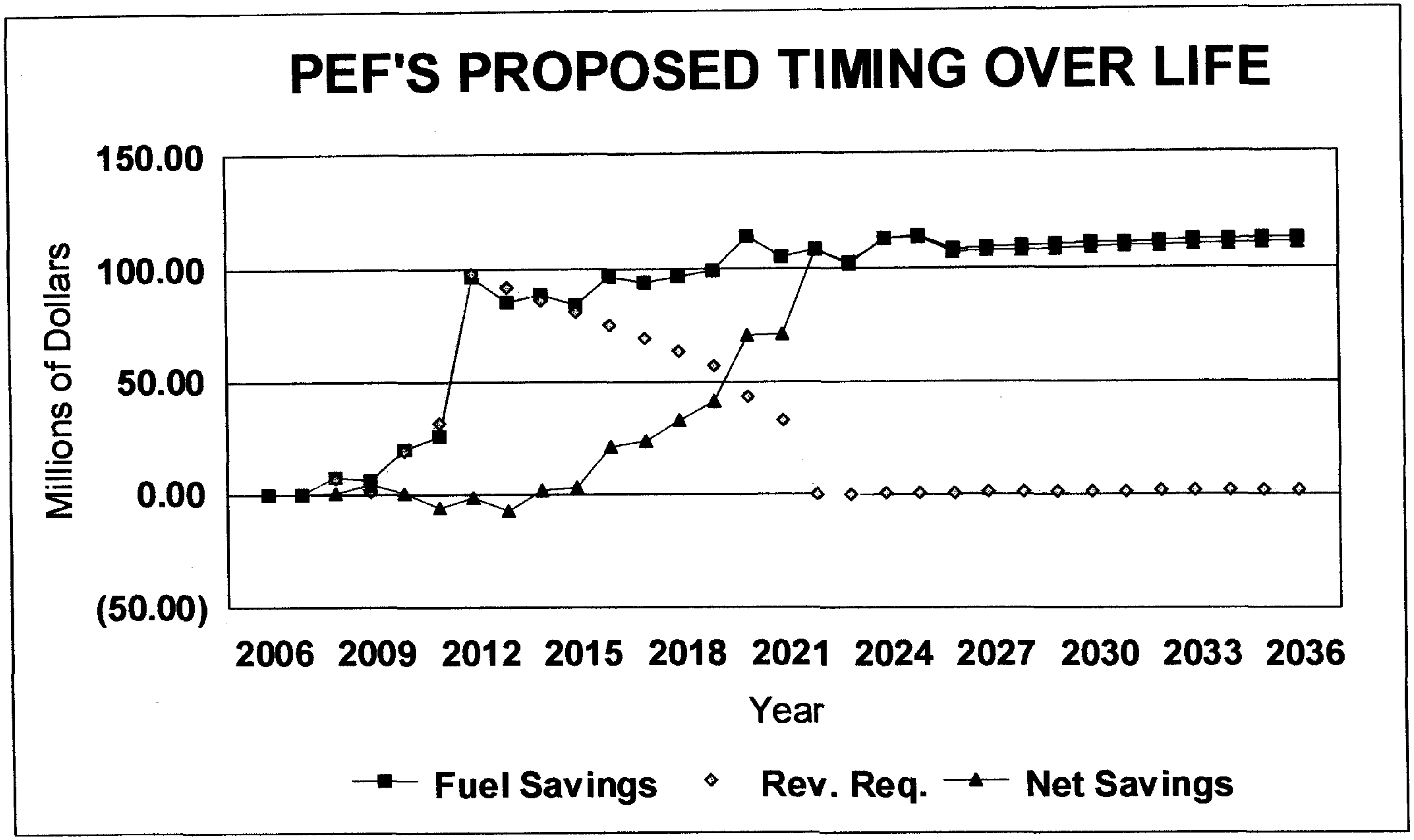
Year	Revenue Requirement	Fuel Savings	Customer Net Savings	Cumulative Net Savings	Equity Return	Cumulative Equity Return
	(a)	(b)	(c)	(d)	(e)	(f)
2008	$7.20	$7.91	$0.71	$0.71	$0.22	$0.22
2009	$1.47	$6.31	$4.84	$5.55	$0.49	$0.72
2010	$19.68	$20.24	$0.56	$6.11	$5.62	$6.34
2011	$31.60	$25.87	-$5.73	$0.38	$8.97	$15.31
2012	$97.85	$96.63	-$1.22	-$0.84	$26.88	$42.19
2013	$92.11	$85.47	-$6.64	-$7.48	$23.87	$66.07
2014	$86.44	$88.54	$2.10	-$5.38	$20.87	$86.94
2015	$80.82	$84.26	$3.44	-$1.94	$17.87	$104.81
2016	$75.10	$96.31	$21.21	$19.27	$14.87	$119.68

SOURCE AND REFERENCES

Columns (a-c) : PEF's response to OPC Interrogatory 12 spreadsheet.
Column (d) : Accumulation of Column (c).
Column (e) : PEF's response to Interrogatory 8 in Docket No. 060642-EI. speadsheet "Debt-Equity Returns" cost of equity divided by grossed up return of 13.19% times average investment in PEF's response to OPC Interrogatory 12 spreadsheet in this case. OPC Interrogatory 12 spreadsheet in this case.
Column (f) : Accumulation of Column (e).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 14
COMPANY OPC
WITNESS Daniel J. Lawton (DJL-4)
DATE 08/07 & 08/07

DOCKET NO. 070052-EI
PEF'S Proposed Timing
Exhibit _________ (DJL-5)
Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 15
COMPANY OPC
WITNESS Daniel J. Lawton (DJL-5)
DATE 08/07 + 08/07

Progress Energy

February 14, 2007

Mr. John Slemkewicz,
Public Utility Supervisor
Electric and Gas Accounting Section
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Dear Mr. Slemkewicz:

Pursuant to Commission Rule 25-6.1352, enclosed please find Progress Energy Florida, Inc.'s Rate of Return report for the twelve months ended December 31, 2006.

The report includes the Company's actual rate of return computed on an end-of-period rate base, the Company's adjusted rate of return computed on an average rate base, the Company's end-of-period required rates of return, and certain financial integrity indicators for the twelve months ended December 31, 2006. The separation factors used for the jurisdictional amounts were developed from the cost of service prepared in compliance with the stipulation and settlement agreement approved in Docket No. 050078-EI, Order No. PSC-05-0945-S-EI.

This report also includes Schedule 6, the supplemental information associated with the Sebring rider as required by the FPSC in Docket No. 920949-EU, Order No. 92-1468-FOF-EI, and as modified by Docket No. 930868-EI, Order No. PSC-93-1519-FOF-EI.

If you have any questions, please feel free to contact Cindy Lee at (727) 820-5535.

Sincerely,

Will Garrett

Will Garrett
Controller, Progress Energy Florida

dc
Attachment
xc: Mr. Harold McLean, Office of the Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 16
COMPANY FIPUG
WITNESS Jeffry Pollock (JP-1)
DATE 08/07 - 08/07

	(1) Actual Per Books	(2) FPSC Adjustments	(3) FPSC Adjusted	(4) Pro Forma Adjustments	(5) Pro Forma Adjusted
I. Average Rate of Return (Jurisdictional)					
Net Operating Income (a) (b)	$412,261,767	($41,238,497)	$371,023,261	$0	$371,023,261
Average Rate Base	$4,587,753,119	($235,950,825)	$4,351,802,294	$0	$4,351,802,294
Average Rate of Return	8.99%		8.53%		8.53%
II. Year End Rate of Return (Jurisdictional)					
Net Operating Income	$412,261,757	($41,238,497)	$371,023,261	$0	$371,023,261
Year End Rate Base	$4,762,106,993	($389,004,469)	$4,373,102,524	$0	$4,373,102,524
Year End Rate of Return	8.66%		8.48%		8.48%

Footnotes
(a) Column (1) includes AFUDC earnings.
(b) Column (2) includes reversal of AFUDC earnings.

III. Required Rates of Return	Average Capital Structure	End of Period Capital Structure
FPSC Adjusted Basis		
Low Point	8.38%	8.42%
Mid Point	8.98%	9.04%
High Point	9.58%	9.65%
Pro Forma Adjusted Basis		
Low Point	8.38%	8.42%
Mid Point	8.98%	9.04%
High Point	9.58%	9.65%

IV. FINANCIAL INTEGRITY INDICATORS		
A. T.I.E. with AFUDC	5.62	(System Per Books Basis)
B. T.I.E. without AFUDC	5.48	(System Per Books Basis)
C. AFUDC to Net Income	6.70%	(System Per Books Basis)
D. Internally Generated Funds	116.07%	(System Per Books Basis)
E. STD/LTD to Total Investor Funds		
LT Debt-Fixed to Total Investor Funds	32.75%	(FPSC Adjusted Basis)
ST Debt to Total Investor Funds	0.00%	(FPSC Adjusted Basis)
F. Return on Common Equity	11.00%	(FPSC Adjusted Basis)
	11.00%	(Pro Forma Adjusted Basis)
G. Current Allowed AFUDC Rate	8.85%	Docket 050078-EI Order PSC-05-0945-S-EI

I am aware that Section 837.06, Florida Statutes, provides:

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775.083, or s. 775.084.

Will Garrett, Controller Progress Energy Florida

2-14-07
Date

ROGRESS ENERGY FLORIDA
verage Rate of Return - Rate Base
ecember 2006

Schedule 2
Page 1 of 3

	Plant In Service	Accum Depr & Amort	Net Plant In Service	Future Use & Appd Unrecov Plant	Const Work in Progress	Nuclear Fuel (Net)	Net Utility Plant	Working Capital	Total Average Rate Base
stem Per Books	$8,937,593,885	$4,261,567,212	$4,676,026,672	$9,046,653	$517,484,715	$65,427,815	$5,267,985,655	$21,355,957	$5,289,341,612
ss Recoverable:									
ARO	10,906,932	(22,104,148)	33,011,080	0	0	0	33,011,080	(378,098,125)	(345,087,045)
ECCR	49,419	25,669	23,749	0	16,426	0	40,175	(6,547,435)	(6,507,260)
ECRC	3,005,530	149,554	2,855,976	0	11,130,036	0	13,986,013	8,258,825	22,244,838
FUEL	282,818,047	50,068,828	232,749,219	0	0	0	232,749,219	183,638,210	416,387,429
SCRC	0	0	0	0	0	0	0	134,285,504	134,285,504
Regulatory Base - System	$8,640,813,956	$4,233,427,309	$4,407,386,647	$9,046,653	$506,338,252	$65,427,615	$4,988,199,167	$81,818,979	$5,070,018,146
Regulatory Base - Retail	$7,921,788,092	$3,924,782,247	$3,997,005,845	$6,851,795	$464,935,490	$63,032,671	$4,521,825,800	$65,927,319	$4,587,753,119
SC Adjustments									
CWIP - AFUDC	0	0	0	0	(237,359,872)	0	(237,359,872)	0	(237,359,872)
GAIN/LOSS ON SALE OF PLANT	0	0	0	0	0	0	0	(2,264,364)	(2,264,364)
CAPITAL LEASE	(4,181,826)	0	(4,181,826)	0	0	0	(4,181,826)	4,181,826	(0)
IUC DECOM UNFUNDED - WHOLESALE	0	(2,286,276)	2,286,276	0	0	0	2,286,276	0	2,286,276
RTO START UP COSTS	0	0	0	0	0	0	0	93,703	93,703
ECTION 1341 INC TAX ADJUSTMENT	0	0	0	0	0	0	0	1,293,432	1,293,432
Total FPSC Adjustments	(4,181,826)	(2,286,276)	(1,895,550)	0	(237,359,872)	0	(239,255,422)	3,304,597	(235,950,825)
FPSC Adjusted	$7,917,606,266	$3,922,495,971	$3,995,110,295	$6,851,795	$217,575,618	$63,032,671	$4,282,570,378	$69,231,915	$4,351,802,294

Docket No. 070052-EI
PEF Rate of Return Report
Exhibit No. ___ (JP-1)
Page 3 of 15

OGRESS ENERGY FLORIDA
erage Rate of Return - Income Statement
cember 2006

	Operating Revenues	Fuel & Net Interchange	O&M Other	Depr & Amort	Taxes Other than Income	Income Taxes Current	Deferred Income Tax (Net)	Investment Tax Credit (Net)	Gain/Loss on Disposition & Other	Total Operating Expenses	Net Operating Income
tem Per Books (a)	$4,560,623,120	$2,530,408,291	$675,343,794	$403,781,163	$309,074,331	$237,704,369	($41,675,714)	($6,410,000)	$0	$4,108,226,231	$452,396,889
s Recoverable:											
ARO	0	0	0	(3,324)	0	0	(41,000)	0	0	(44,324)	44,324
ECCR	60,879,845	0	61,159,893	9,884	15,632	639,294	(757,165)	0	0	61,067,537	(187,692)
ECRC	23,287,033	0	22,855,612	164,160	16,767	96,628	0	0	0	23,133,167	153,866
FUEL	2,545,554,024	2,499,587,326	0	9,006,611	1,748,311	13,582,865	0	0	0	2,523,925,314	21,628,710
SCRC	122,445,779	0	0	122,357,617	0	34,008	0	0	0	122,391,625	54,154
Regulatory Base - System	$1,808,456,439	$30,820,965	$591,328,290	$272,246,015	$307,293,621	$223,351,570	($40,877,549)	($6,410,000)	$0	$1,377,752,912	$430,703,527
Regulatory Base - Retail	$1,648,480,434	$6,329,237	$541,123,476	$249,315,284	$298,425,089	$203,740,235	($37,576,812)	($5,892,838)	$0	$1,255,463,669	$393,016,765
C Adjustments											
ORPORATE AIRCRAFT ALLOCATION	0	0	(668,934)	0	0	258,041	0	0	0	(410,892)	410,892
RANCHISE FEE & GROSS REC TAX REVENUE	(200,515,907)	0	0	0	0	(77,349,011)	0	0	0	(77,349,011)	(123,166,896)
RANCHISE FEES & GROSS REC TAX - TOI	0	0	0	0	(198,830,948)	76,699,038	0	0	0	(122,131,910)	122,131,910
AIN/LOSS ON SALE OF PLANT	0	0	0	0	0	355,660	0	0	(921,995)	(566,335)	566,335
NST./PROMOTIONAL ADVERTISING	0	0	(2,450,994)	0	0	949,328	0	0	0	(1,511,665)	1,511,665
NTEREST ON TAX DEFICIENCY	0	0	(329,843)	0	0	127,237	0	0	0	(202,606)	202,606
IISCELLANEOUS INTEREST EXPENSE	0	0	75,155	0	0	(28,991)	0	0	0	46,164	(46,164)
EMOVE ASSOC/ORGANIZATION DUES	0	0	(70,367)	0	0	27,144	0	0	0	(43,223)	43,223
EMOVE DEFERRED TAX AFUDC DEBT	0	0	0	0	0	0	7,316	0	0	7,316	(7,316)
EMOVE ECONOMIC DEVELOPMENT	0	0	(25,827)	0	0	9,963	0	0	0	(15,864)	15,864
EVENUE SHARING	0	0	0	0	0	0	0	0	0	0	0
TO START UP COSTS	0	0	1,001	0	0	(386)	0	0	0	615	(615)
EBRING - RIDER REVENUE	(3,769,894)	0	0	0	0	(1,454,237)	0	0	0	(1,454,237)	(2,315,657)
EBRING - TRANSITION DEPRECIATION	0	0	0	(3,371,989)	0	1,300,745	0	0	0	(2,071,244)	2,071,244
TORM COSTS - 2004			0			0				0	0
NTEREST SYNCHRONIZATION - FPSC	0	0	0	0	0	23,410,597	0	0	0	23,410,597	(23,410,597)
Total FPSC Adjustments	(204,285,801)	0	(3,479,810)	(3,371,989)	(198,830,948)	24,305,129	7,316	0	(921,995)	(182,292,297)	(21,993,504)
FPSC Adjusted	$1,444,194,633	$6,329,237	$537,643,666	$245,943,295	$99,594,141	$228,045,364	($37,569,496)	($5,892,838)	($921,995)	$1,073,171,373	$371,023,261

notes:

(a) The addition of earnings from AFUDC charges would increase the system NOI by $21,891,699
and Jurisdictional NOI by $19,244,992

rent Month

	Operating Revenues	Fuel & Net Interchange	O&M Other	Depr & Amort	Taxes Other than Income	Income Taxes Current	Deferred Income Tax (Net)	Investment Tax Credit (Net)	Gain/Loss on Disposition & Other	Total Operating Expenses	Net Operating Income
em Per Books											
Excluding AFUDC Earnings and Recoverable	$135,478,356	$2,872,723	$52,309,390	$25,109,767	$19,635,082	$17,071,516	($3,449,194)	($965,000)	$0	$112,584,285	$22,894,070
idictional Per Books											
Excluding AFUDC Earnings and Recoverable	$130,846,993	$570,029	$48,129,253	$22,395,536	$19,210,959	$18,611,562	($3,170,682)	($867,143)	$0	$104,859,515	$25,987,478

OGRESS ENERGY FLORIDA
erage Rate of Return - Adjustments
cember 2006

lotes	Rate Base Adjustments	P=Pro Forma F=FPSC	System	Retail
(1)	CWIP - AFUDC	F	($269,944,276)	($237,359,872)
(1)	GAIN/LOSS ON SALE OF PLANT	F	(2,152,235)	(2,284,364)
(2)	CAPITAL LEASE-EPS	F	(4,181,826)	(4,181,826)
(2)	CAPITAL LEASE-WORKING CAPITAL	F	4,181,826	4,181,826
(1)	NUC. DECOM. UNFUNDED - WHOLESALE	F	2,286,276	2,286,276
(2)	RTO START UP COSTS	F	100,452	93,703
(1)	SECTION 1341 INC TAX ADJUSTMENT	F	1,407,470	1,293,432
	Total		($268,302,313)	($235,950,825)

			System		Retail	
otes	Income Statement Adjustments (to NOI)	P=Pro Forma F=FPSC	Amount	Income Tax Effect	Amount	Income Tax Effect
(2)	CORPORATE AIRCRAFT ALLOCATION	F	($743,438)	$286,781	($668,934)	$258,041
(1)	FRANCHISE FEE & GROSS REC TAX REVENUE	F	200,515,907	(77,349,011)	200,515,907	(77,349,011)
(1)	FRANCHISE FEES & GROSS REC TAX - TOI	F	(198,830,948)	76,699,038	(198,830,948)	76,699,038
(1)	GAIN/LOSS ON SALE OF PLANT	F	(1,043,318)	402,460	(921,995)	355,660
(1)	INST./PROMOTIONAL ADVERTISING	F	(2,700,663)	1,041,781	(2,460,994)	949,328
(1)	INTEREST ON TAX DEFICIENCY	F	(361,966)	139,626	(329,843)	127,237
(1)	MISCELLANEOUS INTEREST EXPENSE	F	572,046	(220,667)	75,155	(28,991)
(1)	REMOVE ASSOC/ORGANIZATION DUES	F	(77,220)	29,788	(70,367)	27,144
(1)	REMOVE DEFERRED TAX AFUDC DEBT	F	0	8,000	0	7,316
(1)	REMOVE ECONOMIC DEVELOPMENT	F	(28,342)	10,933	(25,827)	9,963
(2)	REVENUE SHARING	F	0	0	0	0
(2)	RTO START UP COSTS	F	1,404	(542)	1,001	(386)
(1)	SEBRING - RIDER REVENUE	F	3,769,894	(1,454,237)	3,769,894	(1,454,237)
(1)	SEBRING - TRANSITION DEPRECIATION	F	(3,371,989)	1,300,745	(3,371,989)	1,300,745
	STORM COSTS 2004	F	0	0	0	0
(1)	INTEREST SYNCHRONIZATION - FPSC	F	0	25,830,915	0	23,410,597
	Total		($2,298,633)	$26,725,613	($2,318,940)	$24,312,445

es: (1) Docket No. 910890-EI, Order No. PSC 92-0208-FOF-EI
(2) N/A

OGRESS ENERGY FLORIDA
d of Period Rate of Return - Rate Base
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	Plant In Service	Accum Depr & Amort	Net Plant In Service	Future Use & Appd Unrecov Plant	Const Work In Progress	Nuclear Fuel (Net)	Net Utility Plant	Working Capital	Total Period End Rate Base
tem Per Books	$9,225,460,896	$4,339,961,105	$4,885,499,791	$7,422,007	$641,485,881	$58,409,362	$5,592,817,041	$21,355,957	$5,614,172,998
s Recoverable:									
ARO	10,906,932	(22,088,037)	32,994,969	0	0	0	32,994,969	(378,098,125)	(345,103,156)
ECCR	49,419	27,001	22,418	0	112,155	0	134,573	(8,547,435)	(8,412,863)
ECRC	3,698,169	143,598	3,554,571	0	30,248,528	0	33,803,098	8,258,825	42,061,923
FUEL	286,837,855	57,616,067	229,221,788	0	0	0	229,221,788	183,638,210	412,859,998
SCRC	0	0	0	0	0	0	0	134,285,504	134,285,504
Regulatory Base - System	$8,923,988,523	$4,304,282,476	$4,619,706,046	$7,422,007	$611,125,198	$58,409,362	$5,296,662,613	$81,818,979	$5,378,481,592
Regulatory Base - Retail	$8,115,847,278	$4,041,610,316	$4,074,236,962	$5,621,313	$560,042,428	$56,278,971	$4,696,179,674	$65,927,319	$4,762,106,993
C Adjustments									
WIP - AFUDC	0	0	0	0	(390,413,515)	0	(390,413,515)	0	(390,413,515)
AIN/LOSS ON SALE OF PLANT	0	0	0	0	0	0	0	(2,264,364)	(2,264,364)
APITAL LEASE	(54,363,739)	0	(54,363,739)	0	0	0	(54,363,739)	54,363,739	(0)
IUC DECOM. UNFUNDED - WHOLESALE	0	(2,286,276)	2,286,276	0	0	0	2,286,276	0	2,286,276
TO START UP COSTS	0	0	0	0	0	0	0	93,703	93,703
ECTION 1341 INC TAX ADJUSTMENT	0	0	0	0	0	0	0	1,293,432	1,293,432
Total FPSC Adjustments	(54,363,739)	(2,286,276)	(52,077,463)	0	(390,413,515)	0	(442,490,978)	53,486,509	(389,004,469)
FPSC Adjusted	$8,061,483,539	$4,039,324,040	$4,022,159,499	$5,621,313	$169,628,913	$56,278,971	$4,253,688,696	$119,413,828	$4,373,102,524

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ɔGRESS ENERGY FLORIDA
ɫ of Period - Income Statement
:ember 2006

	Operating Revenues	Fuel & Net Interchange	O&M Other	Depr & Amort	Taxes Other than Income	Income Taxes Current	Deferred Income Tax (Net)	Investment Tax Credit (Net)	Gain/Loss on Disposition & Other	Total Operating Expenses	Net Operating Income
om Per Books (a)	$4,560,623,120	$2,630,408,291	$675,343,794	$403,781,163	$309,074,331	$237,704,366	($41,675,714)	($6,410,000)	$0	$4,108,226,231	$452,396,889
; Recoverable:											
ARO	0	0	0	(3,324)	0	0	(41,000)	0	0	(44,324)	44,324
ECCR	60,879,845	0	61,159,893	9,884	15,632	639,294	(757,165)	0	0	61,067,537	(187,692)
ECRC	23,287,033	0	22,855,612	164,160	16,767	96,628	0	0	0	23,133,167	153,866
FUEL	2,545,554,024	2,499,587,328	0	9,006,811	1,748,311	13,582,865	0	0	0	2,523,925,314	21,628,710
SCRC	122,445,779	0	0	122,357,617	0	34,008	0	0	0	122,391,625	54,154
Regulatory Base - System	$1,808,456,439	$30,820,965	$591,328,290	$272,246,015	$307,293,621	$223,361,570	($40,877,549)	($6,410,000)	$0	$1,377,752,912	$430,703,527
Regulatory Base - Retail	$1,648,480,434	$6,329,237	$541,123,476	$249,315,284	$298,425,089	$203,740,235	($37,576,812)	($5,892,838)	$0	$1,255,463,669	$393,016,765
C Adjustments											
ɔRPORATE AIRCRAFT ALLOCATION	0	0	(668,934)	0	0	258,041	0	0	0	(410,892)	410,892
ɽANCHISE FEE & GROSS REC TAX REVENUE	(200,515,907)	0	0	0	0	(77,349,011)	0	0	0	(77,349,011)	(123,166,896)
ɽANCHISE FEES & GROSS REC TAX - TOI	0	0	0	0	(198,830,948)	76,699,038	0	0	0	(122,131,910)	122,131,910
AIN/LOSS ON SALE OF PLANT	0	0	0	0	0	355,660	0	0	(921,995)	(566,335)	566,335
ːST./PROMOTIONAL ADVERTISING	0	0	(2,460,994)	0	0	949,328	0	0	0	(1,511,665)	1,511,665
ITEREST ON TAX DEFICIENCY	0	0	(329,843)	0	0	127,237	0	0	0	(202,606)	202,606
ISCELLANEOUS INTEREST EXPENSE	0	0	75,155	0	0	(28,991)	0	0	0	46,164	(46,164)
ΞMOVE ASSOC/ORGANIZATION DUES	0	0	(70,367)	0	0	27,144	0	0	0	(43,223)	43,223
ΞMOVE DEFERRED TAX AFUDC DEBT	0	0	0	0	0	0	7,316	0	0	7,316	(7,316)
ΞMOVE ECONOMIC DEVELOPMENT	0	0	(25,827)	0	0	9,963	0	0	0	(15,864)	15,864
ΞVENUE SHARING	0	0	0	0	0	0	0	0	0	0	0
TO START UP COSTS	0	0	1,001	0	0	(386)	0	0	0	615	(615)
ΞBRING - RIDER REVENUE	(3,769,894)	0	0	0	0	(1,454,237)	0	0	0	(1,454,237)	(2,315,657)
ΞBRING - TRANSITION DEPRECIATION	0	0	0	(3,371,989)	0	1,300,745	0	0	0	(2,071,244)	2,071,244
TORM COSTS - 2004			0			0				0	0
ITEREST SYNCHRONIZATION - FPSC	0	0	0	0	0	23,410,597	0	0	0	23,410,597	(23,410,597)
Total FPSC Adjustments	(204,285,801)	0	(3,479,810)	(3,371,989)	(198,830,948)	24,305,129	7,316	0	(921,995)	(182,292,297)	(21,993,504)
FPSC Adjusted	$1,444,194,633	$6,329,237	$537,643,666	$245,943,295	$99,594,141	$228,045,364	($37,569,496)	($5,892,838)	($921,995)	$1,073,171,373	$371,023,261

notes
(a) The addition of earnings from AFUDC charges would increase the system NOI by $21,891,699
and Jurisdictional NOI by $19,244,992

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ROGRESS ENERGY FLORIDA
nd of Period Rate of Return - Adjustments
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Notes	Rate Base Adjustments	P=Pro Forma F=FPSC	System	Retail
(1)	CWIP - AFUDC	F	($448,161,874)	($390,413,515)
(1)	GAIN/LOSS ON SALE OF PLANT	F	(2,152,235)	(2,264,364)
(2)	CAPITAL LEASE	F	(54,363,739)	(54,363,739)
(2)	CAPITAL LEASE	F	54,363,739	54,363,739
(1)	NUC. DECOM. UNFUNDED - WHOLESALE	F	2,286,276	2,286,276
(2)	RTO START UP COSTS	F	100,452	93,703
(1)	SECTION 1341 INC TAX ADJUSTMENT	F	1,407,470	1,293,432
	Total		($446,519,912)	($389,004,469)

lotes	Income Statement Adjustments (to NOI)	P=Pro Forma F=FPSC	System Amount	System Income Tax Effect	Retail Amount	Retail Income Tax Effect
(2)	CORPORATE AIRCRAFT ALLOCATION	F	($743,436)	$286,781	($668,934)	$258,041
(1)	FRANCHISE FEE & GROSS REC TAX REVENUE	F	200,515,907	(77,349,011)	200,515,907	(77,349,011)
(1)	FRANCHISE FEES & GROSS REC TAX - TOI	F	(198,830,948)	76,699,038	(198,830,948)	76,699,038
(1)	GAIN/LOSS ON SALE OF PLANT	F	(1,043,318)	402,460	(921,995)	355,660
(1)	INST./PROMOTIONAL ADVERTISING	F	(2,700,663)	1,041,781	(2,460,994)	949,328
(1)	INTEREST ON TAX DEFICIENCY	F	(361,966)	139,628	(329,843)	127,237
(1)	MISCELLANEOUS INTEREST EXPENSE	F	572,046	(220,667)	75,155	(28,991)
(1)	REMOVE ASSOC/ORGANIZATION DUES	F	(77,220)	29,788	(70,367)	27,144
(1)	REMOVE DEFERRED TAX AFUDC DEBT	F	0	8,000	0	7,316
(1)	REMOVE ECONOMIC DEVELOPMENT	F	(28,342)	10,933	(25,827)	9,963
(2)	REVENUE SHARING	F	0	0	0	0
(2)	RTO START UP COSTS	F	1,404	(542)	1,001	(386)
(1)	SEBRING - RIDER REVENUE	F	3,769,894	(1,454,237)	3,769,894	(1,454,237)
(1)	SEBRING - TRANSITION DEPRECIATION	F	(3,371,989)	1,300,745	(3,371,989)	1,300,745
	STORM COSTS 2004	F	0	0	0	0
(1)	INTEREST SYNCHRONIZATION - FPSC	F	0	25,830,915	0	23,410,597
	Total		($2,298,633)	$26,725,613	($2,318,940)	$24,312,445

es (1) Docket No. 910890-EI, Order No. PSC 92-0203-FOF-EI
(2) N/A

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'ROGRESS ENERGY FLORIDA
verage Rate of Return - Capital Structure
'ro Forma Adjusted Basis
)ecember 2006

	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	FPSC Adjusted Retail	Ratio		Low Point Cost Rate	Low Point Weighted Cost	Mid Point Cost Rate	Mid Point Weighted Cost	High Point Cost Rate	High Point Weighted Cost
ommon Equity	$2,633,063,251	$2,138,567,182	($553,271,829)	$1,040,820,380	$2,626,115,733	60.35%	***	10.75%	6.49%	11.75%	7.09%	12.75%	7.69%
'eferred Stock	33,496,700	27,205,933	(7,242,830)	0	19,963,104	0.46%		4.51%	0.02%	4.51%	0.02%	4.51%	0.02%
ong Term Debt - Fixed	2,532,888,290	2,057,205,337	(547,674,194)	(220,846,764)	1,288,684,378	29.61%		5.74%	1.70%	5.74%	1.70%	5.74%	1.70%
1ort Term Debt *	(74,286,975)	(60,335,690)		60,335,690	1	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ustomer Deposits													
Active	150,338,406	122,104,466	(32,506,947)	0	89,597,519	2.06%		6.21%	0.13%	6.21%	0.13%	6.21%	0.13%
Inactive	686,568	557,629	(148,453)	0	409,176	0.01%							
vestment Tax Credit													
Post '70 Total	26,895,584	21,844,524	(5,815,502)										
Equity **					10,779,316	0.25%		10.70%	0.03%	11.69%	0.03%	12.68%	0.03%
Debt **					5,249,706	0.12%		5.74%	0.01%	5.74%	0.01%	5.74%	0.01%
eferred Income Taxes	406,707,668	330,326,919	(87,940,434)	107,478,530	349,865,015	8.04%							
S 109 DIT - Net	(61,220,561)	(49,723,182)	13,237,425	(2,375,898)	(38,861,654)	-0.89%							
Total	$5,648,568,933	$4,587,753,119	($1,221,362,763)	$985,411,938	$4,351,802,294	100.00%			8.38%		8.98%		9.58%

)aily Weighted Average
Cost Rates Calculated Per IRS Ruling
Equity Ratio Including Debt Associated With Qualifying Facilities Contracts (Based on FPSC Capital Structure) 53.97%
Docket No. 050078-EI, Order No. 05-0945-S-EI, Paragraph No. 13

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ROGRESS ENERGY FLORIDA
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	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	FPSC Adjusted Retail	Ratio	Low Point Cost Rate	Low Point Weighted Cost	Mid Point Cost Rate	Mid Point Weighted Cost	High Point Cost Rate	High Point Weighted Cost
mmon Equity	$2,682,292,656	$2,212,890,214	($603,970,786)	$1,040,820,380	$2,649,739,806	60.59% ***	10.75%	6.51%	11.75%	7.12%	12.75%	7.73%
eferred Stock	33,496,700	27,634,762	(7,412,851)	0	20,221,911	0.46%	4.51%	0.02%	4.51%	0.02%	4.51%	0.02%
ng Term Debt - Fixed	2,509,780,089	2,070,567,425	(555,416,674)	(214,015,134)	1,301,135,618	29.75%	5.79%	1.72%	5.79%	1.72%	5.79%	1.72%
ort Term Debt *	46,890,541	38,684,675		(38,684,675)	(0)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
stomer Deposits												
Active	159,270,769	131,398,311	(35,246,770)	0	96,151,542	2.20%	6.21%	0.14%	6.21%	0.14%	6.21%	0.14%
Inactive	779,017	642,668	(172,397)	0	470,291	0.01%						
estment Tax Credit												
Post '70 Total	23,386,508	19,293,856	(5,175,456)									
Equity **					9,492,488	0.22%	10.70%	0.02%	11.69%	0.03%	12.68%	0.03%
Debt **					4,825,914	0.11%	5.79%	0.01%	5.79%	0.01%	5.79%	0.01%
ferred Income Taxes	380,395,307	313,825,954	(84,181,836)	102,392,661	332,036,779	7.59%						
S 109 DIT - Net	(64,037,484)	(52,830,895)	14,171,555	(2,112,487)	(40,771,827)	-0.93%						
Total	$5,772,254,101	$4,762,106,993	($1,277,405,214)	$888,400,745	$4,373,102,524	100.00%		8.42%		9.04%		9.65%

aily Weighted Average
ost Rates Calculated Per IRS Ruling
Equity Ratio Including Debt Associated With Qualifying Facilities Contracts (Based on FPSC Capital Structure) 54.05%
Docket No. 050078-EI, Order No. 05-0945-S-EI, Paragraph No. 13

Schedule 5

PROGRESS ENERGY FLORIDA
Financial Integrity Indicators
December 2006

A: TIMES INTEREST EARNED WITH AFUDC

Earnings Before Interest	$676,236,960
AFUDC - Debt	$5,056,905
Income Taxes	$193,440,642
Total	$874,734,506
Interest Charges (before deducting AFUDC-Debt)	$155,524,490
T.I.E. with AFUDC	5.62

B: TIMES INTEREST EARNED WITHOUT AFUDC

Earnings Before Interest	$676,236,960
AFUDC - Equity	($16,834,794)
Income Taxes	$193,440,642
Total	$852,842,808
Interest Charges (before deducting AFUDC-Debt)	$155,524,490
T.I.E. without AFUDC	5.48

C: PERCENT AFUDC TO NET INCOME AVAILABLE FOR COMMON SHAREHOLDERS

AFUDC - Debt	$5,056,905
Less: DIT	($8,000)
Subtotal	$5,064,905
AFUDC - Other	$16,834,794
Total AFUDC	$21,899,699
Net Income Available For Common Shareholders	$326,724,531
Percent AFUDC to Available Net Income	6.70%

D: PERCENT INTERNALLY GENERATED FUNDS

Net Income	$328,236,391
Common Dividends	($234,650,392)
Preferred Dividends	($1,511,860)
AFUDC (Debt & EGS Other)	($21,891,699)
Depreciation & Amortization	$409,873,656
Deferred Income Taxes	($42,363,927)
Investment Tax Credits	($6,410,000)
Deferred Fuel (Net)	$403,584,738
Nuclear Fuel Amortization	$23,468,052
Nuclear Refueling	$13,506,021
Other - Incl Nuclear Decommissioning	($14,968,992)
Funds Provided from Operations	$856,871,988
Other Funds Provided - Incl Change in Working Capital	($4,357,207)
Total Funds Provided	$852,514,781
Construction Expenditures (excluding AFUDC)	$734,481,800
Percentage Internally Generated Funds	116.07%

E: SHORT TERM DEBT / LONG TERM DEBT AS PERCENT OF TOTAL INVESTOR CAPITAL - FPSC

Common Equity	$2,626,115,733
Preferred Stock	$19,963,104
Long Term Debt - Fixed Rate	$1,288,684,378
Short Term Debt	$1
Total	$3,934,763,215
% Long Term Debt - Fixed Rate	32.75%
% Short Term Debt	0.00%

F: FPSC ADJUSTED AVERAGE JURISDICTIONAL AND PRO FORMA RETURN ON COMMON EQUITY

	Pro Forma	FPSC
Average Earned Rate of Return	8.53%	8.53%
Less Reconciled Average Retail Weighted Cost Rates for:		
Preferred Stock	0.02%	0.02%
Long Term Debt - Fixed Rate	1.70%	1.70%
Short Term Debt	0.00%	0.00%
Customer Deposits	0.13%	0.13%
Investment Tax Credit (at Midpoint)		
Equity	0.03%	0.03%
Debt	0.01%	0.01%
Subtotal	1.89%	1.89%
Total	6.64%	6.64%
Divided by Common Equity Ratio	60.35%	60.35%
Jurisdictional Return on Common Equity	11.00%	11.00%

ROGRESS ENERGY FLORIDA
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	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	FPSC Adjusted Retail	Ratio	Low Point Cost Rate	Low Point Weighted Cost	Mid Point Cost Rate	Mid Point Weighted Cost	High Point Cost Rate	High Point Weighted Cost
ommon Equity	$2,682,292,656	$2,212,890,214	($603,970,786)	$1,040,820,380	$2,649,739,808	60.59% ***	10.75%	6.51%	11.75%	7.12%	12.75%	7.73%
referred Stock	33,496,700	27,634,762	(7,412,851)	0	20,221,911	0.46%	4.51%	0.02%	4.51%	0.02%	4.51%	0.02%
ong Term Debt - Fixed	2,509,780,089	2,070,567,425	(555,416,674)	(214,015,134)	1,301,135,618	29.75%	5.79%	1.72%	5.79%	1.72%	5.79%	1.72%
hort Term Debt *	46,890,541	38,684,675		(38,684,675)	(0)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ustomer Deposits												
Active	159,270,769	131,398,311	(35,246,770)	0	96,151,542	2.20%	6.21%	0.14%	6.21%	0.14%	6.21%	0.14%
Inactive	779,017	642,688	(172,397)	0	470,291	0.01%						
vestment Tax Credit												
Post '70 Total	23,386,508	19,293,858	(5,175,456)									
Equity **					9,492,488	0.22%	10.70%	0.02%	11.69%	0.03%	12.68%	0.03%
Debt **					4,625,914	0.11%	5.79%	0.01%	5.79%	0.01%	5.79%	0.01%
eferred Income Taxes	380,395,307	313,825,954	(84,181,836)	102,392,661	332,036,779	7.59%						
AS 109 DIT - Net	(64,037,484)	(52,830,895)	14,171,555	(2,112,487)	(40,771,827)	-0.93%						
Total	$5,772,254,101	$4,762,106,993	($1,277,405,214)	$888,400,745	$4,373,102,624	100.00%		8.42%		9.04%		9.65%

Daily Weighted Average
Cost Rates Calculated Per IRS Ruling
Equity Ratio Including Debt Associated With Qualifying Facilities Contracts (Based on FPSC Capital Structure) 54.05%
Docket No. 050078-EI, Order No. 05-0945-S-EI, Paragraph No. 13

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Schedule 5

PROGRESS ENERGY FLORIDA
Financial Integrity Indicators
December 2006

A: TIMES INTEREST EARNED WITH AFUDC

Earnings Before Interest	$676,236,960
AFUDC - Debt	$5,056,905
Income Taxes	$193,440,642
Total	$874,734,506
Interest Charges	
(before deducting AFUDC-Debt)	$155,524,490
T.I.E. with AFUDC	5.62

B: TIMES INTEREST EARNED WITHOUT AFUDC

Earnings Before Interest	$676,236,960
AFUDC - Equity	($16,834,794)
Income Taxes	$193,440,642
Total	$852,842,808
Interest Charges	
(before deducting AFUDC-Debt)	$155,524,490
T.I.E. without AFUDC	5.48

C: PERCENT AFUDC TO NET INCOME AVAILABLE FOR COMMON SHAREHOLDERS

AFUDC - Debt	$5,056,905
Less: DIT	($8,000)
Subtotal	$5,064,905
AFUDC - Other	$16,834,794
Total AFUDC	$21,899,699
Net Income Available	
For Common Shareholders	$326,724,531
Percent AFUDC to Available Net Income	6.70%

D: PERCENT INTERNALLY GENERATED FUNDS

Net Income	$328,236,391
Common Dividends	($234,650,392)
Preferred Dividends	($1,511,860)
AFUDC (Debt & ECS Other)	($21,891,699)
Depreciation & Amortization	$409,873,656
Deferred Income Taxes	($42,363,927)
Investment Tax Credits	($6,410,000)
Deferred Fuel (Net)	$403,584,738
Nuclear Fuel Amortization	$23,466,052
Nuclear Refueling	$13,506,021
Other - Incl Nuclear Decommissioning	($14,968,992)
Funds Provided from Operations	$856,871,988
Other Funds Provided -	
Incl Change in Working Capital	($4,357,207)
Total Funds Provided	$852,514,781
Construction Expenditures (excluding AFUDC)	$734,481,500
Percentage Internally Generated Funds	116.07%

E: SHORT TERM DEBT / LONG TERM DEBT AS PERCENT OF TOTAL INVESTOR CAPITAL - FPSC

Common Equity	$2,626,115,733
Preferred Stock	$19,963,104
Long Term Debt - Fixed Rate	$1,288,684,378
Short Term Debt	$1
Total	$3,934,763,215
% Long Term Debt - Fixed Rate	32.75%
% Short Term Debt	0.00%

FPSC ADJUSTED AVERAGE JURISDICTIONAL AND PRO FORMA

F: RETURN ON COMMON EQUITY

	Pro Forma	FPSC
Average Earned Rate of Return	8.53%	8.53%
Less Reconciled Average		
Retail Weighted Cost Rates for:		
Preferred Stock	0.02%	0.02%
Long Term Debt - Fixed Rate	1.70%	1.70%
Short Term Debt	0.00%	0.00%
Customer Deposits	0.13%	0.13%
Investment Tax Credit (at Midpoint)		
Equity	0.03%	0.03%
Debt	0.01%	0.01%
Subtotal	1.89%	1.89%
Total	6.64%	6.64%
Divided by Common Equity Ratio	60.35%	60.35%
Jurisdictional Return on Common Equity	11.00%	11.00%

ROGRESS ENERGY FLORIDA
FUDC Rate Computation Report
alculation of Jurisdictional Capital Structure
ecember 2006

Schedule A & B
(combined)

		System Per Books	AFUDC Adjustments to System	AFUDC Adjusted System	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	Adjusted Retail	Ratio	Cost Rate	Weighted Cost
mmon Equity	(1)	$2,633,063,251	$0	$2,633,063,251	$2,089,913,458	($513,290,428)	$1,040,820,380	$2,617,443,410	60.15%	11.75%	7.07%
eferred Stock	(2)	33,496,700	0	33,496,700	26,586,982	(6,529,850)	0	20,057,121	0.46%	4.51%	0.02%
ng Term Debt - Fixed	(2)	2,532,888,290	0	2,532,888,290	2,010,402,645	(493,762,230)	(220,846,764)	1,295,793,601	29.78%	5.74%	1.71%
ort Term Debt	(3)	(74,286,975)	131,500,140	57,213,165	45,411,201	(11,153,158)	(34,258,042)	1	0.00%	0.00%	0.00%
stomer Deposits											
Active	(4)	150,338,406	0	150,338,406	119,326,514	(29,307,030)	0	90,019,484	2.07%	6.22%	0.13%
Inactive	(4)	686,568	0	686,568	544,942	(133,040)	0	411,103	0.01%		
estment Tax Credit											
Post '70 Total	(5)	26,895,584	0	26,895,584	21,347,548	(5,243,036)					
Equity	(5)							10,799,004	0.25%		
Debt	(5)							5,305,508	0.12%		
ferred Income Taxes	(4)	406,707,668	0	406,707,668	322,811,778	(79,283,759)	107,478,530	351,006,548	8.07%		
S 109 DIT - Net	(4)	(61,220,561)	0	(61,220,561)	(48,591,949)	11,934,381	(2,375,898)	(39,033,486)	-0.90%		
Total		$5,648,568,933	$131,500,140	$5,780,069,073	$4,587,753,119	($1,126,769,031)	$890,818,206	$4,351,802,294	100.00%		8.93%

otnotes:
Common Equity cost rate is mid-point authorized in Docket No. 910890-EI.
Cost rates are year end.
Balances and cost rates are daily weighted average for 13 months.
Balances and cost rates are 13 month average.
Post '70 ITC credits assigned a zero-cost rate per FPSC Order No. 19282, Docket No. 880157-EI.

PROGRESS ENERGY FLORIDA
Rate of Return Report
SUMMARY OF SEBRING RIDER STATUS
For the Month of December 2006

PART I - SUMMARY

Line No.				
			Total Period	
1	Dollars to be Recovered:			
2	Medium Term Note - Principal		$30,700,000	
3	Medium Term Note - Interest		19,615,117	
4	Final Principal True-up		198,104	
5	Other Interest Expense (Net)	Note a	9,373	
6			50,522,594	
7	Regulatory Assessment Fee	Note a	42,108	
8	Total		$50,564,702	
9				
10	Period - April 1, 1993 - March 31, 2008		15	Years
11				
12	15 Year KWH Sales Forecasted	Note a	3,262,361,000	KWH
13				
14			Period to Date	
15	Dollars Recovered and Other Credits:			
16	Principal and Interest		$45,102,716	
17	Regulatory Assessment Fee		35,639	
18	Interest and Other Adjustments	Note b	916,070	
19	Total		$46,054,425	
20				
21	KWH Sales to date		2,823,387,354	KWH
22				
23	Length of period elapsed	13 Years	8	Months
24				
25				
26				

PART II - CURRENT STATUS

Line No.		Sales Statistics - KWH Actual	Sales Statistics - KWH Forecast	SR-1 Net Revenues Actual $	SR-1 Net Revenues Forecast $	SR-1 Net Revenues Difference $
27						
28						
29						
30						
31	Oct 06	22,072,769	22,171,000	$283,845	$337,643	($53,798)
32	Nov 06	19,864,698	19,541,000	$255,703	$297,590	(41,887)
33	Dec 06	19,569,478	19,706,000	$251,571	$300,103	(48,533)
34	Jan 07		21,231,000	$0	$323,327	
35	Feb 07		20,424,000	$0	$311,035	
36	Mar 07		19,096,000	$0	$290,814	
37						
38						

Line No.			
39	Rider (SR-1) Rate	1.293 Cents per KWH	Effective August 2006 Billings
40			
41			
42	Over/(Under) Recovery Balance -		December
43	Beginning Month Balance		$ 1,373,226
44	SR-1 Revenues (Net of Reg Assessment Fees)		251,571
45	Payment of Principal and Interest		-
46	Final Principal True-up		
47	Adjustments:		
48	Interest on Balance		6,571
49	Interest Adjustment		0
50	Revenue Adjustments - Back Billing Error		0
51			
52	EOM Balance Available for next payment of Principal & Interest		$ 1,631,367
53			
54	Next Principal and Interest Payment:		
53	Amount Due		$1,983,429
54	Date Due		01-Apr-07

Notes:

a. Updated per FPSC Order No. PSC-93-1519-FOF-EI and September 1996 update filed with the FPSC.

b. Other adjustments (net) may include true-up adjustments from final close-out transactions.

