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THOMAS D. HALL
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	DOCKET NO. 001064-EI
PETITION FOR DETERMINATION OF NEED FOR HINES UNIT 2 POWER PLANT BY FLORIDA POWER CORPORATION.	

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VOLUME 5

Pages 499 through 650

PROCEEDINGS:	HEARING
BEFORE:	COMMISSIONER E. LEON JACOBS, JR. COMMISSIONER LILA A. JABER COMMISSIONER BRAULIO L. BAEZ
DATE:	Friday, October 27, 2000
TIME:	Commenced at 8:40 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	TRICIA DEMARTE Official FPSC Reporter

APPEARANCES:

(As heretofore noted.)

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(Transcript follows in sequence from Volume 4.)

COMMISSIONER JACOBS: We'll go back on the record. Staff, call your first witness.

MS. HART: Staff has called Billy Dickens to the stand.

BILLY R. DICKENS

was called as a witness on behalf of the Florida Public Service Commission and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. HART:

Q Could you please state your name for the record.

A My name is Billy R. Dickens.

Q Mr. Dickens, have you been sworn prior to this time?

A Yes, I have.

Q Thank you. Could you give your business address and position?

A My address is Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida.

Q And what position do you hold with the Commission?

A Currently, I hold the position of regulatory analyst in the Bureau of Policy Analysis at the Florida

Public Service Commission.

Q Are you the same Billy R. Dickens who prefiled direct testimony in this docket?

A Yes, I am.

Q Do you have any changes or amendments to that testimony?

A Yes, I would like to offer a couple of changes at this time.

Q Okay. What are those?

A On Page 2, Line 9, kindly strike "Issue 6" and insert "Issues 4 and 7." Also, kindly strike the second sentence of that same answer from Line 10 through Line 13.

Q Okay. Do you have any other changes?

A No, ma'am, I do not.

Q Did you prepare Exhibit BRD-1 to your testimony?

A Yes, I did.

Q And do you have any changes to that exhibit?

A No, I do not.

Q If I ask you the questions today that are contained in your testimony, would your answers be the same?

A They would be the same.

MS. HART: Mr. Chairman, with the noted changes I'd request that Mr. Dickens' testimony be inserted in the record as though read.

MR. SASSO: We renew our objection to Mr. Dickens' testimony.

COMMISSIONER JACOBS: Very well. Having formally addressed that objection was dually noted, and we will admit the testimony. I guess we should wait, shouldn't we, to make sure -- until Panda shows up, make sure before we do that? Has anybody checked -- let's go off the record for a moment.

(Discussion off the record.)

MS. HART: I'd also ask the exhibit be marked as the Exhibit Number 18.

COMMISSIONER JACOBS: That was BRD-1. Show it marked as Exhibit 18.

(Exhibit 18 marked for identification.)

COMMISSIONER JACOBS: We're going to reserve the option of counsel for Panda to raise an objection to the testimony of Mr. Dickens being entered into the record, and we went ahead and entered it subject to that objection, I mean, opportunity, rather. Very well.

MS. HART: Thank you.

DIRECT TESTIMONY OF BILLY R. DICKENS

Q. **Please state your name and address of your employer.**

A. My name is Billy R. Dickens. I work for the Florida Public Service Commission [FPSC] located at 2540 Shumard Oak Boulevard, Tallahassee Florida.

Q. **Please describe your educational background.**

A. My educational training is in the fields of economics, mathematics and history. I received a Certificate in Economics from Northwestern University in August 1978. I was awarded an A.B. in Economics from the University of the District of Columbia in May 1979 with Departmental honors. My graduate course work in economics was completed at American University. I have one chapter remaining on my dissertation.

Q. **Briefly describe your professional experience.**

A. I am currently employed as a Regulatory Analyst for the Bureau of Policy Analysis with the Florida Public Service Commission. I have nearly seventeen years of professional experience in public policy research and university teaching in the field of economics. I am a former W.E.B. Dubois Fellow at Harvard University and visiting Fellow at the Department of Defense. I have

authored several publications looking at how communities cope with economic uncertainty resulting from military base closures. I am a member of several professional economic societies. I was recently elected Vice-President for the American Association for Blacks in Energy [AABE], Florida Chapter.

Q. **What is the purpose of your testimony?**

A. I am here to address ~~issue 6~~ issues 4 and 7 of the Issue ID List for the Hines 2 Need Determination Docket. ~~This issue raises an important question: *Is it reasonable to obligate Florida Power Corporation's retail customers for the costs of the Hines 2 Unit for the expected life of the unit?*~~ It is my intention to explain why economic uncertainty, due to the advent of electric generation restructuring, raises potential risks for Florida ratepayers.

Q. **Do long term assets represent a potential economic burden for Florida Power Corporation's [FPC] ratepayers?**

A. Yes. Market conditions are moving from ownership of generation to procurement in generation. Decisions concerning how generation of power is executed are based on entrepreneurial ingenuity and market incentives. The dynamics of electric restructuring suggest long term commitments and/or obligations for ratepayer financing of

large scale power construction projects might be incompatible with future technology changes. Captive ratepayers may be subject to economic penalty if they are unable to reap the benefits of positive market change. Technological advance, fuel price escalation and relative price changes collectively imply that ratepayers committed to long-term assets involuntarily forfeit efficient alternatives. Inferior choices typically result in suboptimal outcomes and unnecessary burdens for ratepayers.

Q. **What are the kinds of risk associated with building Hines 2?**

A. There are several kinds of risk associated with FPC's decision to construct Hines 2. First, there is the risk that cost overruns or failure to meet the in-service dates may occur. Quite frankly, I expect given the industry past performance, these are not likely to be major risks. Second, there is the risk that the plant will perform below expectations. This would be reflected in things like high forced outage rates or heat rates. I believe ratepayers can be partially protected from these kinds of risks by the incentives created under the Generation Performance Incentive Factor [GPIF] methodology. Third, there is the risk associated with building a long life asset and having fuel costs exceed

the forecast scenarios. In this case, the ratepayers are paying for the capital cost of this asset and are paying the fuel costs through the fuel cost recovery clause.

Q. **Do current FPSC policies regarding long-term generation assets foster cost-effective results for FPC ratepayers?**

A. The orthodox regulatory compact has approached need determination based on a hedging strategy with capital cost recovery guaranteed over a fixed long-term time horizon. However, the orthodox regulatory compact in today's market has undergone significant revision. Long-term assets preclude economic change and disguise the significance of risk. Failure to properly adjust for risk creates market distortions due to inadequate recognition of both current and future events. Generation and fuel risks suggest this Commission may want to look at the feasibility of performance based incentives as a means to ensure ratepayers are not penalized for favorable market shifts. Given the peculiar nature of current market dynamics and long-term contracts, FPC's ratepayers could be held financially liable for an asset which may not be the least cost alternative in the not too distant future.

Q. **Would short-run contracts reduce risk associated with future**

changes in technology and fuel cost?