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Backgrounder

Office of Public Affairs
Telephone: 301/415-8200 E-mail: opa@nrc.gov

Power Uprates for Nuclear Plants

Background

Utilities have been using power uprates since the 1970s as a way to increase the power output of their nuclear plants. The NRC has completed 102 such reviews to date, resulting in a gain of approximately 12,650 MWt (megawatts thermal) or 4,216 MWe (megawatts electric) at existing plants (see Table 1). Collectively, an equivalent of about four nuclear power plant units has been gained through implementation of power uprates at existing plants. NRC licensees have indicated they plan to ask for power uprates over the next four years, that if approved, would add another 2,841 MWt (947 MWe) to the nation's generating capacity.

Discussion

To increase the power output of a reactor, typically a more highly enriched uranium fuel is added. This enables the reactor to produce more thermal energy and therefore more steam, driving a turbine generator to produce electricity. In order to accomplish this, components such as pipes, valves, pumps, heat exchangers, electrical transformers and generators, must be able to accommodate the conditions that would exist at the higher power level. For example, a higher power level usually involves higher steam and water flow through the systems used in converting the thermal power into electric power. These systems must be capable of accommodating the higher flows.

In some instances, licensees will modify and/or replace components in order to accommodate a higher power level. Depending on the desired increase in power level and original equipment design, this can involve major and costly modifications to the plant such as the replacement of main turbines. All of these factors must be analyzed by the licensee as part of a request for a power uprate, which is accomplished by amending the plant's operating license. The analyses must demonstrate that the proposed new configuration remains safe and that measures continue to be in place to protect the health and safety of the public. These analyses are reviewed by the NRC before a request for a power uprate is approved.

Power uprates can be classified in three categories: (1) measurement uncertainty recapture power uprates, (2) stretch power uprates, and (3) extended power uprates.

1) Measurement uncertainty recapture power uprates are power increases less than two percent and are achieved by using enhanced techniques for calculating reactor power. This involves the use of state-of-the-art devices to more precisely measure feedwater flow which is used to calculate reactor power. More precise measurements reduce the degree of uncertainty in the power level which is used by analysts to predict the ability of the reactor to be safely shut down under some accident conditions.

2) Stretch power uprates are typically on the order of up to seven percent and usually involve changes to instrumentation settings. Stretch power uprates generally do not involve major plant modifications. This is especially true for boiling-water reactor plants. In some limited cases where plant equipment was operated near capacity prior to the power uprate, more substantial changes may be required.

3) Extended power uprates are usually greater than stretch power uprates and have been approved for increases as high as 20 percent. Extended power uprates usually require significant modifications to major pieces of plant equipment such as the high pressure turbines, condensate pumps and motors, main generators, and/or transformers.

Review Process

Power uprates are submitted to NRC as license amendment requests. The applications and reviews are complex and involve many areas of NRC including various technical divisions of the Office of Nuclear Reactor Regulation and the Office of the General Counsel. Some reviews may also involve the Office of Nuclear Regulatory Research and the Advisory Committee on Reactor Safeguards. In evaluating a power uprate request, NRC reviews data and accident analyses submitted by a licensee to confirm that the plant can operate safely at the higher power level. Reviews of power uprate requests are a high priority and are therefore, being conducted on accelerated schedules.

Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," dated January 31, 2002, covers analyses of the effect of the power uprate on things such as electrical equipment, major plant systems, and emergency operating procedures. The RIS outlines the staff's information needs for reviewing measurement uncertainty recapture power uprate applications and is intended to result in a more efficient and effective review process. Standardization of licensee's submittals, improvements in the quality of submittals, and more focused reviews by the staff could improve the timeliness of power uprate reviews.

Based on results of its industry survey, NRC expects to receive only one stretch power uprate over the next five years. Therefore, NRC's efforts for improving the power uprate application and review processes initially focused on measurement uncertainty and extended power uprates. Efficiencies gained there will be applied to improve the stretch power uprate review process.

Reviews of extended power uprate applications were initially estimated to take up to 18 months, but have been completed more quickly. The Duane Arnold, Dresden 2 and 3, and Quad Cities 1 and 2 extended power uprates were completed in just under 12 months. This included coordination and review with the NRC's Advisory Committee for Reactor Safeguards -- an independent panel of technical experts from diverse fields that advises the Commission.

The NRC issued a review standard for extended power uprates, RS-001, in December 2003. The standard is a first-of-a-kind document that provides a comprehensive process and technical guidance for reviews by the NRC staff, and also provides useful information to licensees considering applying for an extended uprate. The NRC's Advisory Committee on Reactor Safeguards endorsed RS-001 as an "excellent review standard." The staff is currently using this standard to review the proposed uprates for Vermont Yankee (20 %), Waterford (8 %), Browns Ferry Unit 1 (20 %), Browns Ferry Units 2 and 3 (15 %), and Beaver Valley Units 1 and 2 (8 %). The staff will closely monitor these uprate reviews to identify any issues related to using RS-001.

To keep the public informed of its activities, NRC publishes a notice in the *Federal Register* (1) when it receives a request from a licensee for a power uprate, giving the public the opportunity to request a hearing; (2) after a finding of no significant environmental impact is made, if applicable; and (3) if a power uprate is approved. A press release is also issued if a power uprate is approved.

Plant-Specific Applications Under Review

The NRC usually has several applications for power uprates under review at any given time. An updated list of applications under review can be found on the NRC's Web site at this address: http://www.nrc.gov/reactors/operating/licensing/power-uprates/pending-applications.html .

Steam Dryer Issues Following Uprates

Since 2002, steam dryer cracking and flow-induced vibration damage on components and supports for the main steam and feedwater lines have been observed at the Dresden and Quad Cities nuclear power plants, both of which use boiling water reactors, following implementation of extended power uprates. NRC staff have determined these issues do not pose an immediate safety concern, given the plants' current operating conditions. However, steam dryers and other internal main steam and feedwater components must maintain structural integrity to avoid generating loose parts that could impact safety system or reactor plant operation. The NRC has corresponded with and met with nuclear industry groups concerning these issues since the first occurrences, and continues to examine its regulatory options based on industry actions and the information available.

Future Actions

Licensees have told NRC they plan to submit 18 power uprate applications in the next four years as follows:

- 10 extended power uprates
- 1 stretch power uprate
- 7 measurement uncertainty recapture power uprates

Based on the information provided, planned power uprates are expected to result in an increase of about 2,841 MWt. An updated list of anticipated future applications can be found on the NRC's Web site at this address:
http://www.nrc.gov/reactors/operating/licensing/power-uprates/expected-applications.html .

Tables

- Table 1 - Approved Power Uprates as of November 2004
- Table 2 - Power Uprates Currently Under Review as of November 2004
- Table 3 - Expected Future Submittals for Power Uprates as of October 2004

Table 1 - Approved Power Uprates

(TYPE -- S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

NO.	Plant	% Uprate	Mwt	Year Approved	TYPE
1	Calvert Cliffs 1	5.5	140	1977	S
2	Calvert Cliffs 2	5.5	140	1977	S
3	Millstone 2	5	140	1979	S
4	H. B. Robinson	4.5	100	1979	S
5	Fort Calhoun	5.6	80	1980	S
6	St. Lucie 1	5.5	140	1981	S
7	St. Lucie 2	5.5	140	1985	S
8	Duane Arnold	4.1	65	1985	S
9	Salem 1	2	73	1986	S
10	North Anna 1	4.2	118	1986	S
11	North Anna 2	4.2	118	1986	S
12	Callaway	4.5	154	1988	S
13	TMI-1	1.3	33	1988	S
14	Fermi 2	4	137	1992	S
15	Vogtle 1	4.5	154	1993	S
16	Vogtle 2	4.5	154	1993	S
17	Wolf Creek	4.5	154	1993	S

18	Susquehanna 2	4.5	148	1994	S
19	Peach Bottom 2	5	165	1994	S
20	Limerick 2	5	165	1995	S
21	Susquehanna 1	4.5	148	1995	S
22	Nine Mile Point 2	4.3	144	1995	S
23	WNP-2	4.9	163	1995	S
24	Peach Bottom 3	5	165	1995	S
25	Surry 1	4.3	105	1995	S
26	Surry 2	4.3	105	1995	S
27	Hatch 1	5	122	1995	S
28	Hatch 2	5	122	1995	S
29	Limerick 1	5	165	1996	S
30	V. C. Summer	4.5	125	1996	S
31	Palo Verde 1	2	76	1996	S
32	Palo Verde 2	2	76	1996	S
33	Palo Verde 3	2	76	1996	S
34	Turkey Point 3	4.5	100	1996	S
35	Turkey Point 4	4.5	100	1996	S
36	Brunswick 1	5	122	1996	S
37	Brunswick 2	5	122	1996	S
38	Fitzpatrick	4	100	1996	S
39	Farley 1	5	138	1998	S
40	Farley 2	5	138	1998	S
41	Browns Ferry 2	5	164	1998	S
42	Browns Ferry 3	5	164	1998	S
43	Monticello	6.3	105	1998	E
44	Hatch 1	8	205	1998	E
45	Hatch 2	8	205	1998	E
46	Comanche Peak 2	1	34	1999	MU
47	LaSalle 1	5	166	2000	S
48	LaSalle 2	5	166	2000	S
49	Perry	5	178	2000	S

50	River Bend	5	145	2000	S
51	Diablo Canyon 1	2	73	2000	S
52	Watts Bar	1.4	48	2001	MU
53	Byron 1	5	170	2001	S
54	Byron 2	5	170	2001	S
55	Braidwood 1	5	170	2001	S
56	Braidwood 2	5	170	2001	S
57	Salem 1	1.4	48	2001	MU
58	Salem 2	1.4	48	2001	MU
59	San Onofre 2	1.4	48	2001	MU
60	San Onofre 3	1.4	48	2001	MU
61	Susquehanna 1	1.4	48	2001	MU
62	Susquehanna 2	1.4	48	2001	MU
63	Hope Creek	1.4	46	2001	MU
64	Beaver Valley 1	1.4	37	2001	MU
65	Beaver Valley 2	1.4	37	2001	MU
66	Shearon Harris	4.5	138	2001	S
67	Comanche Peak 1	1.4	47	2001	MU
68	Comanche Peak 2	0.4	13	2001	MU
69	Duane Arnold	15.3	248	2001	E
70	Dresden 2	17	430	2001	E
71	Dresden 3	17	430	2001	E
72	Quad Cities 1	17.8	446	2001	E
73	Quad Cities 2	17.8	446	2001	E
74	Waterford 3	1.5	51	2002	MU
75	Clinton	20	579	2002	E
76	South Texas 1	1.4	53	2002	MU
77	South Texas 2	1.4	53	2002	MU
78	ANO-2	7.5	211	2002	E
79	Sequoyah 1	1.3	44	2002	MU
80	Sequoyah 2	1.3	44	2002	MU
81	Brunswick 1	15	365	2002	E

82	Brunswick 2	15	365	2002	E
83	Grand Gulf	1.7	65	2002	MU
84	H. B. Robinson	1.7	39	2002	MU
85	Peach Bottom 2	1.62	56	2002	MU
86	Peach Bottom 3	1.62	56	2002	MU
87	Indian Point 3	1.4	42.4	2002	MU
88	Point Beach 1	1.4	21.5	2002	MU
89	Point Beach 2	1.4	21.5	2002	MU
90	Crystal River 3	0.9	24	2002	S
91	D.C. Cook 1	1.66	54	2002	MU
92	River Bend	1.7	52	2003	MU
93	D.C. Cook 2	1.66	57	2003	MU
94	Pilgrim	1.5	30	2003	MU
95	Indian Point 2	1.4	43	2003	MU
96	Kewaunee	1.4	23	2003	MU
97	Hatch 1	1.5	41	2003	MU
98	Hatch 2	1.5	41	2003	MU
99	Palo Verde 2	2.9	114	2003	S
100	Kewaunee	6.0	99	2004	S
101	Palisades	1.4	35	2004	MU
102	Indian Point 2	3.2	101.6	2004	S

Table 2 - Power Uprates Under Review

(TYPE -- S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

No.	Plant	% Uprate	MWt	Submittal Date	Projected Completion Date	Type
1	Vermont Yankee	20	319	09/10/03	TBD	E
2	Waterford	8	275	11/13/03	April 2005	E
3	Seabrook	5.2	176	03/17/04	Feb. 2005	S
4	Indian Point 3	4.85	148	06/03/04	March 2005	S
5	Browns Ferry 2	15	494	06/25/04	TBD	E
6	Browns Ferry 3	15	494	06/25/04	TBD	E
7	Browns Ferry 1	20	659	06/28/04	TBD	E
8	Palo Verde 1	2.94	114	07/09/04	March 2005	S
9	Palo Verde 3	2.94	114	07/09/04	March 2005	S
10	Beaver Valley 1	8	211	10/04/04	TBD	E
11	Beaver Valley 2	8	211	10/04/04	TBD	E

Table 3 - Expected Future Submittals for Power Uprates

Fiscal Year	Total Uprates Expected	Measurement Uncertainty Recapture Uprates	Stretch Power Uprates	Extended Power Uprates	Megawatts Thermal	Approximate Megawatts Electric
2005	8	4	0	4	1,315	438
2006	3	3	0	0	161	54
2007	6	0	1	5	843	281
2008	1	0	0	1	522	174
TOTAL	**18**	**7**	**1**	**10**	**2,841**	**947**

Docket No. 070052-EI
Impact of Sales Growth
Exhibit No. ___ (JP-3)
Page 1 of 1

PROGRESS ENERGY FLORIDA

Impact of Sales Growth on Base Rate Recovery

Line	Description	Base Rates Set	Year One Load Growth	Year Two Load Growth
		(1)	(2)	(3)
1	Base Rate Costs	$50,000		
2	Electricity Sales (MWh)	1,000	1,030	1,061
3	Average Base Rate Cost ($/MWh)	$50	$50	$50
4	Base Rate Revenue		$51,500	$53,045
5	Additional Base Rate Cost Recovery		$1,500	$3,045

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 18
COMPANY FIPUG
WITNESS Jeffry Pollock (JP-3)
DATE 08/07+08/07

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 19
COMPANY FIPUG
WITNESS Jeffry Pollock (JP-4)
DATE 08/07/08/07

Docket No. 070052-EI
CCRC vs. Fuel Clause
Exhibit No. ___ (JP-4)
Page 1 of 1

Exhibit__JP-1P
Section C
Page 4 of 5

Progress Energy Florida
Capacity Cost Recovery Clause
Calculation of Capacity Clause Recovery Factor
Using Current 12 CP & 1/13th AD Allocation Method for Production Demand
For the Year 2007

Rate Class		(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrs×(1))	(4) Delivery Efficiency Factor	(5) Sales at Source (Generation) (mWh) (2)/(4)	(6) Avg 12 CP at Source (MW) (3)/(4)	(7) Annual Average Demand (5)/8760hrs	(8) Annual Average Demand Allocator (%)	(9) 12CP Demand Transmission Allocator (%)	(10) 12CP & 1/13 AD Demand Allocator (%)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
	Secondary	0.550	20,912,280	4,340.45	0.9344227	22,379,893	4,645.08	2,554.78	51.462%	60.948%	60.218%
General Service Non-Demand											
GS-1, GST-1											
	Secondary	0.658	1,365,672	236.93	0.9344227	1,461,514	253.56	166.84	3.361%	3.327%	3.330%
	Primary	0.658	6,768	1.17	0.9683000	6,990	1.21	0.80	0.016%	0.016%	0.016%
	Transmission	0.658	3,247	0.56	0.9783000	3,319	0.58	0.38	0.008%	0.008%	0.008%
									3.384%	3.350%	3.353%
General Service											
GS-2	Secondary	1.000	82,483	9.42	0.9344227	88,272	10.08	10.08	0.203%	0.132%	0.138%
General Service Demand											
GSD-1, GSDT-1											
	Secondary	0.789	12,650,152	1,830.27	0.9344227	13,537,933	1,958.72	1,545.43	31.130%	25.700%	26.118%
	Primary	0.789	2,404,893	347.95	0.9683000	2,483,624	359.34	283.52	5.711%	4.715%	4.792%
	Transmission	0.789	0	0.00	0.9783000	0.00	0.00	0.00	0.000%	0.000%	0.000%
SS-1	Primary	1.264	0	0.00	0.9683000	0.00	0.00	0.00	0.000%	0.000%	0.000%
	Transm Del/ Transm Mtr	1.264	17,286	1.56	0.9783000	17,669	1.60	2.02	0.041%	0.021%	0.022%
	Transm Del/ Primary Mtr	1.264	8,113	0.73	0.9683000	8,379	0.76	0.96	0.019%	0.010%	0.011%
									36.901%	30.446%	30.943%
Curtailable											
CS-1, CST-1, CS-2, CST-2, SS-3											
	Secondary	1.093	0	0.00	0.9344227	0.00	0.00	0.00	0.000%	0.000%	0.000%
	Primary	1.093	356,088	37.40	0.9683000	369,811	38.62	42.22	0.850%	0.507%	0.533%
SS-3	Primary	-	5,761	0.00	0.9683000	5,950	0.00	0.68	0.014%	0.000%	0.001%
									0.864%	0.507%	0.534%
Interruptible											
IS-1, IST-1, IS-2, IST-2											
	Secondary	0.927	117,778	14.50	0.9344227	126,044	15.52	14.39	0.290%	0.204%	0.210%
	Primary Del / Primary Mtr	0.927	1,874,168	230.80	0.9683000	1,935,545	238.35	220.95	4.451%	3.127%	3.229%
	Primary Del / Transm Mtr	0.927	2,169	0.27	0.9783000	2,217	0.27	0.25	0.005%	0.004%	0.004%
	Transm Del/ Transm Mtr	0.927	476,762	58.71	0.9783000	487,327	60.01	55.63	1.121%	0.787%	0.813%
	Transm Del/ Primary Mtr	0.927	81,181	10.00	0.9683000	83,839	10.32	9.57	0.193%	0.135%	0.140%
SS-2	Primary	0.749	0	0.00	0.9683000	0.00	0.00	0.00	0.000%	0.000%	0.000%
	Transm Del/ Transm Mtr	0.749	87,945	13.40	0.9783000	89,896	13.70	10.26	0.207%	0.180%	0.182%
	Transm Del/ Primary Mtr	0.749	49,404	7.53	0.9683000	51,021	7.78	5.82	0.117%	0.102%	0.103%
									6.383%	4.539%	4.681%
Lighting											
LS-1 (Secondary)		6.746	326,064	5.52	0.9344227	348,947	5.90	39.83	0.802%	0.077%	0.133%
			40,830,224	7,147.16		43,489,188	7,621.38	4,964.41	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2003
(2) Projected kWh sales for the period January 2006 to December 2006
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) Based on system average line loss analysis for 2004
(5) Column 2 / Column 4
(6) Column 3 / Column 4
(7) Calculated: Column 6 / 8,760 hours
(8) Column 7/ Total Column 7
(9) Column 8/ Total Column 8
(10) Column 8 x 1/13 + Column 9 x 12/13

Ruth. According to my understanding after talking to Lisa Bennett, Exhibits 20, 23 & 25 were not marked or admitted during the hearing & are not part of the record.

LB

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 20
COMPANY Not Admitted
WITNESS
DATE See above note

DOCKET NO 070052-EI
EXTRACT FROM 2005 TEN YEAR SITE PLAN
FIPUG EXHIBIT 21
ID # 21

Progress Energy Florida Ten-Year Site Plan

Hearing Exhibit 21

April 2005

2005-2014

Submitted to:
Florida Public Service Commission

Progress Energy

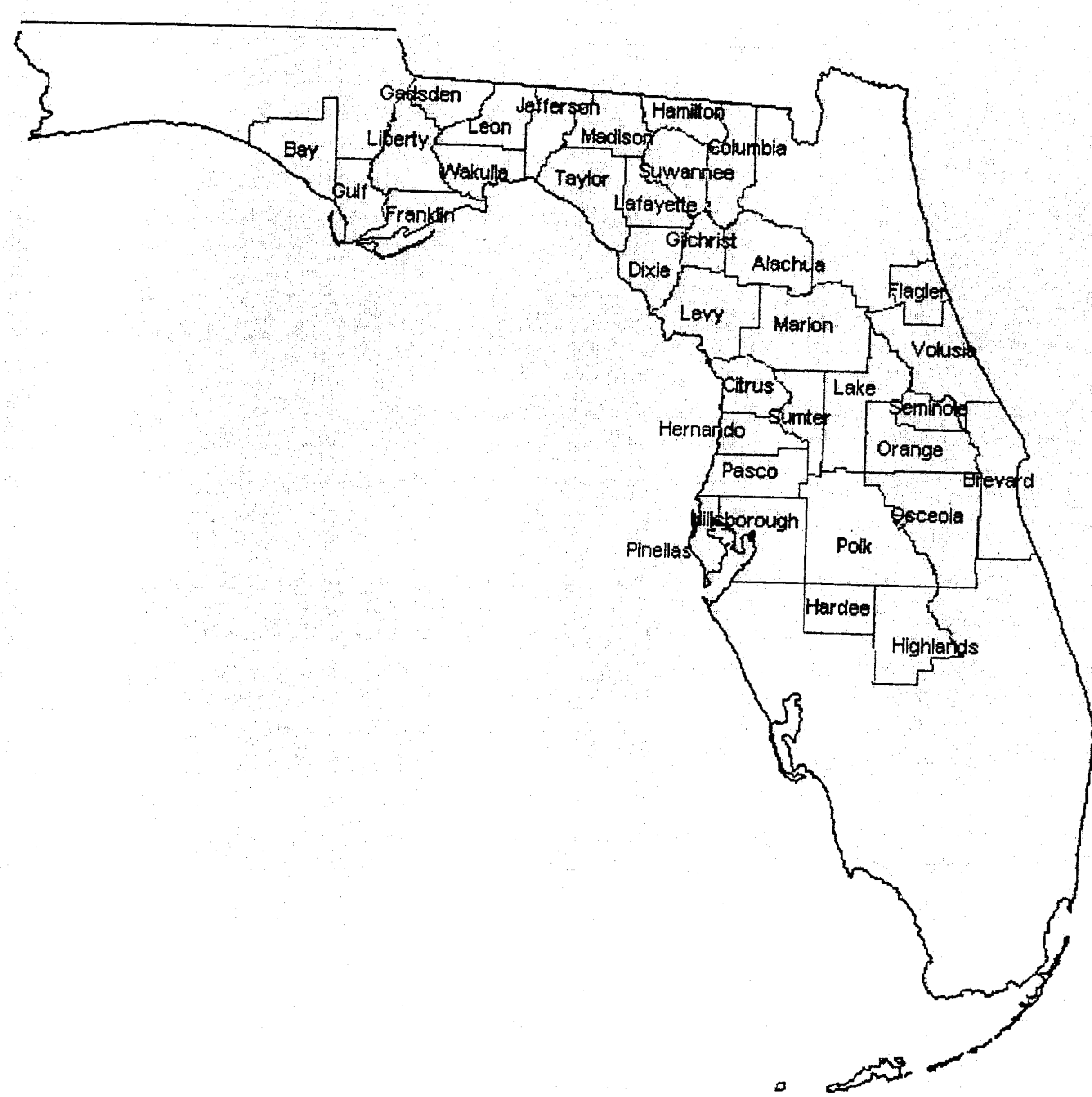
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 21
COMPANY FIPUG
WITNESS PEF Ten year Site Plans
DATE 08/07+08/07

DOCUMENT NUMBER-DATE
03245 APR-1 8
FPSC-COMMISSION CLERK

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map



PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2004

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1995	2,801,105	2.491	14,938	1,124,679	13,282	8.612	126,189	68,247
1996	2,847,802	2.494	15,481	1,141,671	13,560	8,848	129,440	68,356
1997	2,895,266	2.495	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,959,509	2.502	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,047,293	2.511	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,044,449	2.467	17,116	1,234,286	13,867	10,813	143,475	75,368
2001	3,141,867	2.465	17,604	1,274,672	13,810	11,061	146,983	75,251
2002	3,207,661	2.465	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,286,782	2.468	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,348,630	2.454	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,397,566	2.449	20,069	1,387,564	14,464	12.521	161,148	77,701
2006	3,457,712	2.447	20,602	1,412,969	14,581	12,998	164,319	79,101
2007	3,517,107	2.445	21,139	1,438,524	14,695	13,440	167,509	80,235
2008	3,581,336	2.446	21,669	1,463,871	14,803	13,861	170,672	81,212
2009	3,645,405	2.448	22,201	1,489,119	14,909	14,296	173,820	82,244
2010	3,702,998	2.446	22,742	1,514,200	15,019	14,736	176,945	83,281
2011	3,757,423	2.441	23,288	1,539,080	15,131	15,196	180,043	84,404
2012	3,809,526	2.436	23,837	1,563,793	15,243	15,663	183,119	85,533
2013	3,853,021	2.426	24,394	1,588,391	15,358	16,135	186,180	86,662
2014	3,891,403	2.413	24,959	1,612,925	15,475	16,613	189,232	87,790

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1995	3,864	3,143	1,229,399	0	27	2,058	29,499
1996	4,224	2,927	1,443,116	0	26	2,205	30,784
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,957
2004	4,069	2,733	1,488,840	0	28	3,016	38,193
2005	4,403	2,813	1,565,205	0	28	3,264	40,286
2006	4,485	2,813	1,594,218	0	28	3,384	41,497
2007	4,561	2,813	1,621,534	0	28	3,505	42,673
2008	4,600	2,813	1,635,285	0	28	3,617	43,775
2009	4,638	2,813	1,648,721	0	28	3,729	44,892
2010	4,670	2,813	1,660,209	0	28	3,843	46,020
2011	4,701	2,813	1,671,100	0	28	3,966	47,180
2012	4,731	2,813	1,681,991	0	28	4,095	48,354
2013	4,757	2,813	1,691,157	0	28	4,221	49,535
2014	4,780	2,813	1,699,167	0	28	4,344	50,724

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) TOTAL NO. OF CUSTOMERS
1995	1,846	2,322	33,667	17,774	1,271,785
1996	2,089	1,842	34,715	18,035	1,292,073
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,004	1,400,299
2001	3,839	1,830	40,933	20,752	1,444,958
2002	3,173	2,534	42,567	21,156	1,475,783
2003	3,359	2,595	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	4,572	2,773	47,630	22,922	1,574,447
2006	3,518	2,885	47,900	23,499	1,603,600
2007	3,753	2,945	49,372	24,079	1,632,925
2008	3,748	3,044	50,567	24,660	1,662,016
2009	3,674	3,082	51,648	25,241	1,690,993
2010	4,275	3,246	53,541	25,822	1,719,780
2011	4,427	3,275	54,882	26,403	1,748,339
2012	4,554	3,354	56,263	26,984	1,776,709
2013	4,706	3,435	57,676	27,565	1,804,949
2014	5.242	3,555	59.520	28,144	1,833,114

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1995	7.523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6.642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8:367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1.326	7.713	292	505	113	45	153	183	7.747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7.999	300	347	172	44	164	75	7,785
2004	9.554	1.071	8.483	531	283	188	37	166	75	8.274
2005	9,547	948	8.599	633	258	203	38	167	75	8.172
2006	9,808	993	8.815	420	228	214	39	169	75	8,663
2007	10,085	1,063	9.022	417	202	223	40	171	75	8,957
2008	10,298	1.093	9,205	413	179	232	41	172	75	9.186
2009	10,452	1.063	9,388	409	158	241	42	174	75	9,353
2010	10,802	1,213	9.589	400	140	250	43	176	75	9,719
2011	11,007	1,217	9,790	401	124	259	45	177	75	9,926
2012	11,218	1.230	9,988	402	109	269	46	179	75	10.138
2013	11,436	1,251	10,185	403	97	279	47	180	75	10,355
2014	11.651	1.269	10.382	404	86	289	48	182	75	10,567

Historical Values (1995 - 2004):

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

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

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

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

Projected Values (2005 - 2014):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	49,002	445	363	564	40,286	4,620	2,724	47,630	61.0
2006	49,289	459	365	564	41,497	3,565	2,838	47,900	59.4
2007	50,778	474	368	564	42,673	3,761	2,938	49,372	58.1
2008	51,992	489	371	565	43,775	3,748	3,044	50,567	58.1
2009	53,090	504	374	564	44,892	3,674	3,082	51,648	58.2
2010	55,001	519	377	564	46,020	4,275	3,246	53,541	58.1
2011	56,362	536	380	564	47,180	4,427	3,275	54,882	58.3
2012	57,763	552	383	565	48,354	4,554	3,355	56,263	58.4
2013	59,194	568	386	564	49,535	4,706	3,435	57,676	58.8
2014	61,057	585	389	564	50,724	5,242	3,554	59,520	59.5

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2004		FORECAST 2005		FORECAST 2006	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	8,748	3,504	8,914	3,735	9,200	3,695
FEBRUARY	7,791	3,090	7,115	3,362	7,335	3,303
MARCH	6,017	3,171	6,008	3,601	6,216	3,553
APRIL	6,760	3,176	6,691	3,483	6,956	3,409
MAY	8,446	3,960	7,659	4,195	7,965	4,142
JUNE	9,125	4,481	8,021	4,390	8,494	4,490
JULY	9,058	4,621	8,147	4,762	8,641	4,884
AUGUST	8,842	4,432	8,172	4,802	8,663	4,918
SEPTEMBER	8,628	4,064	7,689	4,369	8,136	4,444
OCTOBER	8,324	3,900	7,146	3,904	7,561	3,945
NOVEMBER	7,313	3,237	5,792	3,379	6,149	3,422
DECEMBER	8,303	3,632	7,356	3,648	7,899	3,695
TOTAL		45,268		47,630		47,900

NOTE: "Actual" = "Total" - "Interruptible" - "Res. LM" - "C/I LM" - "Voltage Reduction & Standby Generation"

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 9,769 MW, as shown in Table 3.1. This capacity resource includes utility purchased power (474 MW), non-utility purchased power (820 MW), combustion turbine (2,619 MW, 143 MW of which is owned by Georgia Power for the months June through September), nuclear (769 MW), fossil steam (3,882 MW) and combined-cycle plants (1,205 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QFs).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2005 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

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

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes 3,357 MW (summer rating) of proposed new capacity additions through the summer of 2014. As identified in Schedule 8, PEF's next planned need is the Hines 3 Unit, a 516 MW (summer) power block with a December 2005 in-service date. PEF's self-build option for Hines Unit 3 was determined to be the most cost-effective alternative (FPSC Docket No. 020953-EI, Order No. PSC-03-0175-FOF-EI, issued February 4, 2003). After Hines 3, the next planned unit is Hines 4, 461 MW (summer) power block with a December 2007 in-service date. Hines Unit 4 was granted its Need Certificate by the FPSC in November 2004 (Docket No. 040817-EI, Order No. PSC-04-1168-FOF-EI).

PEF's Base Expansion Plan projects requirements for additional combined-cycle units with proposed in-service dates of 2009, 2010, 2012, 2013 and 2014. These high efficiency gas-fired combined-cycle units, together with the Central Power & Lime Purchase from December 2005 through December 2015, the Shady Hills Purchase from December 2006 through April 2014, and the Southern Company Purchase from June 2010 through December 2015 help the PEF system meet the growing energy requirements of its customer base and also contribute to meeting the requirements of the 1990 Clean Air Act Amendments. Fuel switching, SO_2 emission allowance purchases, re-dispatching of system generation and technology improvements are additional options available to PEF to ensure compliance with these important environmental requirements. Status reports and specifications for new generation facilities are included in Schedule 9. As shown in Schedule 10, there are no new transmission lines associated with the Hines 3 combined-cycle unit, and only one new line (Hines-West Lake Wales 230 kV) required for the Hines 4 combined-cycle unit.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion over the ten-year planning term. New coal units may become a competitive option beyond the ten-year timeframe should forecasted gas prices continue to increase versus coal over that term. The uncertainties associated with fuel price forecasts and the long lead times required to site, permit, license, engineer, and construct a coal unit will require additional study of coal options in the next planning cycle.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2004

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	*(1)*
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,302	
Anclote	2	993	
Paul L. Bartow	3	444	
Suwannee River	3	143	
Total Fossil Steam	12	3,882	
Combined-cycle			
Hines Energy Complex	2	998	
Tiger Bay	1	207	
Total Combined-cycle	3	1,205	
Combustion Turbine			
DeBary	10	667	
Intercession City	14	1,041	*(2)*
Bayboro	4	184	
Bartow	4	187	
Suwannee	3	164	
Turner	4	154	
Higgins	4	122	
Avon Park	2	52	
University of Florida	1	35	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,619	
Total Units	**63**		
Total Net Generating Capability		**8,475**	

(1) Adjusted for sale of approximately 8.2% of total capacity
(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Qualifying Facility Contracts	19	820	
Investor Owned Utilities	2	474	
TOTAL CAPACITY RESOURCES		9,769	

PROGRESS ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL	FIRM	FIRM		TOTAL	SYSTEM FIRM					
	INSTALLED	CAPACITY	CAPACITY		CAPACITY	SUMMER PEAK	RESERVE MARGIN		SCHEDULED	RESERVE MARGIN	
	CAPACITY	IMPORT	EXPORT	QF	AVAILABLE	DEMAND	BEFORE MAINTENANCE		MAINTENANCE	AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2005	8.332	799 *	0	820	9,951	8.173	1,778	22%	0	1,778	22%
2006	8.848	767 *	0	820	10.435	8.663	1,772	20%	0	1.772	20%
2007	8.848	1.087	0	802	10.737	8.958	1,779	20%	0	1,779	20%
2008	9.309	1.087	0	787	11.183	9.187	1.996	22%	0	1,996	22%
2009	9,309	1.087	0	787	11.183	9.353	1.830	20%	0	1.830	20%
2010	9.785	1.098	0	787	11,670	9,719	1,951	20%	0	1.951	20%
2011	10,261	1.028	0	787	12,076	9,926	2,150	22%	0	2.150	22%
2012	10.737	1,028	0	787	12,552	10.138	2,414	24%	0	2.414	24%
2013	10.737	1.028	0	677	12.442	10.355	2.087	20%	0	2,087	20%
2014	11.689	550	0	490	12.729	10.567	2.162	20%	0	2.162	20%

* Progress Energy is pursuing seasonal purchases of approximately 300 MW in 2005 and 150 MW in 2006. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2004 THROUGH DECEMBER 31, 2014

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	9/2003	12/2005			516	582	V	
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	12/2005	12/2007			461	517	T	
HINES ENERGY COMPLEX	5	POLK	CC	NG	DFO	PL	TK	5/2007	12/2009			476	548	P	
HINES ENERGY COMPLEX	6	POLK	CC	NG	DFO	PL	TK	5/2008	12/2010			476	548	P	
COMBINED-CYCLE	1	UNKNOWN	CC	NG	DFO	PL	UN	10/2009	5/2012			476	548	P	
COMBINED-CYCLE	2	UNKNOWN	CC	NG	DFO	PL	UN	5/2011	12/2013			476	548	P	
COMBINED-CYCLE	3	UNKNOWN	CC	NG	DFO	PL	UN	10/2011	5/2014			476	548	P	

DOCKET NO. 070052-EI
EXTRACT FROM PEF 2006 TYSP
FIPUG EXHIBIT __________
ID# 22

Progress Energy Florida
Ten-Year Site Plan

April 2006

2006-2015

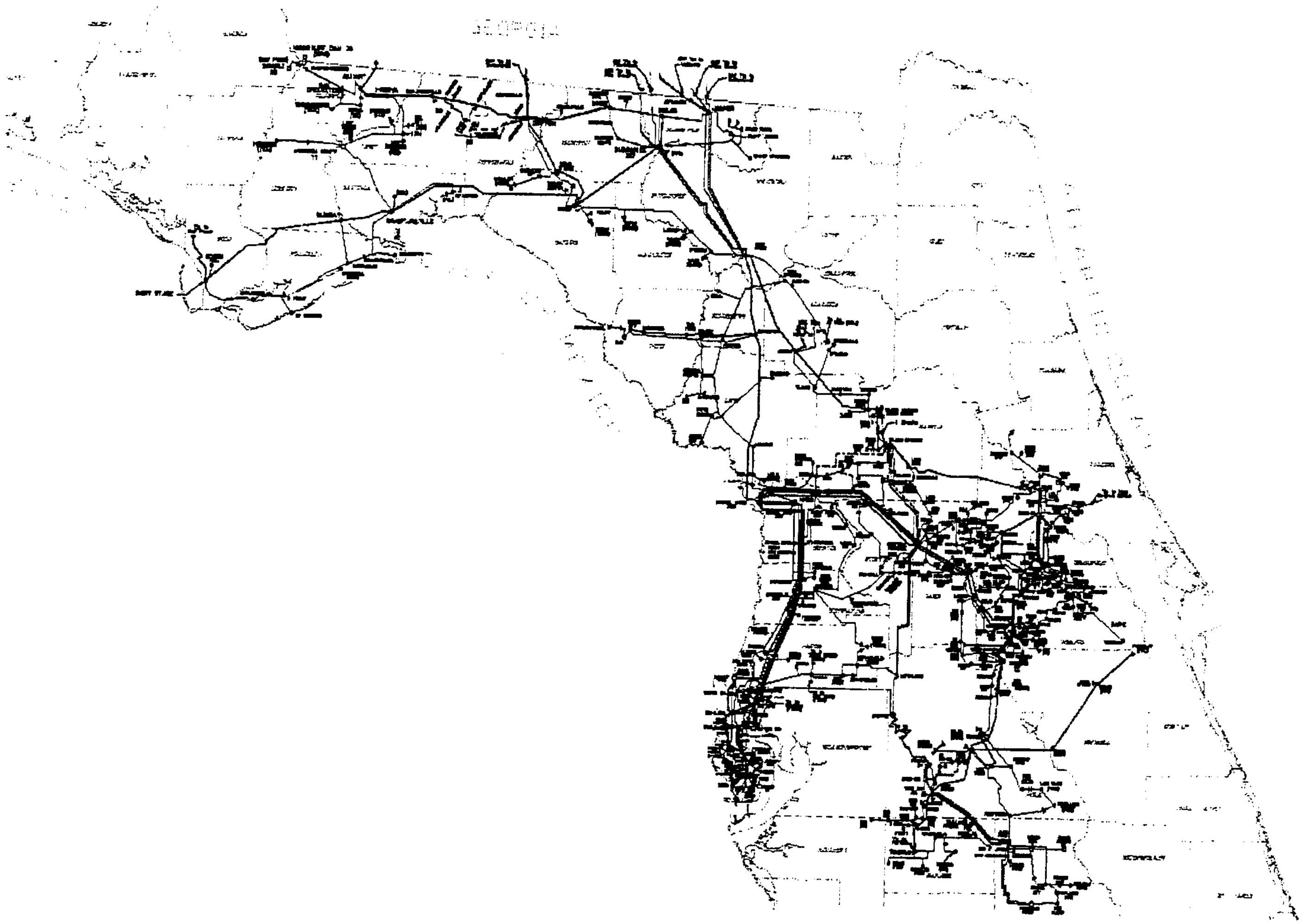
Submitted to:
Florida Public Service Commission

Progress Energy

FIGURE 1.2

PROGRESS ENERGY FLORIDA

Electric System Map



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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1996	2,847,802	2.494	15,481	1,141,671	13,560	8,848	129,440	68,356
1997	2,895,266	2.495	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,959,509	2.502	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,047,293	2.511	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,044,449	2.467	17,116	1,234,286	13,867	10,813	143,475	75,368
2001	3,141,867	2.465	17,604	1,274,672	13,810	11,061	146,983	75,251
2002	3,207,661	2.465	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,286,782	2.468	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,348,630	2.454	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,425,783	2.452	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,473,481	2.447	20,187	1,419,449	14,222	11,899	163,107	72,952
2007	3,530,429	2.441	20,731	1,446,239	14,334	12,292	166,477	73,836
2008	3,585,407	2.435	21,244	1,472,551	14,427	12,725	169,784	74,947
2009	3,639,074	2.428	21,789	1,498,885	14,537	13,155	173,090	75,998
2010	3,690,763	2.420	22,316	1,524,944	14,634	13,559	176,360	76,880
2011	3,740,415	2.412	22,839	1,550,477	14,730	13,966	179,611	77,759
2012	3,788,512	2.404	23,353	1,575,780	14,820	14,370	182,781	78,618
2013	3,835,918	2.396	23,882	1,600,906	14,918	14,785	185,927	79,519
2014	3,883,825	2.389	24,411	1,625,899	15,014	15,204	189,055	80,419
2015	3,932,139	2.382	24,949	1,650,873	15,113	15,629	192,181	81,323

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1996	4,224	2,927	1,443,116	0	26	2,205	30,784
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,957
2004	4,069	2,733	1,488,840	0	28	3,016	38,193
2005	4,140	2,703	1,531,632	0	27	3,171	39,178
2006	4,152	2,687	1,545,218	0	28	3,209	39,475
2007	4,213	2,687	1,567,920	0	28	3,327	40,591
2008	4,383	2,687	1,631,187	0	28	3,436	41,816
2009	4,416	2,687	1,643,469	0	28	3,547	42,935
2010	4,453	2,687	1,657,239	0	28	3,651	44,006
2011	4,491	2,687	1,671,381	0	28	3,756	45,081
2012	4,539	2,687	1,689,245	0	28	3,861	46,150
2013	4,579	2,687	1,704,131	0	28	3,968	47,241
2014	4,622	2,687	1,720,134	0	28	4,076	48,341
2015	4,662	2,687	1,735,020	1	28	4,186	49,456

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
1996	2,089	1,842	34,715	18,035	1,292,073
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,004	1,400,299
2001	3,839	1,831	40,933	20,752	1,444,958
2002	3,173	2,534	42,567	21,155	1,475,783
2003	3,359	2,595	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,505	46,878	22,701	1,583,417
2006	4,038	2,654	46,167	23,160	1,608,403
2007	4,430	2,739	47,759	23,719	1,639,122
2008	4,410	2,850	49,076	24,279	1,669,301
2009	4,323	2,890	50,148	24,837	1,699,499
2010	4,958	3,042	52,006	25,388	1,729,379
2011	5,083	3,055	53,219	25,933	1,758,708
2012	5,159	3,125	54,434	26,474	1,787,722
2013	5,263	3,199	55,704	27,008	1,816,528
2014	5,343	3,265	56,948	27,537	1,845,178
2015	5,419	3,337	58,211	28,059	1,873,800

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS
1996	7,470	828	6,642	309	565	69	41	120	167
1997	7,786	874	6,912	288	555	78	41	131	170
1998	8,367	943	7,424	291	438	97	42	142	182
1999	9,039	1,326	7,713	292	505	113	45	153	183
2000	8,911	1,319	7,592	277	455	127	48	155	75
2001	8,841	1,117	7,724	283	414	139	54	156	75
2002	9,421	1,203	8,218	305	390	153	43	159	75
2003	8,886	887	7,999	300	347	172	44	164	75
2004	9,554	1,071	8,483	531	283	188	37	166	75
2005	10,316	1,118	9,198	393	250	203	38	167	75
2006	9,915	1,105	8,810	419	228	214	39	169	75
2007	10,226	1,181	9,044	431	202	223	40	171	75
2008	10,487	1,223	9,264	437	179	232	41	172	75
2009	10,676	1,201	9,475	433	158	241	42	174	75
2010	11,039	1,357	9,681	424	140	250	43	176	75
2011	11,260	1,372	9,888	425	124	259	45	177	75
2012	11,487	1,396	10,091	426	109	269	46	179	75
2013	11,699	1,406	10,293	427	97	279	47	180	75
2014	11,921	1,429	10,492	428	86	289	48	182	75
2015	12,139	1,446	10,693	429	76	293	48	183	75

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,250	445	363	564	39,177	5,195	2,506	46,878	52.3
2006	47,556	459	365	564	39,475	4,038	2,654	46,167	58.3
2007	49,165	474	368	564	40,591	4,430	2,738	47,759	56.9
2008	50,501	489	371	565	41,816	4,410	2,850	49,076	57.1
2009	51,590	504	374	564	42,935	4,323	2,890	50,148	56.5
2010	53,466	519	377	564	44,006	4,958	3,042	52,006	56.4
2011	54,699	536	380	564	45,081	5,083	3,055	53,219	56.6
2012	55,934	552	383	565	46,150	5,159	3,125	54,434	56.5
2013	57,222	568	386	564	47,242	5,263	3,199	55,704	56.8
2014	58,485	585	389	564	48,341	5,343	3,264	56,948	56.9
2015	59,749	585	389	564	49,455	5,419	3,337	58,211	57.1

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

SCHEDULE 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2005		FORECAST 2006		FORECAST 2007	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	10,226	3,582	9,047	3,566	9,584	3,724
FEBRUARY	7,398	3,106	6,992	3,133	7,455	3,273
MARCH	7,609	3,592	6,008	3,337	6,501	3,552
APRIL	7,011	3,283	6,970	3,284	7,467	3,438
MAY	8,478	3,923	8,025	4,041	8,511	4,190
JUNE	8,927	4,215	8,595	4,337	8,914	4,450
JULY	9,671	4,947	8,754	4,731	9,044	4,863
AUGUST	9,681	5,031	8,771	4,748	9,084	4,885
SEPTEMBER	9,090	4,461	8,184	4,308	8,488	4,433
OCTOBER	8,301	3,968	7,692	3,837	7,963	3,952
NOVEMBER	6,424	3,215	6,282	3,267	6,573	3,347
DECEMBER	7,772	3,555	7,767	3,578	7,860	3,652
TOTAL		46,878		46,167		47,759

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 10,413 MW, as shown in Table 3.1. This capacity resource includes nuclear (769 MW), fossil steam (3,882 MW), combined cycle plants (1,706 MW), combustion turbine (2,619 MW, 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (617 MW), and non-utility purchased power (820 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QF's).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2006 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

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

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes 3,910 net MW (summer rating) of proposed new capacity additions through the summer of 2015. As identified in Schedule 8, PEF's next planned need is the Hines 4 Unit, a 461 MW (summer) power block with a December 2007 in-service date. PEF's self-build option for Hines Unit 4 was determined to be the most cost-effective alternative, followed by the Bartow Repowering Project to be completed by June 2009.