A. Not entirely, but they minimize the risks. What's important in today's economy is that generation planning decisions should use the market as a benchmark for evaluating how well services are being delivered to the end-user. Unlike long-term assets, short-run assets are more flexible and can reflect market changes quicker. It is true that greater reliance on short-run market changes exposes participants to the possibility of greater price volatility. However, under short-term contracts, a power provider would be able to better adjust price and technology decisions induced by market forces. This "speed of adjustment" ensures that production embodies the best available technology and concomitant fuel choice mix. To be sure, sometimes long-term contracts are good for ratepayers and energy providers. However, long-term commitments to assets are "costly" if short-run benefits are forfeited because of contractual obligation. This appears to be the logic that FRCC representative Tom Hernandez articulated in the 1997 Ten Year Site Plan Workshop. As shown in the transcript (Exhibit BRD-1 attached hereto and incorporated by reference), Mr. Hernandez puts forth the case for why a shorter planning period was more efficient than the conventional ten year

horizon for capacity planning. In substance, my recommendation parallels the points he raised.

Q. **Are there any experiences in Florida where commitment to long-term assets has resulted in inefficient outcomes for ratepayers?**

A. Yes. The fundamental problem with long-term commitments is that buyers are locked into fixed prices. Once market forces yield equilibrium prices significantly below the lock-in rate, the result is an inefficient outcome. Typically, long-term contracts are beneficial when they have appropriate "out clauses". One need look no further than the counterproductive results of negotiated cogeneration and PURPA contracts executed in this state and others. During the late 1970s, the State of Florida actively implemented features of the National Energy Act mandating that utilities pay for power at avoided cost to Qualifying Facilities [QF's]. Those contracts assumed that QF's could continue to provide power to IOUs at an avoided cost *lower* than *current* market prices. However, the *ex post market price* for wholesale power is now lower than the *ex ante price* reflected in the negotiated QF contract. This unambiguous finding strongly suggests that the avoidance cost doctrine is no longer ratepayer neutral. PURPA mandated avoided costs makes cogeneration contracts

uncompetitive in today's market. Utilities were correct to recognize this degree of economic myopia in avoided cost, resulting in the rush to "buy-out" these inefficient arrangements.

This Commission has already approved numerous settlement agreements in recent years which had the effect of terminating the time-line of certain QF contracts. Order No.'s PSC-97-0523-FOF-EQ, PSC-96-1217-FOF-EQ, and PSC-96-0898-AS-EQ recognized the inherent intergenerational inequities in QF contracts and permitted FPC early termination. Similar authority was granted to Florida Power & Light in Order No. PSC-96-0889-FOF-EU. The lessons from recent history are clear: long-term fixed-price contracts retard market efficiency. If QF contracts are counter-intuitive to economic efficiency, a similar argument can be made that the same holds true for situations involving need determinations for retail-serving utility generation. Competitive markets are more likely to result in the best set of mutually beneficial outcomes for all parties.

Q. **How would you propose that the Commission address the risks associated with construction of the Hines 2 unit?**

A. Assuming Hines 2 is constructed on budget and on time, the

Commission should allow the capital and O&M costs of the unit to be included in rate base for surveillance purposes upon its commercial in-service date. However, the Commission should require FPC to periodically, say every five years, review current market conditions to determine whether the continued operation and rate base recovery of Hines 2 is in the best interests of FPC's ratepayers. This market review should explore all alternatives including, but not limited to, conservation, load management, distributed generation technologies, short-term and long-term purchased power options and replacement construction. If a more cost effective alternative becomes apparent, then the Commission could deny future recovery or authorize an accelerated write off a certain portion of the remaining book costs of Hines 2 thereby treating this asset similar to current practice of reviewing cogeneration contract buy-outs.

Q. **Does this conclude your testimony?**

A. Yes.

BY MS. HART:

Q Mr. Dickens, have you prepared a summary of your testimony?

A Yes, ma'am, I have.

Q Would you please provide that summary to the Commissioners.

A Yes. Good afternoon, Commissioners. Today, I'm appearing before you to share some of my intimate thoughts about whether the proposed Hines 2 unit satisfies your fundamental concerns about cost-effectiveness and meets adequate assurances that FPC's ratepayers will be the beneficiaries of reasonable electric rates. My written testimony is effectively an exploration which looks at how the advent of electric generation restructuring and economic uncertainty may result in unanticipated risks for key Florida stakeholders. The problem I address is rather basic: Should regulatory policy consider future trends about institutional change, generation technologies, and fuel prices in granting a petitioner's request for an affirmative determination of need? My testimony attempts to explain how regulatory policy can be an ally of efficient decision making by explicitly incorporating expectations about the future and emphasizing market allocation rules.

The proposal I offer focuses on establishing a

short-term prudence review which would periodically evaluate the cost-effectiveness of electric generating units like Hines 2 in order to reassure ratepayers that the power that they are buying and enjoying reflects the best available technology and fuel choice mix. This approach would indeed amend the current practice of granting need determination because ratepayers under my proposal would not necessarily assume financial liability over the economic or uneconomic life span for a generating asset.

My analytical training in economics has taught me that current decision making is heavily influenced by expectations about the future. This strongly suggests that the granting of a need determination based exclusively on current information without any regard for what the future may probably look like is potentially unwise, risky, and could exacerbate the problem of regulatory lag.

My proposal is not one-sided by ignoring the interest of FPC's investors. I believe a reasonable risk-sharing arrangement could be provided, if not in this discussion, perhaps in an alternative forum like the fuel adjustment proceedings. Despite the passionate protests by my distinguished colleagues across the aisle, my proposal is not some meandering missive with the sole

purpose of raising FPC's cost of capital. Furthermore, my proposal is not designed to serve as a showstopper or subterfuge in this need determination proceeding. Risk management, not risk transfer is key to my recommendation.

In closing, let me emphasize that my proposal represents a case for choice. I concede the argument that my recommendation is controversial, and as a consequence, I have become somewhat of an unfortunate cause celebre for advancing this idea. But I work in the Bureau of Policy Analysis which means my service at this Commission should include offering innovative ways for looking at current problems and anticipating what may lie ahead. If I succeed in that task, I fulfill the former Soviet leader V.I. Lenin's humorous oxymoron that certain workers can indeed be useful idiots.

Regulatory policy which seeks to maximize choice for electric producers and consumers compliments market allocation. If market conditions suggest that better alternatives exist in the future for electric power generation, these changes will only just enhance economic welfare. Long-term commitments can indeed and can potentially undermine the choice set when efficient alternatives are forfeited. Thank you and this concludes my opening statement.

MS. HART: We tender the witness for cross.

COMMISSIONER JACOBS: Mr. Sasso.

CROSS EXAMINATION

BY MR. SASSO:

Q Mr. Dickens, I understand that you've now stricken Issue 6 from your prefiled testimony; is that right?

A That is correct, sir.

Q Let me turn your attention to Page 2 of your prefiled testimony. Do you have a copy with you?

A Yes, sir.

Q Page 2, first question, "What is the purpose of your testimony?" Are you with me?

A Yes, sir.

Q Your answer is, "I am here to address Issue 6 of the Issue ID List for the Hines 2 Need Determination Docket." Did I read that correctly?

A Yes, sir, you did.

Q And that was your purpose for providing testimony in this case; is that right?

A That is correct.

Q And then you went ahead and you set forth the version of Issue 6 that existed at that time; is that correct?

A That's correct.

Q And it's your best understanding that the idea

for that issue originated with your bureau, the policy bureau; is that right?

A This particular Issue 6?

Q Yes, sir.

A Yes, that's correct. It originated out of the policy division that I work with.

MS. HART: Mr. Chairman, I'd like to object. Issue 6 has been stricken, and Mr. Dickens' testimony has been amended. So I'd like the record to reflect that, and Mr. Sasso's questions directed to Issue 6 are not appropriate.

MR. SASSO: May I respond?

COMMISSIONER JACOBS: Yes.

MR. SASSO: It is the predicate for this witness's testimony. It was identified as the sole purpose for the testimony. To yank it from the testimony is to yank the reason for being from the testimony. It is impossible for me to cross-examine this witness without discussing the purpose of the testimony, the focus of it, and the thrust of it.

And I think in view of the fact that at the last minute Staff has attempted to substitute entirely different issues as the basis for Mr. Dickens' testimony, we have another objection to this, and that is, it's a violation of our due process rights. Mr. Dickens provided

very different testimony the first time. We learned for the first time today that he is purporting to address different issues. I understand the Prehearing Officer and the Commission ruled that this may have some relevance to those issues, but for the witness now to change his testimony at the eleventh hour fundamentally prejudices our due process rights. So I want to note an objection, and I would like permission to continue to examine this witness on the testimony he originally filed that we had notice of.

COMMISSIONER JACOBS: Well, let's break this into piece parts. First, we've entertained the general objection to his testimony, and we have ruled on that. And I would not want your cross-examination now to be essentially reargument of that. To the extent that you would explore a revision of his prefiled testimony, I would think that will be a legitimate scope of cross. However, I would -- there is a fine line between rearguing the motions, and I would really want to ensure that we don't cross that line to the extent it can be clear to you.

MR. SASSO: I understand that, and I have no intention to reargue that. I have argued it quite enough. I do want to make a record though about what the testimony was all about and the purpose of it and the origination of

it because I think that's necessary to protect our position.

MS. HART: Mr. Chairman, I have two comments and those are: As Mr. Sasso stated, the Prehearing Officer's order that struck Issue 6 also said that the issues brought up by Issue 6 are relevant to Issues 4 and 7. In addition, the statement regarding Issue 6 and the second sentence that was stricken are not the sole statement of the reasons for Mr. Dickens' testimony, and I submit that the last sentence in response to that question states very well what the purpose of his testimony is.

COMMISSIONER JACOBS: Let's do this: The objection indicates that you're rearguing the motion essentially on Issue 6. To the extent that this witness's testimony wishes to support other issues, I will allow your questions, and to the extent that you want to explore the idea to which his testimony is no longer supportive of those issues, that I think is a valid line of questioning. But to the extent that we want to rehash the idea of how Issue 6 got here and to where -- and to went -- as far as it went, I think we are probably wasting our time.

MR. SASSO: Okay. Yeah, I won't do anything further on that.

BY MR. SASSO:

Q But I do want to ask Mr. Dickens -- and we

discussed this in your deposition. I just want to make sure nothing has changed in this regard. The issue as it was originally framed assumed, and I think we agreed on this, that under current regulatory policy, customers would in fact be obligated for the costs of the Hines unit for the life of the unit; is that correct?

A That is correct.

Q And is it still the case as it was at the time of your deposition that what you are proposing in your testimony represents a change from current regulatory policy?

A That would be correct.

Q Now, in your testimony also at Page 2 at Line 13, you indicate that you are addressing implications of the advent of electric generation restructuring; is that right?

A Yes, sir.

Q And as I understand it, you are anticipating change on the generation side away from the ownership of generation resources to the procurement of generation resources?

A That is correct.

Q But you are not talking about any situation that exists currently; is that right?

A No, sir. I'm only making a statement with

regards to how I evaluate the current market and what would probably emerge at sometime in the future.

Q What you're really talking about are changes that you anticipate occurring in the future; is that right?

A That is fundamentally the focus of my testimony.

Q And as a regulatory policy analyst, I think you may have mentioned you're looking at tea leaves, or you're making some assessment using your tools and your skills to exercise your best judgment about what the future will look like; is that right?

A That is correct.

Q And as I understand it, the central change that you anticipate that will take place in the market is the shift from ownership to procurement; is that right?

A That would be correct, yes.

Q And you would agree that you have no specific evidence to point to at this time in order to say that the electric industry in Florida is, in fact, moving from ownership to procurement?

A No, I don't offer or proffer any specific evidence to that effect right now.

Q And, in fact, you didn't review the need cases that have been filed in Florida over the last decade, for example, to see whether the utilities that have brought

forth petitions to the Commission were seeking authority for self-build or procurement; is that right?

A I have not reviewed need determination cases over the last decade. I have been a part of several need determination proceedings before this body within the last couple of years; namely, Gulf Power with regards to Smith Lansing 3, I believe it was, Lakeland, and also Cane Island.

Q And you would agree with me that those were all self-build decisions?

A I would agree with you on that, that's correct.

Q Now, at Page 2, you address the question, "Do long-term assets represent a potential economic burden for Florida Power Corporation's ratepayers," and you answer that yes; is that right?

A That is correct.

Q And you would agree that long-term assets may also represent a potential benefit to Florida Power's ratepayers; correct?

A There is a possibility of a benefit as well. That's correct.

Q And, in fact, in looking at the issue whether retail customers ought to pay the costs of a plant, you would agree that if an IPP, for example, sells power to a utility such as Florida Power Corporation, the IPP would

price the power to recover the costs of building and operating the plant?

A Yes, sir.

Q In fact, the IPP would seek to transfer those costs to Florida Power Corporation; is that right?

A That would be correct.

Q And in turn, a utility like Florida Power Corporation would pass those capacity costs and fuel costs of the power purchase agreement along to its ratepayers; is that right?

A That's correct, yes.

Q So one way or another, whether a utility builds a plant or whether it enters into a purchased power agreement, you would agree that retail customers in Florida are going to be expected to pay for the costs of building generation facilities and operating them?

A Under the current regulatory compact, that is correct, yes.

Q And you're not proposing any change in the way that IPP charges or power purchase agreement charges would be handled, are you?

A Not at all, because under my proposal, it's really not significant or important whether it's an IPP or an IOU.

Q So you would apply your proposal to power

purchase agreements and to self-build options?

A Absolutely.

Q You would apply it across the board, in other words --

A I would apply it across the board, that's correct --

Q -- as a general policy?

A -- as a general policy.

Q Now, at Page 2 going over to Page 3 at Line 23 on Page 2, if you'd like to follow me, you assert that the dynamics of electric restructuring suggests long-term commitments and/or obligations for ratepayer financing of large scale power construction projects might be incompatible with future technology changes; is that right?

A That is correct.