PEF's Base Expansion Plan projects requirements for additional units with proposed in-service dates of 2007 through 2015. These units, together with the Central Power & Lime Purchase (December 2005 through December 2010), the TEA purchase (from June through September 2006, December 2006 through February 2007, and June through September 2007), the Shady Hills Purchase (April 2007 through April 2014), and the Southern Company Purchase (June 2010 through December 2015), help the PEF system meet the growing energy requirements of its customer base. Some of the identified unit additions may be impacted by PEF's ability to extend or replace existing purchase power contracts, as well as contracts with cogenerators and QF's. Status reports and specifications for new generation facilities are included in Schedule 9. Shown in Schedule 10 are the new transmission lines associated with Hines #4 and the Bartow Repowering Project.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion in the near term. The forecast of natural gas prices has risen to the point where new pulverized coal units appear to be a cost effective alternative. Uncertainties over future fuel price relationships, environmental regulations, and the ability to site new coal units in Florida will require ongoing re-evaluations of the coal option. New nuclear technologies appear to offer favorable long-term economics, and provide favorable environmental characteristics, measured against possible emission limits imposed by the recently issued Clean Air Interstate Rule (CAIR). PEF is currently evaluating the nuclear option with the intent to pursue preliminary licensing activities should suitable sites for new nuclear units be available. Currently, the expected lead time to site, license, engineer, and construct a new nuclear unit place its in-service date outside the ten-year planning horizon presented in this document.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2005

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	*(1)*
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,302	
Anclote	2	993	
Bartow	3	444	
Suwannee River	3	143	
Total Fossil Steam	12	3,882	
Combined Cycle			
Hines Energy Complex	3	1,499	
Tiger Bay	1	207	
Total Combined cycle	4	1,706	
Combustion Turbine			
DeBary	10	667	
Intercession City	14	1,041	*(2)*
Bayboro	4	184	
Bartow	4	187	
Suwannee	3	164	
Turner	4	154	
Higgins	4	122	
Avon Park	2	52	
University of Florida	1	35	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,619	
Total Units	**64**		
Total Net Generating Capability		**8,976**	

(1) Adjusted for sale of approximately 8.2% of total capacity
(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power		
Qualifying Facility Contracts	19	820
Investor Owned Utilities	2	617
TOTAL CAPACITY RESOURCES		10,413

TABLE 3.2

PROGRESS ENERGY FLORIDA

QUALIFYING FACILITY GENERATION CONTRACTS

AS OF DECEMBER 31, 2005

Facility Name	Firm Capacity (MW)
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Jefferson Power	2.0
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery 1	40.0
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
Royster	30.8
US Agrichem	5.6
TOTAL	**820.2**

PROGRESS ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2006	8,843	817 *	0	813	10,473	8,771	1,702	19%	0	1,702	19%
2007	8,843	1,253 *	0	802	10,898	9,084	1,814	20%	0	1,814	20%
2008	9,304	1,095	0	798	11,197	9,351	1,846	20%	0	1,846	20%
2009	9,997	1,095	0	798	11,890	9,554	2,336	24%	0	2,336	24%
2010	10,136	1,093	0	798	12,027	9,931	2,096	21%	0	2,095	21%
2011	10,614	890	0	798	12,302	10,155	2,147	21%	0	2,147	21%
2012	10,775	890	0	798	12,463	10,383	2,080	20%	0	2,080	20%
2013	11,525	890	0	687	13,102	10,593	2,509	24%	0	2,509	24%
2014	12,275	412	0	500	13,187	10,813	2,374	22%	0	2,374	22%
2015	12,753	412	0	500	13,665	11,036	2,629	24%	0	2,629	24%

* Progress Energy is pursuing seasonal purchases of approximately 200 MW in 2006 and 158 MW in 2007. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2006 THROUGH DECEMBER 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	12/2005	12/2007			461	517	U	
BARTOW CT	5, 6	PINELLAS	CT	NG	DFO	PL	TK	12/2006	12/2008			322	382	P	(1)
CRYSTAL RIVER	5	CITRUS	ST	BIT	--	WA	--	--	04/2009			(22)	(22)	P	(2)
BARTOW CC	1	PINELLAS	CC	NG	DFO	PL	WA	12/2006	06/2009			837	897	P	(1)
BARTOW	1-3	PINELLAS	ST	RFO	--	WA	--	--	--	06/2009		(444)	(452)	P	(1)
CRYSTAL RIVER	4	CITRUS	ST	BIT	--	WA	--	--	11/2009			(22)	(22)	P	(2)
COMBUSTION TURBINE	1	UNKNOWN	GT	NG	DFO	PL	TK	06/2009	06/2010			161	191	P	
COMBINED CYCLE	1	UNKNOWN	CC	NG	DFO	PL	TK	01/2009	06/2011			478	550	P	
COMBUSTION TURBINE	2	UNKNOWN	GT	NG	DFO	PL	TK	06/2011	06/2012			161	191	P	
P-COAL, Supercritical	1	UNKNOWN	ST	BIT	--	RR	--	06/2008	06/2013			750	750	P	
P-COAL, Supercritical	2	UNKNOWN	ST	BIT	--	RR	--	06/2009	06/2014			750	750	P	
COMBINED CYCLE	2	UNKNOWN	CC	NG	DFO	PL	TK	01/2013	06/2015			478	550	P	

NOTES

(1) As part of the Bartow Repowering Project, two CTs will go into service 12/2008. In June of 2009, they will be combined with an additional two CTs, four HRSGs, and one steam turbine to produce a single, 4x4x1 combined cycle with a total summer capacity of 1,159 MW.

(2) Derations due to FDG scrubber installations.

DOCKET NO. 070052- EI
EXTRACT FROM PEF 2007 TYSP
FIPUG EXHIBIT ____________

ID # 22

Progress Energy Florida
Ten-Year Site Plan

April 2007

2007-2016

Submitted to:
Florida Public Service Commission

Progress Energy

PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2006

(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	507	526
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	125
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	124
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	215
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/66		440,550	379	386
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/69		523,800	491	496
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	722	734
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	721	734
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/53		34,500	30	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/54		37,500	31	31
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK/RR	PL		10/56		75,000	80	82
												4,672	4,796
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	2***	04/99		546,500	463	528
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK		12/03		548,250	490	562
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK		11/05		561,000	503	570
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,100	203	225
												1,659	1,885
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3***	12/68		33,790	25	34
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	25	36
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			05/72, 06/72		111,400	86	112
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	44	56
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	58
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA			04/73		226,800	177	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK			12/75-04/76		401,220	311	393
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	8	10/92		345,000	249	287
DEBARY	P10	VOLUSIA	GT	DFO		TK			10/92		115,000	83	99
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK		03/69, 04/69		67,580	53	68
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70, 01/71		85,850	57	65
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	282	369
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	332	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	161
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	235	278
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	106	133
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	51	66
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	22	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	64	85
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	64	84
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	45	47
												2,513	3,087
											TOTAL RESOURCES (MW)	8,844	9,768

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT

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

*** FOR ENTIRE PLANT

**** P1 REQUIRES A 3-4 DAY OUTAGE IN ORDER TO SWITCH BETWEEN NG & DFO

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1997	2,878,315	2.480	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,941,589	2.487	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,028,821	2.496	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,026,469	2.452	17,116	1,234,286	13,867	10,813	143,475	75,365
2001	3,122,946	2.450	17,604	1,274,672	13,811	11,061	146,983	75,254
2002	3,191,315	2.452	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,267,185	2.453	19,429	1,331,914	14,587	11,553	154,294	74,877
2004	3,348,917	2.454	19,347	1,364,677	14,177	11,734	158,780	73,901
2005	3,429,664	2.455	19,894	1,397,012	14,240	11,945	161,001	74,192
2006	3,512,066	2.453	20,021	1,431,743	13,984	11,975	162,774	73,568
2007	3,565,718	2.455	20,891	1,452,431	14,383	12,340	167,150	73,826
2008	3,629,609	2.450	21,457	1,481,473	14,484	12,674	170,889	74,165
2009	3,694,808	2.447	22,026	1,509,934	14,587	13,009	174,552	74,528
2010	3,762,611	2.446	22,605	1,538,271	14,695	13,361	178,195	74,980
2011	3,828,922	2.444	23,192	1,566,662	14,803	13,708	181,846	75,382
2012	3,895,566	2.442	23,792	1,595,236	14,914	14,056	185,520	75,765
2013	3,959,232	2.438	24,404	1,623,967	15,027	14,417	189,213	76,195
2014	4,025,804	2.436	25,027	1,652,629	15,144	14,796	192,896	76,705
2015	4,091,505	2.434	25,693	1,680,980	15,285	15,202	196,539	77,349
2016	4,155,712	2.432	26,363	1,708,763	15,428	15,622	200,111	78,067

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,958
2004	4,069	2,733	1,488,840	0	28	3,016	38,194
2005	4,140	2,703	1,531,632	0	27	3,171	39,177
2006	4,160	2,697	1,542,455	0	27	3,249	39,432
2007	4,155	2,701	1,538,319	0	28	3,353	40,767
2008	4,393	2,701	1,626,435	0	28	3,457	42,009
2009	4,423	2,701	1,637,542	0	28	3,570	43,056
2010	4,451	2,701	1,647,908	0	28	3,682	44,127
2011	4,518	2,701	1,672,714	0	28	3,798	45,244
2012	4,544	2,701	1,682,340	0	28	3,916	46,336
2013	4,571	2,701	1,692,336	0	28	4,038	47,458
2014	4,599	2,701	1,702,703	0	28	4,164	48,614
2015	4,587	2,701	1,698,260	0	28	4,293	49,803
2016	4,587	2,701	1,698,260	0	28	4,427	51,027

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) TOTAL NO. OF CUSTOMERS
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,003	1,400,299
2001	3,839	1,831	40,933	20,752	1,444,958
2002	3,173	2,535	42,567	21,156	1,475,783
2003	3,359	2,594	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,506	46,878	22,701	1,583,417
2006	4,220	2,389	46,041	23,182	1,620,396
2007	4,524	2,905	48,194	23,687	1,645,969
2008	4,501	2,958	49,468	24,280	1,679,343
2009	4,527	3,026	50,609	24,877	1,712,064
2010	5,238	3,151	52,516	25,474	1,744,641
2011	5,363	3,169	53,776	26,071	1,777,280
2012	5,437	3,244	55,017	26,669	1,810,126
2013	5,542	3,321	56,321	27,266	1,843,147
2014	5,673	3,445	57,732	27,864	1,876,090
2015	5,795	3,476	59,074	28,460	1,908,680
2016	5,873	3,560	60,460	29,058	1,940,633

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1997	7,786	874	6,912	288	555	78	41	124	170	6,531
1998	8,367	943	7,424	291	438	97	42	134	182	7,183
1999	9,039	1,326	7,713	292	505	113	45	145	183	7,756
2000	8,902	1,319	7,583	277	455	127	48	146	75	7,774
2001	8,832	1,117	7,715	283	414	139	48	147	75	7,726
2002	9,412	1,203	8,209	305	390	153	43	150	75	8,296
2003	8,877	887	7,990	300	393	172	44	154	75	7,738
2004	9,578	1,071	8,507	531	355	188	39	155	110	8,200
2005	10,345	1,118	9,227	448	343	206	38	158	110	9,041
2006	10,186	1,257	8,929	329	319	226	37	161	110	9,003
2007	10,658	1,321	9,337	449	319	243	43	168	110	9,327
2008	10,927	1,337	9,590	473	332	259	52	177	110	9,525
2009	11,010	1,192	9,818	474	351	275	61	185	110	9,553
2010	11,318	1,269	10,049	479	372	292	70	194	110	9,801
2011	11,569	1,287	10,282	484	393	308	80	203	110	9,992
2012	11,807	1,296	10,511	485	414	325	89	211	110	10,173
2013	12,062	1,320	10,742	486	427	342	98	220	110	10,379
2014	12,437	1,469	10,968	483	438	360	107	229	110	10,711
2015	12,671	1,483	11,188	478	441	367	110	232	110	10,932
2016	12,906	1,499	11,407	477	441	367	110	232	110	11,169

Historical Values (1997 - 2006):

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

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

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

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

Projected Values (2007 - 2016):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1997	35,752	268	317	562	30,850	1,758	1,997	34,605	49.0
1998	38,949	289	333	564	33,387	2,340	2,036	37,763	53.9
1999	40,375	312	339	564	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,835	427	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,479	460	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,680	495	365	779	39,432	4,220	2,389	46,041	52.1
2007	49,878	522	383	779	40,766	4,524	2,904	48,194	56.7
2008	51,201	552	401	780	42,009	4,501	2,958	49,468	56.6
2009	52,389	582	419	779	43,055	4,527	3,027	50,609	57.6
2010	54,344	612	437	779	44,127	5,238	3,151	52,516	57.3
2011	55,652	642	455	779	45,243	5,363	3,170	53,776	57.5
2012	56,942	672	473	780	46,337	5,437	3,243	55,017	57.0
2013	58,293	702	491	779	47,457	5,542	3,322	56,321	57.0
2014	59,752	732	509	779	48,614	5,673	3,445	57,732	57.3
2015	61,094	732	509	779	49,802	5,795	3,477	59,074	57.4
2016	62,481	732	509	780	51,027	5,873	3,560	60,460	57.2

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2006		FORECAST 2007		FORECAST 2008	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	7,870	3,390	9,705	3,772	9,943	3,914
FEBRUARY	10,095	3,191	7,862	3,257	8,014	3,383
MARCH	6,441	3,286	6,692	3,509	6,863	3,631
APRIL	7,837	3,582	7,387	3,498	7,540	3,576
MAY	8,382	4,020	8,482	4,271	8,672	4,361
JUNE	9,349	4,401	8,905	4,478	9,071	4,574
JULY	9,462	4,699	9,156	4,867	9,337	4,985
AUGUST	9,689	4,920	9,327	4,919	9,525	5,047
SEPTEMBER	8,794	4,270	8,553	4,434	8,729	4,537
OCTOBER	8,286	3,763	7,975	3,982	8,202	4,076
NOVEMBER	6,415	3,192	6,463	3,426	6,569	3,502
DECEMBER	6,792	3,327	7,529	3,781	7,717	3,882
TOTAL		46,041		48,194		49,468

NOTE: "Actual" = "Total" - "Interruptible" - "Res. LM" - "C/I LM" - "Voltage Reduction & Standby Generation"

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 10,752 MW, as shown in Table 3.1. This capacity resource includes nuclear (769 MW), fossil steam (3,903MW), combined cycle plants (1,659 MW), combustion turbine (2,513 MW, 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (484 MW), independent power purchases (611 MW), and non-utility purchased power (813 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QF's).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2007 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

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

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes a net gain in summer capacity of 3,575 MWs through the summer of 2016. As identified in Schedule 8, PEF's next planned unit is the Hines 4 Unit, a 461 MW (summer) power block with a December 2007 in-service date. PEF's self-build option for Hines Unit 4 was determined to be the most cost-effective alternative, followed by the Bartow Repowering Project to be completed by June 2009.

PEF's Base Expansion Plan projects the need for additional units with proposed in-service dates from 2007 through 2016. These units, together with the OUC purchase (December 2006 – February 2007), the Central Power & Lime purchase (December 2005 - December 2010), the Reliant/Osceola purchase (January 2007 - February 2009), the TEA purchase (from January 2007 - February 2007, and June 2007 - September 2007), purchases currently under negotiation for the summers of 2007 and 2008, the Shady Hills Purchase (April 2007 - April 2024), and the Southern Company Purchase (June 2010 - December 2017) help the PEF system meet the growing energy requirements of its customer base. Additionally, some undesignated seasonal purchases for 2007 and 2008 are projected as well to meet requirements. Some of the identified unit additions may be impacted by PEF's ability to extend or replace existing purchase power contracts, as well as contracts with cogenerators and QF's. Status reports and specifications for new generation facilities are included in Schedule 9. Shown in Schedule 10 are the new transmission lines associated with Hines #4 and the Bartow Repowering Project.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion in the near term. New nuclear technologies appear to offer more favorable long-term economics, and provide favorable environmental characteristics, measured against possible emission limits imposed by the recently issued Clean Air Interstate Rule (CAIR). PEF is currently evaluating the nuclear option with the intent of pursuing preliminary licensing activities for the addition of new nuclear capacity in 2016. In the years prior to the addition of new nuclear capacity, PEF also is investigating the possibility of coal gasification as a fuel source for one of the combined cycle facilities listed in the resource plan.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2006

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	*(1)*
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,313	
Anclote	2	1,005	
Bartow	3	444	
Suwannee River	3	141	
Total Fossil Steam	12	3,903	
Combined Cycle			
Hines Energy Complex	3	1,456	
Tiger Bay	1	203	
Total Combined cycle	4	1,659	
Combustion Turbine			
DeBary	10	643	
Intercession City	14	992	*(2)*
Bayboro	4	177	
Bartow	4	176	
Suwannee	3	157	
Turner	4	150	
Higgins	4	110	
Avon Park	2	50	
University of Florida	1	45	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,513	
Total Units	64		
Total Net Generating Capability		**8,844**	

(1) Adjusted for sale of approximately 8.2% of total capacity
(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Qualifying Facility Contracts	19	813	
Investor Owned Utilities	2	484	
Independent Power Producers	2	611	
TOTAL CAPACITY RESOURCES		**10,752**	

PROGRESS ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2007	8,701	1,661 *	0	803	11,165	9,327	1,838	20%	0	1,838	20%
2008	9,175	1,503 *	0	799	11,477	9,525	1,952	20%	0	1,952	20%
2009	9,881	1,095	0	659	11,635	9,553	2,082	22%	0	2,082	22%
2010	9,891	1,253	0	775	11,919	9,801	2,118	22%	0	2,118	22%
2011	9,926	1,370	0	775	12,071	9,992	2,079	21%	0	2,079	21%
2012	10,077	1,530	0	775	12,382	10,173	2,209	22%	0	2,209	22%
2013	10,614	1,530	0	665	12,809	10,379	2,430	23%	0	2,430	23%
2014	11,151	1,530	0	478	13,159	10,711	2,448	23%	0	2,448	23%
2015	11,151	1,530	0	478	13,159	10,933	2,226	20%	0	2,226	20%
2016	12,276	1,459	0	478	14,213	11,169	3,044	27%	0	3,044	27%

* Progress Energy is pursuing summer seasonal purchases of approximately 200 MW in 2007 and 250 MW in 2008. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2006 THROUGH DECEMBER 31, 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES	1	POLK	CC						12/2007			1	1	A	(3)
HINES	4	POLK	CC	NG	DFO	PL	TK	12/2005	12/2007			461	517	V	(1)
HINES	1	POLK	CC						05/2008			2	2	A	(3)
TIGER BAY	1	POLK	CC						05/2008			10	10	A	(3)
CRYSTAL RIVER	4	CITRUS	ST						11/2008			10	10	A	(3)
CRYSTAL RIVER	5	CITRUS	ST						04/2009			(30)	(30)	D	(2)
CRYSTAL RIVER	5	CITRUS	ST						05/2009			10	10	A	(3)
BARTOW	1-3	PINELLAS	ST							06/2009		(444)	(464)	RP	(4)
BARTOW	1	PINELLAS	CC	NG	DFO	PL	WA	12/2006	06/2009			1159	1279	RP	(4)
CRYSTAL RIVER	3	CITRUS	ST						12/2009			40	40	A	(3)
CRYSTAL RIVER	4	CITRUS	ST						04/2010			(30)	(30)	D	(2)
HINES	1	POLK	CC						06/2011			35	0	A	(3)
CRYSTAL RIVER	3	CITRUS	ST						12/2011			140	140	A	(3)
CRYSTAL RIVER	1	CITRUS	ST						03/2012			11	11	A	(3)
UNCOMMITTED	1	UNKNOWN	CC	NG	DFO	PL	TK	06/2010	06/2013			537	618	P	(1)
UNCOMMITTED	2	UNKNOWN	CC	NG	DFO	PL	TK	06/2011	06/2014			537	618	P	(1)
UNCOMMITTED	3	UNKNOWN	NP	NUC	--	RR	--	01/2010	06/2016			1125	1125	P	(1)

NOTES
(1) Committed new unit.
(2) Planned derations due to FGD scrubber installations.
(3) Planned uprates.
(4) Repowering

EXHIBIT NO. ___________

DOCKET NO: 070052-EI

WITNESS: VARIOUS

PARTY: PROGRESS ENERGY FLORIDA, INC.

DESCRIPTION: STAFF'S EXHIBIT

DOCUMENTS:

Progress Energy Florida's response to Staff Interrogatory (No. 5) in Docket Number 060642, Crystal River.

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 22
COMPANY FPSC Staff
WITNESS PEF Response to Staff Int. No. 5
DATE 08/07-08/07

5. Please provide a detailed breakdown of the $2,664,166,852 fuel savings value contained in Exhibit SSW-2 to Witness Waters' September 22, 2006, prefiled direct testimony as follows:

a. Differential energy generated for each capacity type (steam-coal, steam-oil/gas, steam-combined cycle, combustion turbine, nuclear, cogen, purchased power, and any others); and

b. Differential dollar value and energy generated for each individual generating unit.

a. *Please see Attachment 1. The data presented in Attachment 1 is through 2025 only (please see the answer to Interrogatory No. 4). The annual savings shown in Attachment 1 sum to the total $1,444,373,714.*

b. *Please see Attachment 2.*

GWH

Uprate minus Base

StationGroup	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cogen	(1.1)	0.0	(0.9)	(2.8)	0.5	(1.8)	(1.6)	(2.8)	(1.4)	(8.6)	(15.0)	(10.1)	(10.2)	(14.0)	(18.7)	(15.5)	(13.9)
CT	(0.1)	(6.2)	(7.7)	(41.0)	(20.6)	(30.5)	(35.2)	(20.2)	(39.0)	(18.5)	(21.9)	(32.1)	(43.1)	(12.6)	(20.2)	(20.5)	(31.8)
DSM	0.0	(0.2)	(0.2)	(0.5)	(0.6)	(0.5)	(1.4)	(0.3)	(1.3)	(0.0)	(0.0)	(1.7)	0.0	0.0	(0.4)	0.0	(0.6)
Nuclear	11.2	339.9	415.9	1533.8	1416.6	1529.6	1416.6	1533.8	1402.2	1493.3	1389.8	1506.3	1387.9	1457.7	1345.8	1459.3	1360.2
Steam-CC	(10.6)	(231.6)	(310.6)	(929.9)	(923.6)	(910.1)	(847.6)	(960.0)	(811.3)	(884.7)	(873.2)	(927.6)	(703.3)	(890.6)	(816.2)	(848.6)	(828.2)
Steam-Coal	1.3	(36.9)	(32.7)	(192.4)	(240.8)	(358.6)	(344.9)	(378.0)	(370.5)	(505.1)	(385.3)	(417.1)	(467.4)	(458.4)	(403.8)	(472.9)	(368.6)
Steam-Oil	1.5	(32.2)	(19.7)	(201.9)	(88.4)	(125.6)	(80.6)	(76.4)	(91.0)	(62.5)	(66.9)	(79.9)	(124.8)	(51.0)	(46.5)	(58.8)	(66.9)
Purc(Econ+Firm+E.N.S)	(2.2)	(32.9)	(44.6)	(163.7)	(143.8)	(99.0)	(104.7)	(103.7)	(86.5)	(6.6)	(20.4)	(20.2)	(21.6)	(11.0)	(14.4)	(15.5)	(22.8)
TranEcon-Sale + Dump	(0.0)	(0.0)	0.5	(1.5)	0.5	(3.6)	(0.6)	(2.4)	(1.3)	(7.4)	(7.1)	(17.7)	(17.7)	(20.3)	(25.8)	(27.5)	(27.3)

No Uprate - July GFF Base

StationGroup	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cogen	4,551.4	5,312.2	5,314.6	5,332.9	5,314.2	5,311.6	5,309.4	5,328.0	5,312.4	5,296.0	5,295.9	5,308.2	5,296.8	5,262.6	5,275.8	5,280.5	5,276.6
CT	1,670.5	1,596.4	1,674.7	1,611.7	1,580.3	1,568.5	1,665.1	1,550.5	1,691.5	1,580.3	1,560.5	1,641.6	1,661.5	1,534.8	1,542.4	1,564.6	1,631.9
DSM	5.6	4.4	4.7	0.5	2.6	0.7	3.3	0.3	3.8	0.0	0.0	8.9	3.7	-	0.8	0.7	2.7
Nuclear	5,069.1	6,636.4	6,143.5	6,654.5	6,143.1	6,636.4	6,143.9	6,654.5	6,735.7	14,796.3	14,304.9	14,842.5	14,956.2	22,754.3	22,307.5	22,843.7	22,341.6
Steam-CC	15,223.5	15,820.7	18,609.3	20,158.4	19,112.3	17,745.6	18,355.5	16,255.4	17,356.2	13,389.4	15,057.4	15,478.8	16,200.9	12,830.4	13,666.3	14,098.3	15,487.9
Steam-Coal	15,260.6	16,168.3	16,620.9	15,801.8	19,418.7	21,400.0	22,395.4	26,363.4	25,975.8	24,692.4	24,770.6	24,902.4	25,266.8	22,857.7	23,548.6	23,896.4	23,942.7
Steam-Oil	3,611.7	2,940.7	3,021.7	3,099.0	2,678.0	2,895.3	2,857.8	2,740.1	2,924.3	2,685.7	2,761.1	2,856.7	2,958.3	2,523.4	2,687.9	2,628.4	2,827.6
Purc(Econ+Firm+E.N.S)	5,777.2	4,688.2	2,775.7	2,776.2	2,516.9	2,371.8	2,510.5	1,705.2	1,875.4	798.8	814.6	855.0	867.0	793.2	804.7	812.5	835.7
TranEcon-Sale • Dump	(389.6)	(386.3)	(387.5)	(385.8)	(386.2)	(390.9)	(391.1)	(389.7)	(388.1)	(403.8)	(403.0)	(402.4)	(410.6)	(453.3)	(431.0)	(443.0)	(442.0)

Uprate - CR3 180MWs Study

StationGroup	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cogen	4,550.3	5,312.2	5,313.7	5,330.1	5,314.7	5,309.8	5,307.9	5,325.2	5,310.9	5,287.4	5,280.9	5,298.1	5,286.8	5,248.5	5,257.2	5,265.0	5,262.7
CT	1,670.4	1,590.2	1,667.0	1,570.6	1,559.7	1,538.0	1,629.9	1,530.3	1,652.4	1,561.8	1,538.6	1,609.5	1,618.5	1,522.3	1,522.1	1,544.1	1,600.1
DSM	5.6	4.2	4.4	0.0	2.1	0.2	1.9	0.1	2.5	0.0	-	7.2	3.7	-	0.5	0.7	2.1
Nuclear	5,100.3	6,976.3	6,559.4	8,188.3	7,559.7	8,166.0	7,560.5	8,188.3	8,137.9	16,289.6	15,694.7	16,348.8	16,344.1	24,212.0	23,653.3	24,303.0	23,701.7
Steam-CC	15,212.9	15,589.1	18,298.7	19,228.4	18,188.7	16,835.5	17,507.9	15,305.4	16,544.8	12,504.7	14,184.1	14,551.1	15,497.6	11,939.9	12,850.1	13,249.8	14,659.7
Steam-Coal	15,261.9	16,131.5	16,588.2	15,609.4	19,177.9	21,041.4	22,050.4	25,985.4	25,605.3	24,187.3	24,385.3	24,485.2	24,799.5	22,399.4	23,144.7	23,423.5	23,574.1
Steam-Oil	3,613.2	2,908.4	3,002.0	2,897.0	2,589.6	2,769.8	2,777.2	2,663.7	2,833.3	2,623.1	2,694.1	2,776.8	2,833.5	2,472.4	2,641.4	2,569.6	2,760.7
Purc(Econ+Firm+E.N.S)	5,775.0	4,655.3	2,731.1	2,612.5	2,373.3	2,272.9	2,405.8	1,601.4	1,788.9	792.2	794.2	834.8	845.5	782.2	790.3	797.0	812.9
TranEcon-Sale + Dump	(389.7)	(386.4)	(387.1)	(387.3)	(385.7)	(394.5)	(391.7)	(392.1)	(389.4)	(411.0)	(410.1)	(420.1)	(428.3)	(473.6)	(456.6)	(470.4)	(469.3)

Progress Energy Florida
Docket No. 060642-EI
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PEF CR3 Uprate
Uprate minus Base
GWh

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CR NUC 3	11	340	416	1,534	1,417	1,530	1,417	1,534	1,404	1,530	1,417	1,534	1,417	1,530	1,417	1,534	1,417
NUC Future 1	0	0	0	0	0	0	0	0	-2	-36	-27	-27	-25	-28	-32	-33	-25
NUC Future 2	0	0	0	0	0	0	0	0	0	0	0	0	-4	-44	-39	-41	-31
Nuclear, Total	11	340	416	1,534	1,417	1,530	1,417	1,534	1,402	1,493	1,390	1,506	1,388	1,458	1,346	1,459	1,360
Steam-Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crystal 1	1	-9	-9	-51	-44	-59	-57	-45	-46	-53	-46	-52	-49	-50	-48	-47	-42
Crystal 2	0	-15	-10	-52	-73	-71	-76	-59	-56	-67	-49	-53	-53	-62	-51	-60	-46
Crystal 4	0	-7	-7	-40	-62	-83	-81	-82	-85	-96	-66	-75	-98	-82	-74	-87	-70
Crystal 5	1	-6	-6	-49	-54	-85	-76	-83	-89	-95	-67	-76	-95	-81	-76	-83	-64
PV COAL 1	0	0	0	0	-8	-60	-49	-51	-46	-92	-75	-82	-81	-93	-78	-90	-72
PV COAL 2	0	0	0	0	0	0	-7	-57	-48	-102	-82	-79	-92	-91	-77	-105	-75
Steam-Coal, Total	1	-37	-33	-192	-241	-359	-345	-378	-370	-505	-385	-417	-467	-458	-404	-473	-369
Steam-Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Anclote 1	0	-14	-11	-94	-27	-51	-40	-23	-34	-45	-35	-49	-46	-26	-33	-31	-32
Anclote 2	2	-16	-4	-94	-34	-53	-31	-45	-45	-15	-28	-28	-68	-23	-9	-28	-30
BARTOW 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BARTOW 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BARTOW 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUWANNEE 1	0	-1	0	-3	-4	-6	-5	-2	-1	0	-1	-1	-2	1	-3	1	-1
SUWANNEE 2	0	0	1	-2	-3	-4	-2	-6	-3	-1	0	-1	-1	0	-4	-2	-1
SUWANNEE 3	0	-1	-5	-10	-20	-12	-3	-1	-7	-2	-3	0	-7	-2	2	2	-2
Steam-Oil, Total	2	-32	-20	-202	-88	-126	-81	-76	-91	-63	-67	-80	-125	-51	-46	-59	-67
Steam-CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BARTOW CC REP 1	-21	-24	-110	-496	-346	-322	-374	-260	-230	-237	-218	-226	-213	-201	-259	-243	-184
CCF 1	0	0	-66	-119	-143	-134	-148	-144	-156	-189	-158	-194	-126	-192	-103	-176	-171
HINES 1	-2	-15	17	-77	-32	-38	-52	-38	-51	-17	-29	-54	-34	-48	-88	-51	-96
HINES 2	-4	-19	-80	-89	-156	-112	-94	-63	-197	-148	-81	-142	-77	-100	-130	-90	-98
HINES 3	-5	-32	-26	-91	-141	-133	-92	-145	-101	-103	-137	-97	-118	-155	-109	-141	-112
HINES 4	18	-117	-71	-66	-52	-138	-104	-232	-26	-98	-201	-144	-100	-190	-114	-122	-146
TIGERBAY 1	3	-24	25	8	-53	-33	16	-67	-50	-92	-50	-70	-34	-4	-12	-26	-20
Steam-CC, Total	-11	-232	-311	-930	-924	-910	-848	-950	-811	-885	-873	-928	-703	-890	-816	-849	-828
CT, Total	0	-6	-8	-41	-21	-30	-35	-20	-39	-18	-22	-32	-43	-13	-20	-21	-32
Tran-Purc, Total	-2	-33	-45	-164	-144	-99	-105	-104	-86	-7	-20	-20	-22	-11	-14	-16	-23
Cogen, Total	-1	0	-1	-3	0	-2	-1	-3	-1	-9	-15	-10	-10	-14	-19	-15	-14
Sales	0	0	0	-1	1	-4	-1	-2	-1	-7	-7	-18	-18	-20	-26	-27	-27
DSM	0	0	0	0	-1	0	-1	0	-1	0	0	-2	0	0	0	0	-1
Total Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CR NUC 3	5,089	6,636	6,143	6,655	6,143	6,636	6,144	6,655	6,089	6,636	6,143	6,655	6,144	6,636	6,143	6,655	6,143
NUC Future 1									646	8,160	8,162	8,188	8,169	8,095	8,116	8,133	8,130
NUC Future 2													643	8,023	8,048	8,056	8,068
Nuclear, Total	5,089	6,636	6,143	6,655	6,143	6,636	6,144	6,655	6,736	14,796	14,305	14,842	14,956	22,754	22,308	22,844	22,342
Steam-Coal																	
Crystal 1	2,500	2,395	2,679	2,404	2,257	2,461	2,364	2,240	2,404	2,031	2,110	2,210	2,133	1,789	2,101	1,984	2,071
Crystal 2	2,870	3,069	2,892	2,709	3,117	2,851	2,863	2,810	2,758	2,446	2,624	2,535	2,369	2,417	2,379	2,366	2,563
Crystal 4	5,309	5,553	5,398	5,386	5,310	5,125	5,449	4,894	4,643	4,723	4,549	4,597	4,873	4,236	4,365	4,604	4,413
Crystal 5	4,581	5,151	5,652	5,303	5,237	5,053	5,370	4,811	4,570	4,639	4,472	4,515	4,800	4,184	4,261	4,527	4,325
PV COAL 1					3,498	5,910	5,883	5,846	5,829	5,461	5,551	5,571	5,603	5,166	5,271	5,257	5,338
PV COAL 2							467	5,763	5,771	5,393	5,465	5,474	5,489	5,066	5,171	5,158	5,232
Steam-Coal, Total	15,261	16,168	16,621	15,802	19,419	21,400	22,395	26,363	25,976	24,692	24,771	24,902	25,267	22,858	23,549	23,896	23,943
Steam-Oil																	
Anclote 1	1,451	1,503	1,574	1,569	1,289	1,457	1,454	1,381	1,456	1,368	1,391	1,466	1,479	1,237	1,368	1,348	1,423
Anclote 2	1,084	1,114	1,095	1,169	1,035	1,091	1,051	1,040	1,118	1,003	1,040	1,046	1,137	974	1,007	939	1,074
BARTOW 1	195																
BARTOW 2	179																
BARTOW 3	327																
SUWANNEE 1	88	81	89	85	82	86	82	76	80	76	81	82	82	77	77	78	79
SUWANNEE 2	102	93	101	98	96	96	98	94	100	89	90	98	95	88	86	96	92
SUWANNEE 3	184	150	164	178	176	166	173	149	170	149	159	165	165	148	149	168	160
Steam-Oil, Total	3,612	2,941	3,022	3,099	2,678	2,895	2,858	2,740	2,924	2,686	2,761	2,857	2,958	2,523	2,688	2,628	2,828
Steam-CC																	
BARTOW CC REP 1	3,441	5,094	6,077	6,195	5,413	4,864	5,017	4,184	4,556	3,006	3,569	3,643	3,899	2,827	3,080	3,236	3,551
CCF 1			1,576	2,724	2,621	2,369	2,414	2,077	2,276	1,641	1,878	1,971	2,023	1,530	1,611	1,693	1,873
HINES 1	2,851	3,142	2,886	3,094	3,244	3,080	3,075	2,968	3,232	2,794	2,913	2,816	2,891	2,764	2,833	2,959	3,020
HINES 2	2,644	2,251	2,424	2,369	2,300	2,105	2,309	2,114	2,220	1,837	1,866	2,132	2,173	1,738	1,850	1,946	2,147
HINES 3	2,399	2,137	2,151	2,039	2,139	2,179	2,196	1,945	2,134	1,641	1,976	1,972	2,090	1,580	1,725	1,841	2,026
HINES 4	2,699	2,144	2,542	2,528	2,149	2,131	2,178	1,945	2,130	1,488	1,863	1,836	2,070	1,519	1,588	1,590	1,859
TIGERBAY 1	1,190	1,052	954	1,210	1,247	1,016	1,166	1,022	808	981	992	1,108	1,054	872	980	833	1,013
Steam-CC, Total	15,223	15,821	18,609	20,158	19,112	17,746	18,355	16,255	17,356	13,389	15,057	15,479	16,201	12,830	13,666	14,098	15,488
CT																	
AVON PK 1	13	12	13	12	13	12	12	12	13	12	12	13	12	12	12	12	13
AVON PK 2	3	4	4	3	3	3	3	3	4	3	3	4	3	3	3	3	3
BARTOW 1	2	1	1	0	1	0	1	0	1	0	0	1	1	0	0	0	1
BARTOW 2	9	3	4	2	2	1	3	1	4	2	1	3	2	1	1	1	3
BARTOW 3	2	1	1	0	1	0	1	0	1	0	0	1	1	0	0	0	1
BARTOW 4	7	4	5	2	3	2	2	1	5	2	1	3	3	2	1	1	3
BAYBORO 1	11	11	12	11	10	10	11	10	12	10	10	11	11	10	10	10	11
BAYBORO 2	11	12	12	11	11	11	12	11	12	11	10	12	11	11	10	11	11
BAYBORO 3	13	13	14	13	12	12	13	12	14	12	12	14	12	12	12	12	13
BAYBORO 4	13	13	14	13	13	12	13	12	14	12	12	13	13	12	12	12	13
CTBar 1	39																
CTBar 2	31																
CTFG 1		19	39	35	20	25	34	10	39	19	19	34	38	10	12	16	29
CTFG 2		14	27	25	16	14	28	12	28	16	12	28	29	9	11	15	23

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CTFG 3		9	23	17	10	13	21	9	20	9	10	20	20	6	9	9	18
CTFG 4				3	9	9	14	7	14	9	5	8	14	6	6	7	14
DEBARY 1	10	10	10	9	9	9	9	9	10	9	9	10	9	9	9	9	10
DEBARY 2	8	8	9	8	8	8	8	8	9	8	7	9	8	7	8	8	8
DEBARY 3	9	9	9	8	8	8	9	8	9	8	8	10	8	8	8	8	9
DEBARY 4	9	9	9	8	8	8	8	8	9	8	8	9	8	8	8	8	9
DEBARY 5	8	8	8	7	8	7	8	7	8	8	7	9	8	7	7	7	8
DEBARY 6	7	7	8	7	7	7	7	7	8	7	7	9	7	7	7	7	7
DEBARY 7	90	90	91	88	89	89	90	89	92	88	88	88	90	83	89	88	89
DEBARY 8	91	90	94	90	90	90	91	90	91	90	89	91	91	88	90	89	90
DEBARY 9	88	86	88	86	86	86	88	78	87	85	85	86	86	85	84	85	85
DEBARY 10	29	30	30	29	29	29	29	29	30	29	29	30	29	29	29	29	29
HIGGINS 1	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
HIGGINS 2	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
HIGGINS 3	15	14	14	14	14	14	14	14	14	14	14	15	14	14	14	14	14
HIGGINS 4	11	11	11	11	11	11	11	11	11	11	10	11	11	10	10	11	11
INT CITY 1	9	9	9	8	8	8	8	8	9	8	8	9	8	8	8	8	8
INT CITY 2	12	12	12	12	12	11	11	11	12	11	11	12	11	11	11	11	12
INT CITY 3	12	12	12	12	12	11	12	11	13	11	11	13	12	11	11	11	12
INT CITY 4	13	13	14	13	13	13	13	13	14	13	13	13	13	13	13	13	13
INT CITY 5	14	14	15	14	14	13	14	13	15	13	13	15	14	13	13	13	14
INT CITY 6	10	10	10	10	9	9	10	9	11	9	9	10	10	9	9	9	10
INT CITY 7	65	63	65	62	63	62	63	62	64	62	58	64	63	62	62	61	63
INT CITY 8	70	70	72	68	69	68	69	68	67	68	67	70	70	68	67	67	69
INT CITY 9	63	59	63	59	58	58	60	59	61	57	57	60	60	58	58	57	60
INT CITY 10	65	64	67	64	63	63	64	64	66	63	63	65	64	63	63	63	64
INT CITY 11	30	30	32	30	30	30	29	29	31	29	28	32	30	29	29	29	30
INT CITY 12	91	90	90	90	88	86	89	88	89	87	87	90	90	87	87	87	89
INT CITY 13	90	90	90	87	85	87	88	86	89	87	86	88	89	86	87	86	87
INT CITY 14	95	91	93	90	89	89	90	90	91	89	89	91	90	88	89	89	89
RIO PINAR 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUWANNEE 1	35	33	34	35	33	33	34	32	34	30	31	32	33	29	32	31	33
SUWANNEE 2	20	20	22	20	19	19	20	20	21	19	19	21	20	19	19	19	20
SUWANNEE 3	43	40	39	43	40	38	43	39	39	36	37	37	41	33	37	36	39
TURNER 1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TURNER 2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TURNER 3	13	13	15	13	12	12	13	12	13	13	12	14	13	12	12	12	13
TURNER 4	10	11	12	10	10	10	10	10	11	10	10	11	10	9	9	10	10
U OF FL 1	363	346	339	340	347	338	364	348	364	361	362	336	361	357	341	358	358
CT, Total	1,671	1,596	1,675	1,612	1,580	1,568	1,665	1,550	1,691	1,580	1,561	1,642	1,662	1,535	1,542	1,565	1,632
C P & Lime	988	989															
Econpurc offp	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332
Econpurc peak	422	422	422	421	421	421	421	421	421	421	421	423	421	421	421	421	421
Osceola 158 Purc	3																
OUC 150 Purc																	
Shady Hills	89	120	121	153	84	70	139	56	133	45	61	99	113	40	51	59	82
SoCo Franklin		742	1,294	1,315	1,134	1,020	1,088	896	988								
SoCo Scherer		330	557	554	545	529	530										
Southern UPS	3,567	1,456															
TEA 50 Purc																	

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Teco Purc	376	295	50														
Tran-Purc, Total	5,777	4,688	2,776	2,776	2,517	2,372	2,511	1,705	1,875	799	815	855	867	793	805	812	836
As Avail	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Auburn(As Avail)	37	38	37	38	38	38	38	38	38	37	38	38	37	38	37	37	37
Bay County																	
Biomass Energy	68	828	830	832	829	828	828	831	828	821	820	821	822	807	812	810	814
Cargill																	
Dade County	312	313	313	314	313	312	312	314	312	311	311	312	311	307	308	308	308
DTE Biomass	21	21	21	22	21	21	21	21	21	21	21	21	21	21	21	21	21
El Dorado (APP)	475	474	473	477	475	473	473	476	474	474	474	476	475	474	474	476	474
G2 Energy	77	77	77	78	77	77	77	77	77	76	77	76	76	75	76	76	76
Lake Cogen	433	433	433	436	433	433	433	433	434	433	433	434	433	432	433	435	434
Lake County	80	80	80	80	80	80	80	80	80	79	79	80	79	79	79	79	79
LFC (APP)	82	81	82	82	81	81	81	82	81	82	82	82	81	81	81	82	81
Mulberry	383	383	383	384	383	383	383	384	383	383	383	384	383	383	383	384	383
Orange Cogen	378	378	378	379	378	378	378	379	378	378	378	379	378	378	378	379	378
Orlando Cogen	647	647	647	649	647	647	647	649	647	647	647	649	647	647	647	649	647
Pasco Cogen	629	628	629	631	628	629	629	631	629	628	629	630	629	629	628	630	628
Pasco County	173	173	173	174	173	173	173	173	173	172	171	172	171	168	169	169	169
Pinellas County	336	336	336	337	336	336	336	337	336	334	334	334	334	327	330	328	330
Ridge Gen St	246	246	246	247	246	246	245	246	245	244	244	244	244	241	242	242	242
Royster	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Cogen, Total	4,551	5,312	5,315	5,333	5,314	5,312	5,309	5,328	5,312	5,296	5,296	5,308	5,297	5,263	5,276	5,281	5,277
Sales	-390	-386	-388	-386	-386	-391	-391	-390	-388	-404	-403	-402	-411	-453	-431	-443	-442
DSM	6	4	5	0	3	1	3	0	4	0	0	9	4	0	1	1	3
Total Load	50,800	52,781	53,777	55,049	56,380	57,539	58,850	60,208	61,487	62,835	64,162	65,492	66,801	68,103	69,403	70,682	71,905

PEF CR3 Uprate

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CR NUC 3	5,100	6,976	6,559	8,188	7,560	8,166	7,560	8,188	7,494	8,166	7,560	8,188	7,561	8,166	7,560	8,188	7,560
NUC Future 1									644	8,124	8,135	8,160	8,144	8,067	8,084	8,100	8,105
NUC Future 2													639	7,979	8,009	8,015	8,036
Nuclear, Total	5,100	6,976	6,559	8,188	7,560	8,166	7,560	8,188	8,138	16,290	15,695	16,349	16,344	24,212	23,653	24,303	23,702
Steam-Coal																	
Crystal 1	2,501	2,386	2,670	2,353	2,213	2,402	2,307	2,195	2,358	1,978	2,065	2,158	2,084	1,739	2,052	1,937	2,029
Crystal 2	2,870	3,054	2,881	2,656	3,044	2,780	2,788	2,751	2,702	2,379	2,575	2,482	2,315	2,355	2,329	2,305	2,517
Crystal 4	5,309	5,547	5,390	5,346	5,248	5,041	5,368	4,812	4,558	4,627	4,482	4,522	4,776	4,155	4,291	4,517	4,343
Crystal 5	4,582	5,145	5,646	5,254	5,183	4,968	5,294	4,728	4,481	4,543	4,405	4,439	4,706	4,103	4,185	4,445	4,261
PV COAL 1					3,490	5,849	5,835	5,794	5,783	5,369	5,475	5,489	5,522	5,073	5,193	5,167	5,267
PV COAL 2							459	5,705	5,723	5,291	5,383	5,395	5,397	4,975	5,094	5,053	5,157
Steam-Coal, Total	15,262	16,131	16,588	15,609	19,178	21,041	22,050	25,985	25,605	24,187	24,385	24,485	24,799	22,399	23,145	23,423	23,574
Steam-Oil																	
Anclote 1	1,450	1,488	1,563	1,475	1,261	1,407	1,414	1,358	1,422	1,323	1,356	1,417	1,433	1,211	1,336	1,317	1,390
Anclote 2	1,086	1,099	1,090	1,075	1,001	1,038	1,021	995	1,072	988	1,012	1,018	1,069	950	998	911	1,044
BARTOW 1	195																
BARTOW 2	179																
BARTOW 3	327																
SUWANNEE 1	88	80	88	82	79	80	77	74	79	76	80	81	80	77	74	79	78
SUWANNEE 2	102	92	101	96	92	92	96	88	97	88	89	96	94	88	82	94	91
SUWANNEE 3	184	150	158	169	157	154	170	148	163	148	157	165	158	146	151	169	157
Steam-Oil, Total	3,613	2,908	3,002	2,897	2,590	2,770	2,777	2,664	2,833	2,623	2,694	2,777	2,834	2,472	2,641	2,570	2,761
Steam-CC																	
BARTOW CC REP 1	3,421	5,070	5,967	5,699	5,067	4,543	4,643	3,923	4,326	2,769	3,351	3,418	3,686	2,627	2,821	2,993	3,366
CCF 1			1,510	2,605	2,477	2,235	2,267	1,933	2,120	1,453	1,720	1,777	1,897	1,338	1,508	1,517	1,702
HINES 1	2,849	3,127	2,903	3,017	3,212	3,043	3,023	2,930	3,181	2,777	2,884	2,762	2,857	2,716	2,745	2,908	2,924
HINES 2	2,640	2,232	2,344	2,280	2,144	1,993	2,214	2,051	2,023	1,689	1,785	1,990	2,096	1,638	1,719	1,856	2,049
HINES 3	2,394	2,106	2,125	1,947	1,998	2,046	2,104	1,800	2,033	1,538	1,839	1,875	1,972	1,424	1,616	1,701	1,913
HINES 4	2,717	2,027	2,471	2,462	2,097	1,993	2,075	1,713	2,104	1,390	1,662	1,692	1,970	1,329	1,474	1,468	1,713
TIGERBAY 1	1,193	1,028	979	1,218	1,193	983	1,182	955	758	889	943	1,038	1,020	868	968	807	992
Steam-CC, Total	15,213	15,589	18,299	19,228	18,189	16,836	17,508	15,305	16,545	12,505	14,184	14,551	15,498	11,940	12,850	13,250	14,660
CT																	
AVON PK 1	13	12	13	12	12	12	12	12	12	12	12	13	12	12	12	12	13
AVON PK 2	3	4	4	3	3	3	3	3	3	3	3	4	3	3	3	3	3
BARTOW 1	2	1	1	0	0	0	1	0	1	0	0	1	1	0	0	0	0
BARTOW 2	9	3	4	1	2	1	3	1	3	1	1	2	2	1	1	1	2
BARTOW 3	2	1	1	0	0	0	0	0	1	0	0	1	1	0	0	0	0
BARTOW 4	7	3	5	1	2	1	2	1	5	2	1	3	2	1	0	1	2

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
BAYBORO 1	11	11	12	10	10	10	11	10	12	10	10	11	11	10	10	10	10
BAYBORO 2	11	12	12	11	11	10	11	10	12	11	10	11	11	11	10	11	11
BAYBORO 3	13	13	14	12	12	12	13	12	14	12	12	13	12	12	12	12	12
BAYBORO 4	13	13	14	12	12	12	13	12	14	12	12	13	13	12	12	12	13
CTBar 1	39																
CTBar 2	31																
CTFG 1		18	36	24	16	19	27	7	33	16	15	28	26	9	11	11	23
CTFG 2		12	25	19	11	10	21	9	22	13	9	23	22	8	9	12	18
CTFG 3		8	22	11	9	10	17	8	15	7	8	16	16	5	7	6	14
CTFG 4				2	7	7	11	6	12	6	3	7	12	5	5	6	11
DEBARY 1	10	10	10	9	9	9	9	9	10	9	9	10	9	9	9	9	9
DEBARY 2	8	8	9	8	8	8	8	7	8	8	7	9	8	7	7	8	8
DEBARY 3	9	9	9	8	8	8	8	8	8	8	8	9	8	8	8	8	9
DEBARY 4	9	9	9	8	8	8	8	8	9	8	8	9	8	8	8	8	8
DEBARY 5	8	8	8	7	8	7	7	7	8	7	7	8	8	7	7	7	8
DEBARY 6	7	7	8	7	7	7	7	7	8	7	7	8	7	7	7	7	7
DEBARY 7	90	89	91	88	89	88	89	89	91	88	88	87	89	83	88	88	89
DEBARY 8	91	90	93	90	89	89	91	89	91	90	89	91	90	88	89	89	90
DEBARY 9	88	86	88	85	85	85	87	77	86	85	84	85	86	85	84	84	85
DEBARY 10	29	30	30	29	29	29	29	29	29	29	29	30	29	29	29	29	29
HIGGINS 1	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
HIGGINS 2	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
HIGGINS 3	15	14	15	14	14	14	14	14	14	14	14	14	14	14	14	14	14
HIGGINS 4	11	11	11	10	11	11	11	11	11	11	10	11	11	10	10	11	11
INT CITY 1	9	9	9	8	8	8	8	7	9	8	7	9	8	8	8	8	8
INT CITY 2	12	12	12	11	11	11	11	11	12	11	11	12	11	11	11	11	11
INT CITY 3	12	12	12	12	12	11	11	11	12	11	11	12	12	11	11	11	12
INT CITY 4	13	13	14	13	13	13	13	12	14	13	13	13	13	13	13	13	13
INT CITY 5	14	14	15	13	13	13	14	13	14	13	13	14	14	13	13	13	13
INT CITY 6	10	10	10	10	9	9	9	9	10	9	9	10	9	9	9	9	9
INT CITY 7	65	63	65	62	62	62	63	62	64	62	59	63	63	61	61	61	63
INT CITY 8	70	70	72	68	68	67	69	68	66	68	66	69	69	67	67	67	68
INT CITY 9	63	59	63	58	58	58	59	58	60	57	56	59	58	56	56	57	59
INT CITY 10	65	64	67	63	63	63	64	64	65	63	63	65	63	63	63	62	63
INT CITY 11	30	30	32	30	30	30	28	29	30	29	28	31	30	29	29	29	30
INT CITY 12	91	90	90	89	88	84	89	88	88	87	87	89	89	87	87	87	88
INT CITY 13	90	89	89	88	85	86	88	86	88	86	86	88	88	86	86	86	86
INT CITY 14	95	91	94	90	89	88	91	89	90	89	88	90	89	88	88	88	89
RIO PINAR 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SUWANNEE 1	35	33	35	33	31	31	33	31	34	30	30	32	32	29	31	30	32
SUWANNEE 2	20	20	22	19	19	19	20	19	21	19	18	21	20	19	18	19	20
SUWANNEE 3	43	40	39	40	39	37	41	37	38	35	35	35	38	32	37	34	38
TURNER 1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TURNER 2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

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CR3 Uprate (180MW full ownership, July 06 GFF base) – Florida
GWh
ANNUAL

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
TURNER 3	13	13	14	12	12	12	13	12	13	13	12	14	13	12	12	12	13
TURNER 4	10	11	12	10	10	10	10	9	10	10	10	11	10	9	9	10	10
U OF FL 1	362	346	338	339	347	337	363	347	363	359	360	334	359	355	339	357	356
CT, Total	1,670	1,590	1,667	1,571	1,560	1,538	1,630	1,530	1,652	1,562	1,539	1,609	1,618	1,522	1,522	1,544	1,600
C P & Lime	988	989															
Econpurc offp	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332
Econpurc peak	422	422	422	421	421	421	421	421	421	421	421	423	421	421	421	421	421
Osceola 158 Purc	3																
OUC 150 Purc																	
Shady Hills	89	110	112	106	58	43	108	42	110	39	41	80	92	29	37	44	60
SoCo Franklin		723	1,258	1,204	1,024	956	1,023	806	926								
SoCo Scherer		330	557	549	538	521	521										
Southern UPS	3,566	1,457															
TEA 50 Purc																	
Teco Purc	375	292	50														
Tran-Purc, Total	5,775	4,655	2,731	2,613	2,373	2,273	2,406	1,601	1,789	792	794	835	845	782	790	797	813
As Avail	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Auburn(As Avail)	37	38	37	38	38	38	38	38	38	37	38	38	37	38	37	37	37
Bay County																	
Biomass Energy	68	828	829	831	830	827	827	831	828	818	813	818	817	801	806	804	808
Cargill																	
Dade County	312	313	313	313	313	312	313	313	312	309	309	310	310	304	305	306	306
DTE Biomass	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
El Dorado (APP)	475	474	473	477	475	473	473	476	474	474	474	476	475	474	474	476	474
G2 Energy	77	77	77	77	77	77	77	77	77	76	76	76	76	74	75	75	75
Lake Cogen	433	433	433	435	433	433	432	433	434	433	433	434	432	431	433	434	433
Lake County	80	80	80	80	80	80	80	80	80	79	79	80	79	79	79	79	79
LFC (APP)	82	81	82	81	81	81	81	82	81	81	82	82	81	81	81	82	81
Mulberry	383	383	383	384	383	383	383	384	383	383	383	384	383	383	383	384	383
Orange Cogen	378	378	378	379	378	378	378	379	378	378	378	379	378	378	378	379	378
Orlando Cogen	647	647	647	649	647	647	647	649	647	647	647	649	647	647	647	649	647
Pasco Cogen	629	628	629	631	628	629	629	631	629	628	629	630	629	629	628	630	628
Pasco County	173	172	173	173	173	173	173	173	172	171	170	171	170	167	167	167	168
Pinellas County	336	336	336	337	336	336	336	337	336	333	331	332	333	325	325	325	327
Ridge Gen St	245	246	246	246	246	245	245	246	245	243	243	243	242	240	240	240	241
Royster	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Cogen, Total	4,550	5,312	5,314	5,330	5,315	5,310	5,308	5,325	5,311	5,287	5,281	5,298	5,287	5,249	5,257	5,265	5,263
Sales	-390	-386	-387	-387	-386	-395	-392	-392	-389	-411	-410	-420	-428	-474	-457	-470	-469
DSM	6	4	4	0	2	0	2	0	3	0	0	7	4	0	0	1	2
Total Load	50,800	52,781	53,777	55,049	56,380	57,539	58,850	60,208	61,487	62,835	64,162	65,492	66,801	68,103	69,403	70,682	71,905

PEF CR3 Uprate
Uprate minus Base
$000

ANNUAL

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CR NUC 3	59	1,813	2,250	8,561	7,949	8,899	8,287	9,302	8,560	9,670	9,004	10,121	9,401	10,534	9,809	11,019	10,235
NUC Future 1	0	0	0	0	0	0	0	0	-13	-245	-182	-193	-176	-205	-232	-254	-190
NUC Future 2	0	0	0	0	0	0	0	0	0	0	0	0	-28	-320	-286	-312	-240
Nuclear, Total	59	1,813	2,250	8,561	7,949	8,899	8,287	9,302	8,547	9,425	8,822	9,928	9,198	10,009	9,291	10,454	9,805
Steam-Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crystal 1	17	-282	-286	-1,683	-1,478	-2,054	-2,036	-1,673	-1,748	-2,025	-1,834	-2,045	-2,064	-2,181	-2,039	-2,103	-1,968
Crystal 2	-5	-467	-331	-1,744	-2,364	-2,425	-2,662	-2,140	-2,088	-2,541	-1,841	-2,143	-2,217	-2,507	-2,119	-2,722	-2,128
Crystal 4	8	-162	-183	-1,040	-1,638	-2,262	-2,291	-2,353	-2,486	-2,875	-2,063	-2,367	-3,161	-2,725	-2,556	-3,071	-2,540
Crystal 5	16	-136	-148	-1,265	-1,432	-2,308	-2,116	-2,383	-2,617	-2,884	-2,071	-2,422	-3,064	-2,731	-2,622	-2,908	-2,330
PV COAL 1	0	0	0	0	-186	-1,407	-1,172	-1,274	-1,179	-2,385	-2,039	-2,239	-2,270	-2,650	-2,295	-2,745	-2,222
PV COAL 2	0	0	0	0	0	0	-169	-1,414	-1,235	-2,524	-2,181	-2,152	-2,558	-2,598	-2,264	-3,179	-2,342
Steam-Coal, Total	36	-1,046	-948	-5,733	-7,098	-10,456	-10,446	-11,236	-11,353	-15,235	-12,029	-13,368	-15,334	-15,392	-13,894	-16,727	-13,531
Steam-Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Anclote 1	89	-1,159	-1,027	-8,403	-2,596	-4,501	-3,644	-2,214	-3,677	-4,764	-4,049	-5,842	-5,828	-3,323	-4,316	-4,440	-4,561
Anclote 2	115	-1,297	-470	-8,458	-3,216	-4,821	-3,013	-4,416	-4,734	-1,731	-3,418	-3,616	-8,453	-3,041	-1,389	-3,864	-4,190
BARTOW 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BARTOW 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BARTOW 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SUWANNEE 1	-13	-108	-41	-356	-454	-708	-629	-298	-204	-81	-132	-213	-348	153	-491	144	-212
SUWANNEE 2	0	-47	72	-242	-403	-525	-204	-746	-422	-120	-51	-251	-250	31	-646	-371	-266
SUWANNEE 3	0	-44	-564	-1,007	-2,101	-1,203	-306	-117	-891	-204	-372	53	-1,094	-347	301	281	-351
Steam-Oil, Total	191	-2,655	-2,030	-18,466	-8,770	-11,760	-7,796	-7,791	-9,928	-6,899	-8,023	-9,869	-15,974	-6,527	-6,540	-8,250	-9,580
Steam-CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BARTOW	-1,716	-1,450	-7,001	-32,768	-22,673	-21,366	-25,543	-19,182	-17,785	-19,533	-19,228	-20,540	-20,391	-19,260	-25,130	-24,027	-18,945
CC REP 1																	
CCF 1	0	0	-3,920	-7,524	-9,059	-8,577	-9,877	-10,443	-11,828	-15,317	-13,445	-17,557	-11,576	-18,386	-9,570	-17,117	-17,336
HINES 1	-112	-802	940	-4,597	-1,881	-2,126	-3,153	-2,424	-3,456	-1,233	-2,156	-4,471	-2,755	-4,149	-7,895	-4,623	-8,716
HINES 2	-344	-1,150	-5,890	-6,098	-11,518	-7,935	-6,965	-5,462	-17,109	-13,354	-7,230	-14,384	-7,591	-10,629	-13,738	-10,239	-10,909
HINES 3	-480	-2,264	-1,903	-7,007	-10,877	-9,793	-7,188	-11,868	-9,099	-10,156	-13,085	-10,665	-12,921	-16,572	-12,041	-15,431	-12,708
HINES 4	1,615	-7,646	-4,804	-4,557	-3,754	-9,807	-7,482	-18,500	-1,689	-8,843	-18,638	-14,416	-10,083	-19,351	-12,368	-12,531	-15,676
TIGERBAY 1	329	-1,612	1,652	963	-3,564	-2,030	1,431	-4,910	-4,076	-7,952	-4,438	-6,774	-3,144	-211	-885	-2,725	-1,736
Steam-CC, Total	-708	-14,923	-20,926	-61,588	-63,326	-61,634	-58,778	-72,789	-65,042	-76,387	-78,220	-88,807	-68,461	-88,558	-81,627	-86,691	-86,028
CT, Total	-4	-734	-869	-5,221	-2,725	-3,765	-4,646	-2,987	-6,020	-2,770	-3,513	-5,537	-7,025	-2,080	-3,839	-3,588	-6,101
Tran-Purc, Total	-85	-2,451	-3,241	-12,946	-10,550	-7,758	-8,614	-8,490	-8,087	-1,198	-3,088	-3,591	-3,660	-1,779	-2,368	-2,737	-3,894
Cogen, Total	-77	-226	-91	-1,121	-787	-1,765	-1,981	-1,948	-1,519	-3,265	-2,523	-2,452	-3,069	-3,568	-2,812	-4,955	-4,285
NH3	0	-4	-5	-31	-43	-78	-73	-95	-94	-135	-103	-111	-131	-125	-111	-134	-104
CaCO3	0	-11	-12	-85	-120	-223	-213	-278	-280	-407	-315	-345	-413	-400	-361	-442	-348
Total Cost	(587.3)	(20,237.8)	(25,870.9)	(96,630.0)	(85,470.8)	(88,538.8)	(84,260.4)	(96,311.5)	(93,775.4)	(96,862.1)	(98,991.0)	(114,151.3)	(104,868.6)	(108,419.6)	(102,262.2)	(113,069.5)	(114,066.6)

PEF CR3 Uprate
July 2006 Generation & Fuel Forecast Base - Florida
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ANNUAL

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CR NUC 3	24,003	35,402	32,966	37,139	34,469	38,607	35,939	40,353	37,120	41,948	39,045	43,908	40,776	45,699	42,539	47,806	44,386
NUC Future 1									4,352	54,955	55,361	57,399	57,663	59,059	59,634	61,745	62,184
NUC Future 2													4,691	58,534	59,144	61,157	61,698
Nuclear, Total	24,003	35,402	32,966	37,139	34,469	38,607	35,939	40,353	41,473	96,904	94,406	101,308	103,130	163,292	161,317	170,708	168,267
Steam-Coal																	
Crystal 1	77,516	77,815	90,132	83,496	80,651	90,839	89,904	87,883	96,842	84,643	90,171	96,694	95,497	83,447	100,032	96,981	103,781
Crystal 2	87,026	97,102	94,882	92,048	108,438	102,526	106,131	107,448	108,441	99,370	109,285	108,300	104,024	109,441	110,662	112,956	125,355
Crystal 4	153,019	146,950	145,187	149,113	151,015	150,574	164,937	152,643	148,709	156,474	154,274	159,765	173,326	156,514	165,396	179,166	176,236
Crystal 5	134,640	136,847	152,171	147,210	149,115	148,793	162,995	150,374	146,735	154,038	152,026	157,174	171,394	154,912	161,862	176,556	173,134
PV COAL 1					86,930	151,596	155,333	158,379	162,094	156,814	162,925	167,480	172,662	165,157	172,905	177,547	184,563
PV COAL 2							12,346	156,564	160,655	154,957	160,701	164,854	169,513	162,626	169,997	174,153	181,266
Steam-Coal, Total	452,201	458,715	482,373	471,867	576,149	644,328	691,646	813,292	823,476	806,295	829,381	854,267	886,416	832,097	880,854	917,358	944,336
Steam-Oil																	
Anclote 1	147,444	125,402	137,235	144,256	118,220	131,972	136,859	138,509	155,068	154,308	166,308	184,436	190,229	162,270	183,356	184,514	198,070
Anclote 2	130,926	97,106	100,278	112,181	99,077	102,925	102,919	108,679	123,759	118,351	129,918	137,902	152,074	133,846	141,009	134,104	155,802
BARTOW 1	24,979																
BARTOW 2	23,274																
BARTOW 3	39,600																
SUWANNEE 1	14,606	9,199	10,548	10,551	10,269	10,599	10,565	10,401	11,673	11,753	13,151	14,068	14,419	13,710	14,109	14,587	15,026
SUWANNEE 2	17,039	10,722	12,155	12,361	12,053	12,052	12,733	13,043	14,631	13,908	14,816	16,984	16,848	15,964	15,922	18,140	17,837
SUWANNEE 3	26,633	15,010	17,081	19,452	19,178	17,958	19,437	18,035	21,640	20,149	22,737	24,718	25,290	23,300	23,887	27,379	26,652
Steam-Oil, Total	424,501	257,439	277,297	298,801	258,797	275,507	282,512	288,667	326,771	318,469	346,929	378,108	398,859	349,090	378,282	378,724	413,387
Steam-CC																	
BARTOW CC REP 1	268,371	346,360	421,543	447,874	393,247	355,857	378,454	340,089	386,694	282,785	344,622	367,644	398,816	303,592	332,944	354,291	392,595
CCF 1			112,204	202,219	194,147	176,626	185,333	171,933	196,078	155,633	183,762	200,865	208,712	166,562	176,614	187,760	209,030
HINES 1	168,943	178,635	192,838	214,400	222,728	210,844	217,874	223,636	255,145	236,853	258,058	262,726	273,841	268,568	279,097	296,003	306,383
HINES 2	236,058	172,691	193,450	197,046	192,007	175,236	197,596	193,982	213,160	190,900	201,944	239,069	247,151	206,447	222,115	237,033	262,955
HINES 3	224,449	163,075	170,030	169,986	174,972	175,833	183,941	173,060	200,206	165,866	205,673	216,436	232,605	182,103	200,686	217,122	242,118
HINES 4	245,081	158,657	191,637	198,888	170,428	167,760	177,036	169,157	193,846	148,498	191,159	197,944	224,873	172,775	183,038	185,757	218,269
TIGERBAY 1	100,912	73,341	69,650	90,601	92,974	76,161	89,673	84,207	71,537	91,307	96,798	113,239	109,358	93,841	106,340	92,925	113,425
Steam-CC, Total	1,243,814	1,092,758	1,351,351	1,521,015	1,440,503	1,338,316	1,429,908	1,356,064	1,516,665	1,271,842	1,482,015	1,597,923	1,695,355	1,393,887	1,500,834	1,570,893	1,744,775
CT																	
AVON PK 1	2,709	2,216	2,309	2,376	2,387	2,275	2,421	2,530	2,728	2,829	2,955	3,251	3,169	3,215	3,217	3,337	3,441
AVON PK 2	1,237	784	789	808	809	814	862	894	985	1,002	1,044	1,180	1,167	1,129	1,183	1,209	1,256
BARTOW 1	842	159	185	86	125	58	155	34	241	108	39	344	211	20	31	52	197
BARTOW 2	2,432	1,053	1,173	960	875	815	1,151	809	1,349	876	825	1,146	1,090	866	897	845	1,164
BARTOW 3	810	160	160	81	123	54	154	22	232	90	31	331	170	14	31	59	213
BARTOW 4	1,987	1,089	1,333	965	968	823	964	774	1,539	894	822	1,269	1,132	999	860	882	1,320
BAYBORO 1	3,084	2,037	2,210	2,096	2,001	1,977	2,229	2,201	2,810	2,402	2,523	2,932	2,952	2,760	2,827	2,978	3,143
BAYBORO 2	3,181	2,095	2,245	2,220	2,136	2,121	2,440	2,330	2,888	2,643	2,690	3,155	3,027	2,985	2,985	3,167	3,251
BAYBORO 3	3,929	2,418	2,670	2,496	2,456	2,408	2,764	2,740	3,288	2,984	3,027	3,662	3,450	3,357	3,528	3,655	3,885
BAYBORO 4	3,903	2,449	2,686	2,566	2,512	2,486	2,818	2,771	3,329	3,076	3,129	3,627	3,595	3,463	3,538	3,706	3,903
CTBar 1	8,634																
CTBar 2	7,721																
CTFG 1		5,387	9,924	9,752	8,306	8,797	9,789	7,453	10,696	8,617	8,718	10,765	11,417	7,803	8,090	8,727	10,506
CTFG 2		4,880	8,873	8,855	7,916	7,740	9,160	7,613	9,448	8,246	7,938	10,053	10,318	7,651	7,910	8,546	9,614
CTFG 3		4,436	8,510	8,031	7,401	7,599	8,470	7,331	8,613	7,524	7,654	9,015	9,065	7,259	7,642	7,632	8,908
CTFG 4				3,971	7,262	7,243	7,830	7,100	7,958	7,425	7,002	7,393	8,335	7,172	7,253	7,448	8,355
DEBARY 1	3,341	2,071	2,211	2,121	2,187	2,202	2,357	2,386	2,767	2,743	2,784	3,296	3,083	3,026	3,111	3,153	3,407
DEBARY 2	2,781	1,797	1,939	1,801	1,838	1,822	1,998	1,988	2,367	2,276	2,292	2,868	2,584	2,508	2,575	2,691	2,884
DEBARY 3	3,265	2,085	2,140	2,137	2,170	2,182	2,326	2,381	2,680	2,716	2,772	3,302	3,040	3,049	3,094	3,173	3,369

Progress Energy Florida
Docket No. 060642-EI
Response to Staff Interrogatory No. 5
Attachment 2

PEF CR3 Uprate
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Annual

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
DEBARY 4	3,198	2,018	2,089	2,080	2,118	2,138	2,254	2,327	2,648	2,633	2,697	3,161	2,951	2,946	3,010	3,084	3,320
DEBARY 5	2,906	1,839	1,910	1,887	1,946	1,914	2,018	2,093	2,304	2,402	2,430	2,902	2,654	2,668	2,753	2,779	2,982
DEBARY 6	2,498	1,521	1,758	1,596	1,619	1,630	1,794	1,802	2,102	2,060	2,089	2,632	2,245	2,286	2,337	2,421	2,599
DEBARY 7	14,525	12,073	12,755	12,921	12,895	12,770	13,290	13,999	15,114	15,442	16,219	16,868	17,520	16,559	18,029	18,203	18,662
DEBARY 8	15,002	12,335	13,230	13,351	13,167	13,088	13,689	14,288	15,283	15,878	16,593	17,700	18,037	17,750	18,502	18,634	19,138
DEBARY 9	14,460	11,843	12,519	12,817	12,698	12,550	13,247	12,524	14,668	15,198	15,847	16,832	17,246	17,361	17,413	17,853	18,312
DEBARY 10	8,551	5,293	5,650	5,678	5,686	5,824	6,070	6,368	6,880	7,103	7,423	8,111	8,046	8,124	8,296	8,491	8,715
HIGGINS 1	1,806	1,519	1,580	1,618	1,615	1,589	1,643	1,711	1,832	1,886	1,962	2,170	2,102	2,118	2,168	2,192	2,299
HIGGINS 2	1,803	1,524	1,581	1,614	1,624	1,580	1,652	1,711	1,832	1,897	1,965	2,169	2,038	2,127	2,175	2,199	2,260
HIGGINS 3	3,006	2,471	2,597	2,634	2,615	2,578	2,672	2,796	3,015	3,125	3,248	3,560	3,516	3,521	3,587	3,658	3,792
HIGGINS 4	2,500	1,988	2,053	2,099	2,094	2,061	2,178	2,227	2,418	2,510	2,571	2,849	2,793	2,791	2,830	2,885	2,995
INT CITY 1	2,779	1,717	1,905	1,811	1,749	1,696	1,883	1,880	2,386	2,131	2,146	2,645	2,499	2,384	2,474	2,574	2,757
INT CITY 2	3,681	2,333	2,553	2,511	2,542	2,486	2,602	2,726	3,140	3,118	3,176	3,622	3,376	3,499	3,591	3,703	3,862
INT CITY 3	3,789	2,359	2,545	2,580	2,554	2,467	2,655	2,744	3,252	2,986	3,143	3,668	3,552	3,508	3,532	3,565	3,889
INT CITY 4	4,051	2,513	2,790	2,757	2,779	2,721	2,862	2,939	3,460	3,291	3,467	3,679	3,835	3,806	3,901	4,000	4,153
INT CITY 5	4,409	2,785	3,058	2,885	2,939	2,824	3,150	3,177	3,720	3,540	3,649	4,224	4,129	3,945	4,137	4,082	4,424
INT CITY 6	3,126	2,019	2,072	2,070	1,992	1,973	2,215	2,216	2,675	2,437	2,489	2,977	2,901	2,794	2,869	2,975	3,089
INT CITY 7	8,929	8,834	9,415	9,461	9,430	9,258	9,717	10,192	11,062	11,311	11,167	12,757	12,876	12,812	13,171	13,203	13,799
INT CITY 8	9,586	9,714	10,343	10,309	10,285	10,112	10,607	11,123	11,490	12,265	12,741	13,851	14,258	13,992	14,177	14,354	14,953
INT CITY 9	8,850	8,500	9,230	9,152	8,974	8,931	9,401	9,865	10,683	10,657	11,131	12,166	12,361	12,276	12,495	12,566	13,292
INT CITY 10	9,161	9,246	9,928	9,913	9,739	9,679	10,113	10,646	11,537	11,816	12,267	13,225	13,460	13,342	13,711	13,792	14,284
INT CITY 11	7,628	4,682	5,109	4,997	5,052	5,075	5,101	5,557	6,123	6,090	6,157	7,277	6,967	7,002	7,119	7,309	7,629
INT CITY 12	11,869	12,074	12,522	13,057	12,692	12,259	13,179	13,798	14,686	15,265	16,119	17,254	17,667	17,472	17,800	18,125	18,737
INT CITY 13	10,867	11,007	11,470	11,664	11,282	11,469	11,949	12,415	13,459	13,869	14,560	15,587	15,959	15,781	16,270	16,358	16,774
INT CITY 14	11,472	11,333	11,978	12,149	11,897	11,823	12,381	13,061	13,930	14,459	15,162	16,254	16,455	16,374	16,791	17,099	17,436
RIO PINAR 1	599	386	396	399	415	401	415	442	477	492	509	587	568	558	577	580	616
SUWANNEE 1	10,642	5,991	6,445	6,869	6,592	6,778	7,264	7,256	8,084	7,577	8,257	8,863	9,364	8,491	9,406	9,432	10,120
SUWANNEE 2	6,011	3,616	4,089	3,823	3,795	3,766	4,175	4,261	4,884	4,671	4,737	5,536	5,516	5,314	5,435	5,529	5,976
SUWANNEE 3	12,671	6,998	7,114	8,201	7,699	7,485	8,667	8,466	8,861	8,644	9,425	9,658	10,901	9,068	10,453	10,345	11,529
TURNER 1	273	183	183	172	180	173	190	191	232	221	215	284	257	236	252	255	267
TURNER 2	390	254	263	255	255	252	282	280	312	315	316	397	372	350	364	370	393
TURNER 3	3,765	2,370	2,633	2,417	2,419	2,406	2,636	2,609	3,053	3,094	2,975	3,733	3,455	3,341	3,396	3,493	3,801
TURNER 4	3,034	1,958	2,163	1,916	1,918	1,963	2,096	2,101	2,526	2,480	2,507	3,046	2,810	2,678	2,706	2,861	3,093
U OF FL 1	19,048	18,538	30,984	32,402	32,767	31,714	35,138	35,649	39,346	41,161	43,398	42,548	46,328	46,740	45,621	48,614	49,482
CT, Total	276,741	218,947	256,269	261,388	259,493	256,848	277,072	276,800	311,394	308,473	319,003	350,381	356,817	341,290	350,122	358,845	378,243
C P & Lime	48,882	49,236															
Econpurc offp	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017
Econpurc peak	49,009	48,852	48,872	48,453	48,453	48,453	48,453	48,453	48,527	48,453	48,453	49,561	48,563	48,453	48,453	48,453	48,501
Osceola 158 Purc	1,768																
OUC 150 Purc																	
Shady Hills	42,468	42,483	43,251	47,912	39,670	41,822	51,522	42,394	52,498	41,357	44,511	50,432	53,233	41,269	43,572	45,249	49,319
SoCo Franklin		63,736	113,946	119,241	106,740	98,780	105,947	96,601	107,610								
SoCo Scherer		16,115	27,763	28,112	28,189	28,101	28,587										
Southern UPS	143,923	60,078															
TEA 50 Purc																	
Teco Purc	27,904	23,615	3,954														
Tran-Purc, Total	337,972	328,132	261,802	287,736	247,069	241,173	258,526	211,465	232,653	113,827	116,981	124,010	125,813	113,739	116,042	117,719	121,838
As Avail	1,844	1,510	1,625	1,686	1,573	1,594	1,597	1,595	1,787	1,534	1,739	1,803	1,902	1,683	1,908	1,900	2,027
Auburn(As Avail)	3,214	2,514	2,591	2,704	2,653	2,546	2,737	2,754	3,038	2,770	3,091	3,162	3,351	3,019	3,248	3,427	3,574
Bay County																	
Biomass Energy	4,201	52,186	51,185	50,651	50,641	50,731	51,449	52,354	52,902	53,278	53,979	54,646	55,452	55,376	56,522	57,225	58,325
Cargill																	
Dade County	25,913	26,828	28,326	29,566	29,673	19,693	20,252	20,252	20,986	19,677	20,551	21,140	21,723	20,515	21,459	21,767	22,787
DTE Biomass	1,815	1,603	1,549	1,516	1,514	1,519	1,545	1,581	1,605	1,617	1,670	1,846	1,897	1,916	1,979	2,025	2,084
El Dorado (APP)	52,835	55,548	57,940	60,674	63,193	37,658	38,575	39,391	40,709	39,978	41,263	42,148	43,179	42,328	44,110	44,698	46,319

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	2009	2010	2011	2012	2013	2014	2015	2016	2017
G2 Energy	3,843	3,871	3,898	3,932	3,944	3,968	3,991	4,032	4,045
Lake Cogen	54,520	57,451	60,037	62,953	52,462	34,450	35,453	35,842	37,219
Lake County	9,263	9,736	10,239	10,791	11,364	8,646	5,329	5,339	5,541
LFC (APP)	9,803	10,304	10,838	11,417	12,031	6,176	6,350	6,439	6,643
	2009	2010	2011	2012	2013	2014	2015	2016	2017
Mulberry	47,724	50,246	52,582	55,114	57,627	60,354	63,229	66,213	69,293
Orange Cogen	42,603	44,809	46,808	46,113	48,121	50,278	52,586	54,920	57,374
Orlando Cogen	52,929	55,018	57,356	59,952	62,317	64,791	67,363	70,023	72,705
Pasco Cogen	47,230	42,644	43,882	44,399	43,730	43,151	44,291	44,440	46,165
Pasco County	17,449	18,304	19,228	20,230	21,272	22,339	23,497	24,730	26,070
Pinellas County	39,628	41,653	43,825	46,172	48,648	51,194	53,927	56,863	60,011
Ridge Gen St	18,883	19,437	19,770	20,143	20,318	20,584	20,842	21,127	21,354
Royster	16,489	11,222	11,309	11,509	11,406	11,288	11,582	11,754	12,158
Cogen, Total	450,187	504,884	522,988	539,522	542,487	490,959	504,594	519,650	539,603
NH3	3,611	4,066	4,119	3,940	5,181	5,948	6,397	8,024	7,894
CaCO3	1,098	10,389	10,959	10,860	14,462	16,913	18,492	23,392	23,390
Total Cost	3,214,129	2,910,732	3,200,124	3,412,267	3,378,609	3,308,600	3,505,086	3,537,707	3,823,319

	2018	2019	2020	2021	2022	2023	2024	2025
G2 Energy	4,041	4,086	4,109	4,134	4,117	5,385	5,445	5,687
Lake Cogen	36,274	37,769	38,568	39,352	38,662	40,171	40,985	42,412
Lake County	5,251	5,493	5,591	5,715	5,505	5,696	5,821	6,062
LFC (APP)	6,501	6,757	6,887	7,061	6,874	7,168	7,278	7,572
	2018	2019	2020	2021	2022	2023	2024	2025
Mulberry	72,492	75,907	79,484	83,157	87,028	91,191	75,277	35,636
Orange Cogen	59,736	62,496	65,320	68,232	71,118	74,496	77,882	81,532
Orlando Cogen	75,504	78,461	81,575	84,630	88,094	91,649	44,531	46,531
Pasco Cogen	44,010	45,898	46,848	48,194	46,581	48,261	49,067	51,137
Pasco County	27,376	28,892	30,531	32,212	33,822	35,759	37,792	12,531
Pinellas County	63,110	66,732	70,569	74,594	78,447	83,042	87,830	25,475
Ridge Gen St	21,531	21,794	22,053	22,262	22,455	22,804	18,757	19,653
Royster	11,882	12,333	12,599	12,879	12,597	13,127	13,325	13,858
Cogen, Total	546,562	568,910	588,880	609,925	620,138	647,974	595,032	483,203
NH3	7,783	7,765	7,855	8,154	7,441	7,656	7,916	7,876
CaCO3	23,429	23,712	24,407	25,739	23,828	24,894	26,158	26,407
Total Cost	3,493,585	3,789,102	4,027,139	4,210,207	3,844,802	4,067,973	4,143,351	4,288,333

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CR NUC 3	24,063	37,215	35,215	45,700	42,417	47,506	44,225	49,654	45,680	51,618	48,049	54,029	50,177	56,233	52,348	58,825	54,621
NUC Future 1									4,339	54,711	55,180	57,207	57,488	58,854	59,401	61,491	61,993
NUC Future 2													4,663	58,214	58,858	60,846	61,458
Nuclear, Total	24,063	37,215	35,215	45,700	42,417	47,506	44,225	49,654	50,020	106,329	103,229	111,236	112,328	173,301	170,607	181,162	178,072
Steam-Coal																	
Crystal 1	77,533	77,533	89,846	81,813	79,173	88,784	87,868	86,211	95,094	82,618	88,337	94,649	93,433	81,266	97,993	94,878	101,813
Crystal 2	87,021	96,636	94,551	90,304	106,074	100,102	103,469	105,309	106,352	96,828	107,444	106,157	101,807	106,934	108,543	110,235	123,227
Crystal 4	153,027	146,788	145,005	148,073	149,378	148,312	162,646	150,290	146,223	153,598	152,211	157,398	170,165	153,789	162,840	176,095	173,696
Crystal 5	134,656	136,711	152,023	145,945	147,683	146,485	160,879	147,991	144,118	151,154	149,955	154,752	168,330	152,180	159,240	173,647	170,805
PV COAL 1					86,744	150,189	154,161	157,105	160,915	154,429	160,885	165,241	170,391	162,507	170,610	174,802	182,340
PV COAL 2							12,177	155,150	159,420	152,433	158,520	162,702	166,955	160,028	167,733	170,974	178,925
Steam-Coal, Total	452,237	457,668	481,425	466,134	569,051	633,872	681,200	802,056	812,123	791,060	817,351	840,900	871,082	816,704	866,959	900,632	930,806
Steam-Oil																	
Anclote 1	147,533	124,243	136,208	135,853	115,624	127,471	133,215	136,295	151,391	149,544	162,259	178,594	184,400	158,947	179,040	180,074	193,509
Anclote 2	131,041	95,809	99,808	103,722	95,861	98,104	99,906	104,263	119,025	116,620	126,500	134,286	143,621	130,805	139,620	130,241	151,612
BARTOW 1	24,979																
BARTOW 2	23,274																
BARTOW 3	39,600																
SUWANNEE 1	14,593	9,091	10,507	10,195	9,815	9,891	9,936	10,103	11,469	11,672	13,019	13,854	14,071	13,863	13,619	14,731	14,814
SUWANNEE 2	17,039	10,675	12,227	12,119	11,650	11,526	12,528	12,297	14,209	13,789	14,764	16,733	16,597	15,995	15,276	17,769	17,570
SUWANNEE 3	26,633	14,966	16,517	18,445	17,077	16,755	19,131	17,918	20,749	19,944	22,365	24,771	24,196	22,953	24,188	27,659	26,301
Steam-Oil, Total	424,692	254,784	275,268	280,334	250,026	263,747	274,716	280,876	316,843	311,570	338,907	368,240	382,886	342,563	371,742	370,474	403,807
Steam-CC																	
BARTOW CC REP 1	266,655	344,910	414,542	415,107	370,574	334,492	352,911	320,906	368,908	263,253	325,394	347,104	378,425	284,332	307,815	330,264	373,650
CCF 1			108,284	194,695	185,089	168,048	175,456	161,491	184,250	140,316	170,317	183,308	197,136	148,176	167,044	170,644	191,694
HINES 1	168,831	177,834	193,777	209,803	220,847	208,718	214,720	221,212	251,689	235,621	255,902	258,256	271,086	264,419	271,202	291,381	297,667
HINES 2	235,713	171,541	187,560	190,948	180,489	167,301	190,631	188,520	196,051	177,546	194,714	224,685	239,559	195,818	208,377	226,795	252,045
HINES 3	223,969	160,811	168,128	162,979	164,095	166,041	176,753	161,192	191,107	155,710	192,588	205,771	219,684	165,531	188,645	201,691	229,410
HINES 4	246,696	151,011	186,833	194,331	166,673	157,953	169,554	150,657	192,157	139,655	172,521	183,527	214,789	153,423	170,669	173,227	202,592
TIGERBAY 1	101,241	71,729	71,301	91,564	89,410	74,131	91,105	79,297	67,461	83,355	92,360	106,465	106,214	93,629	105,455	90,200	111,689
Steam-CC, Total	1,243,106	1,077,834	1,330,425	1,459,427	1,377,177	1,276,682	1,371,130	1,283,275	1,451,623	1,195,455	1,403,796	1,509,116	1,626,894	1,305,329	1,419,207	1,484,202	1,658,747
CT																	
AVON PK 1	2,709	2,211	2,314	2,366	2,364	2,275	2,415	2,536	2,696	2,819	2,955	3,246	3,168	3,215	3,217	3,337	3,441
AVON PK 2	1,237	779	790	802	816	811	874	894	982	992	1,044	1,175	1,160	1,129	1,183	1,209	1,236
BARTOW 1	842	155	152	59	82	46	115	17	158	70	13	288	181	20	31	30	130
BARTOW 2	2,432	1,040	1,160	813	850	726	1,051	731	1,207	827	728	977	1,051	778	711	739	985
BARTOW 3	810	149	157	40	83	41	108	17	165	44	13	282	158	14	31	39	135
BARTOW 4	1,987	1,048	1,284	810	935	712	835	752	1,373	919	732	1,098	1,085	800	674	823	1,109
BAYBORO 1	3,084	2,043	2,234	2,027	1,966	1,935	2,177	2,139	2,657	2,345	2,487	2,791	2,870	2,760	2,764	2,922	3,037
BAYBORO 2	3,181	2,101	2,235	2,108	2,099	2,100	2,353	2,282	2,722	2,598	2,690	3,052	2,967	3,014	2,906	3,168	3,208
BAYBORO 3	3,929	2,403	2,678	2,403	2,405	2,357	2,721	2,663	3,195	2,986	3,004	3,543	3,335	3,337	3,431	3,587	3,730
BAYBORO 4	3,903	2,424	2,692	2,459	2,457	2,451	2,757	2,710	3,244	3,035	3,089	3,618	3,507	3,440	3,492	3,657	3,829
CTBar 1	8,634																
CTBar 2	7,721																
CTFG 1		5,316	9,716	8,709	7,967	8,202	9,070	7,139	10,025	8,288	8,200	10,001	9,848	7,661	7,924	8,018	9,708
CTFG 2		4,758	8,732	8,241	7,506	7,384	8,519	7,384	8,864	7,888	7,530	9,387	9,340	7,428	7,624	8,032	8,980
CTFG 3		4,402	8,415	7,519	7,235	7,308	8,043	7,209	8,027	7,272	7,374	8,517	8,510	7,096	7,383	7,289	8,421
CTFG 4				3,874	7,087	7,105	7,535	6,992	7,755	7,122	6,832	7,259	8,001	7,032	7,096	7,208	8,013
DEBARY 1	3,341	2,067	2,203	2,114	2,185	2,189	2,309	2,384	2,642	2,716	2,769	3,226	3,059	3,026	3,093	3,153	3,361
DEBARY 2	2,781	1,778	1,917	1,776	1,802	1,816	1,929	1,964	2,258	2,254	2,284	2,829	2,580	2,508	2,566	2,676	2,833
DEBARY 3	3,265	2,070	2,114	2,128	2,178	2,174	2,283	2,374	2,575	2,687	2,764	3,212	3,037	3,049	3,094	3,155	3,340

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DEBARY 4	3,198	1,982	2,062	2,071	2,116	2,102	2,226	2,318	2,546	2,601	2,697	3,105	2,956	2,946	3,010	3,084	3,216
DEBARY 5	2,906	1,835	1,908	1,878	1,928	1,886	1,992	2,099	2,268	2,318	2,430	2,834	2,666	2,668	2,753	2,779	2,946
DEBARY 6	2,498	1,516	1,729	1,590	1,619	1,630	1,754	1,800	2,057	2,040	2,081	2,555	2,245	2,286	2,328	2,421	2,553
DEBARY 7	14,525	12,023	12,758	12,931	12,847	12,672	13,231	13,934	15,031	15,435	16,162	16,814	17,434	16,559	17,927	18,200	18,637
DEBARY 8	15,002	12,338	13,199	13,262	13,057	13,002	13,663	14,206	15,247	15,896	16,511	17,626	17,869	17,728	18,369	18,621	19,060
DEBARY 9	14,460	11,823	12,560	12,762	12,610	12,447	13,181	12,502	14,617	15,168	15,811	16,761	17,127	17,310	17,373	17,817	18,257
DEBARY 10	8,551	5,284	5,582	5,685	5,686	5,824	6,070	6,368	6,818	7,091	7,423	8,018	8,009	8,124	8,296	8,481	8,715
HIGGINS 1	1,806	1,515	1,571	1,604	1,617	1,581	1,637	1,711	1,822	1,872	1,962	2,130	2,116	2,118	2,168	2,192	2,268
HIGGINS 2	1,803	1,522	1,581	1,604	1,612	1,580	1,642	1,711	1,830	1,895	1,965	2,161	2,052	2,127	2,175	2,194	2,237
HIGGINS 3	3,006	2,494	2,614	2,612	2,594	2,569	2,639	2,796	2,983	3,105	3,241	3,545	3,493	3,521	3,587	3,658	3,783
HIGGINS 4	2,500	1,973	2,038	2,074	2,077	2,054	2,147	2,227	2,386	2,487	2,561	2,832	2,788	2,791	2,828	2,884	2,986
INT CITY 1	2,779	1,704	1,891	1,700	1,728	1,650	1,763	1,789	2,322	2,096	2,079	2,500	2,407	2,379	2,377	2,537	2,641
INT CITY 2	3,681	2,325	2,552	2,452	2,514	2,477	2,578	2,726	3,078	3,098	3,164	3,572	3,379	3,499	3,559	3,682	3,802
INT CITY 3	3,789	2,345	2,552	2,499	2,514	2,442	2,617	2,699	3,154	2,981	3,123	3,619	3,491	3,498	3,492	3,540	3,807
INT CITY 4	4,051	2,513	2,775	2,688	2,757	2,712	2,812	2,931	3,362	3,280	3,438	3,672	3,824	3,816	3,861	3,980	4,095
INT CITY 5	4,409	2,771	3,048	2,856	2,880	2,814	3,083	3,128	3,631	3,480	3,629	4,192	4,075	3,974	4,086	4,072	4,383
INT CITY 6	3,126	1,968	2,035	2,022	1,969	1,965	2,141	2,136	2,618	2,405	2,480	2,940	2,809	2,793	2,810	2,985	3,016
INT CITY 7	8,929	8,824	9,453	9,386	9,388	9,237	9,673	10,190	11,002	11,257	11,238	12,675	12,794	12,743	13,000	13,203	13,723
INT CITY 8	9,586	9,692	10,357	10,233	10,241	9,990	10,612	11,050	11,349	12,244	12,665	13,798	14,063	13,844	14,078	14,354	14,846
INT CITY 9	8,850	8,499	9,246	9,032	8,957	8,883	9,355	9,671	10,530	10,666	11,040	11,993	12,156	12,013	12,179	12,544	13,075
INT CITY 10	9,161	9,191	9,900	9,876	9,766	9,614	10,054	10,654	11,458	11,773	12,253	13,228	13,266	13,355	13,597	13,776	14,242
INT CITY 11	7,628	4,682	5,082	4,957	5,026	5,064	5,074	5,528	6,008	6,090	6,157	7,191	6,967	7,002	7,100	7,309	7,584
INT CITY 12	11,869	12,072	12,500	12,936	12,680	12,080	13,145	13,790	14,586	15,277	16,064	17,178	17,547	17,488	17,767	18,125	18,687
INT CITY 13	10,867	10,965	11,386	11,678	11,277	11,307	11,886	12,381	13,353	13,791	14,470	15,528	15,880	15,733	16,040	16,292	16,730
INT CITY 14	11,472	11,335	12,018	12,104	11,897	11,756	12,403	12,955	13,783	14,476	15,041	16,104	16,284	16,358	16,686	17,001	17,436
RIO PINAR 1	599	386	399	391	410	398	415	441	476	483	509	598	575	558	577	580	610
SUWANNEE 1	10,642	6,017	6,565	6,575	6,321	6,411	7,046	6,938	7,952	7,499	7,939	8,691	9,003	8,437	9,279	9,150	9,667
SUWANNEE 2	6,011	3,582	4,066	3,748	3,723	3,674	4,090	4,177	4,814	4,625	4,651	5,454	5,375	5,214	5,241	5,449	5,809
SUWANNEE 3	12,671	7,002	7,010	7,675	7,479	7,227	8,227	8,050	8,576	8,470	8,975	9,271	10,324	8,870	10,461	9,916	11,199
TURNER 1	273	178	191	170	178	167	187	184	223	205	215	282	257	236	252	255	273
TURNER 2	390	256	259	248	252	247	275	273	312	302	316	398	369	350	364	370	393
TURNER 3	3,765	2,368	2,606	2,391	2,384	2,394	2,595	2,614	2,977	3,036	2,971	3,667	3,456	3,341	3,396	3,478	3,724
TURNER 4	3,034	1,958	2,144	1,892	1,883	1,930	2,038	2,082	2,405	2,406	2,463	2,991	2,756	2,678	2,706	2,839	3,025
U OF FL 1	19,044	18,533	30,970	32,335	32,766	31,666	35,083	35,565	39,258	40,995	43,259	42,416	46,121	46,544	45,341	48,446	49,224
CT, Total	276,737	218,214	255,401	256,167	256,767	253,083	272,426	273,813	305,374	305,703	315,490	344,844	349,792	339,211	346,282	355,257	372,143
C P & Lime	48,873	49,223															
Econpurc offp	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017	24,017
Econpurc peak	49,009	48,852	48,822	48,453	48,453	48,453	48,453	48,453	48,453	48,453	48,453	49,200	48,453	48,453	48,453	48,453	48,453
Osceola 158 Purc	1,768																
OUC 150 Purc																	
Shady Hills	42,468	41,381	42,331	42,523	36,589	38,559	47,661	40,365	49,275	40,159	41,423	47,202	49,683	39,491	41,204	42,511	45,474
SoCo Franklin		62,572	111,675	111,849	99,496	94,517	101,477	90,140	102,821								
SoCo Scherer		16,096	27,765	27,947	27,964	27,870	28,305										
Southern UPS	143,902	60,089															
TEA 50 Purc																	
Teco Purc	27,849	23,450	3,951														
Tran-Purc, Total	337,887	325,681	258,561	254,790	236,520	233,415	249,912	202,976	224,566	112,629	113,893	120,418	122,153	111,961	113,674	114,981	117,944
As Avail	1,843	1,497	1,632	1,621	1,562	1,539	1,557	1,551	1,733	1,483	1,694	1,756	1,845	1,633	1,851	1,822	1,979
Auburn(As Avail)	3,214	2,489	2,583	2,566	2,581	2,473	2,656	2,617	2,963	2,670	3,057	3,028	3,203	2,932	3,220	3,317	3,480
Bay County																	
Biomass Energy	4,180	52,192	51,153	50,595	50,666	50,700	51,399	52,304	52,876	53,083	53,552	54,441	55,190	55,064	56,151	56,848	57,965
Cargill																	
Dade County	25,919	26,801	28,313	29,423	29,519	19,404	19,955	20,004	20,745	19,332	20,219	20,779	21,324	20,041	21,067	21,332	22,480
DTE Biomass	1,814	1,603	1,549	1,513	1,514	1,515	1,540	1,577	1,603	1,611	1,657	1,839	1,888	1,905	1,962	2,010	2,071
El Dorado (APP)	52,835	55,548	57,940	60,674	63,193	37,350	38,250	39,055	40,520	39,347	40,938	41,827	42,752	41,788	43,809	44,183	45,938

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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
G2 Energy	3,840	3,870	3,899	3,925	3,944	3,962	3,986	4,025	4,041	4,022	4,063	4,092	4,115	4,097	5,299	5,342	5,609
Lake Cogen	54,516	57,451	60,027	62,943	52,395	34,221	35,136	35,526	36,977	35,733	37,485	38,282	38,905	38,215	39,861	40,498	42,034
Lake County	9,262	9,738	10,237	10,783	11,364	8,591	5,263	5,271	5,467	5,159	5,415	5,501	5,613	5,408	5,617	5,719	5,986
LFC (APP)	9,803	10,305	10,838	11,418	12,031	6,122	6,299	6,381	6,608	6,395	6,698	6,829	6,982	6,775	7,104	7,186	7,506
Mulberry	47,724	50,247	52,582	55,117	57,629	60,352	63,228	66,207	69,283	72,456	75,892	79,466	83,128	86,985	91,150	75,065	35,345
Orange Cogen	42,603	44,806	46,808	46,103	48,113	50,259	52,560	54,889	57,340	59,633	62,451	65,274	68,156	71,006	74,418	77,777	81,488
Orlando Cogen	52,929	55,018	57,356	59,952	62,317	64,791	67,363	70,023	72,705	75,504	78,461	81,575	84,630	88,094	91,649	43,691	45,900
Pasco Cogen	47,203	42,505	43,862	43,887	43,300	42,670	43,721	43,965	45,751	43,309	45,342	46,284	47,502	45,742	47,699	48,270	50,577
Pasco County	17,447	18,303	19,223	20,215	21,271	22,322	23,485	24,710	26,053	27,336	28,852	30,482	32,169	33,749	35,696	37,736	12,323
Pinellas County	39,623	41,660	43,819	46,150	48,646	51,156	53,905	56,838	59,987	63,040	66,647	70,479	74,524	78,317	82,895	87,696	25,091
Ridge Gen St	18,878	19,438	19,769	20,136	20,316	20,570	20,832	21,110	21,346	21,502	21,732	22,005	22,200	22,396	22,701	18,424	19,399
Royster	16,476	11,187	11,309	11,378	11,338	11,199	11,479	11,650	12,084	11,692	12,231	12,490	12,729	12,423	13,014	13,160	13,745
Cogen, Total	450,111	504,659	522,897	538,401	541,699	489,195	502,613	517,703	538,083	543,307	566,387	586,428	606,856	616,570	645,162	590,076	478,917
NH3	3,612	4,062	4,115	3,909	5,139	5,870	6,324	7,929	7,801	7,648	7,662	7,744	8,023	7,316	7,545	7,783	7,772
CaCO3	1,098	10,378	10,947	10,775	14,342	16,691	18,279	23,114	23,110	23,022	23,397	24,062	25,325	23,429	24,532	25,716	26,059
Total Cost	**3,213,541**	**2,890,494**	**3,174,253**	**3,315,637**	**3,293,139**	**3,220,061**	**3,420,826**	**3,441,395**	**3,729,543**	**3,396,723**	**3,690,111**	**3,912,987**	**4,105,339**	**3,736,383**	**3,965,711**	**4,030,282**	**4,174,266**

Ruth. According to my understanding after talking to Lisa Bennett, Exhibits 20, 23 & 25 were not marked or admitted during the hearing & are not part of the record.