Q But you would also agree that long-term commitments might not be incompatible with future technology changes; is that right?

A That possibility is also true.

Q And, in fact, you can often refit a power plant once it's built and introduce new technological changes to improve the efficiency of existing plants; is that right?

A Provided those options are available, that's correct.

Q And, in fact, even if Florida Power Corporation builds Hines 2, you would agree that there would still be a role in its system for existing plants of older technology such as coal plants; is that right?

A Yes; assuming, of course, that there has been some significant relative price change in fuel that would warrant now moving the coal plants up the supply stack.

Q Well, you understand that currently, for example, Florida Power Corporation has two combined cycles in its system?

A Yes.

Q It also has coal plants?

A Yes.

Q And nuclear?

A Yes.

Q And oil?

A That's correct.

Q And these are all plants of differing age and technology; is that right?

A That is correct.

Q And even though the combined cycle may be newer and more efficient, the company still leans on the older coal plants or nuclear plant or oil plant; is that right?

A That is my understanding.

Q They do have a place in the system stack; is

that right?

A They do have a role and a place.

Q And, in fact, you would agree that a utility like Florida Power Corporation actually needs to have a diversity of fuel sources and resources on its system; is that right?

A Yes, I do believe that fuel diversity is an important factor in providing an efficient delivery of electric power services.

Q And, in fact, that diversity enables a utility like Florida Power to operate its system in the most cost-effective manner for the benefit of its ratepayers; correct?

A That is correct.

Q And this diversity, I think you mentioned this, of generating resources provides flexibility to the utility to turn from one type of unit to the other in the event of changes in the pricing of one fuel service. For example, if the price of gas goes up, the company can lean on coal; if coal goes up, they can lean on gas; is that right?

A That's correct.

Q Now, you go on to say at Page 3, Line 2 that captive ratepayers may be subject to economic penalty if they are unable to reap the benefits of market change.

Now, that assumes that the future would in fact present positive alternatives to present alternatives in comparison to present alternatives; right?

A That's correct, yes.

Q But, in fact, a long-term commitment of building a plant can actually protect ratepayers from future trends that might adversely affect their interests?

A Provided the opposite scenario holds that that would be true. Under the current arrangement whereby we have entered into these type of cases with the need determinations, there's a -- the presumption, of course, is that regulated rates will be lower than what market rates would in a sense predict, unquote, over this time frame. So in that sense, the long-term commitment of a long-term arrangement has provided this type of blanket of security.

But as you allude to in this particular sentence here in my testimony, I'm just simply now posing a question about the flip side of that. Well, what happens if given these type of changes that I anticipate that could occur that that would result in market prices now being lower than what the established regulated rates would have been over that time frame?

Q Let's talk about the first part of your response for a moment. I believe you indicated that there is a

security blanket under the current system in that the utilities like Florida Power are held to a regulated rate of return; is that right?

A That is correct.

Q And their rates are regulated in terms of what they can charge their ratepayers?

A Yes, sir.

Q And that does provide some cost control in terms of the burden that may be shouldered by ratepayers for the costs of service they obtain; is that right?

A That's correct.

Q And in the marketplace, risk takers like merchant developers or whatever may have to pay more for their capital to build their facilities, right, because they don't have the security of a regulated rate of return?

A That's right.

Q And so they may actually need a greater price return to recover their investment and to return an investment to their shareholders; is that right?

A That would be correct.

Q Now, if a utility like Florida Power Corporation builds a power plant which will exist under a regulated rate structure for a period of years, you would agree that that can protect ratepayers from price volatility in the

marketplace; is that right?

A That is correct. That has been the basic presumption of the regulatory compact as I understand it in its application to need determination.

Q Now, you say at Page 3, Line 5 that technological advance, fuel price escalation, and relative price changes collectively imply that ratepayers committed to long-term assets involuntarily forfeit efficient alternatives. Are you with me?

A That's correct, yes, sir.

Q Now, you would agree, and I think we have discussed, that IPPs would be affected by fuel price escalation just like Florida Power; is that right?

A IPPs are not immune to fuel price escalation.

Q They are not immune to it?

A They are not immune.

Q They have to buy gas too?

A Yes, sir.

Q And, in fact, they would seek to pass along any escalated price of fuel to Florida Power and its customers, is that right, if we entered into a power purchase arrangement?

A That is correct.

Q Now, at the bottom of Page 3 of your testimony, you address three kinds of risks associated with building

Hines 2; is that right?

A Yes, sir.

Q And the first risk you identify is the risk of cost overruns or the failure to meet the in-service date; correct?

A Correct.

Q But you discount that, essentially. You say that's not a likely risk based on past industry performance; correct?

A Correct.

Q Next, you identify as the second risk that the plant may perform below expectations; is that right?

A Yes.

Q But, again, you say that may be mitigated by the fact that our incentives are available under the generation performance incentive factor methodology; is that right?

A That's correct.

Q And we'll call that GPIF for short.

A Very good.

Q And as I understand it, that program is currently in place in Florida; is that right?

A That's correct.

Q So the Commission already has a policy in place to help mitigate that risk?

A That's correct, yes, sir.

Q Now, the third risk appears to be the focus of your concern, and you say, this risk is associated with building a long life asset and having fuel costs exceed that -- exceed the forecast scenarios; is that right?

A That's correct.

Q And that's essentially the risk you're attempting to address through your proposal?

A Correct, yes.

Q And, again, you would agree that an IPP who might sell power to Florida Power Corporation would be affected by fuel costs exceeding forecast scenarios and would attempt to pass those along to Florida Power's ratepayers?

A Yes, sir.

Q And as we've discussed, when a utility has a diverse system that has different kinds of power plants that use different types of fuel sources, that helps a utility mitigate that risk of being affected by escalation of a particular type of fuel because it could lean on a different type of plant; is that right?

A That's correct, yes.

Q Now, in fact, you've heard some discussion about Hines 2. It's a gas plant with oil backup; is that right?

A That's correct.

Q So in the event there were a temporary spike in gas prices, the Hines plant could lean on its oil backup and avoid that risk; is that right?

A As I understand it, that would be correct, yes.

Q Now, at Page 4, Line 5 of your testimony, you address the question, "Do current FPSC policies regarding long-term generation assets foster cost-effective results for FPC ratepayers," and you answer that on Line 17 (sic) with, "The orthodox regulatory compact has approached need determination based on a hedging strategy with capital cost recovery guaranteed over a fixed long-term time horizon;" correct?

A That is correct.

Q Now, when we talk about the regulatory compact, we're essentially talking about an agreement; right?

A That's correct, yes.

Q An agreement among the regulated utilities, the State, and the ratepayers; right?

A That's correct. Those would be the three primary parties involved.

Q And under this compact, you would agree that the utilities assume an obligation to serve the ratepayers?

A That's correct.

Q And pursuant to that obligation to serve, a utility such as Florida Power may take on the

responsibility and obligation to build power plants like Hines 2?

A That's correct, yes.

Q And under the compact that has been traditionally in place in Florida, a utility that builds a power plant can expect and is entitled to recover the costs reasonably incurred in building that plant; correct?