LB

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 23
COMPANY Not Admitted
WITNESS See above
DATE note

EXHIBIT NO. ___________

DOCKET NO: 070052-EI

WITNESS: VARIOUS

PARTY: PROGRESS ENERGY FLORIDA, INC.

DESCRIPTION: STAFF'S EXHIBIT

DOCUMENTS:

Late Filed Exhibit (No. 2) of July 24, 2007 deposition of Javier Portuondo in Docket Number 070052.

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 24
COMPANY FPSC Staff
WITNESS Deferred Tax Impact of Different Recovery Period
DATE 08/07-08/07

Deferred Tax Impact of Different Recovery Periods

	Impact to Base Rates	Base Rate Impact on WACC	Notes
Recoverable Life > Tax Life	Favorable	Decrease	
Recoverable Life < Tax Life	Detrimental	Increase	(1)
Recoverable Life = Tax Life	No Significant Impact	No Significant Impact	(2)

Notes:

(1) This is generally the case, however, if there is a base rate case in the first year the asset goes in-service, the impact may be favorable due to regulatory lag.

(2) There will be a slight difference between the the straight line book vs. MACRS tax depreciation rates. This difference is very small and at some points will have a favorable impact on rates and at other times a detrimental impact.

Ruth. According to my understanding after talking to Lisa Bennett, Exhibits 20, 23 & 25 were not marked or admitted during the hearing & are not part of the record.

LB

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 25
COMPANY Not Admitted
WITNESS See above note
DATE

EXHIBIT NO. __________

DOCKET NO: 070052-EI

WITNESS: VARIOUS

PARTY: PROGRESS ENERGY FLORIDA, INC.

DESCRIPTION: STAFF'S EXHIBIT

DOCUMENTS:

Progress Energy Florida's 2006 Ten Year Site Plan.

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 26
COMPANY PEF
WITNESS 2006 10-Year Site Plan
DATE 08/07-08/07

Progress Energy Florida
Ten-Year Site Plan

April 2006

2006-2015

Submitted to:
Florida Public Service Commission

Progress Energy

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CHAPTER 3 <u>FORECAST OF FACILITIES REQUIREMENTS</u>

CHAPTER 4 <u>ENVIRONMENTAL AND LAND USE INFORMATION</u>

LIST OF
REQUIRED SCHEDULES

LIST OF
TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine
CT - Combustion Turbine
CC - Combined cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

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

Future Generating Unit Status

A - Generating unit capability increased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

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INTRODUCTION

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

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

The TYSP document contains four chapters as described below:

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 2

FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

Progress Energy

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

PEF is a wholly owned subsidiary of Progress Energy, Inc. (Progress Energy). Congress enacted legislation in 2005 repealing the Public Utilities Holding Company Act of 1935 (PUCHA) effective February 8, 2006. Subsequent to that date, Progress Energy is no longer subject to regulation by the Securities and Exchange Commission as a public utility holding company. Progress Energy is the parent company of PEF and certain other subsidiaries.

AREA OF SERVICE

PEF provided electric service during 2005 to an average of 1.6 million customers in Florida. Its service area covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 22 municipal and 9 rural electric cooperative systems. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) and the FPSC. PEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The PEF transmission system includes approximately 5,000 circuit miles of transmission lines. The distribution system includes approximately 35,000 circuit miles, with approximately 13,000 of those miles underground. A map of the Electric System can be found in Figure 1.2.

ENERGY MANAGEMENT

PEF customers participating in the company's residential Energy Management program help to manage future growth and costs. Approximately 345,000 customers participated in the Energy Management program at the end of 2005, contributing about 700,000 kW of winter peak-shaving capacity for use during high load periods.

TOTAL CAPACITY RESOURCE

As of December 31, 2005, PEF had total summer capacity resources of approximately 10,413 MW consisting of installed capacity of 8,976 MW (excluding Crystal River 3 joint ownership) and 1,437 MW of firm purchased power. Additional information on PEF's existing generating resources is shown on Schedule 1 and Table 3.1.

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map

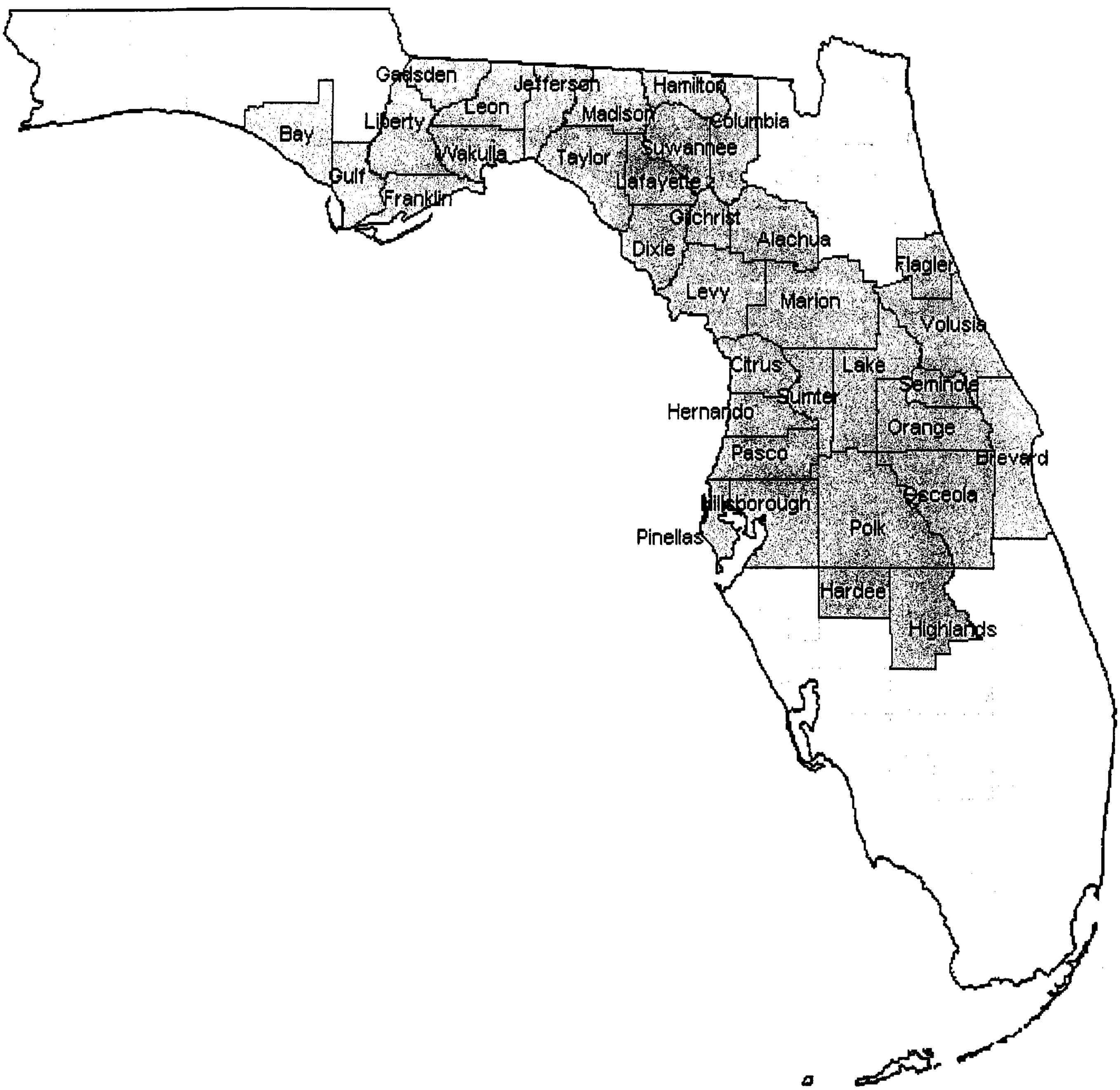
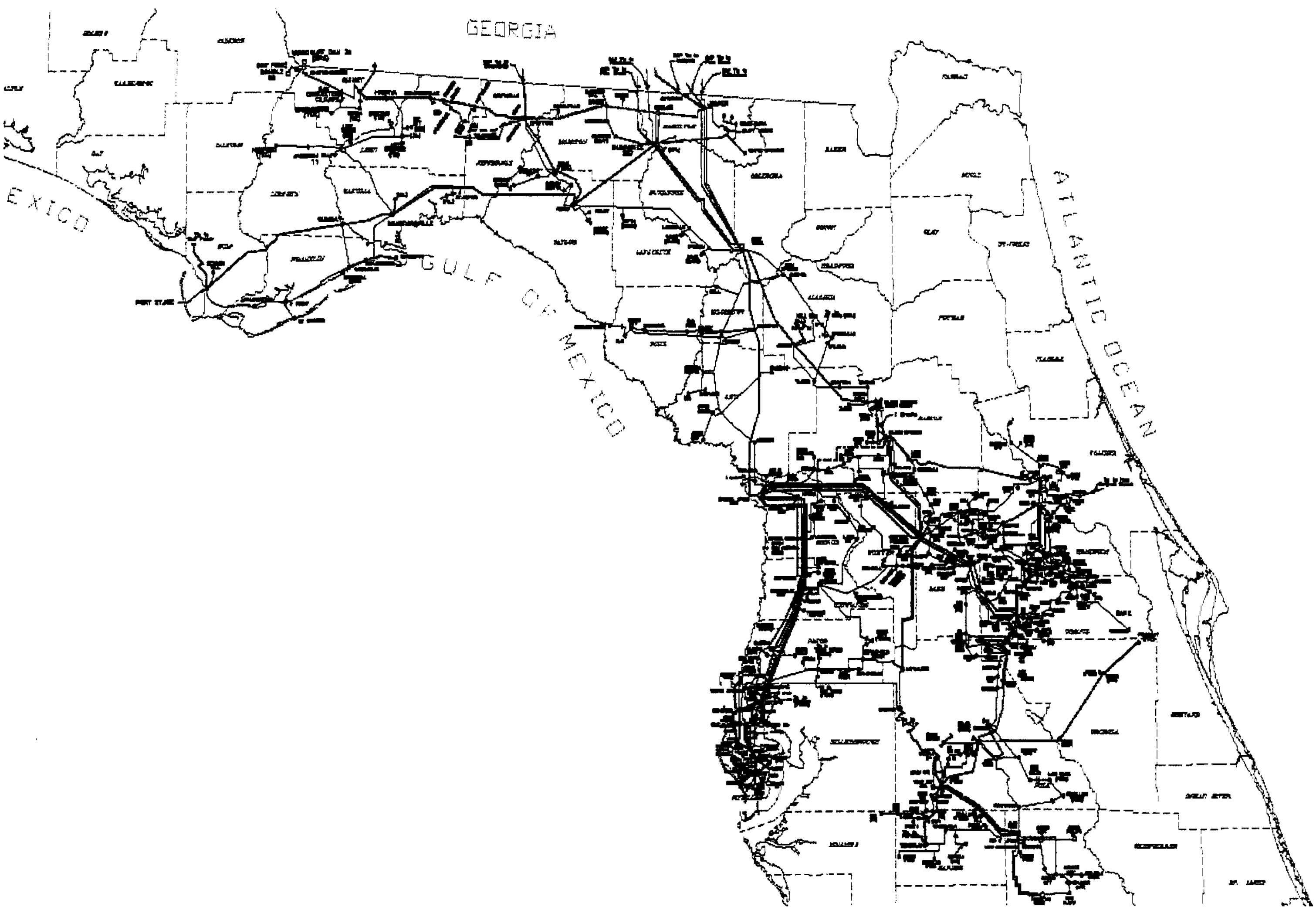


FIGURE 1.2

PROGRESS ENERGY FLORIDA

Electric System Map



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

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

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

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

PEF's customer growth is expected to average 1.7 percent between 2006 and 2015, less than the ten-year historical average of 2.3 percent. The ten-year historical growth rate falls to 2.0 percent when accounting for the creation of PEF's Seasonal Service Rate tariff, which artificially inflates customer growth figures. Slower population growth - based on the latest projection from the University of Florida's Bureau of Economic and Business Research – and economic conditions less favorable for the housing/construction industry (higher interest rates) result in a lower base case customer projection when compared to the higher historical growth rate. This translates into lower projected energy and demand growth rates from historic rate levels.

Net energy for load (NEL), which had grown at an average of 3.4 percent between 1996 and 2005, is expected to increase by 2.6 percent per year from 2006-2015 in the base case, 2.8 percent in the high case and 2.3 percent in the low case. A lower contribution from the wholesale jurisdiction, which grew an average of 10.7 percent between 1996 and 2005, results in lower expected system growth going forward than the historic rate. Retail NEL, which grew at a

2.7 percent average rate historically, is expected to grow 2.5 percent over the next ten years. Wholesale NEL is expected to average 3.3 percent between 2006 and 2015.

Summer net firm demand is expected to grow an average of 2.6 percent per year during the next ten years. This compares to the 4.5% growth rate experienced throughout the last ten years. Again, lower contribution from the wholesale jurisdiction is expected going forward. High and low summer growth rates for net firm demand are 2.9 percent and 2.3 percent per year, respectively. Winter net firm demand is projected to grow at 2.8 percent per year after having increased by 0.3 percent per year from 1996 to 2005. The low historical growth figure is driven by an extreme weather peak day in 1996. High and low winter net firm demand growth rates are 3.1 percent and 2.6 percent, respectively.

Summer net firm retail demand is expected to grow an average of 2.5 percent per year during the next ten years; this compares to the 4.7 percent average annual growth rate experienced throughout the last ten years. The historical growth percentage is driven by an extremely hot 2005 peak day condition. High and low summer growth rates for net firm retail demand are 2.8 percent and 2.2 percent per year, respectively. Winter net firm retail demand is projected to grow at approximately 2.1 percent per year after having grown by 0.4% from 1996 to 2005. Again, an extremely cold 1996 peak day causes this anomaly. High and low winter net firm retail demand growth rates are 2.5 percent and 1.8 percent, respectively.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1.1, 3.1.2 and 3.1.3	History and Forecast of Base, High and Low Summer Peak Demand (MW)
3.2.1, 3.2.2 and 3.2.3	History and Forecast of Base, High, and Low Winter Peak Demand (MW)
3.3.1, 3.3.2 and 3.3.3	History and Forecast of Base, High and Low Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1996	2,847,802	2.494	15,481	1,141,671	13,560	8,848	129,440	68,356
1997	2,895,266	2.495	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,959,509	2.502	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,047,293	2.511	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,044,449	2.467	17,116	1,234,286	13,867	10,813	143,475	75,368
2001	3,141,867	2.465	17,604	1,274,672	13,810	11,061	146,983	75,251
2002	3,207,661	2.465	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,286,782	2.468	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,348,630	2.454	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,425,783	2.452	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,473,481	2.447	20,187	1,419,449	14,222	11,899	163,107	72,952
2007	3,530,429	2.441	20,731	1,446,239	14,334	12,292	166,477	73,836
2008	3,585,407	2.435	21,244	1,472,551	14,427	12,725	169,784	74,947
2009	3,639,074	2.428	21,789	1,498,885	14,537	13,155	173,090	75,998
2010	3,690,763	2.420	22,316	1,524,944	14,634	13,559	176,360	76,880
2011	3,740,415	2.412	22,839	1,550,477	14,730	13,966	179,611	77,759
2012	3,788,512	2.404	23,353	1,575,780	14,820	14,370	182,781	78,618
2013	3,835,918	2.396	23,882	1,600,906	14,918	14,785	185,927	79,519
2014	3,883,825	2.389	24,411	1,625,899	15,014	15,204	189,055	80,419
2015	3,932,139	2.382	24,949	1,650,873	15,113	15,629	192,181	81,323

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1996	4,224	2,927	1,443,116	0	26	2,205	30,784
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,957
2004	4,069	2,733	1,488,840	0	28	3,016	38,193
2005	4,140	2,703	1,531,632	0	27	3,171	39,178
2006	4,152	2,687	1,545,218	0	28	3,209	39,475
2007	4,213	2,687	1,567,920	0	28	3,327	40,591
2008	4,383	2,687	1,631,187	0	28	3,436	41,816
2009	4,416	2,687	1,643,469	0	28	3,547	42,935
2010	4,453	2,687	1,657,239	0	28	3,651	44,006
2011	4,491	2,687	1,671,381	0	28	3,756	45,081
2012	4,539	2,687	1,689,245	0	28	3,861	46,150
2013	4,579	2,687	1,704,131	0	28	3,968	47,241
2014	4,622	2,687	1,720,134	0	28	4,076	48,341
2015	4,662	2,687	1,735,020	1	28	4,186	49,456

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
1996	2,089	1,842	34,715	18,035	1,292,073
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,004	1,400,299
2001	3,839	1,831	40,933	20,752	1,444,958
2002	3,173	2,534	42,567	21,155	1,475,783
2003	3,359	2,595	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,505	46,878	22,701	1,583,417
2006	4,038	2,654	46,167	23,160	1,608,403
2007	4,430	2,739	47,759	23,719	1,639,122
2008	4,410	2,850	49,076	24,279	1,669,301
2009	4,323	2,890	50,148	24,837	1,699,499
2010	4,958	3,042	52,006	25,388	1,729,379
2011	5,083	3,055	53,219	25,933	1,758,708
2012	5,159	3,125	54,434	26,474	1,787,722
2013	5,263	3,199	55,704	27,008	1,816,528
2014	5,343	3,265	56,948	27,537	1,845,178
2015	5,419	3,337	58,211	28,059	1,873,800

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS
1996	7,470	828	6,642	309	565	69	41	120	167
1997	7,786	874	6,912	288	555	78	41	131	170
1998	8,367	943	7,424	291	438	97	42	142	182
1999	9,039	1,326	7,713	292	505	113	45	153	183
2000	8,911	1,319	7,592	277	455	127	48	155	75
2001	8,841	1,117	7,724	283	414	139	54	156	75
2002	9,421	1,203	8,218	305	390	153	43	159	75
2003	8,886	887	7,999	300	347	172	44	164	75
2004	9,554	1,071	8,483	531	283	188	37	166	75
2005	10,316	1,118	9,198	393	250	203	38	167	75
2006	9,915	1,105	8,810	419	228	214	39	169	75
2007	10,226	1,181	9,044	431	202	223	40	171	75
2008	10,487	1,223	9,264	437	179	232	41	172	75
2009	10,676	1,201	9,475	433	158	241	42	174	75
2010	11,039	1,357	9,681	424	140	250	43	176	75
2011	11,260	1,372	9,888	425	124	259	45	177	75
2012	11,487	1,396	10,091	426	109	269	46	179	75
2013	11,699	1,406	10,293	427	97	279	47	180	75
2014	11,921	1,429	10,492	428	86	289	48	182	75
2015	12,139	1,446	10,693	429	76	293	48	183	75

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS
1996	7,470	828	6,642	309	565	69	41	120	167
1997	7,786	874	6,912	288	555	78	41	131	170
1998	8,367	943	7,424	291	438	97	42	142	182
1999	9,039	1,326	7,713	292	505	113	45	153	183
2000	8,911	1,319	7,592	277	455	127	48	155	75
2001	8,841	1,117	7,724	283	414	139	54	156	75
2002	9,421	1,203	8,218	305	390	153	43	159	75
2003	8,886	887	7,999	300	347	172	44	164	75
2004	9,554	1,071	8,483	531	283	188	37	166	75
2005	10,316	1,118	9,198	393	250	203	38	167	75
2006	10,083	1,105	8,977	419	228	214	39	169	75
2007	10,413	1,181	9,232	431	202	223	40	171	75
2008	10,699	1,223	9,476	437	179	232	41	172	75
2009	10,913	1,201	9,712	433	158	241	42	174	75
2010	11,294	1,357	9,937	424	140	250	43	176	75
2011	11,531	1,372	10,159	425	124	259	45	177	75
2012	11,798	1,396	10,402	426	109	269	46	179	75
2013	12,059	1,406	10,653	427	97	279	47	180	75
2014	12,320	1,429	10,891	428	86	289	48	182	75
2015	12,615	1,446	11,169	429	76	293	48	183	75

Historical Values (*1996 - 2005*):

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

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

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

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

Projected Values (2006 - 2015):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS
1996	7,470	828	6,642	309	565	69	41	120	167
1997	7,786	874	6,912	288	555	78	41	131	170
1998	8,367	943	7,424	291	438	97	42	142	182
1999	9,039	1,326	7,713	292	505	113	45	153	183
2000	8,911	1,319	7,592	277	455	127	48	155	75
2001	8,841	1,117	7,724	283	414	139	54	156	75
2002	9,421	1,203	8,218	305	390	153	43	159	75
2003	8,886	887	7,999	300	347	172	44	164	75
2004	9,554	1,071	8,483	531	283	188	37	166	75
2005	10,316	1,118	9,198	393	250	203	38	167	75
2006	9,747	1,105	8,641	419	228	214	39	169	75
2007	10,056	1,181	8,875	431	202	223	40	171	75
2008	10,293	1,223	9,070	437	179	232	41	172	75
2009	10,473	1,201	9,272	433	158	241	42	174	75
2010	10,788	1,357	9,431	424	140	250	43	176	75
2011	10,975	1,372	9,603	425	124	259	45	177	75
2012	11,162	1,396	9,766	426	109	269	46	179	75
2013	11,332	1,406	9,926	427	97	279	47	180	75
2014	11,521	1,429	10,092	428	86	289	48	182	75
2015	11,670	1,446	10,224	429	76	293	48	183	75

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201
1996/97	8,486	1,235	7,251	290	917	133	16	104	190
1997/98	7,752	941	6,811	318	663	164	17	112	168
1998/99	10,473	1,741	8,732	305	874	196	18	117	187
1999/00	10,040	1,728	8,312	225	849	229	20	119	182
2000/01	11,450	1,984	9,466	255	809	254	29	120	194
2001/02	10,676	1,624	9,052	285	770	278	24	121	188
2002/03	11,555	1,538	10,017	271	768	313	27	124	201
2003/04	9,290	1,167	8,123	498	761	343	24	125	227
2004/05	10,798	1,602	9,196	350	725	371	26	125	247
2005/06	10,987	1,413	9,574	430	696	405	28	127	254
2006/07	11,525	1,740	9,786	426	671	429	30	128	258
2007/08	11,750	1,734	10,016	444	649	453	31	130	262
2008/09	12,113	1,894	10,220	440	631	479	33	132	265
2009/10	12,514	2,088	10,426	432	615	506	35	133	269
2010/11	12,742	2,112	10,629	434	603	534	37	135	272
2011/12	13,019	2,191	10,828	435	593	566	38	136	276
2012/13	13,278	2,253	11,025	436	586	597	40	138	279
2013/14	13,537	2,314	11,223	437	581	628	42	139	282
2014/15	13,776	2,358	11,418	438	577	660	42	141	285

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201
1996/97	8,486	1,235	7,251	290	917	133	16	104	190
1997/98	7,752	941	6,811	318	663	164	17	112	168
1998/99	10,473	1,741	8,732	305	874	196	18	117	187
1999/00	10,040	1,728	8,312	225	849	229	20	119	182
2000/01	11,450	1,984	9,466	255	809	254	29	120	194
2001/02	10,676	1,624	9,052	285	770	278	24	121	188
2002/03	11,555	1,538	10,017	271	768	313	27	124	201
2003/04	9,290	1,167	8,123	498	761	343	24	125	227
2004/05	10,798	1,602	9,196	350	725	371	26	125	247
2005/06	11,167	1,413	9,755	430	696	405	28	127	254
2006/07	11,725	1,740	9,986	426	671	429	30	128	258
2007/08	11,975	1,734	10,240	444	649	453	31	130	262
2008/09	12,364	1,894	10,470	440	631	479	33	132	265
2009/10	12,785	2,088	10,697	432	615	506	35	133	269
2010/11	13,026	2,112	10,913	434	603	534	37	135	272
2011/12	13,345	2,191	11,154	435	593	566	38	136	276
2012/13	13,656	2,253	11,403	436	586	597	40	138	279
2013/14	13,954	2,314	11,640	437	581	628	42	139	282
2014/15	14,272	2,358	11,914	438	577	660	42	141	285

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201
1996/97	8,486	1,235	7,251	290	917	133	16	104	190
1997/98	7,752	941	6,811	318	663	164	17	112	168
1998/99	10,473	1,741	8,732	305	874	196	18	117	187
1999/00	10,040	1,728	8,312	225	849	229	20	119	182
2000/01	11,450	1,984	9,466	255	809	254	29	120	194
2001/02	10,676	1,624	9,052	285	770	278	24	121	188
2002/03	11,555	1,538	10,017	271	768	313	27	124	201
2003/04	9,290	1,167	8,123	498	761	343	24	125	227
2004/05	10,798	1,602	9,196	350	725	371	26	125	247
2005/06	10,806	1,413	9,394	430	696	405	28	127	254
2006/07	11,344	1,740	9,605	426	671	429	30	128	258
2007/08	11,542	1,734	9,807	444	649	453	31	130	262
2008/09	11,897	1,894	10,003	440	631	479	33	132	265
2009/10	12,249	2,088	10,161	432	615	506	35	133	269
2010/11	12,441	2,112	10,328	434	603	534	37	135	272
2011/12	12,677	2,191	10,486	435	593	566	38	136	276
2012/13	12,894	2,253	10,641	436	586	597	40	138	279
2013/14	13,120	2,314	10,806	437	581	628	42	139	282
2014/15	13,290	2,358	10,932	438	577	660	42	141	285

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,250	445	363	564	39,177	5,195	2,506	46,878	52.3
2006	47,556	459	365	564	39,475	4,038	2,654	46,167	58.3
2007	49,165	474	368	564	40,591	4,430	2,738	47,759	56.9
2008	50,501	489	371	565	41,816	4,410	2,850	49,076	57.1
2009	51,590	504	374	564	42,935	4,323	2,890	50,148	56.5
2010	53,466	519	377	564	44,006	4,958	3,042	52,006	56.4
2011	54,699	536	380	564	45,081	5,083	3,055	53,219	56.6
2012	55,934	552	383	565	46,150	5,159	3,125	54,434	56.5
2013	57,222	568	386	564	47,242	5,263	3,199	55,704	56.8
2014	58,485	585	389	564	48,341	5,343	3,264	56,948	56.9
2015	59,749	585	389	564	49,455	5,419	3,337	58,211	57.1

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,250	445	363	564	39,177	5,195	2,506	46,878	52.3
2006	48,533	459	365	564	40,256	4,038	2,850	47,144	58.3
2007	50,099	474	368	564	41,464	4,430	2,799	48,693	56.8
2008	51,560	489	371	565	42,807	4,410	2,918	50,135	57.1
2009	52,777	504	374	564	44,047	4,323	2,965	51,335	56.4
2010	54,760	519	377	564	45,220	4,958	3,122	53,300	56.4
2011	56,076	536	380	564	46,369	5,083	3,144	54,596	56.6
2012	57,522	552	383	565	47,633	5,159	3,230	56,022	56.4
2013	59,068	568	386	564	48,970	5,263	3,317	57,550	56.7
2014	60,550	585	389	564	50,266	5,343	3,404	59,013	56.9
2015	62,217	585	389	564	51,768	5,419	3,492	60,679	57.1

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.2)

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,250	445	363	564	39,177	5,195	2,506	46,878	52.3
2006	46,765	459	365	564	38,666	4,038	2,672	45,376	58.4
2007	48,293	474	368	564	39,776	4,430	2,681	46,887	56.9
2008	49,496	489	371	565	40,873	4,410	2,788	48,071	57.2
2009	50,528	504	374	564	41,946	4,323	2,817	49,086	56.5
2010	52,169	519	377	564	42,793	4,958	2,958	50,709	56.4
2011	53,220	536	380	564	43,699	5,083	2,958	51,740	56.6
2012	54,242	552	383	565	44,566	5,159	3,017	52,742	56.5
2013	55,309	568	386	564	45,450	5,263	3,078	53,791	56.8
2014	56,389	585	389	564	46,383	5,343	3,126	54,852	56.9
2015	57,307	585	389	564	47,160	5,419	3,190	55,769	57.1

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.3)

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2005		FORECAST 2006		FORECAST 2007	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	10,226	3,582	9,047	3,566	9,584	3,724
FEBRUARY	7,398	3,106	6,992	3,133	7,455	3,273
MARCH	7,609	3,592	6,008	3,337	6,501	3,552
APRIL	7,011	3,283	6,970	3,284	7,467	3,438
MAY	8,478	3,923	8,025	4,041	8,511	4,190
JUNE	8,927	4,215	8,595	4,337	8,914	4,450
JULY	9,671	4,947	8,754	4,731	9,044	4,863
AUGUST	9,681	5,031	8,771	4,748	9,084	4,885
SEPTEMBER	9,090	4,461	8,184	4,308	8,488	4,433
OCTOBER	8,301	3,968	7,692	3,837	7,963	3,952
NOVEMBER	6,424	3,215	6,282	3,267	6,573	3,347
DECEMBER	7,772	3,555	7,767	3,578	7,860	3,652
TOTAL		46,878		46,167		47,759

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel units) are shown on Schedule 5. PEF's two-year actual and ten-year projected energy sources, in GWh and percent, are shown by fuel type on Schedules 6.1 and 6.2, respectively. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one-fuel source. In the near term, natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth. The proportion of energy provided by natural gas will decrease with the addition of new coal resources toward the latter years of the ten-year planning horizon.

PROGRESS ENERGY FLORIDA

SCHEDULE 5

FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	NUCLEAR		TRILLION BTU	69	60	65	62	68	52	68	63	68	63	68	63
(2)	COAL		1,000 TON	5,915	6,249	5,877	6,083	5,872	6,045	6,690	6,766	6,648	7,882	9,588	10,374
(3)	RESIDUAL	TOTAL	1,000 BBL	10,864	10,324	7,658	8,219	8,055	5,379	2,935	2,951	3,101	2,677	2,605	2,443
(4)		STEAM	1,000 BBL	10,864	10,324	7,658	8,219	8,055	5,379	2,935	2,951	3,101	2,677	2,605	2,443
(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	1,019	1,098	1,255	1,204	1,144	1,116	1,063	1,078	1,056	1,027	1,003	1,040
(9)		STEAM	1,000 BBL	152	97	50	43	47	41	48	50	56	59	57	65
(10)		CC	1,000 BBL	2	3	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	865	998	1,205	1,161	1,098	1,074	1,016	1,028	1,000	969	946	974
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	62,674	68,447	86,145	91,824	103,618	132,457	145,075	170,627	177,247	170,540	152,332	151,001
(14)		STEAM	1,000 MCF	1,071	732	0	0	0	0	10,335	10,290	10,921	9,127	9,091	8,801
(15)		CC	1,000 MCF	45,816	52,590	67,698	73,841	85,931	114,696	118,175	143,499	149,403	145,137	127,210	126,012
(16)		CT	1,000 MCF	15,787	15,125	18,447	17,983	17,687	17,760	16,566	16,838	16,923	16,276	16,031	16,187
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	N/A	N/A	0	0	1	12	4	15	0	0	0	0
(18)	OTHER, NATURAL GA	ANNUAL FIRM INTERCHANGE,	1,000 MCF	N/A	N/A	0	0	0	0	4,953	7,856	7,716	6,931	5,502	4,999
(18)	OTHER, NATURAL GA	ANNUAL FIRM INTERCHANGE,	1,000 MCF	N/A	N/A	672	3,061	1,923	1,314	1,396	1,697	2,049	1,290	915	538

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	417	2,220	1,371	1,690	1,563	1,495	2,596	1,958	1,899	1,694	1,418	1,303
(2)	NUCLEAR		GWh	6,703	5,829	6,307	6,052	6,655	5,089	6,636	6,143	6,655	6,143	6,636	6,144
(3)	COAL		GWh	15,063	15,834	15,058	15,602	15,024	15,353	16,583	16,792	16,495	19,904	24,645	26,816
(4)	RESIDUAL	TOTAL	GWh	6,981	6,618	4,696	5,081	4,956	3,291	1,794	1,802	1,902	1,623	1,583	1,483
(5)		STEAM	GWh	6,981	6,618	4,696	5,081	4,956	3,291	1,794	1,802	1,902	1,623	1,583	1,483
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	361	414	430	415	390	385	362	368	356	345	336	345
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	2	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	359	414	430	415	390	385	362	368	356	345	336	345
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	7,516	8,236	10,123	10,867	12,471	16,515	18,077	21,662	22,621	21,711	19,180	19,008
(15)		STEAM	GWh	106	74	0	0	0	0	1,023	1,019	1,085	898	895	861
(16)		CC	GWh	6,227	7,025	8,786	9,565	11,182	15,188	15,827	19,394	20,267	19,603	17,094	16,937
(17)		CT	GWh	1,183	1,137	1,337	1,302	1,290	1,327	1,227	1,249	1,269	1,210	1,191	1,209
(18)	OTHER 2/														
	QF PURCHASES		GWh	4,685	4,211	4,650	4,528	4,496	4,485	4,492	4,494	4,506	4,284	3,151	3,112
	IMPORT FROM OUT OF STATE		GWh	3,862	3,599	3,532	3,525	3,521	3,535	1,466	0	0	0	0	0
	EXPORT TO OUT OF STATE		GWh	-320	-83	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	45,268	46,878	46,167	47,759	49,076	50,148	52,006	53,219	54,434	55,704	56,948	58,211

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

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

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	ANNUAL FIRM INTERCHANGE 1/		%	0.9%	4.7%	3.0%	3.5%	3.2%	3.0%	5.0%	3.7%	3.5%	3.0%	2.5%	2.2%
(2)	NUCLEAR		%	14.8%	12.4%	13.7%	12.7%	13.6%	10.1%	12.8%	11.5%	12.2%	11.0%	11.7%	10.6%
(3)	COAL		%	33.3%	33.8%	32.6%	32.7%	30.6%	30.6%	31.9%	31.6%	30.3%	35.7%	43.3%	46.1%
(4)	RESIDUAL	TOTAL	%	15.4%	14.1%	10.2%	10.6%	10.1%	6.6%	3.5%	3.4%	3.5%	2.9%	2.8%	2.5%
(5)		STEAM	%	15.4%	14.1%	10.2%	10.6%	10.1%	6.6%	3.5%	3.4%	3.5%	2.9%	2.8%	2.5%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.8%	0.9%	0.9%	0.9%	0.8%	0.8%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.8%	0.9%	0.9%	0.9%	0.8%	0.8%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	16.6%	17.6%	21.9%	22.8%	25.4%	32.9%	34.8%	40.7%	41.6%	39.0%	33.7%	32.7%
(15)		STEAM	%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	2.0%	1.9%	2.0%	1.6%	1.6%	1.5%
(16)		CC	%	13.8%	15.0%	19.0%	20.0%	22.8%	30.3%	30.4%	36.4%	37.2%	35.2%	30.0%	29.1%
(17)		CT	%	2.6%	2.4%	2.9%	2.7%	2.6%	2.6%	2.4%	2.3%	2.3%	2.2%	2.1%	2.1%
(18)	OTHER 2/														
	QF PURCHASES		%	10.3%	9.0%	10.1%	9.5%	9.2%	8.9%	8.6%	8.4%	8.3%	7.7%	5.5%	5.3%
	IMPORT FROM OUT OF STATE		%	8.5%	7.7%	7.7%	7.4%	7.2%	7.0%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	-0.7%	-0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

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

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric energy usage over the planning horizon. PEF's forecasting framework utilizes a set of econometric models to achieve this end. This chapter will describe the underlying methodology of the customer, energy, and peak demand forecasts including any assumptions incorporated within each. Also included is a description of how Demand-Side Management (DSM) impacts the forecast, the development of high and low forecast scenarios and a review of DSM programs.

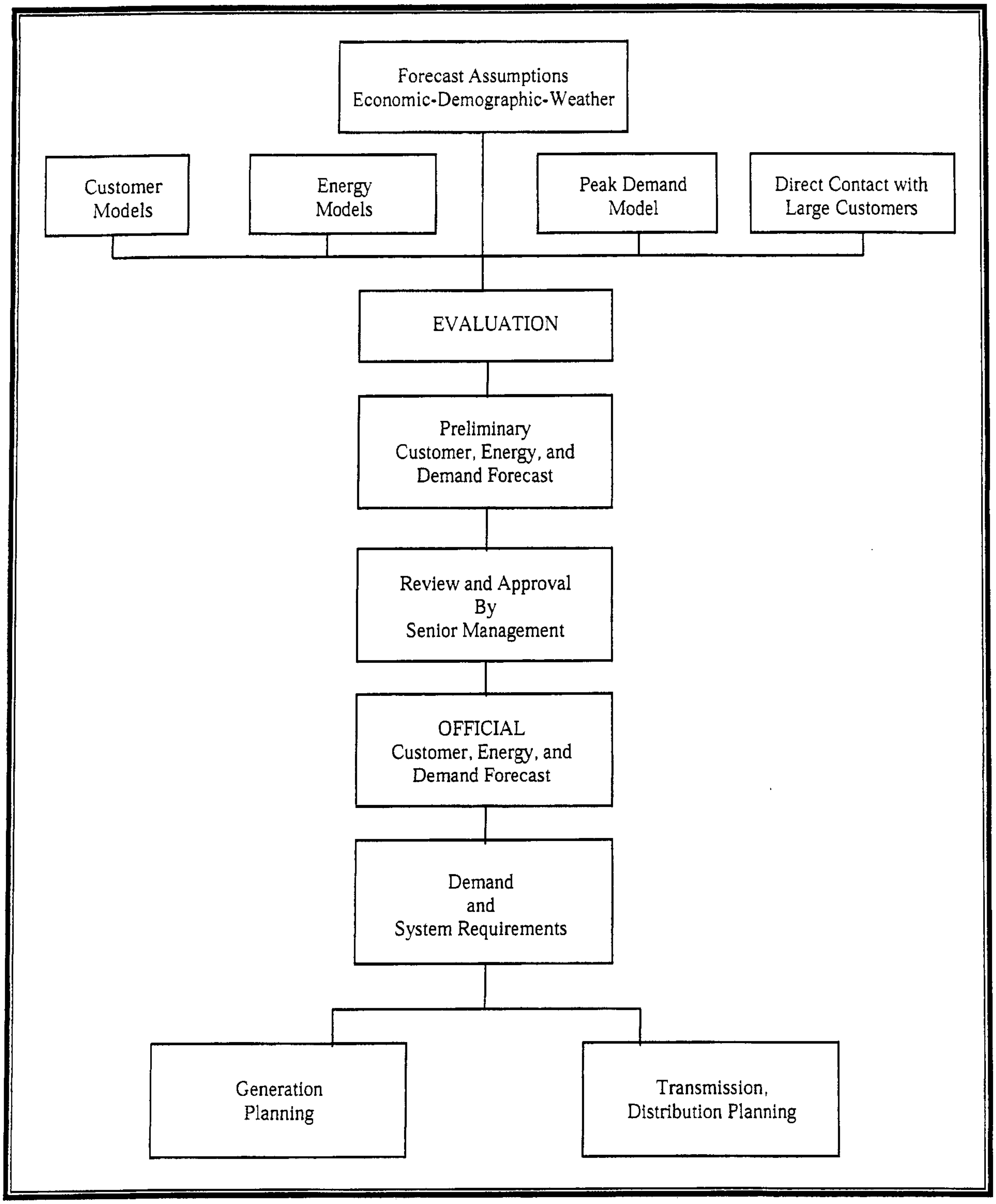
Figure 2.1, entitled "Customer, Energy and Demand Forecast", gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage as well as customer growth based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Corporate Planning Department develops these assumptions based on discussions with a number of departments within PEF, 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 forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions are assumed over the forecast horizon using a sales-weighted average of conditions at the St. Petersburg, Orlando and Tallahassee weather stations. For kilowatt-hour sales projections, normal weather is based on a historical thirty-year average of service area weighted billing month degree-days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak.

2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 141 (February 2005) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (February 2005) are also incorporated.

3. Within the PEF service area the phosphate mining industry is the dominant sector in the industrial sales class. Four major customers accounted for nearly 31% of the industrial class MWh sales in 2005. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by the state of these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions. A weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer producers becoming more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase – as we have recently experienced - to the levels just below that experienced in the late 1990 boom period. A significant risk to this projection lies in the continued high price of natural gas, which is a major cost of production.

Operations at several sites in the U.S. have already scaled back or shutdown due to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

4. PEF supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Contracts for this service include the cities of Bartow, Chattahoochee, Mt. Dora, Quincy, Williston and Winter Park. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations received by PEF as of May 31, 2005. The forecast of energy and demand to PR customers reflects the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Florida Municipal Power Agency (FMPA), New Smyrna Beach, Tallahassee, Homestead, Reedy Creek Utilities, TECO Energy (Market Mitigation Sale) and Seminole Electric Cooperative, Inc. (SECI). PEF's contractual arrangement with SECI includes a "supplemental" service contract (1983 contract) for service over and above stated levels they commit to supply themselves. The firm PR contract with SECI includes 150 MW of stratified intermediate service (October 1995 contract) which is projected to continue through the forecast horizon. The firm PR contract with SECI also includes amendments to provide an additional 150 MW of stratified intermediate service beginning June 2006, and another 150 MW beginning December 2006. Agreements to provide interruptible service at three individual SECI metering sites have also been included in this projection. Finally, a FR contract to serve SECI load will commence in 2010 and last through the forecast horizon.

5. This forecast assumes that PEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions from PEF's dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the FPSC.

7. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the company does not plan for generation resources unless a long-term contract is in place. Current FR customers are assumed to renew their contracts with PEF except those who have given notice to terminate. Current PR contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur based on information provided by the Regulated Commercial Operations Department.

SHORT-TERM ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in 2005 as energy prices were hitting record highs around the world. The general consensus was that the U.S. economy, which was growing at a reasonable rate, would not slip into recession due to the higher cost of energy. A described "soft patch" in economic activity apparent at the time of this forecast development as high gasoline prices had been reducing consumer confidence levels. Short term interest rates, controlled mostly by Federal Reserve Board (FED) policy decisions, have increased significantly in the last 12 months as hints of inflation have filtered through the reported price indexes. The days of 45-plus year lows in interest rates have ended. The FED had moved to increase rates ten times at this point – no longer seeing the need to stimulate the national economy from the post September 11th weakness that occurred. The national economy had bounced back significantly (except for job growth statistics). Economists were not in complete agreement about where monetary policy would go from here. Most thought that the FED was much closer to ending its "tightening" policy of gradually raising interest rates than those who believed that inflationary fears would require many more rate increases.