A That is correct, yes.

Q And traditionally you would agree that the reasonableness of that decision to build the plant has been tested on the basis of circumstances that exist and information available at the time the decision is made to build the plant; right?

A Information that currently exists --

Q Yes.

A -- that's correct.

Q And you would agree that this regulatory compact has been in place and followed by the Public Service Commission in Florida for decades?

A Yes, I would. Yes.

Q And you're proposing a change in this regulatory compact based on an observation that the long-term assets of a utility might preclude economic change and disguise the significance of risk; right?

A I'm suggesting, Mr. Sasso, my preferred language

is an amendment. I'm not suggesting any type of fundamental or wholesale change in any way. I'm just interested in looking at this as a type of rider that could be attached to future need determination proceedings.

Q So your term is you would amend the regulatory compact, you wouldn't fundamentally change it?

A That's correct. That was indicated in my opening statement.

Q Now, you argue that long-term commitments may have some negative effect on ratepayers, but as I understand it, you agree that long-term commitments can also protect ratepayers against future adverse conditions; right?

A Yes, sir. My proposal essentially has focussed on looking at what individuals may describe as the downside risk that's involved with changes in relative prices or technology shifts.

Q So you're really focussing on the downside risk, not the upside benefits of long-term commitments?

A No, I'm not. No.

Q You would agree with my statement then?

A Oh, I'm sorry. Yes, I would.

Q Okay. Now, you understand that after Florida Power builds Hines 2, the company's demand will continue

to grow; right?

A That is correct.

Q And in the future in the company's ten-year site plan, the company has identified that it will be needing to add further capacity after Hines 2 in 2005, 2007, 2009, et cetera; right?

A That's correct, yes.

Q And, in fact, the company will need to add generation resources of about equal size to Hines 2 in those years in order to maintain its reserve margin of planning criteria; is that right?

A Yes, that is the fundamental of planning constraint, as I understand it, that capacity additions have to obviously reflect the agreed upon 20 percent reserve margin.

Q And this will enable the company, among other things, to retire some older units that may be less efficient; is that right?

A Yes, sir.

Q And so it will actually be reducing through that retirement some of the generation assets that it actually owns; is that right?

A That's correct.

Q Okay. Now, in selecting resources for 2005 and 2007, the company will actually be making decisions before

the time that you had proposed that there be some type of forward market test on Hines 2 if it's built; right? You're proposing that there be something five years out from the in-service date, which would be about 2008?

A Yes. The idea about a type of market review or prudence review would occur, you know, five, seven years after in-service date commences.

Q So between now and then if the Commission were to adopt that proposal, the company would in any event be looking at adding additional generation resources of about equal size to Hines 2 for in-service in 2005 and 2007; is that correct?

A That would be correct.

Q And there is nothing that would prevent Florida Power from adding contracts to its portfolio in the future for those needs in 2005 and 2007 if it goes ahead and builds Hines 2; right?

A No, not at all.

Q And if existing laws and regulations stay in place, you would expect that before 2005, Florida Power will test the market again as they did in this situation by issuing an RFP, and then deciding whether Hines 3 is an appropriate decision or whether they should enter into a power purchase agreement; right?

A That would be correct. The actual point in time

is less important to me as it is with regards to the necessary steps that will be taken to really examine -- you know, doing a fairly exhaustive search with respect to the most cost-effective alternatives at that time. Sometime it will be at 2008, 2009. You know, I'm somewhat hesitant about pinpointing a specific year, but I'm not hesitant about my recommendation that this type of market review should be put in place.

Q And we'll talk more about the particular year in a moment, but right now, I'm just trying to establish the fact that in building Hines 2, you would agree that it's not an all-or-nothing situation for Florida Power in terms of ownership or procurement that the company could build Hines 2 for its current need in 2003, 2004, and then still have the opportunity to add power purchase agreements for the need in 2005 and a power purchase agreement in 2007 if that's what the market indicated when they issue an RFP later; is that right?

A That would be correct.

Q And, in fact, you understand that Florida Power currently has a number of power purchase agreements as part of its portfolio of generation resources; correct?

A Yes, sir.

Q And you would agree that it's appropriate for a utility to have a mix of generation resources, both

contract and utility-owned resources; is that right?

A Yes, I would agree with that.

Q That would be a managerially prudent decision to make; is that right?

A That's correct. I think in my deposition I refer to that.

Q And, in fact, as we have discussed in the future Florida Power plans to retire some of its existing generation assets. So if it wants to maintain utility-owned generation assets on its fleet, you would certainly support that it build state-of-the-art, more efficient units in place of those older ones?

A Yes.

Q Now, you go on to say at Page 4 of your testimony, Line 13, that failure to properly adjust for risks creates market distortions due to inadequate recognition of both current and future events. Do you see that?

A Yes, sir.

Q And you would agree that when you speak about market distortions, you are limiting your remarks in this context to those industries that are essentially operating in an unregulated environment; right?

A Yes. If I could allow some clarification about that particular sentence?

Q Sure.

A Market distortion here, of course, would not be appropriate with respect to looking at how regulated utilities operate in a current environment as we have now in Florida. My rational for inserting this type of language is only -- looks at what I think -- how the future could very well emerge, which we are now, you know, making that type of transition that this advent of electric generating restructuring will be that time period whereby we move from regulated to a lesser regulated environment or area.

So with that type of caveat then if the decision is still being made with regards to need determinations that only take into consideration current information and not look at what's happening in terms of these changes and if these changes do occur, then by ignoring future possibilities, this is what generates, in my view, the type of market distortion.

Q So when you're talking about market distortions, you're really looking ahead to a time when the electric industry in Florida may become unrelated maybe five or ten years from now in your estimation; is that right?

A That's correct, yes.

Q But as long as the industry is regulated, you would agree that the Public Service Commission in some

sense is taking the place of the market; is that right?

A The Public Service Commission is in effect -- functions as an important ally with the market. I mean, we work to help markets work better, not to necessarily supplant market decisions. But recognizing that there are some serious and important market shortcomings, thereby this type of necessary intervention, hence regulation, is warranted.

Q But when you are talking about market distortions, you really don't mean to be speaking about a regulated environment because then in a sense anything the Commission did or regulated utilities did would be market distortions?

A That would be correct, yes.

Q Now, at Page 5 of your testimony, Line 6, you say that unlike long-term assets, short-run assets are more flexible and can reflect market changes quicker; is that right?

A I'm sorry, Mr. Sasso, what line was that again?

Q Page 5, Line 6, I believe.

A Yes, I'm here.

Q Are you with me now?

A Yes, sir.

Q Now, the fact that short-run assets are more flexible and can reflect market changes more quickly, that

could be a good thing or a bad thing; right?

A Yes, sir.

Q And, in fact, if there is a bad market change a few years down the road and Florida Power has a short-term contract and comes out of that contract, it would be confronting a bad market environment; right?

A That possibility definitely would exist.

Q Now, you say also at Page 5, Line 10 that under short-term contracts, a power provider would be able to better adjust price and technology decisions induced by market forces; correct?