Consensus opinion believes that the economic stimulus supplied by the three federal tax cuts and the refinancing boom have pretty much run their course. Additional stimulus from these two phenomena is not expected going forward. One item believed to become a positive factor for future economic momentum is the weaker U.S. currency. Up to this point it had not supplied the punch assumed in the last forecast. This is due to several major U.S. trading partners, mainly China, having their currencies pegged to the U.S. Dollar. The Mexican Peso has actually weakened against the Dollar. This has kept the typical advantages of a weaker currency from helping U.S. manufacturers. Also, European economies have not been robust enough to fuel added imports of U.S. products. Going forward, it is expected that economic and political pressures will force the Chinese to de-link their currency and allow it to appreciate in value. This likely will make American-produced products more competitive with imported Chinese goods around the globe.

The housing sector has continued on an unprecedented pace. Most signs, however, point to an industry that likely will not maintain this level of growth. Long term interest rates (and mortgage rates) have not increased at the same pace as short term rates allowing the momentum to continue. At some point the demand for housing pushed by new household formations will, in all likelihood, weaken. The demand for second homes could fall as interest rates finally rise.

The Florida economy has faired much better than the nation, especially in terms of job growth. The tourism industry, which has bounced back from the terrorism fears of 2001, will now have to juggle the impact of high oil prices on the travel industry.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. Many factors influence the pace of in-migration to Florida but there is one broad, demographically created influence one can expect during the next few years. The University of Florida's latest population projection (February 2005) shows a return to more normal levels of growth in Florida population as we move into the mid-decade. This is due to economy-related conditions as well as demographic conditions that measure population by age brackets. There will be a significant jump in the retirement-age population later this decade.

LONG-TERM ECONOMIC ASSUMPTIONS

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

Population Growth Trends

This forecast assumes Florida will experience slower in-migration and population growth over parts of 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 several reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Now that this generation is retiring, there exists a smaller pool of retirees capable of migrating to Florida. As we enter into the second decade of the new century and the baby-boom generation enters retirement age, the reverse effect can be expected.

Second, the enormous growth in population and corresponding development of the 1980s, 1990s and early 2000s made portions of Florida less desirable and less affordable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

Another reason for a population growth slowdown appears to be the fear and expense of Hurricanes. The summers of 2004 and 2005 may force some in-migrants to rethink their retirement location as the inconvenience caused by recent destruction and ever-increasing cost of hazard insurance makes Florida a less desirable place to live.

Economic Growth Trends

Florida has been recently experiencing a 1980s-style population explosion and service sector job creation. The State has benefited greatly from generational lows in interest rates, which along with investors' unfriendly attitude toward the equity markets, set the stage for a tremendous explosion in home construction. The national level of homebuilding in 2005, which rose to more than 31% higher than in 2000, set an all time record. This growth produced strong gains in both the construction industry and service-producing sectors of the Florida economy.

While most agree that this pace of growth is not sustainable, the economic environment that produced this construction boom has begun to wane. Interest rates are returning to more "long term" norms. Investment in equity markets appears to have bounced back of late. More importantly, affordability rates have dropped as housing prices in many parts of Florida have out-paced many areas of the country. This could have a major impact on retiree decisions to move into the area. Making matters worse is the availability and affordability of homeowners insurance, which has become a concern of increasing importance since the Hurricane seasons of 2004 and 2005.

Florida's rapid population growth of late has created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also a number of corporations migrating to Florida capitalizing on the low cost, low tax business environment. This being the case, 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 but at a less significant level. Florida's successful effort to attract a large biotech firm, Scripps Research, has the potential to draw a whole new growth industry to the State, the same way Disney and NASA once did.

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

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

FORECAST METHODOLOGY

The PEF forecast of customers, energy sales and peak demand is developed using customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, subtle changes in existing customer usage are better captured as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management and interruptible service.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and annual data for customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the 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. The external sources of data include Moody's Economy.Com and the University of Florida's Bureau of Economic and Business Research. Internal company forecasts are used for projections of electricity price, weather conditions and the length of the billing month. Normal weather, which is assumed throughout the forecast horizon, is based on the 30-year average of heating and cooling degree-days by month as measured at the St Petersburg, Orlando and Tallahassee weather stations. Projections of PEF's demand-side management (conservation programs) are also incorporated as reductions to the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real Florida personal income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures significant variation in residential usage caused by economic cycles, weather fluctuations, electric price movements and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual customer growth with PEF service area population growth and mortgage rates. County level population projections for the 29 counties, in which PEF serves residential customers, are provided by the BEBR.

Commercial Sector

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

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry comprises nearly a 30% share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment and a Florida industrial production index developed by Economy.Com, the real price of electricity to the industrial class, and the average number of sales month billing days.

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

Street Lighting

Electricity sales to the street and highway lighting class are projected to increase due to growth in the service area population base. Because this class comprised less than 0.01% of PEF's 2005 electric sales and just 0.1% of total customers, a simple time trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected to grow with the size of the service area. The level of government services, and thus energy use per customer, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will affect the need for additional governmental services (i.e., schools, city services, etc.) thereby increasing SPA energy usage per customer. 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, the real price of electricity and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Intercept shift variables are also included in this model to account for the large change in school-related energy use in the billing months of January, July and August. SPA customers are projected linearly as a function of a time-trend.

Sales for Resale Sector

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

SECI is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average of several years' historical load shape of total load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has an agreement with SECI to serve stratified intermediate and peaking energy. This agreement involves serving 150 MW of stratified intermediate demand that is assumed to remain a requirement on the PEF system throughout the forecast horizon. This contract has been amended to provide an additional 300 MW stratified intermediate product beginning in 2006. Energy usage under this contract is projected using typical intermediate strata load factors. Agreements to provide non-firm or interruptible service are currently in effect between PEF and SECI at three separate metering points amounting to an estimated 50 MW. Another contract, signed in 2004 to supply full requirements service for 150 MW, will begin in 2010.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Several of the customers in this class are municipalities whose full energy requirements are met by PEF. The full requirement customers are modeled individually using local weather station data and population growth trends. 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 PEF retail-based residential and commercial customer classes. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach (NSB), Homestead and Tallahassee, and other power providers like FMPA. In each case, these customers contract with PEF for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of the FMPA and NSB contracts are subject to change each year via a letter of "declared" MW nomination. More specifically, this means that the level and type of demand and energy under contract can increase or decrease for each year a value is nominated. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load. The energy projections for FMPA also include a "losses service contract" for energy PEF supplies to FMPA for transmission losses incurred when "wheeling" power to their ultimate customers in PEF's transmission area. This projection is based on the projected requirements of the aggregated needs of the cities of Ocala, Leesburg, Bushnell, Havana and Newberry.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, PEF's coincident system peak is dissected into five major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand and interruptible demand.

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

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been approved by the FPSC. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm retail demand resulting in a projected series of retail demand figures one would expect to occur.

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

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

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system peak demand is then calculated as the arithmetic sum of the five components.

HIGH AND LOW FORECAST SCENARIOS

The high and low bandwidth scenarios around the base MWh energy sales forecast are developed using a Monte Carlo simulation applied to a multivariate regression model that closely replicates the base retail MWh energy forecast in aggregate. This model accounts for variation in Gross Domestic

Product, retail customers and electricity price. The base forecasts for these variables were developed based on input from Economy.Com and internal company price projections. Variation around the base forecast predictor variables used in the Monte Carlo simulation was based on an 80 percent confidence interval calculated around variation in each variable's historic growth rate. While the total number of degree-days (weather) was also incorporated into the model specification, the high and low scenarios do not attempt to capture extreme weather conditions. Normal weather conditions were assumed in all three scenarios.

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

The low retail scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate probability of occurrence of 0.10. The high retail scenario similarly represents a bandwidth forecast with an approximate probability of occurrence of 0.90. 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

PEF's DSM performance is shown in the following tables, which compare the conservation savings actually achieved through PEF's DSM programs for the reporting year of 2005 with the Commission-approved conservations goals.

On August 9, 2004, the FPSC issued a PAA Order approving new conservation goals for PEF that span the ten-year period from 2005 through 2014 (in Docket 040031-EG, Order No. PSC-04-0769-PAA-EG). In that same PAA Order, the Commission also approved a new DSM Plan for PEF that was specifically designed to meet the new conservation goals. The PAA Order was subsequently made effective and final in a Consummating Order (PSC-04-0852-CO-EG) issued by the Commission on September 1, 2004.

Residential Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	13	18	43	48	21	29

Commercial Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	4	8	3	6	3	3

The forecasts contained in this Ten-Year Site Plan document are based on PEF's new DSM Plan and, therefore, appropriately reflect the level of DSM savings required to meet the Commission-established conservation goals. PEF's DSM Plan consists of five residential programs, seven commercial and industrial programs, and one research and development program. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all DSM resources are acquired in a cost-effective manner and that the program savings are durable. Following is a brief description of these programs.

RESIDENTIAL PROGRAMS

Home Energy Check Program

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit –A customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type

6: Home Energy Rating Audit (Class I, II, III). 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 energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement Program

This is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps.

Residential New Construction Program

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising.

Low Income Weatherization Assistance Program

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Residential Energy Management Program

This is a voluntary customer program that allows PEF 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 PEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated above 600 kWh/month.

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 facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of the following types of audits: A free walk-through audit, and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online at Progress Energy's website. 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 PEF and its customers. The Better Business Program promotes energy efficient heating, ventilation, air conditioning (HVAC), and some building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation and Energy Star cool roof coating products.)

Commercial/Industrial New Construction Program

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

Innovation Incentive Program

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for customers in PEF'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 PEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it will be eligible for an incentive payment, subject to PEF approval.

Commercial Energy Management Program (Rate Schedule GSLM-1)

This direct load control program reduces PEF's demand during peak or emergency conditions. As described in PEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants 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 existing participants 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). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

Standby Generation Program

This demand control program reduces PEF'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 PEF demand when PEF deems it necessary. The customers participating in the Standby Generation program receive a monthly credit on their electricity bills according to the demonstrated ability of the customer to reduce demand at PEF's request.

Interruptible Service Program

This direct load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for this ability to interrupt load, customers participating in the Interruptible Service program receive a monthly interruptible demand credit applied to their electric bills.

Curtailable Service

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

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development Program

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

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

Progress Energy

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 10,413 MW, as shown in Table 3.1. This capacity resource includes nuclear (769 MW), fossil steam (3,882 MW), combined cycle plants (1,706 MW), combustion turbine (2,619 MW, 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (617 MW), and non-utility purchased power (820 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QF's).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2006 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

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

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes 3,910 net MW (summer rating) of proposed new capacity additions through the summer of 2015. As identified in Schedule 8, PEF's next planned need is the Hines 4 Unit, a 461 MW (summer) power block with a December 2007 in-service date. PEF's self-build option for Hines Unit 4 was determined to be the most cost-effective alternative, followed by the Bartow Repowering Project to be completed by June 2009.

PEF's Base Expansion Plan projects requirements for additional units with proposed in-service dates of 2007 through 2015. These units, together with the Central Power & Lime Purchase (December 2005 through December 2010), the TEA purchase (from June through September 2006, December 2006 through February 2007, and June through September 2007), the Shady Hills Purchase (April 2007 through April 2014), and the Southern Company Purchase (June 2010 through December 2015), help the PEF system meet the growing energy requirements of its customer base. Some of the identified unit additions may be impacted by PEF's ability to extend or replace existing purchase power contracts, as well as contracts with cogenerators and QF's. Status reports and specifications for new generation facilities are included in Schedule 9. Shown in Schedule 10 are the new transmission lines associated with Hines #4 and the Bartow Repowering Project.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion in the near term. The forecast of natural gas prices has risen to the point where new pulverized coal units appear to be a cost effective alternative. Uncertainties over future fuel price relationships, environmental regulations, and the ability to site new coal units in Florida will require ongoing re-evaluations of the coal option. New nuclear technologies appear to offer favorable long-term economics, and provide favorable environmental characteristics, measured against possible emission limits imposed by the recently issued Clean Air Interstate Rule (CAIR). PEF is currently evaluating the nuclear option with the intent to pursue preliminary licensing activities should suitable sites for new nuclear units be available. Currently, the expected lead time to site, license, engineer, and construct a new nuclear unit place its in-service date outside the ten-year planning horizon presented in this document.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2005

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	*(1)*
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,302	
Anclote	2	993	
Bartow	3	444	
Suwannee River	3	143	
Total Fossil Steam	12	3,882	
Combined Cycle			
Hines Energy Complex	3	1,499	
Tiger Bay	1	207	
Total Combined cycle	4	1,706	
Combustion Turbine			
DeBary	10	667	
Intercession City	14	1,041	*(2)*
Bayboro	4	184	
Bartow	4	187	
Suwannee	3	164	
Turner	4	154	
Higgins	4	122	
Avon Park	2	52	
University of Florida	1	35	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,619	
Total Units	**64**		
Total Net Generating Capability		**8,976**	

(1) Adjusted for sale of approximately 8.2% of total capacity
(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Qualifying Facility Contracts	19	820	
Investor Owned Utilities	2	617	
TOTAL CAPACITY RESOURCES		**10,413**	

TABLE 3.2

PROGRESS ENERGY FLORIDA

QUALIFYING FACILITY GENERATION CONTRACTS

AS OF DECEMBER 31, 2005

Facility Name	Firm Capacity (MW)
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Jefferson Power	2.0
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery 1	40.0
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
Royster	30.8
US Agrichem	5.6
TOTAL	**820.2**

PROGRESS ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2006	8,843	817 *	0	813	10,473	8,771	1,702	19%	0	1,702	19%
2007	8,843	1,253 *	0	802	10,898	9,084	1,814	20%	0	1,814	20%
2008	9,304	1,095	0	798	11,197	9,351	1,846	20%	0	1,846	20%
2009	9,997	1,095	0	798	11,890	9,554	2,336	24%	0	2,336	24%
2010	10,136	1,093	0	798	12,027	9,931	2,096	21%	0	2,096	21%
2011	10,614	890	0	798	12,302	10,155	2,147	21%	0	2,147	21%
2012	10,775	890	0	798	12,463	10,383	2,080	20%	0	2,080	20%
2013	11,525	890	0	687	13,102	10,593	2,509	24%	0	2,509	24%
2014	12,275	412	0	500	13 187	10,813	2,374	22%	0	2,374	22%
2015	12,753	412	0	500	13,665	11,036	2,629	24%	0	2,629	24%

* Progress Energy is pursuing seasonal purchases of approximately 200 MW in 2006 and 158 MW in 2007. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 7.2
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM WINTER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2005/06	9,757	617	0	813	11,187	9,047	2,140	24%	0	2,140	24%
2006/07	9,757	1,117 *	0	802	11,676	9,584	2,092	22%	0	2,092	22%
2007/08	10,274	1,137	0	798	12,209	9,780	2,429	25%	0	2,429	25%
2008/09	10,656	1,137	0	798	12,591	10,134	2,457	24%	0	2,457	24%
2009/10	11,057	1,137	0	798	12,992	10,524	2,468	23%	0	2,468	23%
2010/11	11,248	1,002	0	798	13,048	10,727	2,321	22%	0	2,321	22%
2011/12	11,798	932	0	798	13,528	10,975	2,553	23%	0	2,553	23%
2012/13	11,989	932	0	798	13,719	11,203	2,516	22%	0	2,516	22%
2013/14	12,739	932	0	513	14,184	11,427	2,757	24%	0	2,757	24%
2014/15	13,489	412	0	501	14,402	11,634	2,768	24%	0	2,768	24%

* Includes Seasonal Purchase of 500 MW in 2006/07.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2006 THROUGH DECEMBER 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	12/2005	12/2007			461	517	U	
BARTOW CT	5, 6	PINELLAS	CT	NG	DFO	PL	TK	12/2006	12/2008			322	382	P	(1)
CRYSTAL RIVER	5	CITRUS	ST	BIT	--	WA	--	--	04/2009			(22)	(22)	P	(2)
BARTOW CC	1	PINELLAS	CC	NG	DFO	PL	WA	12/2006	06/2009			837	897	P	(1)
BARTOW	1-3	PINELLAS	ST	RFO	--	WA	--	--	--	06/2009		(444)	(452)	P	(1)
CRYSTAL RIVER	4	CITRUS	ST	BIT	--	WA	--	--	11/2009			(22)	(22)	P	(2)
COMBUSTION TURBINE	1	UNKNOWN	GT	NG	DFO	PL	TK	06/2009	06/2010			161	191	P	
COMBINED CYCLE	1	UNKNOWN	CC	NG	DFO	PL	TK	01/2009	06/2011			478	550	P	
COMBUSTION TURBINE	2	UNKNOWN	GT	NG	DFO	PL	TK	06/2011	06/2012			161	191	P	
P-COAL, Supercritical	1	UNKNOWN	ST	BIT	--	RR	--	06/2008	06/2013			750	750	P	
P-COAL, Supercritical	2	UNKNOWN	ST	BIT	--	RR	--	06/2009	06/2014			750	750	P	
COMBINED CYCLE	2	UNKNOWN	CC	NG	DFO	PL	TK	01/2013	06/2015			478	550	P	

NOTES

(1) As part of the Bartow Repowering Project, two CTs will go into service 12/2008. In June of 2009, they will be combined with an additional two CTs, four HRSGs, and one steam turbine to produce a single, 4x4x1 combined cycle with a total summer capacity of 1,159 MW.

(2) Derations due to FDG scrubber installations.

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #4	
(2)	Capacity		
	a. Summer:	461	
	b. Winter:	517	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	12/2005	
	b. Commercial in-service date:	12/2007	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	Cooling Method:	COOLING POND	
(8)	Total Site Area:	8,200 ACRES	
(9)	Construction Status:	REGULATORY APPROVAL RECEIVED UNDER CONSTRUCTION	
(10)	Certification Status:	SITE PERMITTED	
(11)	Status with Federal Agencies:	SITE PERMITTED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.0 %	
	b. Forced Outage Factor (FOF):	3.0 %	
	c. Equivalent Availability Factor (EAF):	91.2 %	
	d. Resulting Capacity Factor (%):	47.0 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,915 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	495.40	
	c. Direct Construction Cost ($/kW):	443.09	
	d. AFUDC Amount ($/kW):	52.31	
	e. Escalation ($/kW):	0.00	
	f. Fixed O&M ($/kW-yr):	1.26	
	g. Variable O&M ($/MWh):	2.38	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	BARTOW REPOWERING	
(2)	Capacity		
	a. Summer:	1,159	
	b. Winter:	1,279	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	12/2006	
	b. Commercial in-service date:	06/2009	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION	
(7)	Cooling Method:	COOLING WATER	
(8)	Total Site Area:	1,348 ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	N/A	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.6 %	
	c. Equivalent Availability Factor (EAF):	88.8 %	
	d. Resulting Capacity Factor (%):	53.9 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,236 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	435.08	
	c. Direct Construction Cost ($/kW):	403.56	
	d. AFUDC Amount ($/kW):	31.52	
	e. Escalation ($/kW):	0.00	
	f. Fixed O&M ($/kW-yr):	4.53	
	g. Variable O&M ($/MWh):	2.50	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	SIMPLE CYCLE 1	
(2)	Capacity		
	a. Summer:	161	
	b. Winter:	191	
(3)	Technology Type:	SIMPLE CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	06/2009	
	b. Commercial in-service date:	06/2010	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.7 %	
	c. Equivalent Availability Factor (EAF):	88.7 %	
	d. Resulting Capacity Factor (%):	1.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	10,579 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	349.59	
	c. Direct Construction Cost ($/kW):	273.09	
	d. AFUDC Amount ($/kW):	35.84	
	e. Escalation ($/kW):	40.66	
	f. Fixed O&M ($/kW-yr):	2.16	
	g. Variable O&M ($/MWh):	10.64	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COMBINED CYCLE 1	
(2)	Capacity		
	a. Summer:	478	
	b. Winter:	550	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	01/2009	
	b. Commercial in-service date:	06/2011	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	Cooling Method:	UNKNOWN	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.6 %	
	c. Equivalent Availability Factor (EAF):	88.8 %	
	d. Resulting Capacity Factor (%):	58.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,461 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	486.17	
	c. Direct Construction Cost ($/kW):	352.00	
	d. AFUDC Amount ($/kW):	70.02	
	e. Escalation ($/kW):	64.15	
	f. Fixed O&M ($/kW-yr):	2.03	
	g. Variable O&M ($/MWh):	1.21	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	SIMPLE CYCLE 2	
(2)	Capacity		
	a. Summer:	161	
	b. Winter:	191	
(3)	Technology Type:	SIMPLE CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	06/2011	
	b. Commercial in-service date:	06/2012	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.7 %	
	c. Equivalent Availability Factor (EAF):	88.7 %	
	d. Resulting Capacity Factor (%):	1.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	10,579 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	369.08	
	c. Direct Construction Cost ($/kW):	273.09	
	d. AFUDC Amount ($/kW):	37.84	
	e. Escalation ($/kW):	58.15	
	f. Fixed O&M ($/kW-yr):	2.16	
	g. Variable O&M ($/MWh):	10.64	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COAL-1	
(2)	Capacity		
	a. Summer:	750	
	b. Winter:	750	
(3)	Technology Type:	PULVERIZED COAL-SUPERCRITICAL	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	06/2008	
	b. Commercial in-service date:	06/2013	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	BITUMINOUS	
	b. Alternate fuel:		
(6)	Air Pollution Control Strategy (a):	LOW-NOX BURNERS, SELECTIVE	
(7)	Cooling Method:	UNKNOWN	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	4.8 %	
	b. Forced Outage Factor (FOF):	4.2 %	
	c. Equivalent Availability Factor (EAF):	91.2 %	
	d. Resulting Capacity Factor (%):	89.5 %	
	e. Average Net Operating Heat Rate (ANOHR):	8,712 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	40	
	b. Total Installed Cost (In-service year $/kW):	1651.57	
	c. Direct Construction Cost ($/kW):	1143.70	
	d. AFUDC Amount ($/kW):	224.49	
	e. Escalation ($/kW):	283.38	
	f. Fixed O&M ($/kW-yr):	31.94	
	g. Variable O&M ($/MWh):	3.21	
	h. K Factor:	NO CALCULATION	

(a) Subject to future requirements

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COAL-2	
(2)	Capacity		
	a. Summer:	750	
	b. Winter:	. 750	
(3)	Technology Type:	PULVERIZED COAL-SUPERCRITICAL	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	06/2009	
	b. Commercial in-service date:	06/2014	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	BITUMINOUS	
	b. Alternate fuel:		
(6)	Air Pollution Control Strategy (a):	LOW-NOX BURNERS, SELECTIVE	
(7)	Cooling Method:	UNKNOWN	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	4.8 %	
	b. Forced Outage Factor (FOF):	4.2 %	
	c. Equivalent Availability Factor (EAF):	91.2 %	
	d. Resulting Capacity Factor (%):	89.5 %	
	e. Average Net Operating Heat Rate (ANOHR):	8,712 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	40	
	b. Total Installed Cost (In-service year $/kW):	1696.99	
	c. Direct Construction Cost ($/kW):	1143.70	
	d. AFUDC Amount ($/kW):	230.66	
	e. Escalation ($/kW):	322.63	
	f. Fixed O&M ($/kW-yr):	31.94	
	g. Variable O&M ($/MWh):	3.21	
	h. K Factor:	NO CALCULATION	

(a) Subject to future requirements

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COMBINED CYCLE 2	
(2)	Capacity		
	a. Summer:	478	
	b. Winter:	550	
(3)	Technology Type:	COMBINED CYCLE	
(4)	*Anticipated Construction Timing*		
	a. Field construction start date:	01/2013	
	b. Commercial in-service date:	06/2015	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	Cooling Method:	UNKNOWN	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	*Projected Unit Performance Data*		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.6 %	
	c. Equivalent Availability Factor (EAF):	88.8 %	
	d. Resulting Capacity Factor (%):	58.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,461 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	541.89	
	c. Direct Construction Cost ($/kW):	352.00	
	d. AFUDC Amount ($/kW):	78.05	
	e. Escalation ($/kW):	111.84	
	f. Fixed O&M ($/kW-yr):	2.03	
	g. Variable O&M ($/MWh):	1.21	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

HINES UNIT #4

(1) POINT OF ORIGIN AND TERMINATION:	West Lake Wales Substation-Hines Energy Complex
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing Hines Energy Complex Site and new transmission right-of-way
(4) LINE LENGTH:	21
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	6/2007
(7) ANTICIPATED CAPITAL INVESTMENT:	$32,987,944 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* As recognized by the Florida Public Service Commission in its Order Granting Petition for Determination of Need for Hines Unit 4, the projected capital estimate may vary during construction of the Hines 4 facility.

PROGRESS ENERGY FLORIDA

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

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Bartow Plant - Northeast Substation
(2) NUMBER OF LINES:	3
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	4
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$74,005,735 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

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

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Northeast Substation - Thirty-Second Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New and existing transmission line right-of-ways
(4) LINE LENGTH:	2
(5) VOLTAGE:	115kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$4,000,000 *
(8) SUBSTATIONS:	Thirty-Second Street Substation - Addition
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

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

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Northeast Substation - Fortieth Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-ways
(4) LINE LENGTH:	8
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$8,000,000 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

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

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Pasadena Substation - Fifty-First Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-or-way
(4) LINE LENGTH:	0.4
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,000,000 *
(8) SUBSTATIONS:	Fifty-First Street Substation - Addition
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

INTEGRATED RESOURCE PLANNING OVERVIEW

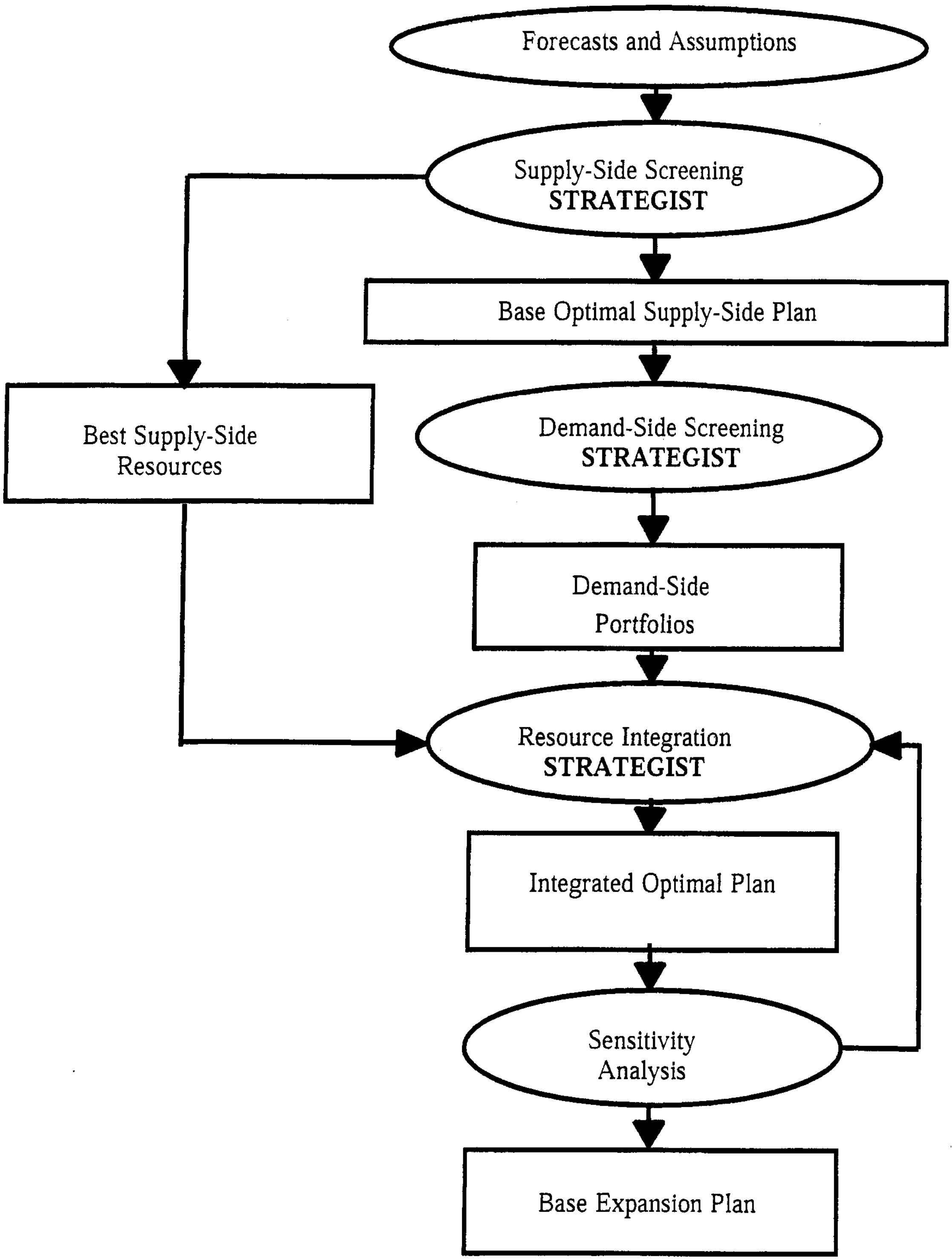
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide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

An overview of PEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for PEF to pursue over the next ten years to meet the company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different relevant sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust under sensitivity analysis and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The IRP Process".

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

FIGURE 3.1

IRP Process Overview



THE IRP PROCESS

Forecasts and Assumptions

The evaluation of possible supply- and demand-side alternatives, and development of the optimal plan, is an integral part of the IRP process. These steps together comprise the integration process that begins with the development of forecasts and collection of input data. Base forecasts that reflect PEF'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 PEF's existing generating units. This establishes a consistent starting point for all further analysis.

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and 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.

PEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of PEF's ability to meet its forecasted seasonal peak load with firm capacity. PEF plans its resources to satisfy a 20 percent minimum Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin only considers the peak load and amount of installed resources, LOLP also takes into account generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by PEF, is a maximum of one day in ten years loss of load probability.

PEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. PEF's resource portfolio is designed to satisfy the minimum 20% Reserve Margin requirement and probabilistic analyses are conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, PEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions.

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 PEF's experiences. The wide range of resource options is pre-screened to set aside those that do not warrant a detailed cost-effectiveness analysis. Typical screening criteria are costs, fuel source, technology maturity, environmental parameters, and overall resource feasibility.

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

Demand-Side Screening

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

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

Resource Integration and the Integrated Optimal Plan

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

Developing the Base Expansion Plan

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

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast is described in detail in Chapter 2 of this TYSP.

Fuel Forecast

Base Fuel Case: The base case fuel price forecast was developed using short-term and long-term market price projections from industry-recognized sources. Coal prices are expected to be relatively stable month to month; however, oil and natural gas prices are expected to be more volatile on a day-to-day and month-to-month basis.

In the short term, the base cost for coal is based on the existing contractual structure between Progress Fuels Corporation (PFC) and PEF and both contract and spot market coal and transportation arrangements between PFC and its various suppliers. For the longer term, the costs are based on market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates and tends to change less frequently than commodity prices.

Financial Forecast

The key financial assumptions used in PEF's most recent planning studies were 48% debt and 52% equity capital structure, projected debt cost of 6.5%, and an equity return of 12.0%. These assumptions resulted in a weighted average cost of capital of 9.36% and an after-tax discount rate of 8.16%.

TYSP RESOURCE ADDITIONS

In this TYSP, PEF's supply-side resources include the projected combined cycle (CC) expansion of the Hines Energy Complex (HEC) with Unit 4 forecasted to be in-service by December 2007. The TYSP also includes repowering the Bartow Steam Units with F-Class combined cycle technology that would provide a portion of the capacity in-service by December 2008 with the completed combined cycle facility in-service by June 2009. Two generic combustion turbine units and two generic combined cycle units are included in the TYSP with forecasted in-service dates of June 2010 and June 2012 for the CTs and June 2011 and June 2015 for the CCs.

The Company continues to study the economics of baseload generation alternatives including gas, coal, and nuclear options. Analyses indicate that coal and nuclear resources may provide economical baseload generation in the long-term. This TYSP thus includes the addition of two supercritical pulverized coal units during the planning horizon with forecasted in-service dates of June 2013 and June 2014. The Company has also announced its intent to file a combined construction permit-operating license (COL) application for a potential new nuclear facility in Florida with a possible in-service date beyond the 2015 planning horizon.

The economics of the baseload alternatives are partly dependent on legislation, projected load growth, fuel prices, and environmental compliance considerations. Although PEF has not committed to building a new coal or nuclear facility, the Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure the optimal selection of resource additions. The Company is also currently conducting detailed analyses of generation sites and has not finalized its decision on the preferred site(s) for possible future generic combined cycle, coal, and nuclear additions.

PLAN SENSITIVITIES

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. PEF's TYSP includes the Hines 4 addition and Bartow repowering projects in the near term, with generic CT, CC, and coal additions in the longer term. The Company's resource plan would provide the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize. PEF therefore did not conduct detailed sensitivity analyses of the plan to the base case load forecast.

Fuel Forecast

PEF's current TYSP includes new natural gas fueled resources through 2012. The plan also includes coal units in 2013 and 2014, with 2013 being the earliest possible date that a new coal plant can be placed in-service. PEF focused its fuel forecast sensitivity on price projections for natural gas. Higher gas prices would improve the economics for pulverized coal; however, this scenario would not impact the schedule of resource additions since 2013 is the earliest date that a new coal plant can be placed in-service. PEF conducted a sensitivity analysis of the plan to lower gas prices relative to the base forecast. Results for the low gas price scenario did not shift the in-service date for the 2013 and 2014 coal units, which indicate the potential for new coal fired generation to remain economical in the long-term.

The fuel price forecasts used in development of the TYSP show a greater differential in gas/oil versus coal prices in the early years, with the differential decreasing in 2009 and increasing again beginning 2016. Similar to the discussion above, a higher differential between gas/oil and coal prices would improve the economics for pulverized coal; however, the TYSP already includes coal in the resource mix beginning June 2013 which is the earliest year that a coal plant can be constructed and placed in-service. Similarly, a smaller differential in gas/oil versus coal prices would benefit the economics for a combined cycle plant; however, the low gas price forecast sensitivity discussed above still resulted in coal units included in the optimal plan.

Fuel price forecasts can have a significant impact on the economics of generation alternatives. Results of the fuel forecast sensitivity analysis conducted for this TYSP did not suggest any significant reconsideration of the base plan. PEF will continue to monitor fuel price relationships to identify long-term structural changes and assess the potential impacts on the economics of resource selection.

Financial Forecast

PEF's current TYSP includes combustion turbine and combined cycle additions through 2012 with pulverized coal additions in 2013 and 2014. Lower cost of capital escalation and escalation rates would favor options with longer construction lead times and higher capital costs such as the pulverized coal additions. However, PEF does not expect these assumptions to go much lower than the current base case forecast and, in any event, coal units likely cannot be added any sooner than 2013 as shown in the base plan. Higher financial assumptions would disfavor the pulverized coal additions; however, the Company has not committed to building new coal generation at this time. Thus, PEF did not test the sensitivity of the base resource plan to varying financial assumptions. PEF will continue to assess the economics of future generation alternatives including consideration of the uncertainties in planning assumptions.

TRANSMISSION PLANNING

PEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form 715 filing. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. PEF normally runs this analysis for system load levels from minimum to peak for all possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, less probable criteria, to assure the system meets PEF and Florida Reliability Coordinating Council, Inc. (FRCC) criteria. These studies include the loss of multiple generators or lines, and combinations of each, and some load loss is permissible under these more severe disturbances. These credible, less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

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

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

- FRCC: FRCC ATC Calculation and Coordination Procedures, November 4, 2003, which is posted on the FRCC website: (http://frcc.com/downloads/FRCC%20ATC%20methodology-%20final-11-03.pdf)

- NERC: Transmission Transfer Capability, May 1, 1995

- NERC: Available Transfer Capability – Definitions and Determination, July 30, 1996

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

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

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

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

TABLE 3.3
PROGRESS ENERGY FLORIDA

LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS

2006-2015

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT.-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1141	PEF/FPL	VANDOLAH	CHARLOTTE	55*	12/2006	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #1	21	6 / 2007	230
1141	PEF	LAKE BRYAN	WINDERMERE #1	10 *	1 / 2008	230
1141	PEF	LAKE BRYAN	WINDERMERE #2	10	1 / 2008	230
1141	PEF	AVALON	GIFFORD	7	7 / 2008	230
612	PEF	BARTOW	NORTHEAST Circuit 1	4	9/2008	230
612	PEF	BARTOW	NORTHEAST Circuit 2	4	9/2008	230
612	PEF	BARTOW	NORTHEAST Circuit 3	4	9/2008	230
525	PEF	NORTHEAST	32ND STREET	2	9/2008	115
810	PEF	NORTHEAST	40TH STREET	8*	9/2008	230
810	PEF	PASADENA	51ST STREET	0.2	9/2008	230
810	PEF	51ST STREET	40TH STREET	0.2	9/2008	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #2	30	6 / 2010	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #2	21	5 / 2011	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #1	30 *	6/2011	230

* Rebuild existing circuit

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

Progress Energy

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

PEF's base expansion plan proposes new combined cycle generation at the Hines Energy Complex (HEC) site in Polk County and to repower the existing Bartow Plant in Pinellas County with combined cycle technology. Although not delineated in the base expansion plan, potential peaking simple-cycle combustion turbine generation site options for the 2010 and 2012 units include Intercession City (Osceola County), Anclote (Pasco County), Bartow (Pinellas) and DeBary (Volusia County). While these sites are suitable for new generation, PEF continues to evaluate other available options for future supply alternatives.

The next proposed combined cycle unit at the HEC site is scheduled for commercial operation in December 2007. PEF will repower its existing Bartow Plant which is scheduled for commercial operation in June 2009. PEF continues to pursue siting opportunities for undesignated coal and combined cycle units with a commercial operation date of 2011 and beyond. PEF's existing sites, as identified in Table 3.1 of Chapter 3, include the capability to further develop generation. All appropriate permitting requirements will be addressed for PEF's preferred sites as discussed in the following site descriptions. The base expansion plan does not currently include any potential new sites for generation additions. Therefore, detailed environmental or land use data are not included.

The ability to site new baseload generation (coal and/or nuclear) in Florida is extremely limited, and PEF has not identified suitable sites for these technologies at this time. Siting studies are currently underway to identify possible sites for new baseload generation.

HINES ENERGY COMPLEX SITE

In 1990, PEF completed a statewide 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 south of the City of Bartow, near the cities of Fort Meade and Homeland, south of S.R. 640 and west of U.S. 17/98 (reference Figure 4.1). It is an area that has been extensively mined and remains predominantly unreclaimed.

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

The site's initial preparation involved moving over 10 million cubic yards of soil and draining 4 billion gallons of water. Construction of the energy complex recycled the land for a beneficial use and promote habitat restoration.

The Hines Energy Complex is visited by several species of wildlife, including alligators, bobcats, turtles, and over 50 species of birds. The Hines site also contains a wildlife corridor, which creates a continuous connection between the Peace River and the Alafia River.

PEF arranged for the City of Bartow to provide treated effluent for cooling pond make-up. The complex's cooling pond initially covered 722 acres with an eventual expansion to 2,500 acres.

The Hines Energy Complex is designed and permitted to be a zero discharge site. This means that there will be no discharges to surface waters either from the power plant facilities or from storm water runoff. Based on this design, storm water runoff from the site can be used as cooling pond make-up, minimizing groundwater withdrawals.

The Florida Department of Environmental Protection air rules currently list all of Polk County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

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

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

The second combined cycle unit at this site entered commercial operation in December 2003 with a seasonal capacity rating of 516 MW summer. The transmission improvement associated with the second combined cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to Barcola.

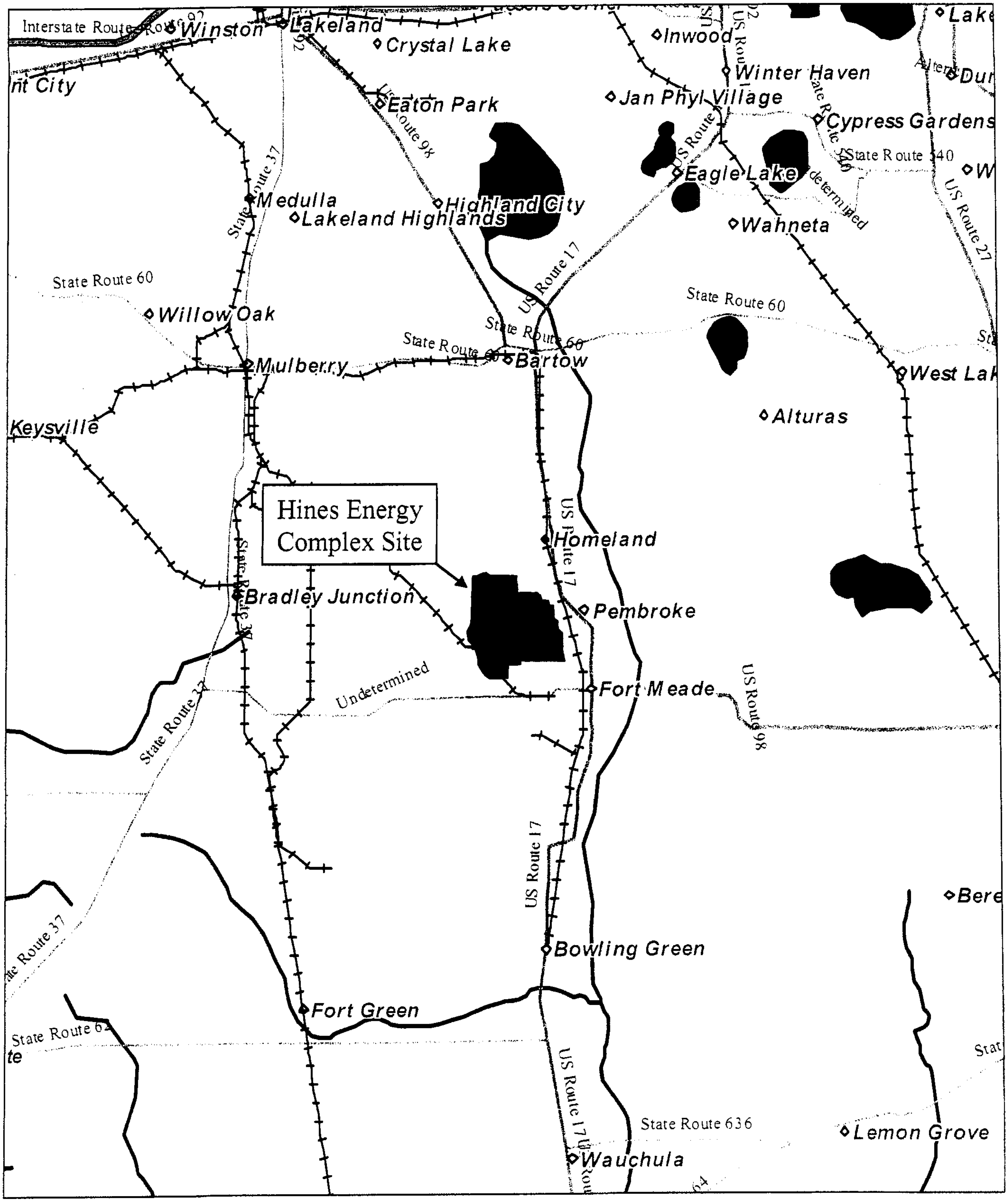
The third combined cycle unit at this site entered commercial operation in November 2005 with a seasonal capacity rating of 501 MW summer, and required no transmission upgrades.

The fourth HEC combined cycle unit is currently under construction. This unit has a commercial operation date of December 2007 with a seasonal capacity rating of 461 MW summer. The transmission improvements associated with the fourth combined cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to West Lake-Wales and associated substation expansion and breaker replacements.

The HEC is also a potential site for a combined cycle unit required in 2011.

FIGURE 4.1

Hines Energy Complex Site (Polk County)



INTERCESSION CITY SITE

Intercession City was chosen as a potential site for installation of peaking combustion turbine units.

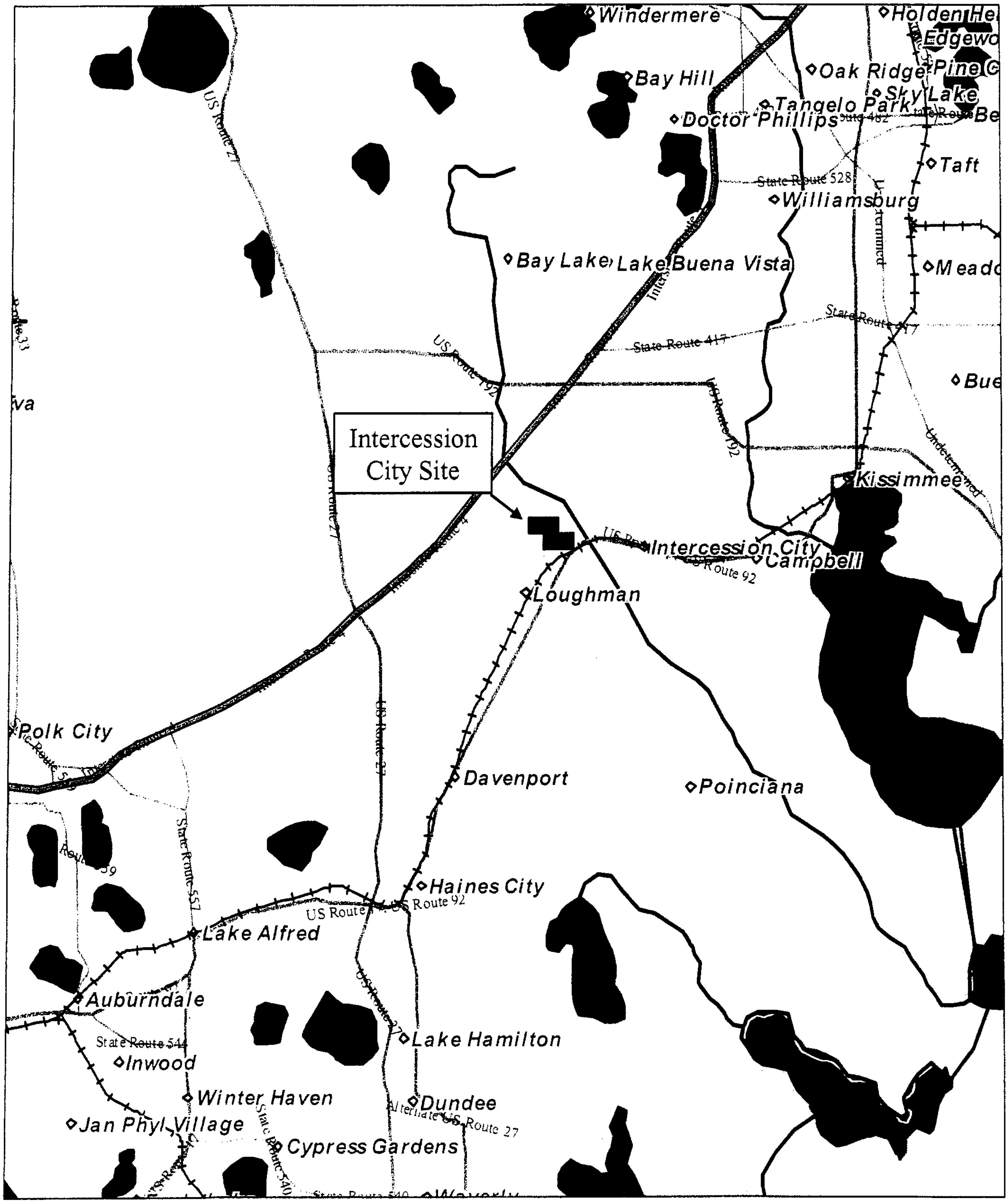
The Intercession City site (Figure 4.2) consists of 162 acres in Osceola County, two miles west of Intercession City. The site is immediately west of Reedy Creek and the adjacent Reedy Creek Swamp. The site is adjacent to a secondary effluent pipeline from a municipal wastewater treatment plant, an oil pipeline, and natural gas supply from the Florida Gas Transmission (FGT) and Gulfstream pipelines.

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 PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.2

Intercession City Site (Osceola County)



DEBARY SITE

DeBary was chosen as a potential site for installation of peaking combustion turbine units.

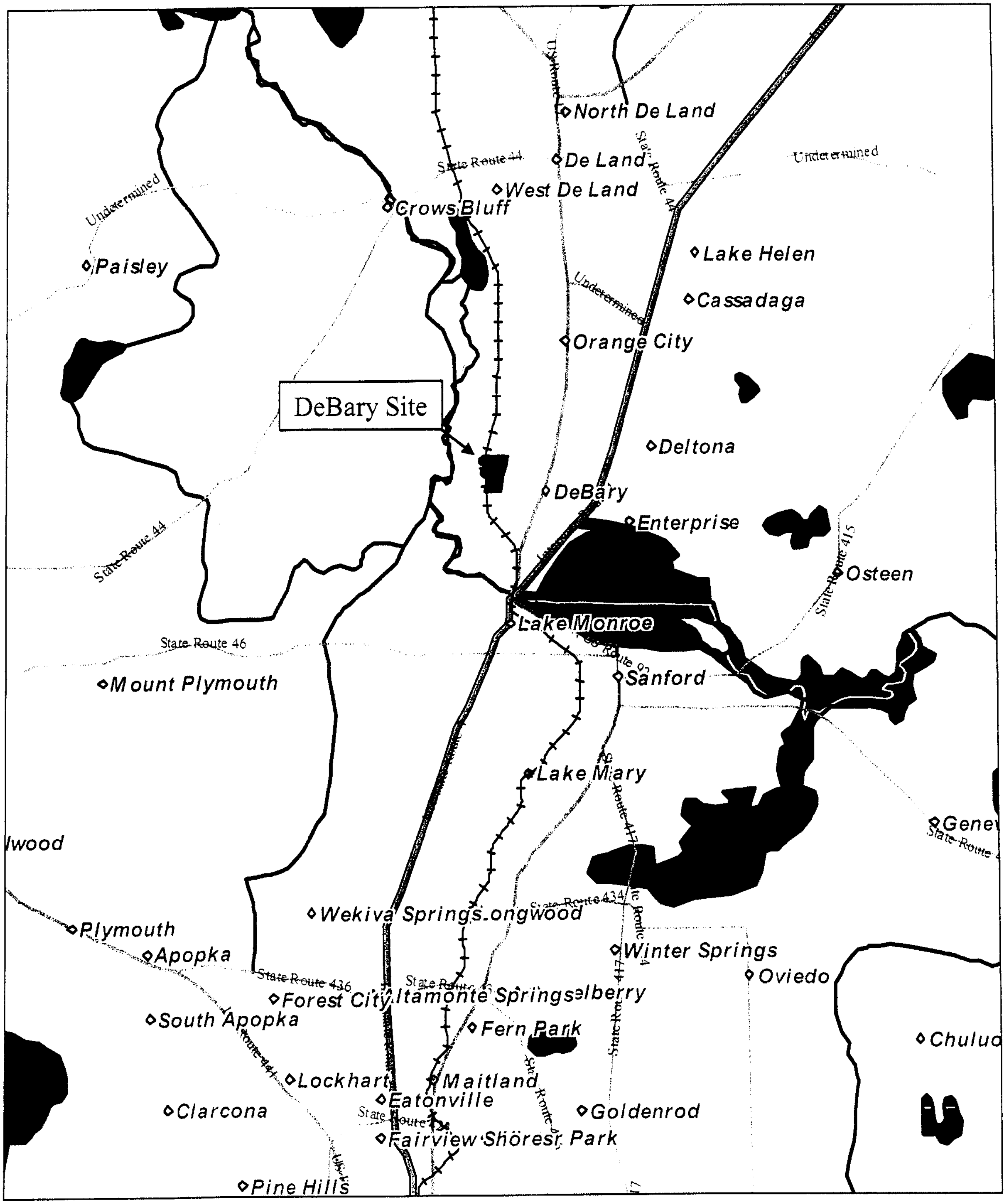
The DeBary site (Figure 4.3) consists of 2,210 acres in Volusia County, immediately west of the town of DeBary. The site is bordered on the west by the St. Johns River and on the north by Blue Springs State Park. This site is adjacent to an oil pipeline and natural gas supply from the Florida Gas Transmission (FGT) pipeline.

The Florida Department of Environmental Protection air rules currently list all of Volusia County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.3

DeBary Site (Volusia County)



ANCLOTE SITE

Anclote was chosen as a potential site for installation of peaking combustion turbine units.

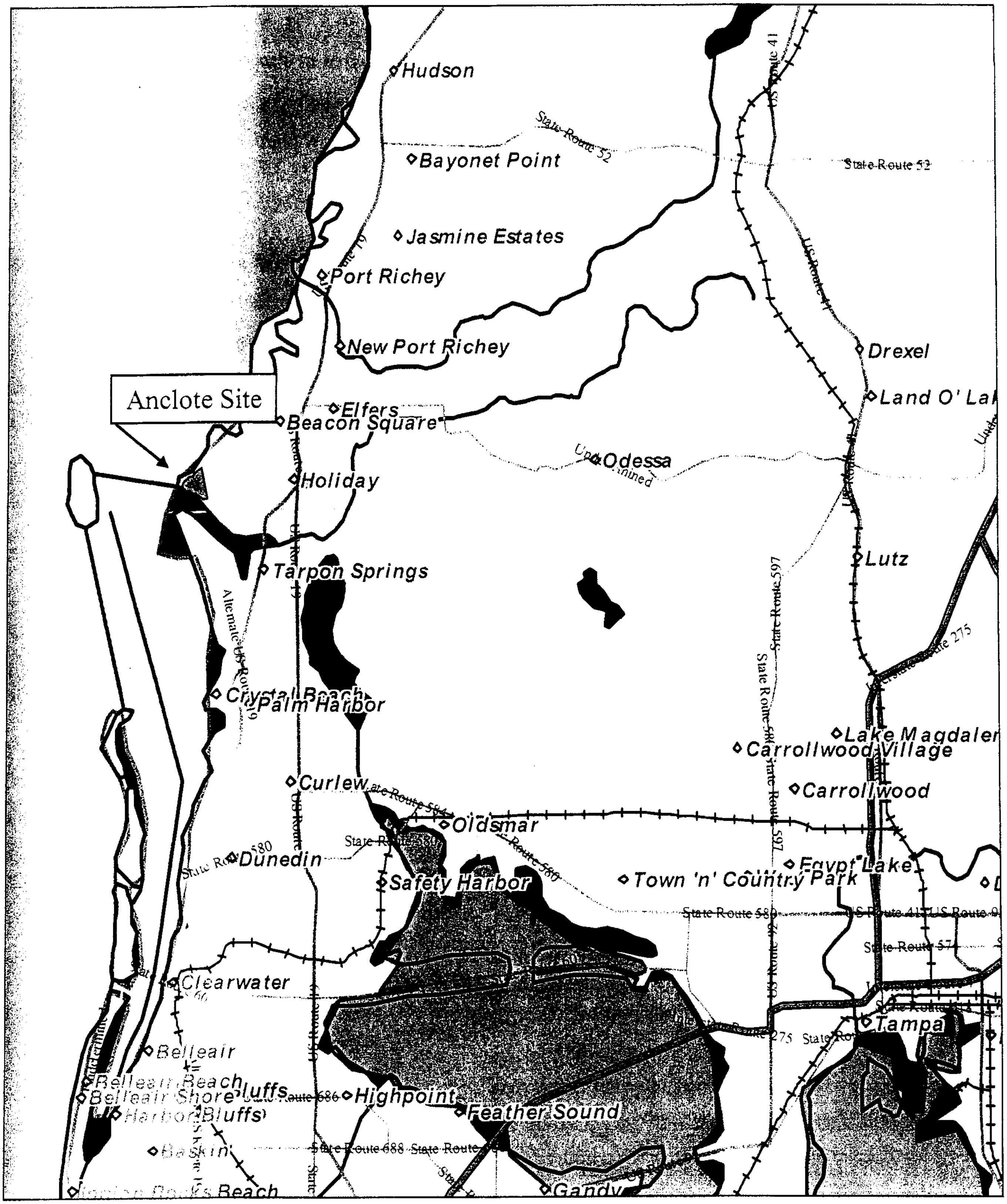
The Anclote site (Figure 4.4) consists of approximately 400 acres in Pasco County. The site is located in Holiday Florida at the mouth of the Anclote River. The site receives make-up water from the city of Tarpon Springs, fuel oil through a pipeline from the Bartow plant, and natural gas supply from the Florida Gas Transmission (FGT) pipeline.

The Florida Department of Environmental Protection air rules currently list all of Pasco County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.4

Anclote (Pasco County)



BARTOW SITE

PEF has chosen to repower its existing Bartow Plant with combined cycle technology, which is scheduled for commercial operation in June 2009.

The Bartow site (Figure 4.5) consists of 1,348 acres in Pinellas County, on the west shore of Tampa Bay. The site is on Weedon Island, north of downtown St. Petersburg. The site is adjacent to a barge fuel oil off-loading facility, a natural gas supply from the Florida Gas Transmission (FGT) pipeline, and a proposed Gulfstream natural gas pipeline.

The Florida Department of Environmental Protection air rules currently list all of Pinellas County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate the repowering of Bartow steam units.

FIGURE 4.5
Bartow Site (Pinellas County)

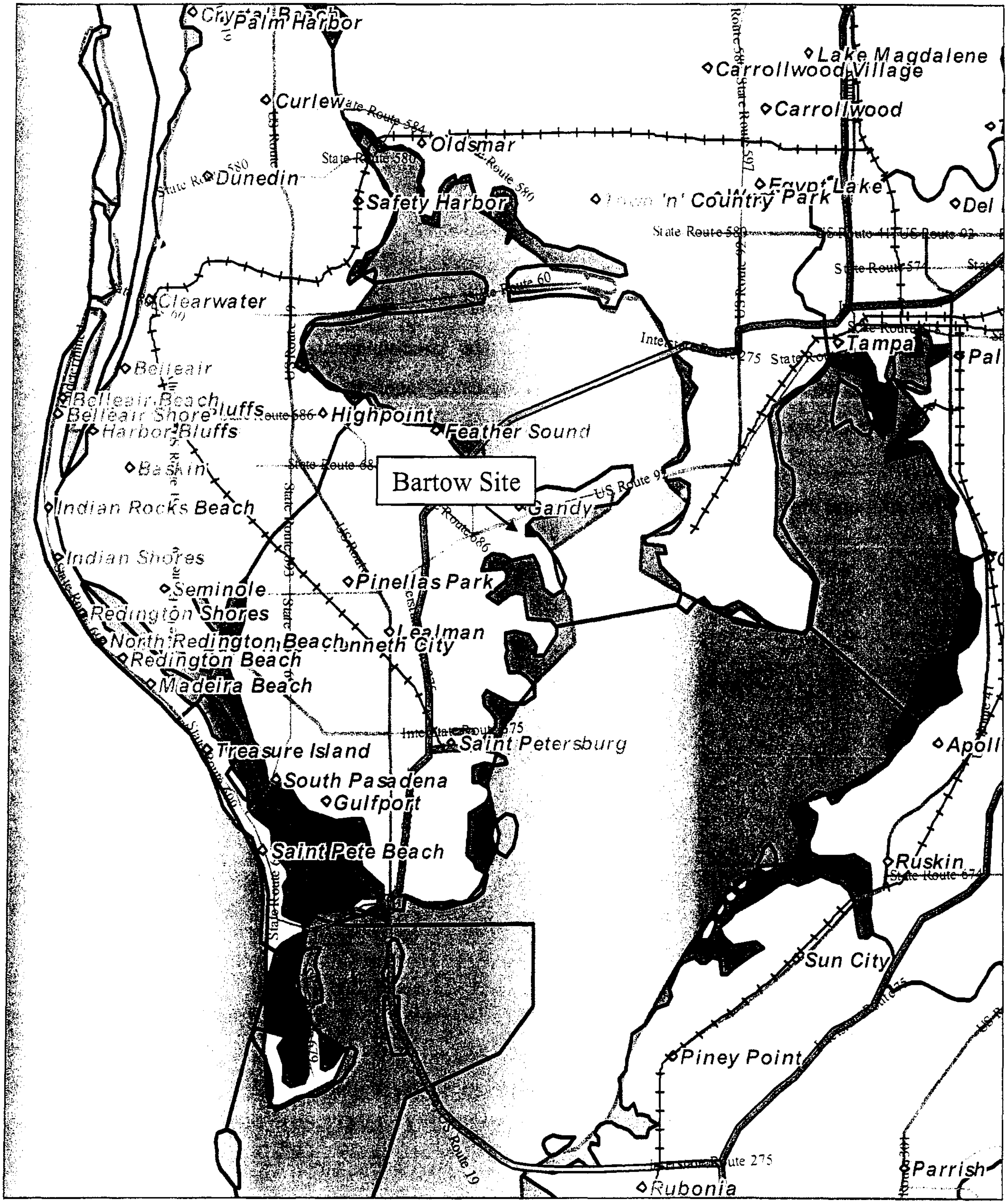


EXHIBIT NO. __________

DOCKET NO: 070052-EI

WITNESS: VARIOUS

PARTY: PROGRESS ENERGY FLORIDA, INC.

DESCRIPTION: STAFF'S EXHIBIT

DOCUMENTS:

Progress Energy Florida's 2007 Ten Year Site Plan.

PROFFERED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI **EXHIBIT** 27
COMPANY PEF
WITNESS 2007 10-yr. Site Plan
DATE 08/07 + 08/07

Progress Energy Florida
Ten-Year Site Plan

April 2007

2007-2016

Submitted to:
Florida Public Service Commission

Progress Energy

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CODE IDENTIFICATION SHEET

Generating Unit Type

ST - Steam Turbine - Non-Nuclear
NP - Steam Power - Nuclear
GT - Gas Turbine
CT - Combustion Turbine
CC - Combined cycle
SPP - Small Power Producer
COG - Cogeneration Facility

Fuel Type

NUC - Nuclear (Uranium)
NG - Natural Gas
RFO - No. 6 Residual Fuel Oil
DFO - No. 2 Distillate Fuel Oil
BIT - Bituminous Coal
MSW - Municipal Solid Waste
WH - Waste Heat
BIO - Biomass

Fuel Transportation

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

Future Generating Unit Status

A - Generating unit capability increased
FC - Existing generator planned for conversion to another fuel or energy source
P - Planned for installation but not authorized; not under construction
RP - Proposed for repowering or life extension
RT - Existing generator scheduled for retirement
T - Regulatory approval received but not under construction
U - Under construction, less than or equal to 50% complete
V - Under construction, more than 50% complete

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INTRODUCTION

Section 186.801 of the Florida Statutes requires electric generating utilities to submit a Ten-Year Site Plan (TYSP) to the Florida Public Service Commission (FPSC). The TYSP includes historical and projected data pertaining to the utility's load and resource needs as well as a review of those needs. It is compiled in accordance with FPSC Rules 25-22.070 through 22.072, Florida Administrative Code.

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

The TYSP document contains four chapters as described below:

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 2

FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

Progress Energy

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

PEF is a wholly owned subsidiary of Progress Energy, Inc. (Progress Energy). Congress enacted legislation in 2005 repealing the Public Utilities Holding Company Act of 1935 (PUCHA) effective February 8, 2006. Subsequent to that date, Progress Energy is no longer subject to regulation by the Securities and Exchange Commission as a public utility holding company. Progress Energy is the parent company of PEF and certain other subsidiaries.

AREA OF SERVICE

PEF provided electric service during 2006 to an average of 1.6 million customers in Florida. Its service area covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 22 municipal and 9 rural electric cooperative systems. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) and the FPSC. PEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The PEF transmission system includes approximately 5,000 circuit miles of transmission lines. The distribution system includes approximately 18,000 circuit miles of overhead distribution conductors and approximately 13,000 miles of underground cable. A map of the Electric System can be found in Figure 1.2.

ENERGY MANAGEMENT and ENERGY EFFICIENCY

PEF customers participating in the company's residential Energy Management program help to manage future growth and costs. Approximately 389,000 customers participated in the Energy Management program at the end of 2006, contributing about 755,000 kW of winter peak-shaving capacity for use during high load periods.

PEF's DSM Plan currently consists of seven residential programs, eight commercial and industrial programs, and one research and development program. This includes the 39 additional DSM measures and 2 new residential programs approved by the FPSC on January 5, 2007. (Docket 060647: Consummating Order PSC-07-0017-CO-EG making Order PSC-0601018-TRG-EG effective and final). Megawatt contributions to the TYSP have increased as a result of these changes to conservation, standby, and residential load management programs.

TOTAL CAPACITY RESOURCE

As of December 31, 2006, PEF had total summer capacity resources of approximately 10,752 MW consisting of installed capacity of 8,844 MW (excluding Crystal River 3 joint ownership) and 1,908 MW of firm purchased power. Additional information on PEF's existing generating resources is shown on Schedule 1 and Table 3.1.

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map

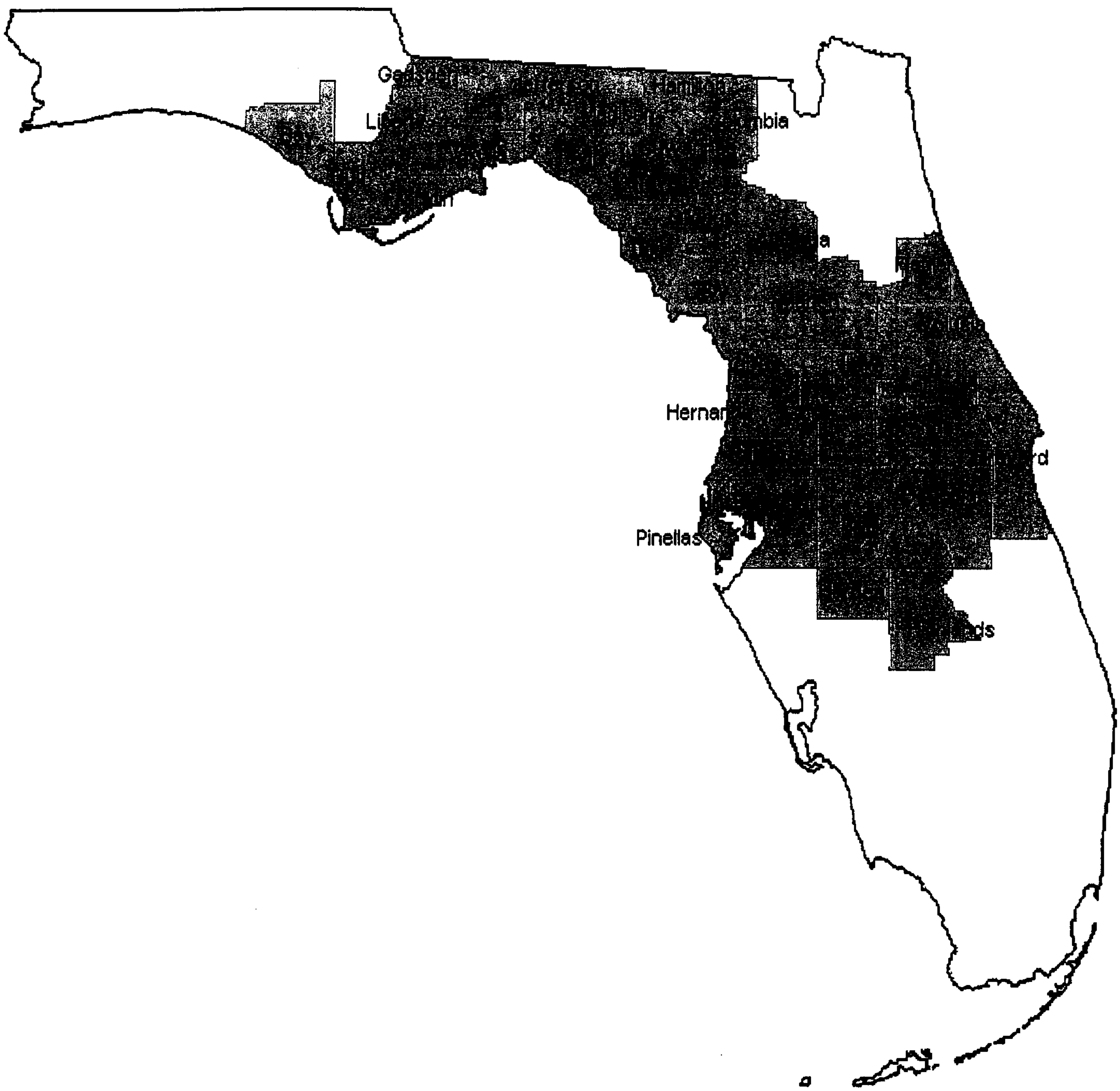

FIGURE 1.2

PROGRESS ENERGY FLORIDA

Electric System Map

PROGRESS ENERGY FLORIDA

SCHEDULE 1

EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2006

(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	507	526
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	125
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	124
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	215
CRYSTAL RIVER	1	CITRUS	ST	BIT		RR	WA		10/66		440,550	379	386
CRYSTAL RIVER	2	CITRUS	ST	BIT		RR	WA		11/69		523,800	491	496
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	722	734
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA	RR		10/84		739,260	721	734
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/53		34,500	30	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/54		37,500	31	31
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK/RR	PL		10/56		75,000	80	82
												4,672	4,796
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	2***	04/99		546,500	463	528
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK		12/03		548,250	490	562
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK		11/05		561,000	503	570
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,100	203	225
												1,659	1,885
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3***	12/68		33,790	25	34
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	25	36
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			05/72, 06/72		111,400	86	112
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	44	56
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	58
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA			04/73		226,800	177	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK			12/75-04/76		401,220	311	393
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	8	10/92		345,000	249	287
DEBARY	P10	VOLUSIA	GT	DFO		TK			10/92		115,000	83	99
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK		03/69, 04/69		67,580	53	68
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70, 01/71		85,850	57	65
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	282	369
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	332	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	161
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	235	278
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	106	133
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	51	66
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	22	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	64	85
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	64	84
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	45	47
												2,513	3,087
										TOTAL RESOURCES (MW)		8,844	9,768

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT

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

*** FOR ENTIRE PLANT

**** P1 REQUIRES A 3-4 DAY OUTAGE IN ORDER TO SWITCH BETWEEN NG & DFO

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

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

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

PEF's customer growth is expected to average 1.8 percent between 2007 and 2016, less than the ten-year historical average of 2.4 percent. The ten-year historical growth rate falls to 2.1 percent when accounting for the creation of PEF's Seasonal Service Rate tariff, which artificially inflates customer growth figures. Slower population growth - based on the latest projection from the University of Florida's Bureau of Economic and Business Research – and economic conditions less favorable for the housing/construction industry (including, for example, higher interest rates, property insurance and property taxes) result in a lower base case customer projection when compared to the higher historical growth rate. This translates into lower projected energy and demand growth rates from historic rate levels.

Net energy for load (NEL), which had grown at an average of 3.2 percent between 1997 and 2006, is expected to increase by 2.6 percent per year from 2007-2016 in the base case, 2.7 percent in the high case and 2.2 percent in the low case. A lower contribution from the wholesale jurisdiction, which grew an average of 10.2 percent between 1997 and 2006, results in lower expected system growth going forward than the historic rate. Retail NEL, which grew at a

2.8 percent average rate historically, is expected to grow 2.5 percent over the next ten years. Wholesale NEL is expected to average 2.9 percent between 2007 and 2016.

Summer net firm demand is expected to grow an average of 2.1 percent per year during the next ten years. This compares to the 3.6 percent growth rate experienced throughout the last ten years. Again, lower contribution from the wholesale jurisdiction is expected going forward and a higher load management capability for the projected period. High and low summer growth rates for net firm demand are 2.3 percent and 1.8 percent per year, respectively. Winter net firm demand is projected to grow at 2.5 percent per year after having increased by 2.9 percent per year from 1997 to 2006. High and low winter net firm demand growth rates are 2.7 percent and 2.2 percent, respectively.

Summer net firm retail demand is expected to grow an average of 2.1 percent per year during the next ten years; this compares to the 3.6 percent average annual growth rate experienced throughout the last ten years. The historical growth percentage is driven by a period of declining load management capability while the projection period has a return to higher capability. High and low summer growth rates for net firm retail demand are 2.4 percent and 1.8 percent per year, respectively. Winter net firm retail demand is projected to grow at approximately 1.9 percent per year after having grown by 3.1 percent from 1997 to 2006. Again, higher load control capability is incorporated in the projection period. High and low winter net firm retail demand growth rates are 2.2 percent and 1.6 percent, respectively.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

SCHEDULE	DESCRIPTION
2.1, 2.2 and 2.3	History and Forecast of Energy Consumption and Number of Customers by Customer Class
3.1.1, 3.1.2 and 3.1.3	History and Forecast of Base, High and Low Summer Peak Demand (MW)
3.2.1, 3.2.2 and 3.2.3	History and Forecast of Base, High, and Low Winter Peak Demand (MW)
3.3.1, 3.3.2 and 3.3.3	History and Forecast of Base, High and Low Annual Net Energy for Load (GWh)
4	Previous Year Actual and Two-Year Forecast of Peak Demand and Net Energy for Load by Month

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1997	2,878,315	2.480	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,941,589	2.487	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,028,821	2.496	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,026,469	2.452	17,116	1,234,286	13,867	10,813	143,475	75,365
2001	3,122,946	2.450	17,604	1,274,672	13,811	11,061	146,983	75,254
2002	3,191,315	2.452	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,267,185	2.453	19,429	1,331,914	14,587	11,553	154,294	74,877
2004	3,348,917	2.454	19,347	1,364,677	14,177	11,734	158,780	73,901
2005	3,429,664	2.455	19,894	1,397,012	14,240	11,945	161,001	74,192
2006	3,512,066	2.453	20,021	1,431,743	13,984	11,975	162,774	73,568
2007	3,565,718	2.455	20,891	1,452,431	14,383	12,340	167,150	73,826
2008	3,629,609	2.450	21,457	1,481,473	14,484	12,674	170,889	74,165
2009	3,694,808	2.447	22,026	1,509,934	14,587	13,009	174,552	74,528
2010	3,762,611	2.446	22,605	1,538,271	14,695	13,361	178,195	74,980
2011	3,828,922	2.444	23,192	1,566,662	14,803	13,708	181,846	75,382
2012	3,895,566	2.442	23,792	1,595,236	14,914	14,056	185,520	75,765
2013	3,959,232	2.438	24,404	1,623,967	15,027	14,417	189,213	76,195
2014	4,025,804	2.436	25,027	1,652,629	15,144	14,796	192,896	76,705
2015	4,091,505	2.434	25,693	1,680,980	15,285	15,202	196,539	77,349
2016	4,155,712	2.432	26,363	1,708,763	15,428	15,622	200,111	78,067

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,958
2004	4,069	2,733	1,488,840	0	28	3,016	38,194
2005	4,140	2,703	1,531,632	0	27	3,171	39,177
2006	4,160	2,697	1,542,455	0	27	3,249	39,432
2007	4,155	2,701	1,538,319	0	28	3,353	40,767
2008	4,393	2,701	1,626,435	0	28	3,457	42,009
2009	4,423	2,701	1,637,542	0	28	3,570	43,056
2010	4,451	2,701	1,647,908	0	28	3,682	44,127
2011	4,518	2,701	1,672,714	0	28	3,798	45,244
2012	4,544	2,701	1,682,340	0	28	3,916	46,336
2013	4,571	2,701	1,692,336	0	28	4,038	47,458
2014	4,599	2,701	1,702,703	0	28	4,164	48,614
2015	4,587	2,701	1,698,260	0	28	4,293	49,803
2016	4,587	2,701	1,698,260	0	28	4,427	51,027

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) TOTAL NO. OF CUSTOMERS
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,003	1,400,299
2001	3,839	1,831	40,933	20,752	1,444,958
2002	3,173	2,535	42,567	21,156	1,475,783
2003	3,359	2,594	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,506	46,878	22,701	1,583,417
2006	4,220	2,389	46,041	23,182	1,620,396
2007	4,524	2,905	48,194	23,687	1,645,969
2008	4,501	2,958	49,468	24,280	1,679,343
2009	4,527	3,026	50,609	24,877	1,712,064
2010	5,238	3,151	52,516	25,474	1,744,641
2011	5,363	3,169	53,776	26,071	1,777,280
2012	5,437	3,244	55,017	26,669	1,810,126
2013	5,542	3,321	56,321	27,266	1,843,147
2014	5,673	3,445	57,732	27,864	1,876,090
2015	5,795	3,476	59,074	28,460	1,908,680
2016	5,873	3,560	60,460	29,058	1,940,633

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1997	7,786	874	6,912	288	555	78	41	124	170	6,531
1998	8,367	943	7,424	291	438	97	42	134	182	7,183
1999	9,039	1,326	7,713	292	505	113	45	145	183	7,756
2000	8,902	1,319	7,583	277	455	127	48	146	75	7,774
2001	8,832	1,117	7,715	283	414	139	48	147	75	7,726
2002	9,412	1,203	8,209	305	390	153	43	150	75	8,296
2003	8,877	887	7,990	300	393	172	44	154	75	7,738
2004	9,578	1,071	8,507	531	355	188	39	155	110	8,200
2005	10,345	1,118	9,227	448	343	206	38	158	110	9,041
2006	10,186	1,257	8,929	329	319	226	37	161	110	9,003
2007	10,658	1,321	9,337	449	319	243	43	168	110	9,327
2008	10,927	1,337	9,590	473	332	259	52	177	110	9,525
2009	11,010	1,192	9,818	474	351	275	61	185	110	9,553
2010	11,318	1,269	10,049	479	372	292	70	194	110	9,801
2011	11,569	1,287	10,282	484	393	308	80	203	110	9,992
2012	11,807	1,296	10,511	485	414	325	89	211	110	10,173
2013	12,062	1,320	10,742	486	427	342	98	220	110	10,379
2014	12,437	1,469	10,968	483	438	360	107	229	110	10,711
2015	12,671	1,483	11,188	478	441	367	110	232	110	10,932
2016	12,906	1,499	11,407	477	441	367	110	232	110	11,169

Historical Values (1997 - 2006):

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

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

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

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

Projected Values (2007 - 2016):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1997	7,786	874	6,912	288	555	78	41	124	170	6,531
1998	8,367	943	7,424	291	438	97	42	134	182	7,183
1999	9,039	1,326	7,713	292	505	113	45	145	183	7,756
2000	8,902	1,319	7,583	277	455	127	48	146	75	7,774
2001	8,832	1,117	7,715	283	414	139	48	147	75	7,726
2002	9,412	1,203	8,209	305	390	153	43	150	75	8,296
2003	8,877	887	7,990	300	393	172	44	154	75	7,738
2004	9,578	1,071	8,507	531	355	188	39	155	110	8,200
2005	10,345	1,118	9,227	448	343	206	38	158	110	9,041
2006	10,186	1,257	8,929	329	319	226	37	161	110	9,003
2007	10,801	1,321	9,480	449	319	243	43	168	110	9,470
2008	11,086	1,337	9,748	473	332	259	52	177	110	9,683
2009	11,185	1,192	9,993	474	351	275	61	185	110	9,728
2010	11,513	1,269	10,244	479	372	292	70	194	110	9,996
2011	11,814	1,287	10,527	484	393	308	80	203	110	10,237
2012	12,067	1,296	10,771	485	414	325	89	211	110	10,433
2013	12,369	1,320	11,049	486	427	342	98	220	110	10,686
2014	12,773	1,469	11,304	483	438	360	107	229	110	11,047
2015	13,065	1,483	11,582	478	441	367	110	232	110	11,327
2016	13,338	1,499	11,839	477	441	367	110	232	110	11,601

Historical Values (1997 - 2006):

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

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

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

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

Projected Values (2007 - 2016):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1997	7,786	874	6,912	288	555	78	41	124	170	6,531
1998	8,367	943	7,424	29[illegible]	438	97	42	134	182	7,183
1999	9,039	1,326	7,713	292	505	113	45	145	183	7,756
2000	8,902	1,319	7,583	277	455	127	48	146	75	7,774
2001	8,832	1,117	7,715	283	414	139	48	147	75	7,726
2002	9,412	1,203	8,209	305	390	153	43	150	75	8,296
2003	8,877	887	7,990	300	393	172	44	154	75	7,738
2004	9,578	1,071	8,507	531	355	188	39	155	110	8,200
2005	10,345	1,118	9,227	448	343	206	38	158	110	9,041
2006	10,186	1,257	8,929	329	319	226	37	161	110	9,003
2007	10,524	1,321	9,203	449	319	243	43	168	110	9,193
2008	10,776	1,337	9,438	473	332	259	52	177	110	9,373
2009	10,849	1,192	9,657	474	351	275	61	185	110	9,392
2010	11,122	1,269	9,853	479	372	292	70	194	110	9,605
2011	11,350	1,287	10,063	484	393	308	80	203	110	9,773
2012	11,548	1,296	10,252	485	414	325	89	211	110	9,914
2013	11,778	1,320	10,458	486	427	342	98	220	110	10,095
2014	12,106	1,469	10,637	483	438	360	107	229	110	10,380
2015	12,305	1,483	10,822	478	441	367	110	232	110	10,567
2016	12,513	1,499	11,014	477	441	367	110	232	110	10,776

Historical Values (1997 - 2006):

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

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

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

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

Projected Values (2007 - 2016):

Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1996/97	8,486	1,235	7,251	290	917	133	16	98	190	6,842
1997/98	7,752	941	6,811	318	663	164	17	106	168	6,317
1998/99	10,473	1,741	8,732	305	874	196	18	110	187	8,783
1999/00	10,033	1,728	8,305	225	849	229	20	112	182	8,416
2000/01	11,443	1,984	9,459	255	826	254	23	113	187	9,785
2001/02	10,669	1,624	9,045	285	819	278	24	114	188	8,960
2002/03	11,548	1,538	10,010	271	793	313	27	117	198	9,828
2003/04	9,317	1,167	8,150	498	786	343	26	117	261	7,287
2004/05	10,824	1,600	9,224	575	777	371	26	117	282	8,676
2005/06	10,736	1,467	9,269	298	769	413	26	118	281	8,830
2006/07	11,728	1,711	10,017	366	760	454	27	120	296	9,705
2007/08	12,132	1,789	10,343	452	777	495	37	126	302	9,943
2008/09	12,302	1,727	10,575	453	793	538	47	133	305	10,034
2009/10	12,817	2,012	10,805	454	811	580	57	139	309	10,468
2010/11	13,126	2,082	11,044	464	829	623	67	146	313	10,685
2011/12	13,516	2,241	11,275	465	846	666	76	152	316	10,994
2012/13	13,885	2,377	11,508	466	864	710	86	158	320	11,280
2013/14	14,197	2,456	11,741	467	882	754	96	165	324	11,509
2014/15	14,513	2,548	11,965	461	899	798	105	171	327	11,751
2015/16	14,827	2,639	12,187	456	899	798	105	171	332	12,064
2016/17	15,139	2,729	12,410	457	899	798	105	171	336	12,372

Historical Values (1997 - 2006):

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

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

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

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

Projected Values (2007 - 2016):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1996/97	8,486	1,235	7,251	290	917	133	16	98	190	6,842
1997/98	7,752	941	6,811	318	663	164	17	106	168	6,317
1998/99	10,473	1,741	8,732	305	874	196	18	110	187	8,783
1999/00	10,033	1,728	8,305	225	849	229	20	112	182	8,416
2000/01	11,443	1,984	9,459	255	826	254	23	113	187	9,785
2001/02	10,669	1,624	9,045	285	819	278	24	114	188	8,960
2002/03	11,548	1,538	10,010	271	793	313	27	117	198	9,828
2003/04	9,317	1,167	8,150	498	786	343	26	117	261	7,287
2004/05	10,824	1,600	9,224	575	777	371	26	117	282	8,676
2005/06	10,736	1,467	9,269	298	769	413	26	118	281	8,830
2006/07	11,880	1,711	10,169	366	760	454	27	120	296	9,857
2007/08	12,300	1,789	10,510	452	777	495	37	126	302	10,111
2008/09	12,487	1,727	10,761	453	793	538	47	133	305	10,219
2009/10	13,022	2,012	11,010	454	811	580	57	139	309	10,672
2010/11	13,383	2,082	11,302	464	829	623	67	146	313	10,943
2011/12	13,788	2,241	11,548	465	846	666	76	152	316	11,266
2012/13	14,207	2,377	11,831	466	864	710	86	158	320	11,603
2013/14	14,548	2,456	12,092	467	882	754	96	165	324	11,860
2014/15	14,923	2,548	12,376	461	899	798	105	171	327	12,161
2015/16	15,275	2,639	12,636	456	899	798	105	171	332	12,513
2016/17	15,643	2,729	12,915	457	899	798	105	171	336	12,876

Historical Values (1997 - 2006):

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

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

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

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

Projected Values (2007 - 2016):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1996/97	8,486	1,235	7,251	290	917	133	16	98	190	6,842
1997/98	7,752	941	6,811	318	663	164	17	106	168	6,317
1998/99	10,473	1,741	8,732	305	874	196	18	110	187	8,783
1999/00	10,033	1,728	8,305	225	849	229	20	112	182	8,416
2000/01	11,443	1,984	9,459	255	826	254	23	113	187	9,785
2001/02	10,669	1,624	9,045	285	819	278	24	114	188	8,960
2002/03	11,548	1,538	10,010	271	793	313	27	117	198	9,828
2003/04	9,317	1,167	8,150	498	786	343	26	117	261	7,287
2004/05	10,824	1,600	9,224	575	777	371	26	117	282	8,676
2005/06	10,736	1,467	9,269	298	769	413	26	118	281	8,830
2006/07	11,586	1,711	9,875	366	760	454	27	120	296	9,563
2007/08	11,971	1,789	10,181	452	777	495	37	126	302	9,782
2008/09	12,132	1,727	10,406	453	793	538	47	133	305	9,864
2009/10	12,609	2,012	10,597	454	811	580	57	139	309	10,259
2010/11	12,894	2,082	10,813	464	829	623	67	146	313	10,454
2011/12	13,244	2,241	11,004	465	846	666	76	152	316	10,722
2012/13	13,588	2,377	11,212	466	864	710	86	158	320	10,984
2013/14	13,853	2,456	11,397	467	882	754	96	165	324	11,165
2014/15	14,134	2,548	11,587	461	899	798	105	171	327	11,372
2015/16	14,418	2,639	11,779	456	899	798	105	171	332	11,656
2016/17	14,687	2,729	11,959	457	899	798	105	171	336	11,920

Historical Values (1997 - 2006):

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

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

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

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

Projected Values (2007 - 2016):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1997	35,752	268	317	562	30,850	1,758	1,997	34,605	49.0
1998	38,949	289	333	564	33,387	2,340	2,036	37,763	53.9
1999	40,375	312	339	564	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,835	427	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,479	460	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,680	495	365	779	39,432	4,220	2,389	46,041	52.1
2007	49,878	522	383	779	40,766	4,524	2,904	48,194	56.7
2008	51,201	552	401	780	42,009	4,501	2,958	49,468	56.6
2009	52,389	582	419	779	43,055	4,527	3,027	50,609	57.6
2010	54,344	612	437	779	44,127	5,238	3,151	52,516	57.3
2011	55,652	642	455	779	45,243	5,363	3,170	53,776	57.5
2012	56,942	672	473	780	46,337	5,437	3,243	55,017	57.0
2013	58,293	702	491	779	47,457	5,542	3,322	56,321	57.0
2014	59,752	732	509	779	48,614	5,673	3,445	57,732	57.3
2015	61,094	732	509	779	49,802	5,795	3,477	59,074	57.4
2016	62,481	732	509	780	51,027	5,873	3,560	60,460	57.2

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1997	35,752	268	317	562	30,850	1,758	1,997	34,605	49.0
1998	38,949	289	333	564	33,387	2,340	2,036	37,763	53.9
1999	40,375	312	339	564	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,835	427	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,479	460	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,680	495	365	779	39,432	4,220	2,389	46,041	52.1
2007	51,005	522	383	779	41,429	4,524	3,368	49,321	57.1
2008	51,987	552	401	780	42,744	4,501	3,009	50,254	56.6
2009	53,260	582	419	779	43,869	4,527	3,084	51,480	57.5
2010	55,320	612	437	779	45,032	5,238	3,222	53,492	57.2
2011	56,877	642	455	779	46,389	5,363	3,249	55,001	57.4
2012	58,250	672	473	780	47,555	5,437	3,333	56,325	56.9
2013	59,848	702	491	779	48,911	5,542	3,423	57,876	56.9
2014	61,459	732	509	779	50,203	5,673	3,563	59,439	57.2
2015	63,097	732	509	779	51,675	5,795	3,607	61,077	57.3
2016	64,684	732	509	780	53,083	5,873	3,707	62,663	57.2

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.2)

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1997	35,752	268	317	562	30,850	1,758	1,997	34,605	49.0
1998	38,949	289	333	564	33,387	2,340	2,036	37,763	53.9
1999	40,375	312	339	564	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,835	427	360	780	38,193	4,301	2,774	45,268	56.5
2005	48,479	460	363	779	39,177	5,195	2,506	46,878	52.3
2006	47,680	495	365	779	39,432	4,220	2,389	46,041	52.1
2007	49,569	522	383	779	40,147	4,524	3,214	47,885	57.2
2008	50,448	552	401	780	41,304	4,501	2,910	48,715	56.7
2009	51,583	582	419	779	42,306	4,527	2,970	49,803	57.6
2010	53,358	612	437	779	43,207	5,238	3,085	51,530	57.3
2011	54,549	642	455	779	44,216	5,363	3,094	52,673	57.5
2012	55,637	672	473	780	45,117	5,437	3,158	53,712	57.0
2013	56,860	702	491	779	46,123	5,542	3,223	54,888	57.0
2014	58,077	732	509	779	47,049	5,673	3,335	56,057	57.3
2015	59,234	732	509	779	48,062	5,795	3,357	57,214	57.4
2016	60,468	732	509	780	49,147	5,873	3,427	58,447	57.2

* Column (OTH) includes Conservation Energy For Lighting and Public Authority Customers, Customer-Owned Self-service Cogeneration and Load Control Programs.

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.3)

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2006		FORECAST 2007		FORECAST 2008	
	PEAK DEMAND	NEL	PEAK DEMAND	NEL	PEAK DEMAND	NEL
MONTH	MW	GWh	MW	GWh	MW	GWh
JANUARY	7,870	3,390	9,705	3,772	9,943	3,914
FEBRUARY	10,095	3,191	7,862	3,257	8,014	3,383
MARCH	6,441	3,286	6,692	3,509	6,863	3,631
APRIL	7,837	3,582	7,387	3,498	7,540	3,576
MAY	8,382	4,020	8,482	4,271	8,672	4,361
JUNE	9,349	4,401	8,905	4,478	9,071	4,574
JULY	9,462	4,699	9,156	4,867	9,337	4,985
AUGUST	9,689	4,920	9,327	4,919	9,525	5,047
SEPTEMBER	8,794	4,270	8,553	4,434	8,729	4,537
OCTOBER	8,286	3,763	7,975	3,982	8,202	4,076
NOVEMBER	6,415	3,192	6,463	3,426	6,569	3,502
DECEMBER	6,792	3,327	7,529	3,781	7,717	3,882
TOTAL		46,041		48,194		49,468

NOTE: "Actual" = "Total" - "Interruptible" - "Res. LM" - "C/I LM" - "Voltage Reduction & Standby Generation"

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel units) are shown on Schedule 5. PEF's two-year actual and ten-year projected energy sources, in GWh and percent, are shown by fuel type on Schedules 6.1 and 6.2, respectively. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one-fuel source. Natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth. However, the planned nuclear addition in 2016 decreases future natural gas consumption as is shown in the projections.