A Yes, sir.

Q Now, by the term "power provider," you would agree that we could include a wholesale power provider that sells power, for example, to Florida Power?

A Yes, sir, that would be correct. Yes.

Q So under a short-term contract then, a wholesale power provider would be better able to adjust price decisions induced by market forces; correct?

A I happen to think so, yes.

Q Which means that at the expiration of a short-term contract, they could hike up the prices?

A Well, depending on the state of the market at that time. I'm somewhat reluctant to conclude in any type of, you know, definitive sense that we would be looking at

price spikes, but, yes, depending on the state of the market at that time that possibility could exist. But also if market conditions are such that we have adequate and sufficient providers in the market, that could have some type of depressing effect on prices too.

Q But as I understand it, you're not offering any opinion about which case will confront whether prices will be up or prices will be down. You're not committing yourself to that; right?

A No, I'm really not.

COMMISSIONER JABER: Mr. Sasso, may I interrupt --

MR. SASSO: Sure.

COMMISSIONER JABER: -- before you leave a point? Mr. Dickens, let me make sure I understood your testimony with respect to what you thought the role of regulation and the role of the Commission was, which I think you testified was that it's not to supplant the market or, you know, to take the place of the market but to provide some of the protections that the market, a true market, would provide and to facilitate a true market.

THE WITNESS: Yes, Commissioner Jaber. My comments about that point was just the reflection of my understanding of regulation as the important economic tool that's utilized when there's, you know, clear evidence of

market power, market abuse, externalities that result in market inefficiencies. Thereby, you know, regulation works to try to correct those external deficiencies and bring about a more orderly efficient outcome.

COMMISSIONER JABER: All right. Now, tell me then, now that I understand your testimony in that regard, tell me then how you reconcile that with your recommendation that we should review Florida Power Corp's construction of the Hines 2 unit every five years.

THE WITNESS: Well, I actually look at this review as an extension of regulatory policy in an effort to provide these type of basic concerns that you and your colleagues on the bench have with respect to whether or not the power that's being generated and provided does meet the test of cost-effectiveness, or are ratepayers reaping the benefits of having this power provided with the state-of-the-art technology, proper fuel choice mix.

Over a short-term prudence review, I think, in my opinion, you're just better able to make that type of definitive judgment as opposed to having only the type of traditional framework whereby if everything is signed off today, then this is essentially what we're going to be looking at with regards to the prospects of cost recovery over 25 or 30 years, something that's provided in the interim because we recognize that change occurs.

And if my view and opinion about change is even close to being correct, then I think it is in our best interest for the people that we serve as well as the company that we regulate to bring that to your attention.

COMMISSIONER JABER: So it's your testimony that a plant could at some point in the near future because of changes in the environment, in the electric environment, no longer become cost-effective?

THE WITNESS: I think that that specific possibility is one that is real. I don't think it's trivial, and as a result, I think there should be some type of assurances that will enable Commissioners to have any doubt or concerns erased that these electric generating units are in fact, be it 2008 or 2015 regardless, that the power that is being generated and the services that our ratepayers are enjoying reflects that best technology at the most appropriate fuel choice mix.

COMMISSIONER JABER: Okay. Now, could the reverse be true in a changing environment where five years from now we find out that construction of the Hines 2 facility in the fashion that FPC proposes that it be a long-term asset spread over 25 years is so cost-effective that there should be a reward for constructing it in the fashion that they have? In other words, could the environment changing result in an opposite effect to what

you're testifying to?

THE WITNESS: Yes, ma'am. That's a really -- your question really gets right at the crux of something which has been discussed by me and that is the idea about risk sharing. I do believe that this type of for lack of a better phrase forecast that I have provided could very well be wrong, and I'm not bashful about admitting my mistakes, I have made my share. But if that forecast is wrong and, in fact, Hines 2 does embody the best available technology and their fuel forecasts are right on the mark, then I think that does warrant some type of, you know, recognition or statement that obviously the company has done something which is managerially prudent. Ratepayers are benefiting from that, and as a result, you know, perhaps some type of pecuniary reward could be offered to show that.

COMMISSIONER JABER: All right. So then I understand your testimony better now. See, with your recommendation, it appeared that it was one-sided with respect to reviewing the construction of the plant in five years, and to the degree it's no longer cost-effective, you were recommending disallowing costs going forward.

What I hear you saying today is, review the construction of the plant in five years, and there might be rewards and there might be penalties.

THE WITNESS: At the -- if at the end of this prudence review period it has been determined by Staff and, of course, you and your colleagues on the bench that Hines 2 has definitely met and exceeded all of the benchmark parameters, whereby the benchmark parameters would, in fact, be the market itself, then it would only be appropriate for some type of pecuniary incentive or reward that could be considered.

COMMISSIONER JABER: Thank you.

COMMISSIONER JACOBS: I have a question. Much of your focus has to do on the prevailing technology that would be in place at the time of that review.

THE WITNESS: Yes, sir.

COMMISSIONER JACOBS: Kind of following in that line of reasoning, could someone -- could a review kind of give an offset? For instance, if indeed there is newer technology but if the current economic posture of a plant can favorably compete with implementing the new technology, would that be a reasonable trade-off to you?

THE WITNESS: That would be a reasonable trade-off, yes. However, I would only just extend that by just suggesting that in looking at the generation technologies that it will have to be clear in my mind that given that trade-off that these generation technologies do in fact -- that they have met the litmus test of providing

electric power at rates and at a cost that the Commissioners find as appropriate, fair, and reasonable. That's only the extent of the limit of my discussion about those alternative technologies.

COMMISSIONER JACOBS: I understand. Thank you.

BY MR. SASSO:

Q Getting back to your testimony, Mr. Dickens, that you prefiled in this case. As I understand it, you rely upon and you attach to your testimony some statements made by Mr. Hernandez on behalf of the FRCC about ten-year planning projections; is that right?

A Yes, Mr. Sasso, that's correct.

Q And you believe that what Mr. Hernandez said in this ten-year planning discussion supports your view that utilities might not want to commit past five years; is that right?

A Not exactly, and perhaps in my testimony it is somewhat vague with regards to my reference to that particular exhibit. If I can be allowed, then I would like to clarify that.

Q Sure. Go ahead.

A In looking at the information that was provided at the particular ten-year site plan workshop and the comments that was proffered by Mr. Hernandez, what was of interest and intriguing to me was nothing more than the

dialogue that resulted between Witness Hernandez and Commissioner J. Terry Deason. And the substance of that dialogue between Commissioner Deason and Witness Hernandez was one which essentially Commissioner Deason was pinpointing the witness and basically recognizing that what he, he being Mr. Hernandez, was essentially arguing was in a sense a retreat of the ten-year site plan review and more of an acceptance of a five-year.

I think if you look in the body of that dialogue, you will see that that was essentially the direction that Commissioner Deason was heading. My interest with respect to that particular dialogue was one in which, at least it offered me in my formulation of this idea, that even within the industry itself, there has been some reference to, you know, perhaps it may be more managerially prudent, you know, to have a five-year plan horizon as opposed to a ten-year or what I have proposed as more of a short-term review as opposed to long term. So within that narrow context, that's how I utilized it.

Q Did you understand, Mr. Dickens, with respect to this dialogue between Mr. Hernandez and Mr. Deason that the occasion for the dialogue was that Mr. Hernandez was coming before the Commission with a roll-up of utility ten-year site plans that had some unspecified purchases in the last five years of the ten-year planning period, and

Commissioner Deason and the other Commissioners were concerned that there didn't seem to be adequate provision for reserve margins at the back end of the planning period?

A Yes, sir.

Q And Mr. Hernandez was explaining to the Commission that the Commission should be concerned because with new technologies, utilities could build power plants in under five years much more quickly. Do you remember that?

A Yes, sir.

Q And that was really the thrust of his remarks, that now, you know, perhaps we don't have to show units ten years out because we can actually build them more quickly, and so a couple of utilities may not have power plants planned yet but that shouldn't be a problem because we can build them fast. Do you remember that?

A Yes, I do.

Q And he wasn't talking about --

MS. BROWNLESS: Excuse me. Can I object? Are these questions, or is this commentary and testimony by Mr. Sasso?

MR. SASSO: This is classic cross-examination. I'm entitled to ask questions --

COMMISSIONER JACOBS: I think he was leading up

to a question; right?

MR. SASSO: Yes. Mr. Dickens is agreeing with my characterization. We are talking about the discussion between the Commission and Mr. Hernandez.

COMMISSIONER JACOBS: From the exhibit?

MR. SASSO: From the exhibit, yes. Mr. Dickens attached a portion of the transcript of this discussion between Mr. Hernandez and the Commission to his testimony. He relies on this, and I just wanted to clarify what this was all about.

BY MR. SASSO:

Q That's what they were discussing. And do you recall what Commissioner Deason's reaction was to that?

A Yes, I do.

Q And let me quote from that. He said to Mr. Hernandez, "What you need to -- I'm going to be very polite, but what you need to realize -- you're sitting there saying, 'Well, this is an aggregate and each individual utility needs to make economic decisions' and all that. That's fine and dandy, but this Commission has the responsibility to make sure that there is adequate capacity for the entire State, not each individual utility, and it's not going to do a lot of good if one utility has adequate capacity and another doesn't and there's no way for there to be a sharing of that capacity,

and when there are brownouts and blackouts and things of that nature, that's where the rubber meets the road and that's where we have failed in our responsibility." Do you remember that?

A Yes, sir.

Q And you would agree that in proposing to build this power plant, Florida Power has stepped up to the plate to meet the concern that Commissioner Deason was discussing?

A I would agree that the proposed Hines 2 unit would in fact satisfy that particular need that Commissioner Deason had pointed out in that dialogue.

Q Yes, sir. Now, in your testimony, you also rely for support on the experience that the utilities have had and the Commission has had with PURPA cogen contracts; is that right?

A That's correct.

Q And you point out at Page 6, Line 20 that the ex post market price for wholesale market power is now lower than the ex ante price reflected in the negotiated QF contract; correct?

A That's correct.

Q And by ex post, you mean after the fact?

A Correct.

Q And this means, as I understand it, that after

the utilities entered into agreements with these cogens after a passage of years, we can now look back and conclude that the utilities have had to pay more for power than they might otherwise have had to pay?

A That would be correct, yes.

Q And you would agree that PURPA's requirement that utilities enter into cogen agreements at avoided costs has shown a significant shortcoming?

A Yes, I would.

Q And that PURPA was attempting, among other things, to encourage utilities to promote the development of independent power producers; is that right?

A That's my economic opinion of that. It may not be shared by, you know, some of my other colleagues, but, yes, I do.

Q You're familiar with the legislative history of PURPA to any extent?

A Superficially. I mean, I remember how it got, you know, started, but that's basically it.

Q And you would agree with me that the federal government has gone on through some other regulatory policy such as the National Energy Policy Act and has further attempted to promote the development of independent power producers; is that right?

A Yes, sir.

Q And you would agree that the jury is still out on whether that's going to prove to be a good policy or not as far as the ratepayer benefit is concerned?

A Yes, I do believe that as we accumulate more data information, we will be able to make a better assessment about the role of those alternative power providers.

Q And, in fact, there have been some very negative results in some states like California and New York that have embraced IPPs aggressively; correct?

A There is information that we are now reading and receiving that does suggest that there are some short-term problems. I would not go so far as to conclude that these problems that we are currently seeing in other states necessarily provide any kind of signal about what's going to happen over the long term, but, yes, there are some short-term adjustment problems.

Q Now, getting back to this ex post, ex ante issue or concept. You would agree that if a utility made the right decision at the time to make a commitment for a generating resource, it would be inappropriate and unfair to later deny that utility cost recovery for costs associated with that resource; correct?

A It depends. It depends on where we are at that particular time when the market review or prudence review

was being applied. If it's a situation, again, not to be purposely redundant, but if it's a situation in which the embodied technology and fuel choice mix of the company, you know, does in fact meet and exceed the standards that a regulatory body like this Commission would have in place, of course, I would not be, you know, favoring any type of denial of economical recovery.

Of course, what's problematic is that if the opposite holds, and this is where, you know, we would have to really take a close -- a look at would it be in the interest of ratepayers when efficient alternatives have been forfeited if we are still in a sense obligated to long-term commitments.

Q Now, Mr. Dickens, you remember that we discussed this topic in your deposition, and at Page 73, I will read you what I asked and what you answered. "Question: If the utility made the right decision at the time to make that commitment for that generating resource, it would be inappropriate and unfair to later deny that utility cost recovery for costs associated with that resource; correct? Answer: That would be correct." Do you recall giving that testimony?

A Yes, sir, I do.

Q Now, isn't the real lesson of the cogen contract experience that utilities are in the best position to know

their own business?

A That would be correct.

Q And, in fact, utilities were made to enter into these contracts by PURPA as implemented by the regulatory scheme?

A Yes, sir.

Q And you would agree that when we're talking about the bad experience with cogen agreements, we're really talking about contracts, not decisions by utilities to build their own units; right?

A That's correct, yes.

Q And you would agree that in general it's very difficult for a utility to acquire through a contract the type of optionality and control over the resource that they would have if they build their own unit?

A That's true, yes.

Q And for every type of optionality or flexibility or attribute of ownership that a utility tries to negotiate, they are going to have to pay some kind of price for that to the wholesale provider; right?

A Yes, sir.

Q Now, at the bottom of Page 7 of your testimony you answer the question, "How would you propose that the Commission address the risks associated with construction of the Hines 2 unit," and you start your answer by saying,

"Assuming Hines 2 is constructed on budget and on time," and then you describe your proposal; right?

A Yes, sir.

Q And you would agree that the risk of delay in getting a project going on time is a risk that a utility needs to address and mitigate in order to meet its reserve margin objectives?

A Yes, that would be correct.

Q And one possible cause for delay is regulatory delay; for example, running into problems or hurdles or appeals, that type of thing?