PROGRESS ENERGY FLORIDA

SCHEDULE 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	NUCLEAR		TRILLION BTU	60	66	61	69	52	69	64	81	75	81	75	135
(2)	COAL		1,000 TON	6,249	5,977	6,179	6,059	6,240	6,389	6,977	6,959	6,728	6,874	6,951	6,792
(3)	RESIDUAL	TOTAL	1,000 BBL	10,324	7,353	9,646	8,490	6,338	5,030	5,522	5,384	5,152	5,307	5,190	4,780
(4)		STEAM	1,000 BBL	10,324	7,353	9,646	8,490	6,338	5,030	5,522	5,384	5,152	5,307	5,190	4,780
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	1,098	713	987	784	901	986	1,196	1,192	1,284	1,220	1,335	1,056
(9)		*STEAM*	*1,000 BBL*	97	90	41	38	46	54	53	44	54	42	47	45
(10)		CC	1,000 BBL	3	2	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	998	621	946	746	855	932	1,144	1,148	1,230	1,177	1,288	1,010
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	68,447	76,448	83,645	100,282	129,303	140,233	150,996	149,977	168,758	180,835	193,010	175,170
(14)		STEAM	1,000 MCF	732	1,731	0	0	0	0	0	0	0	0	0	0
(15)		CC	1,000 MCF	52,590	61,487	65,316	84,124	112,747	125,315	133,815	132,786	151,618	164,412	175,697	159,507
(16)		CT	1,000 MCF	15,125	13,230	18,328	16,159	16,556	14,918	17,180	17,191	17,140	16,423	17,312	15,663
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL	1,000 BBL	N/A	N/A	47	11	13	5	13	19	15	0	0	0
(18)	OTHER, NATURAL GAS	ANNUAL	1,000 MCF	N/A	N/A	0	0	0	0	0	0	0	0	0	0
(18.1)	*OTHER, NATURAL GAS*	*ANNUAL*	*1,000 MCF*	*N/A*	*N/A*	*8,512*	*4,954*	4,720	4,327	6,867	6,743	6,524	5,956	*6,720*	3,861

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	2,220	2,091	2,200	1,854	1,881	1,750	734	689	672	592	669	349
(2)	NUCLEAR		GWh	5,829	6,382	5,951	6,671	5,099	6,992	6,473	8,114	7,575	8,183	7,576	13,385
(3)	COAL		GWh	15,834	14,968	15,260	14,781	15,187	14,782	16,149	16,108	15,568	15,900	16,083	15,680
(4)	RESIDUAL	TOTAL	GWh	6,618	4,656	5,968	5,217	3,894	3,092	3,418	3,329	3,181	3,278	3,207	2,926
(5)		STEAM	GWh	6,618	4,656	5,968	5,217	3,894	3,092	3,418	3,329	3,181	3,278	3,207	2,926
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	414	258	364	277	321	356	449	451	495	464	511	394
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	1	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	414	257	364	277	321	356	449	451	495	464	511	394
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	8,236	9,657	10,408	12,714	16,828	18,507	19,966	19,780	22,442	24,111	25,777	23,266
(15)		STEAM	GWh	74	161	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	7,025	8,517	9,002	11,480	15,510	17,328	18,601	18,416	21,070	22,809	24,400	22,014
(17)		CT	GWh	1,137	979	1,406	1,234	1,318	1,179	1,365	1,363	1,372	1,303	1,377	1,252
(18)	OTHER 2/														
	QF PURCHASES		GWh	4,211	4,394	3,357	3,247	2,552	2,460	2,463	2,468	2,283	1,473	1,473	1,476
	RENEWABLES		GWh	--	--	1,145	1,231	1,301	2,064	2,062	2,065	2,033	1,700	1,658	1,657
	IMPORT FROM OUT OF STATE		GWh	3,599	3,683	3,542	3,476	3,546	2,512	2,061	2,014	2,072	2,031	2,121	1,328
	EXPORT TO OUT OF STATE		GWh	-83	-48	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	46,878	46,041	48,194	49,468	50,609	52,516	53,776	55,017	56,321	57,732	59,074	60,460

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

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

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	ANNUAL FIRM INTERCHANGE 1/		%	4.7%	4.5%	4.6%	3.7%	3.7%	3.3%	1.4%	1.3%	1.2%	1.0%	1.1%	0.6%
(2)	NUCLEAR		%	12.4%	13.9%	12.3%	13.5%	10.1%	13.3%	12.0%	14.7%	13.4%	14.2%	12.8%	22.1%
(3)	COAL		%	33.8%	32.5%	31.7%	29.9%	30.0%	28.1%	30.0%	29.3%	27.6%	27.5%	27.2%	25.9%
(4)	RESIDUAL	TOTAL	%	14.1%	10.1%	12.4%	10.5%	7.7%	5.9%	6.4%	6.1%	5.6%	5.7%	5.4%	4.8%
(5)		STEAM	%	14.1%	10.1%	12.4%	10.5%	7.7%	5.9%	6.4%	6.1%	5.6%	5.7%	5.4%	4.8%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.9%	0.6%	0.8%	0.6%	0.6%	0.7%	0.8%	0.8%	0.9%	0.8%	0.9%	0.7%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.9%	0.6%	0.8%	0.6%	0.6%	0.7%	0.8%	0.8%	0.9%	0.8%	0.9%	0.7%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	17.6%	21.0%	21.6%	25.7%	33.3%	35.2%	37.1%	36.0%	39.8%	41.8%	43.6%	38.5%
(15)		STEAM	%	0.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(16)		CC	%	15.0%	18.5%	18.7%	23.2%	30.6%	33.0%	34.6%	33.5%	37.4%	39.5%	41.3%	36.4%
(17)		CT	%	2.4%	2.1%	2.9%	2.5%	2.6%	2.2%	2.5%	2.5%	2.4%	2.3%	2.3%	2.1%
(18)	OTHER 2/														
	QF PURCHASES		%	9.0%	9.5%	7.0%	6.6%	5.0%	4.7%	4.6%	4.5%	4.1%	2.6%	2.5%	2.4%
	IMPORT FROM OUT OF STATE		%	7.7%	8.0%	7.3%	7.0%	7.0%	4.8%	3.8%	3.7%	3.7%	3.5%	3.6%	2.2%
	EXPORT TO OUT OF STATE		%	-0.2%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

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

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth, and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric energy usage over the planning horizon. PEF's forecasting framework utilizes a set of econometric models to achieve this end. This section will describe the underlying methodology of the customer, energy, and peak demand forecasts including the principal assumptions incorporated within each. Also included is a description of how Demand-Side Management (DSM) impacts the forecast, the development of high and low forecast scenarios and a review of DSM programs.

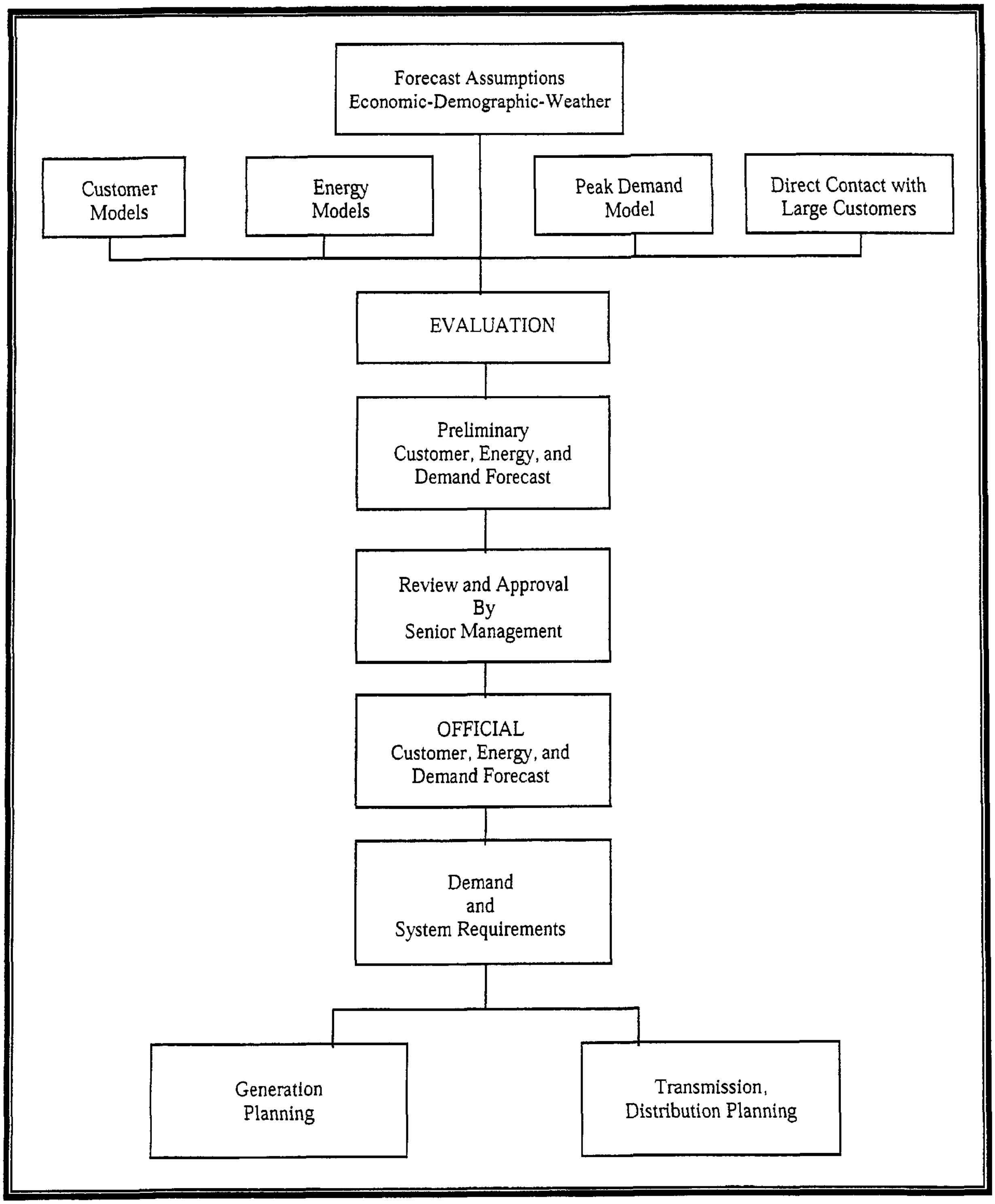
Figure 2.1, entitled "Customer, Energy and Demand Forecast", gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage as well as customer growth based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Corporate Planning Department develops these assumptions based on discussions with a number of departments within PEF, 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 forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

1. Normal weather conditions for energy sales are assumed over the forecast horizon using a sales-weighted thirty-year average of conditions at seven weather stations across Florida (St. Petersburg, Tampa, Orlando, Winter Haven, Gainesville, Daytona, and Tallahassee). For kilowatt-hour sales projections, normal weather is based on a historical thirty-year average of service area weighted billing month degree-days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak at the Tampa, Orlando, and Tallahassee weather stations; the other weather stations are not used in developing the historic average because they lack the data needed for peak-weather normalization.

2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 144 (February 2006) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (March 2006) are also incorporated.

3. Within the PEF service area the phosphate mining industry is the dominant sector in the industrial sales class. Four major customers accounted for 30% of the industrial class MWh sales in 2006. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by the state of these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions. Also, a weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer

producers becoming more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase in the near term, as a new mine operation is expected to open. A significant risk to this projection lies in the volatile price of energy (natural gas), which is a major cost of fertilizer production. Operations at several sites in the U.S. have already scaled back or shutdown in 2005-2006 due to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

4. PEF supplies load and energy service to wholesale customers on a "full", "partial", and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Contracts for this service include the cities of Bartow, Chattahoochee, Mt. Dora, Quincy, Williston, and Winter Park. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations reflected by the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Florida Municipal Power Agency (FMPA), New Smyrna Beach, Tallahassee, Homestead, Reedy Creek Utilities, TECO Energy (Market Mitigation Sale) and Seminole Electric Cooperative, Inc. (SECI). PEF's contractual arrangement with SECI includes a "supplemental" service contract (1983 contract) for service over and above stated levels they commit to supply themselves. This contract is projected to become a "winter only" seasonal purchase in 2014 when the term of this contract expires in December 2013. A firm PR contract with SECI includes 450 MW of stratified intermediate service (October 1995 contract) which is projected to continue through the forecast horizon. In addition, a FR contract to serve SECI load, will commence in 2010, and last through the forecast horizon. Finally, an agreement to provide interruptible service at a SECI metering site has also been included in this projection.

5. This forecast assumes that PEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions from PEF's dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the FPSC.

7. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the company does not plan for generation resources unless a long-term contract is in place. Current FR customers are assumed to renew their contracts with PEF except those who have given notice to terminate. Current PR contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur based on information provided by the Regulated Commercial Operations Department.

SHORT-TERM ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in 2006 as energy prices were hitting record highs around the world. The consensus was that the U.S. economy, which was growing at a reasonable rate, would not slip into recession due to the higher cost of energy. Instead, a "soft patch" in economic activity apparent at the time of this forecast development as high gasoline prices had been reducing consumer confidence levels. Short term interest rates, controlled mostly by Federal Reserve Board (FED) policy decisions, peaked in mid-2006 and have remained stable after 17 increases based upon signs coming from a weakening construction industry and lower inflation. Economists are not in complete agreement about where monetary policy may go from here. A slight majority suspect that the FED has ended its "tightening" policy of gradually raising interest rates as opposed to those who believe that new inflationary fears will require more rate increases.

Consensus opinion believes that the economic stimulus supplied by the three federal tax cuts and the refinancing boom have successfully kept the U.S. economy out of recession after the September 11, 2001 terrorist attacks. Now, with rates back up to more normal levels, and talk of rescinding some of the tax cuts, stimulus from these two economic tools is not expected going forward. One item believed to become a positive factor for future economic momentum is the weaker U.S. currency. Up to this point several major U.S. trading partners, mainly China, have their currencies pegged to the U.S. Dollar. This has kept the typical advantages of a weaker currency from helping U.S. manufacturers. Going forward, it is expected that economic and political pressures will force the Chinese to de-link their currency and allow it to appreciate in value. This likely will make American-produced products more competitive with imported Chinese goods, as well as other goods produced around the globe.

The housing sector, which had a record run in the first half of the decade, has peaked and has now slowed. While the fall-off in housing starts has only taken the industry down to normal levels seen before the run-up, no one feels confident predicting when the bottom will be reached. Home sales have dipped significantly and the number of unsold and even vacant homes has hit record levels leading to significant price reductions in some areas of the country. On top of all this, the number of foreclosures and mortgages in default has risen of late. More homeowners, struggling to meet higher payments from adjustable-rate loans, are walking away from homes as they become "upside-down" in the mortgage (when the market price falls below the outstanding loan amount.) All of this does not bode well for Florida, which played a major part in the recent housing boom. In order to grow out of this, migration into the State will need to absorb this overhang in available housing at a time when out-of-state homeowners may have a difficult time selling their property.

The Florida economy has faired much better than the nation, especially in terms of job growth. The tourism industry, which has bounced back from the terrorism fears of 2001, will now have to juggle the impact of high oil prices on the travel industry. Also, the increases in property insurance and property taxes in Florida have caused anxiety. Florida's reputation as a low cost-of-living state has been impacted.

Besides growth in State population, growth in energy consumption can also be directly tied to the levels of economic activity as measured by total personal income and employment. Florida has experienced excellent employment growth since the last recession – better than most other states.
However, due to the run-up in energy prices, the need for greater national energy independence and the wider review of the potential effects of climate change upon the environment, energy consumption of all types and at all consumer levels are coming under greater scrutiny. In addition, federal and state tax incentives to conserve energy are becoming more widespread and energy-saving

capital improvements are becoming more economically viable. Even players with significant economic influence – like Wal-Mart stores – are pressing their suppliers to become more energy efficient. Just as occurred after each of the Arab oil embargoes, all of these factors may drive the country to improve energy use per unit of Gross Domestic Product (GDP), which could reduce the growth in energy demand. The level of energy prices will obviously play a major role in the outcome.

LONG-TERM ECONOMIC ASSUMPTIONS

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

Population Growth Trends

This forecast assumes Florida will experience slower in-migration and population growth over parts of 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 several reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Now that this generation is retiring, there exists a smaller pool of retirees capable of migrating to Florida. As we enter into the second decade of the new century and the baby-boom generation enters retirement age, the reverse effect can be expected.

Second, the enormous growth in population and corresponding development of the 1980s, 1990s and early 2000s made portions of Florida less desirable and less affordable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

Another reason for a population growth slowdown appears to be the fear and expense of Hurricanes. The summers of 2004 and 2005 may force some in-migrants to rethink their retirement location as the inconvenience caused by recent destruction and ever-increasing cost of property insurance makes Florida a less desirable place to live.

Economic Growth Trends

Florida has been recently experiencing a 1980s-style population explosion and service sector job creation. The State has benefited greatly from generational lows in interest rates, which along with investors' unfriendly attitude toward the equity markets, set the stage for a tremendous explosion in home construction. The national level of homebuilding in 2005, which rose to more than 31% higher than in 2000, set an all time record. This growth produced strong gains in both the construction industry and service-producing sectors of the Florida economy.

We now see that this pace of growth has not been sustained, and the economic environment that produced this construction boom has returned to normal. Interest rates have risen to more "long term" norms. Investment in equity markets over housing has occurred as well. More importantly, affordability rates have dropped as housing prices in many parts of Florida have out-paced many areas of the country. This could have a major impact on retiree decisions to move into the area. Making matters worse is the availability and affordability of homeowners insurance, which has become a concern of increasing importance since the Hurricane seasons of 2004 and 2005.

Florida's rapid population growth of late has created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also a number of corporations migrating to Florida capitalizing on the low cost, low tax business environment. This being the case, 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 but at a less significant level. Florida's successful effort to attract a large biotech firm, Scripps Research, has the potential to draw a whole new growth industry to the State, the same way Disney and NASA once did.

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

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

FORECAST METHODOLOGY

The PEF forecast of customers, energy sales, and peak demand is developed using customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, subtle changes in existing customer usage are better captured as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management, and interruptible service.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and annual data for customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the 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. The external sources of data include Moody's Economy.Com and the University of Florida's Bureau of Economic and Business Research. Internal company forecasts are used for projections of electricity price, weather conditions, and the length of the billing month. Normal weather, which is assumed throughout the forecast horizon, is based on the 30-year average of heating and cooling degree-days by month as measured at several weather stations throughout Florida for energy projections and temperatures around the hour of peak for the firm retail demand forecast. Projections of PEF's demand-side management (conservation programs) are also incorporated as reductions to the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real Florida personal income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures significant variation in residential usage caused by economic cycles, weather fluctuations, electric price movements, and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual customer growth with PEF service area population growth and mortgage rates. County level population projections for the 29 counties, in which PEF serves residential customers, are provided by the BEBR.

Commercial Sector

Commercial MWh energy sales are forecast based on commercial (non-agricultural, non-manufacturing and non-governmental) employment, the real price of electricity to the commercial class, the average number of billing days in each sales month and heating and cooling degree-days. The measure of cooling degree-days utilized here differs slightly from that used in the residential sector reflecting different temperature bases where heating and cooling load become observable. Commercial customers are projected as a function of the number of residential customers served.

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry comprises nearly a 30% share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment and a Florida industrial production index developed by Economy.Com, the real price of electricity to the industrial class, and the average number of sales month billing days.

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

Street Lighting

Electricity sales to the street and highway lighting class are projected to increase due to growth in the service area population base. Because this class comprised less than 0.01% of PEF's 2006 electric sales and just 0.1% of total customers, a simple time trend was used to project energy consumption and customer growth in this class.

Public Authorities

Energy sales to public authorities (SPA), comprised mostly of government operated services, is also projected to grow with the size of the service area. The level of government services, and thus energy use per customer, can be tied to the population base, as well as to the state of the economy. Factors affecting population growth will affect the need for additional governmental services (i.e., schools, city services, etc.) thereby increasing SPA energy usage per customer. 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 (class specific), the real price of electricity and the average number of sales month billing days, results in a significant level of explained variation over the historical sample period. Intercept shift variables are also included in this model to account for the large change in school-related energy use in the billing months of January, July, and August. SPA customers are projected linearly as a function of a time-trend.

Sales for Resale Sector

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

SECI is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average historical load shape of total SECI load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has an agreement with SECI to serve stratified intermediate and peaking energy. This agreement involves serving 450 MW of stratified intermediate demand that is assumed to remain a requirement on the PEF system throughout the forecast horizon. A "winter-only" seasonal peaking strata contract for 600 MW will replace the supplemental contract in 2014. An agreement to provide non-firm service is currently in effect between PEF and SECI amounting to an estimated 15 MW. Another contract, signed in 2004 to supply full requirements service for 150 MW, will begin in 2010.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Several of the customers in this class are municipalities whose full energy requirements are met by PEF. The full requirement customers are modeled individually using local weather station data and population growth trends. 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 PEF retail-based residential and commercial customer classes. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach (NSB), Homestead, and Tallahassee, and other power providers like FMPA. In each case, these customers contract with PEF for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of the FMPA contract is subject to change each year via a letter of "declared" MW nomination. More specifically, this means that the level and type of demand and energy under contract can increase or decrease for each year a value is nominated. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load. The energy projections for FMPA also include a "losses service contract" for energy PEF supplies to FMPA for transmission losses incurred when "wheeling" power to their ultimate customers in PEF's transmission area. This projection is based on the projected requirements of the aggregated needs of the cities of Ocala, Leesburg, Bushnell, Havana, and Newberry.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, PEF's coincident system peak is dissected into five major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand and interruptible demand.

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

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been approved by the FPSC. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm retail demand resulting in a projected series of retail demand figures one would expect to occur.

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

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

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand

and are assigned a negative value. Total system firm peak demand is then calculated as the arithmetic sum of the five components.

HIGH AND LOW FORECAST SCENARIOS

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

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

The low retail scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate probability of occurrence of 0.10. The high retail scenario similarly represents a bandwidth forecast with an approximate probability of occurrence also at 0.10. 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

PEF's DSM performance is shown in the following tables, which compare the conservation savings actually achieved through PEF's DSM programs for the reporting years of 2005 and 2006 with the Commission-approved conservations goals.

On August 9, 2004, the FPSC issued a PAA Order approving new conservation goals for PEF that span the ten-year period from 2005 through 2014, as well as a new DSM Plan for PEF that was specifically designed to meet the new conservation goals. (Docket 040031-EG, Order No. PSC-04-0769-PAA-EG). On January 5, 2007, the FPSC issued a PAA Order approving 39 additional DSM measures and 2 residential programs, which will serve to increase the demand and energy savings available through PEF's DSM Plan. (Docket 060647: Consummating Order PSC-07-0017-CO-EG making Order PSC-06-1018-TRF-EG effective and final.)

Residential Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	13	18	43	48	21	29
2006	21	37	75	99	35	58

Commercial Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	4	8	3	6	3	3
2006	7	16	7	12	6	9

The forecasts contained in this Ten-Year Site Plan document are based on these 2007 program additions and modifications to PEF's DSM Plan and, therefore, appropriately reflect the most current projection of DSM savings over the next ten years. PEF's DSM Plan consists of seven residential programs, eight commercial and industrial programs, and one research and development program. On January 5, 2007, the FPSC issued a PAA Order approving 39 additional DSM measures and 2 residential programs. (Docket 060647: Consummating Order PSC-07-0017-CO-EG making Order PSC-06-1018-TRF-EG effective and final). Megawatt contributions to the TYSP, reflected in this report, have increased as a result of these changes to conservation, standby and residential load management programs. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all DSM resources are acquired in a cost-effective manner and that the program savings are durable. Following is a brief description of these programs.

RESIDENTIAL PROGRAMS

Home Energy Check Program

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit –A customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III). Additionally, a student audit was piloted in 2006. 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 energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement Program

This is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps. The additional measures within this program include spray-in wall insulation, central AC 14 SEER non-electric heat, supply and return plenum duct seal, proper sizing of hi-efficiency HVAC, HVAC commissioning, reflective roof coating for manufactured homes, reflective roof for single-family homes, window film or screen, and replacement windows.

Residential New Construction Program

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising. New measures within the Residential New Construction Program include HVAC commissioning, window film or screen, reflective roof for single-family homes, attic spray-on foam insulation, conditioned space air handler and energy recovery ventilation.

Low Income Weatherization Assistance Program

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Neighborhood Energy Saver Program

The newly approved Neighborhood Energy Saver (NES) Program consists of 12 measures including compact fluorescent bulb replacement, water heater wrap and insulation for water pipes, water heater temperature check and adjustment, low-flow faucet aerator, low-flow showerhead / refrigerator coil brush, HVAC filters and weatherization measures (weather stripping / door sweeps / etc.). In addition to the installation of new conservation measures, an important component of this program is educating families on energy efficiency techniques and the promotion of behavioral changes to help customers control their energy usage.

Residential Energy Management Program

This is a voluntary customer program that allows PEF 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 PEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated above 600 kWh/month.

Renewable Energy Saver Program (2007)

The Renewable Energy Saver Program is designed to reduce system peak demand and increase renewable energy generation on the PEF grid. The program seeks to meet the following overall goals:

1. Obtain energy and demand reductions that are significant and measurable.
2. Enhance customers/contractors awareness of the capabilities of renewable energy technologies.
3. Educate customers/contractors about additional opportunities to generate / use renewable energy.
4. Develop and offer renewable energy measures to the marketplace.
5. Minimize "lost opportunities" in the renewable energy market.
6. Increase participation in the PEF Load Management program.

The Renewable Energy Saver Program consists of two measures:

- Solar Water Heater with Energy Management – This measure encourages residential customers to install a solar thermal water heating system. The customer must have whole house electric cooling, electric water heating, and electric heating to be eligible for this program. Pool heaters and photovoltaic systems would not qualify. In order to qualify for this incentive, the heating, air conditioning, and water heating systems must be on the Energy Management Program and the solar thermal system must provide a minimum of 50% of the water-heating load.

- Solar Photovoltaics with Energy Management – This measure promotes environmental stewardship and renewable energy education through the installation of solar energy systems at schools within Progress Energy Florida's service territory. Customers participating in the Winter-Only Energy Management or Year-Round Energy Management plan can elect to donate their monthly credit toward the Solar Photovoltaics with Energy Management Fund. The fund will accumulate associated participant credits for a period of two years, at which time the customer may elect to renew for an additional two years. All proceeds collected from participating customers, and their associated monthly credits, will be used to promote photovoltaics and renewable energy education opportunities.

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 facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of the following types of audits: A free walk-through audit, and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online at Progress Energy's website. 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 PEF and its customers. The Better Business Program promotes energy efficient heating, ventilation, air conditioning (HVAC), and some building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation and Energy Star cool roof coating products.) Newly approved measures within this program include demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, packaged AC steam cleaning, roof insulation, roof-top unit recommissioning, thermal energy storage and window film or screen.

Commercial/Industrial New Construction Program

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the state energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives will be provided for high efficiency HVAC equipment, energy recovery ventilation and Energy Star cool roof coating products. Additional options, beginning in 2007, include demand-control ventilation, efficient compressed air systems, efficient motors, efficient indoor lighting, green roof, occupancy sensors, roof insulation, thermal Energy Storage and window film or screen.

Innovation Incentive Program

This program promotes a reduction in demand and energy by subsidizing energy conservation projects for customers in PEF'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 PEF representatives during a Business Energy Check audit. If a candidate project meets program specifications, it will be eligible for an incentive payment, subject to PEF approval.

Commercial Energy Management Program (Rate Schedule GSLM-1)

This direct load control program reduces PEF's demand during peak or emergency conditions. As described in PEF's DSM Plan, this program is currently closed to new participants. It is applicable to existing program participants 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 existing participants 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). Customers receive a monthly credit on their bills depending on the type of equipment in the program and the interruption schedule.

Standby Generation Program

This demand control program reduces PEF'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 PEF demand when PEF deems it necessary. The customers participating in the Standby Generation program receive a monthly credit on their electricity bills according to the demonstrated ability of the customer to reduce demand at PEF's request.

Interruptible Service Program

This direct load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for this ability to interrupt load, customers participating in the Interruptible Service program receive a monthly interruptible demand credit applied to their electric bills.

Curtailable Service

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

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development Program

The primary purpose of this program is to establish a system to "Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects" (Rule 25-17.001, {5}(f), Florida Administration Code). PEF will undertake certain development, educational and demonstration projects that have promise to become cost-effective demand reduction and energy efficiency programs. This would include projects like Broadband-Over-the

Power-Line-In-Premise load management capabilities, which the Company is currently evaluating and testing. The objective of this project is to develop the next generation of load management with goals of increasing customer awareness to efficiently use energy, while advancing demand response capabilities. Additional projects include the evaluation of off-peak generation storage for on-peak demand consumption. In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program requires field-testing with customers.

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

Progress Energy

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 10,752 MW, as shown in Table 3.1. This capacity resource includes nuclear (769 MW), fossil steam (3,903MW), combined cycle plants (1,659 MW), combustion turbine (2,513 MW, 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (484 MW), independent power purchases (611 MW), and non-utility purchased power (813 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QF's).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2007 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

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

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes a net gain in summer capacity of 3,575 MWs through the summer of 2016. As identified in Schedule 8, PEF's next planned unit is the Hines 4 Unit, a 461 MW (summer) power block with a December 2007 in-service date. PEF's self-build option for Hines Unit 4 was determined to be the most cost-effective alternative, followed by the Bartow Repowering Project to be completed by June 2009.

PEF's Base Expansion Plan projects the need for additional units with proposed in-service dates from 2007 through 2016. These units, together with the OUC purchase (December 2006 – February 2007), the Central Power & Lime purchase (December 2005 - December 2010), the Reliant/Osceola purchase (January 2007 - February 2009), the TEA purchase (from January 2007 - February 2007, and June 2007 - September 2007), purchases currently under negotiation for the summers of 2007 and 2008, the Shady Hills Purchase (April 2007 - April 2024), and the Southern Company Purchase (June 2010 - December 2017) help the PEF system meet the growing energy requirements of its customer base. Additionally, some undesignated seasonal purchases for 2007 and 2008 are projected as well to meet requirements. Some of the identified unit additions may be impacted by PEF's ability to extend or replace existing purchase power contracts, as well as contracts with cogenerators and QF's. Status reports and specifications for new generation facilities are included in Schedule 9. Shown in Schedule 10 are the new transmission lines associated with Hines #4 and the Bartow Repowering Project.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion in the near term. New nuclear technologies appear to offer more favorable long-term economics, and provide favorable environmental characteristics, measured against possible emission limits imposed by the recently issued Clean Air Interstate Rule (CAIR). PEF is currently evaluating the nuclear option with the intent of pursuing preliminary licensing activities for the addition of new nuclear capacity in 2016. In the years prior to the addition of new nuclear capacity, PEF also is investigating the possibility of coal gasification as a fuel source for one of the combined cycle facilities listed in the resource plan.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2006

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	*(1)*
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,313	
Anclote	2	1,005	
Bartow	3	444	
Suwannee River	3	141	
Total Fossil Steam	12	3,903	
Combined Cycle			
Hines Energy Complex	3	1,456	
Tiger Bay	1	203	
Total Combined cycle	4	1,659	
Combustion Turbine			
DeBary	10	643	
Intercession City	14	992	*(2)*
Bayboro	4	177	
Bartow	4	176	
Suwannee	3	157	
Turner	4	150	
Higgins	4	110	
Avon Park	2	50	
University of Florida	1	45	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,513	
Total Units	64		
Total Net Generating Capability		**8,844**	

(1) Adjusted for sale of approximately 8.2% of total capacity
(2) Includes 143 MW owned by Georgia Power Company (Jun-Sep)

Purchased Power			
Qualifying Facility Contracts	19	813	
Investor Owned Utilities	2	484	
Independent Power Producers	2	611	
TOTAL CAPACITY RESOURCES		**10,752**	

TABLE 3.2 PROGRESS ENERGY FLORIDA QUALIFYING FACILITY GENERATION CONTRACTS AS OF DECEMBER 31, 2006	
Facility Name	**Firm Capacity (MW)**
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery 1	40.0
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
Royster	30.8
TOTAL	**812.6**

PROGRESS ENERGY FLORIDA

SCHEDULE 7.1
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2007	8,701	1,661 *	0	803	11,165	9,327	1,838	20%	0	1,838	20%
2008	9,175	1,503 *	0	799	11,477	9,525	1,952	20%	0	1,952	20%
2009	9,881	1,095	0	659	11,635	9,553	2,082	22%	0	2,082	22%
2010	9,891	1,253	0	775	11,919	9,801	2,118	22%	0	2,118	22%
2011	9,926	1,370	0	775	12,071	9,992	2,079	21%	0	2,079	21%
2012	10,077	1,530	0	775	12,382	10,173	2,209	22%	0	2,209	22%
2013	10,614	1,530	0	665	12,809	10,379	2,430	23%	0	2,430	23%
2014	11,151	1,530	0	478	13,159	10,711	2,448	23%	0	2,448	23%
2015	11,151	1,530	0	478	13,159	10,933	2,226	20%	0	2,226	20%
2016	12,276	1,459	0	478	14,213	11,169	3,044	27%	0	3,044	27%

* Progress Energy is pursuing summer seasonal purchases of approximately 200 MW in 2007 and 250 MW in 2008. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

Hearing ID# 28

Prior Application of Item 10 under Order No. 14546

Company	Order No.	Date	Project Description	Project Cost	Amortization Period	Estimated Savings Over Recovery Period	Ratio of Savings to Costs Over Recovery Period
FPL	PSC-96-1172-FOF-EI	09/19/96	Thermal Uprate of Turkey Point units 3 & 4	$10 million	2-years	$18.7 million	1.9
FPC	PSC-97-0359-FOF-EI	03/31/97	Conversion of peaking units to natural gas (DeBary 7, Bartow 3 & 4, Suwannee 1)	$7.5 million	5-years	$22 million	2.9
FPC	PSC-96-0353-FOF-EI	03/13/96	Conversion of combustion turbine units to natural gas (Intercession City CT units P8 and P10)	$2.6 million	5-years	$16 million	6.2
FPC	PSC-95-1089-FOF-EI	09/05/95	Conversion of combustion turbine units to natural gas (Intercession City CT units P7 and P9)	$2.5 million	5-years	$20 million	8.0
FPC	PSC-98-0412-FOF-EI	03/20/98	Conversion of Suwannee 3 to natural gas	$2.45 million	5-years	$3.25 million	1.3
PEF			CR3 Uprate Project	$381.8 million	10-years	$1,020.2 million	2.7

Source: Relevant Orders per Javier Portuondo July 19, 2007 Rebuttal Testimony, pages 20-21.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 28
COMPANY PEF
WITNESS Prior Application of Item 10 under Order No. 14546
DATE 08/07+08/07

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 29
COMPANY PEF
WITNESS Excel Spread Sheet Showing AFUDC
DATE 08/07-08/07

Crystal River 3 Uprate
NPV Analysis - For Discussion Purposes Only

Retail Return on rate base (pretax) 13.19%

	EST 2006	EST 2007	EST 2008	EST 2009	EST 2010	EST 2011	EST 2012	EST 2013	EST 2014	EST 2015	EST 2016	EST 2017	EST 2018	EST 2019	EST 2020	EST 2021
MUR Plant Mods																
Beginning Balance	-	2.09	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Add Investment	2.09	4.36	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	2.09	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Average Balance	1.04	4.27	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Depreciation Rate			1.0000													
Depreciation Expense	-	-	6.45	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	-	-	-	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Ending Balance Depreciation	-	-	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Phase 1 Plant																
Beginning Balance	-	1.04	13.67	32.64	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Add Investment	1.04	12.63	18.97	55.12	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	1.04	13.67	32.64	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Average Balance	0.52	7.36	23.16	60.20	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Depreciation Rate				0.0083	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.0917		
Depreciation Expense	-	-	-	0.73	8.78	8.78	8.78	8.78	8.78	8.78	8.78	8.78	8.78	8.05	-	-
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	-	-	-	-	0.73	9.51	18.28	27.06	35.84	44.61	53.39	62.17	70.94	79.72	87.77	87.77
Ending Balance Depreciation	-	-	-	0.73	9.51	18.28	27.06	35.84	44.61	53.39	62.17	70.94	79.72	87.77	87.77	87.77
Phase 2 Plant																
Beginning Balance	-	2.09	31.52	55.21	85.19	134.54	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
Add Investment	2.09	29.43	23.69	29.98	49.35	64.18	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	2.09	31.52	55.21	85.19	134.54	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
Average Balance	1.04	16.80	43.37	70.20	109.86	166.63	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
Depreciation Rate						0.016667	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.083333
Depreciation Expense	-	-	-	-	-	3.31	19.87	19.87	19.87	19.87	19.87	19.87	19.87	19.87	19.87	16.56
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	-	-	-	-	-	-	3.31	23.18	43.06	62.93	82.80	102.67	122.55	142.42	162.29	182.16
Ending Balance Depreciation	-	-	-	-	-	3.31	23.18	43.06	62.93	82.80	102.67	122.55	142.42	162.29	182.16	198.72
POD Plant																
Beginning Balance	-	-	-	4.31	24.60	42.69	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16
Add Investment	-	-	4.31	20.29	18.10	8.47	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	-	-	4.31	24.60	42.69	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16
Average Balance	-	-	2.15	14.45	33.64	46.93	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16
Depreciation Rate						0.016667	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.083333
Depreciation Expense	-	-	-	-	-	0.85	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	4.26
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	-	-	-	-	-	-	0.85	5.97	11.08	16.20	21.32	26.43	31.55	36.66	41.78	46.90
Ending Balance Depreciation	-	-	-	-	-	0.85	5.97	11.08	16.20	21.32	26.43	31.55	36.66	41.78	46.90	51.16

	EST 2022	EST 2023	EST 2024	EST 2025	EST 2026	EST 2027	EST 2028	EST 2029	EST 2030	EST 2031	EST 2032	EST 2033	EST 2034	EST 2035	EST 2036
MUR Plant Mods															
Beginning Balance	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Average Balance	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Depreciation Rate															
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Ending Balance Depreciation	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45	6.45
Phase 1 Plant															
Beginning Balance	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Average Balance	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Depreciation Rate															
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Ending Balance Depreciation	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77	87.77
Phase 2 Plant															
Beginning Balance	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
Average Balance	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
Depreciation Rate															
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
Ending Balance Depreciation	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72	198.72
POD Plant															
Beginning Balance	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16
Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16
Average Balance	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16
Depreciation Rate															
Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16
Ending Balance Depreciation	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16	51.16

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Javier Portunondo
Late – Filed Deposition Exhibit 3
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Transmission Equip																															
Beginning Balance	-	-	4.30	13.55	32.97	73.34	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90
Add Investment	-	4.30	9.25	19.42	40.37	30.56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ending Balance	-	4.30	13.55	32.97	73.34	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90
Average Balance	-	2.15	8.93	23.26	53.15	88.62	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90
Depreciation Rate						0.016667	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.083333															
Depreciation Expense	-	-	-	-	-	1.73	10.39	10.39	10.39	10.39	10.39	10.39	10.39	10.39	10.39	8.66	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Beginning Balance Depreciation	-	-	-	-	-	-	1.73	12.12	22.51	32.90	43.29	53.68	64.07	74.46	84.85	95.24	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90
Ending Balance Depreciation	-	-	-	-	-	1.73	12.12	22.51	32.90	43.29	53.68	64.07	74.46	84.85	95.24	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90	103.90
Total Depreciation																															
Total Depreciation Expense	-	-	6.45	0.73	8.78	14.67	44.15	44.15	44.15	44.15	44.15	44.15	44.15	43.42	35.38	29.48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total End Balance Depreciation	-	-	6.45	7.18	15.96	30.63	74.79	118.94	163.10	207.25	251.41	295.56	339.72	383.14	418.52	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00	448.00
Return																															
Beginning Plant In Service			6.45	-	87.04	78.26	417.37	373.21	329.06	284.90	240.75	196.59	152.44	108.28	64.86	29.48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ending Plant In Service		6.45	-	87.04	78.26	417.37	373.21	329.06	284.90	240.75	196.59	152.44	108.28	64.86	29.48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Investment	-	3.23	3.23	43.52	82.65	247.81	395.29	351.14	306.98	262.83	218.67	174.52	130.36	86.57	47.17	14.74	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate of Return	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%	13.19%
Return on Investment	-	-	0.43	0.96	10.91	17.40	52.14	46.31	40.49	34.67	28.84	23.02	17.19	11.42	6.22	1.94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Tax Impact																															
Tax Depr Exp MUR			0.32	0.61	0.55	0.50	0.45	0.40	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.19	-	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depr Exp Phase 1				4.39	8.34	7.50	6.75	6.08	5.47	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	5.18	2.59	-	-	-	-	-	-	-	-	-	-	-	-
Tax Depr Exp Phase 2 Plant						9.94	18.88	16.99	15.29	13.76	12.39	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	5.87	-	-	-	-	-	-	-	-	-	-
Trans & POD						5.81	11.19	10.35	9.58	8.86	8.19	7.58	7.01	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	3.46	-	-	-	-	-
Total Tax Depr Exp	-	-	0.32	5.00	8.89	23.75	37.27	33.83	30.72	28.19	26.14	24.88	24.31	24.22	24.22	24.22	24.22	24.03	21.24	18.65	12.79	6.92	6.92	6.92	6.92	3.46	-	-	-	-	-
Difference B/t Tax & Book	-	-	6.13	(4.27)	(0.11)	(9.08)	6.88	10.33	13.43	15.97	18.01	19.28	19.85	19.21	11.16	5.27	(24.22)	(24.03)	(21.24)	(18.65)	(12.79)	(6.92)	(6.92)	(6.92)	(6.92)	(3.46)	-	-	-	-	-
Deferred Tax Asset/Liab	-	-	2.39	(1.66)	(0.04)	(3.54)	2.68	4.03	5.24	6.22	7.02	7.51	7.73	7.49	4.35	2.05	(9.44)	(9.36)	(8.28)	(7.27)	(4.98)	(2.70)	(2.70)	(2.70)	(2.70)	(1.35)	-	-	-	-	-
Deffered Tax Asset/Liab Impact on Rev Req's	-	-	0.32	(0.22)	(0.01)	(0.47)	0.35	0.53	0.69	0.82	0.93	0.99	1.02	0.99	0.57	0.27	(1.25)	(1.24)	(1.09)	(0.96)	(0.66)	(0.36)	(0.04)	(0.36)	(0.36)	(0.18)	-	-	-	-	-
Revenue Requirements																															
Depreciation Expense	-	-	6.45	0.73	8.78	14.67	44.15	44.15	44.15	44.15	44.15	44.15	44.15	43.42	35.38	29.48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Return on Investment	-	-	0.43	0.96	10.91	17.40	52.14	46.31	40.49	34.67	28.84	23.02	17.19	11.42	6.22	1.94	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	-	-	-	-	-	-	0.38	0.39	0.40	0.41	0.42	0.43	0.44	0.45	0.47	0.48	0.49	0.51	0.52	0.54	0.55	0.57	0.58	0.60	0.61	0.63	0.65	0.67	0.68	0.70	0.72
Aux Power	-	-	-	-	-	-	0.83	0.72	0.71	0.77	0.76	0.83	0.83	0.92	1.05	1.12	1.05	1.03	1.09	1.21	1.15	1.18	1.21	1.24	1.28	1.31	1.34	1.37	1.40	1.43	1.46
DTA Rev Req	-	-	0.32	(0.22)	(0.01)	(0.47)	0.35	0.53	0.69	0.82	0.93	0.99	1.02	0.99	0.57	0.27	(1.25)	(1.24)	(1.09)	(0.96)	(0.66)	(0.36)	(0.04)	(0.36)	(0.36)	(0.18)	-	-	-	-	-
Less: Depreciation in Base Rates - Retired Plant																															
Total Revenue Requirement	-	-	7.20	1.47	19.68	31.60	97.85	92.11	86.44	80.82	75.10	69.43	63.65	57.21	43.69	33.29	0.29	0.30	0.52	0.79	1.04	1.39	1.76	1.48	1.53	1.76	1.98	2.03	2.08	2.13	2.18
Impact to Ratepayer																															
Annual Fuel Savings	-	-	7.91	6.31	20.24	25.87	96.63	85.47	88.54	84.26	96.31	93.78	96.86	98.99	114.15	104.87	108.42	102.26	113.07	114.07	108.31	108.92	109.49	110.02	110.53	111.01	111.47	111.90	112.32	112.72	113.10
Annual Fuel Savings Net of Rev Req's	-	-	0.71	4.84	0.56	(5.73)	(1.22)	(6.64)	2.10	3.44	21.21	24.35	33.22	41.78	70.46	71.58	108.13	101.96	112.55	113.28	107.27	107.53	107.73	108.54	109.00	109.25	109.48	109.87	110.24	110.59	110.92
NPV of Gross Fuel Savings	$706.23																														
NPV of Benefit to Ratepayer	$352.62																														
NPV of Gross Fuel Savings (Retail)	$639.844																														
NPV of Benefit to Ratepayer (Retail)	$319.471																														
NPV Cost (Retail)	$320.373																														
Tax Depr Rates																															
Years In Service	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Tax Depr Rate Plant (15 yr)	0.05	0.10	0.09	0.08	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.03															
Tax Depr Rate POD & Trans (20 yr)	0.04	0.07	0.07	0.06	0.06	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.02										

Progress Energy Announces 2007 Second-Quarter Results; Continues to See Strong Performance From Core Businesses

Highlights:

- Reports second-quarter GAAP loss of $0.75 per share, compared to a loss of $0.19 per share for the same period last year due primarily to losses from the final transactions associated with exiting the merchant energy segment
- Reports core ongoing earnings of $0.59 per share, compared to $0.47 per share for the same period last year due primarily to lower interest expense and lower income taxes
- Reaffirms 2007 core ongoing earnings guidance of $2.70 to $2.90 per share

RALEIGH, N.C., Aug. 8 /PRNewswire-FirstCall/ -- Progress Energy (NYSE: PGN) announced second-quarter net losses of $193 million, or $0.75 per share, compared with net losses of $47 million, or $0.19 per share, for the same period last year. The unfavorable quarter-over-quarter variance in GAAP net income is due primarily to losses incurred as part of the final transactions associated with exiting the merchant energy segment. Second- quarter ongoing earnings were $166 million, or $0.65 per share, compared to $81 million, or $0.33 per share, last year. The favorable quarter-over-quarter variance in ongoing earnings is due primarily to synthetic fuels operating results, lower interest expense and lower income tax expense. (See the discussion later in this release for a reconciliation of GAAP earnings per share to ongoing earnings per share.)

(Logo: http://www.newscom.com/cgi-bin/prnh/20020923/CHM008LOGO-c)

Core ongoing earnings for the second quarter of 2007, which exclude the ongoing earnings from the company's coal and synthetic fuels operations, were $0.59 per share, compared with $0.47 per share last year. The company benefited from lower interest expense and lower income taxes primarily due to the closure of certain tax years and positions related to divested subsidiaries. Favorable weather at Progress Energy Carolinas also contributed to quarter-over-quarter favorability.

"Our core businesses continued to perform well in the second quarter," said Bob McGehee, chairman and chief executive officer of Progress Energy. "With the sale of our energy contracts with the Georgia cooperatives we have completed the last major step in our plan to focus our capital and our attention on meeting the needs of our two growing utilities. We have completed this transition ahead of schedule. More important, the results of this initiative have produced a stronger balance sheet, enhanced credit ratings and have contributed to strong ongoing earnings growth. We believe these actions firmly support our investment objective of offering a reasonable total return with low volatility."

Non-core ongoing earnings for the second-quarter 2007 were $0.06 per share, compared with losses of $0.14 per share last year, primarily due to increased synthetic fuels sales.

PROGRESS VENTURES EXIT REVIEW

The company has closed on the last of the divestitures of assets within the Progress Ventures reporting segment. Over the past two years, the company sold its merchant energy related nonregulated power plants, natural gas assets and associated long-term power contracts. In total, these divestitures produced about $1.7 billion of after-tax proceeds which were applied to debt reduction and other corporate purposes.

"This business was successfully exited while realizing a modest return on our invested capital," McGehee said.

2007 CORE ONGOING EARNINGS GUIDANCE

"We've had a strong first half of the year and our core businesses continue to perform very well. We are confident in reaffirming our 2007 core ongoing earnings guidance of $2.70 to $2.90 per share," McGehee said.

The 2007 core ongoing earnings guidance excludes any impacts from the CVO mark-to-market adjustment, potential impairments, coal and synthetic fuels operations and discontinued operations of other businesses. Progress Energy is not able to provide a corresponding GAAP equivalent for the 2007 earnings guidance figures due to the uncertain nature and amount of these adjustments.

2007 NON-CORE EARNINGS

The company expects earnings from our non-core businesses to be between $0.30 and $0.40 per share with oil prices and production levels being the primary determining factors. However, due to the anticipated conclusion of the synthetic fuels production program at the end of 2007, virtually all of these earnings are likely to be reclassified to discontinued operations and excluded from ongoing earnings results later this year. Based on the latest estimates, the company expects to have in excess of $900 million of deferred tax credits when the synthetic fuels program concludes at the end of this year.

RECENT DEVELOPMENTS

-- Comprehensive energy bill passed in North Carolina; presented to governor to sign into law.
-- Received order from the Florida Public Service Commission to refund $13.8 million of previously collected fuel costs plus interest (the company is considering options).
-- Closed on the sale of remaining nonregulated power plants, hedges and contracts in Progress Ventures.
-- Selected Westinghouse AP1000 reactor technology for potential nuclear plant site in Levy County, Fla.
-- Kicked off the Save the Watts energy efficiency and conservation campaign.
-- Signed long-term contract for 75 MW of electricity generated by what will be the largest wood waste biomass plant in the nation.
-- Issued a request for renewables to expand the company's renewable portfolio and provide cost effective renewable energy to Progress Energy Florida customers.
-- Announced 2,000 MW energy-efficiency goal for Progress Energy

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 070052-EI EXHIBIT 30
COMPANY PEF
WITNESS Second Quarter Results
DATE 08/07-08/07