A Regulatory delay would be one of several causes for delay.

Q And it would be prudent to try to avoid regulatory problems if possible?

A The best scenario is obviously one of which you would want to avoid or minimize that.

Q It wouldn't be prudent necessarily to try to go to the regulators with a project that appears to be illegal under existing law?

A Yes.

Q Okay. Now, you say that assuming that the plant is constructed on budget and on time, the Commission should allow the capital and O&M costs of the unit to be included in rate base for surveillance purposes upon its

commercial in-service date; correct?

A That's correct.

Q Now, before the Commission would actually get around to allowing the capital and O&M costs to be put in rate base, they would first have to determine that the plant was needed; correct?

A Yes, sir.

Q And you would agree that Florida Power Corporation has demonstrated that it's met all of the conditions appropriate for the PSC to grant a favorable determination of need with the exception of considering your specific proposal about a future market test, say, five years after the plant is in service?

A That would be correct, yes.

Q And your specific proposal is that the Commission should require FPC periodically, say, every five years to review current market conditions to determine whether continued operation and rate base recovery of Hines 2 is in fact in the best interest of FPC ratepayers?

A Yes, sir.

Q Okay. And we talked a little bit earlier about the period you picked, five years. There's really nothing magic about five years as opposed to seven or nine or ten; right? You're just trying to pick a benchmark period

where the Commission could require a review?

A I have personally struggled with a year that would best reflect short term. I mean, the basic thrust from the origin of this idea to its fulfillment when testimony was filed on September 18th was to have something that will approximate a short-term kind of market review, and five years was a time frame that was selected. However, that should not be misinterpreted that it's a time frame etched in stone because it has not in a sense been defined in any kind of mathematical sense with regards to being, you know, the optimal short-term time year to use.

Q So, I mean, if there were, for example, a market opportunity in year three, you might miss it if you waited to five, or if there were a market opportunity in year eight, you might miss it if it were five?

A Yes, sir.

Q But that's your best effort to pick a date?

A That's correct.

Q Now, you say at Page 8, Line 7 that the market review should explore all the alternatives including, but not limited to, conservation, load management, distributed generation technologies, short-term and long-term power options and replacement construction; correct?

A Yes, sir.

Q So if we conduct this review five years out after the plant is built, it might be perfectly appropriate for Florida Power to enter into a long-term power purchase agreement at that time?

A That possibility could very well exist.

Q It could enter into a 20- or 25-year contract at that time; right?

A At that time, yes.

Q And that would be based on the fact that that alternative appeared to be the best one available at that time?

A At that time, yes.

Q And to determine what was the best option, Florida Power might issue an RFP to get proposals; correct?

A That's correct.

Q In fact, that's the current procedure for the company to test the market before deciding what option to pursue?

A As I understand the -- and what I've learned over the last couple of days with regard to the bid rule process in the State, that's correct.

Q And, in fact, in this case you understand that Florida Power issued an RFP, it got proposals, and evaluated them?

A That's correct. Although, I was not, of course, involved with that, but that's my general understanding.

Q Now, you also include as an option that could be looked at five years after in-service that the company might consider replacement construction; right?

A That's a part of it, yes.

Q So if five years out the company issued an RFP and tested the market and looked at options, you would agree that it might be perfectly appropriate for the company to decide to build a different plant at that time?

A Yes, that's why that language is inserted. Yes.

Q In fact, it might make a decision to build a plant that would own and operate for 25 or 30 years?

A Again, contingent on what the market signals are at that particular time, that would be correct.

Q And depending upon what the market signals were at that point in time, it might be perfectly appropriate to obligate the company's ratepayers to pay for the cost of that plant for 25 or 30 years?

A Yes, provided that that caveat still holds.

Q Now, you're contemplating the possibility, as I understand it, that five years out, a more cost-effective alternative might become apparent; correct?

A Well, no, I'm not necessarily contemplating it.

Q Just might happen?

A That this is something which, you know, could occur. It's what I think a fairly plausible view of the future short term and -- but then again, it may not be. I'm just simply interested in looking at some type of rider or amendment that would, in effect, provide for these type of contingencies that I've discussed earlier both here as well as in my testimony about the possibility of these downside risks occuring.

Q Now, you would agree that at this point in time, based on the analysis that Florida Power has conducted and the RFP results, that Florida Power has elected the most cost-effective alternative available to it today; correct?

A That would be correct.

Q Now, you're anticipating that there might be some situation five years out where a more cost-effective alternative becomes apparent, but we won't know that until we actually do the review five years out.

A Yes, sir, that's right.

Q And there's some undefined probability that that may occur, but you're not prepared to say whether that's 1 percent or 100 percent or any number in between; correct?

A At the present time, I would not be able to assign any specific probability to that.

Q Now, you're suggesting, as I understand your

proposal, that the Commission might want to deny future cost recovery?

A That would be one option.

Q And that would be available under your proposal to the Commission even though the decision Florida Power makes today to build the plant is perfectly appropriate given what we know today?

A Given what we know today, that's correct.

Q And it's your position, as I understand it, that Florida Power and its shareholders would have to absorb those costs if cost recovery is denied?

A If that decision has been made with regards to denying cost recovery, then that would be an adjustment that would have to be made obviously by FPC investors.

Q And as I understand it under your proposal, for the first five years, you're proposing that the company would build the plant, put the costs in rate base, and get full cost of recovery on a cost-of-service basis; correct?

A That's correct, yes.

Q But either during that first five years or later, under your proposal the company could not get the upside of market risk; is that right?

A That's right, yes.

Q So, in other words, if the plant actually operated under the market price for power, you're not

proposing that FPC ought to be able to recover that from its ratepayers and return it to its shareholders?

A No, I'm not.

Q Now, you would agree that investors in an IPP would be very reluctant to go forward with a project on the basis where they would have to accept the downside market risk but not the upside market prices; correct?

A That remains to be seen. The behavior of companies in this particular market is one obviously in which the attraction to the market is going to be based on clearly expectations about return on capital, return on equity, the extent of present demand, future demand. So I basically look at IPPs or other alternative power providers as essentially using all of these as inputs in making a decision to --

Q But you would agree that in a truly competitive market that a market actor, a firm, under principles of microeconomics would expect to get and would hope to get prices when they're up and prices when they're down?

A Yes.

Q And if you were to take away the upside risk and impose -- take away the upside benefit and impose the risk of having just to accept the downside market prices, you would create exposure to investors in the company participating in that market; correct?

A Yes, the possibility of risk exposure would be present.

Q And you agree as an economist that when the market perceives that there is greater risk exposure, the market will demand a greater return on capital?

A That's correct, yes.

Q And that can translate into a higher cost of goods and services?

A Typically that would be reflected in an upward adjustment in prices.

MR. SASSO: Okay. I have no further questions.

COMMISSIONER JACOBS: Ms. Brownless.

MS. BROWNLESS: Thank you.

CROSS EXAMINATION

BY MS. BROWNLESS:

Q Let me ask this question: As you're aware -- well, let me ask you this: Have you been sitting through the hearing, Mr. Dickens?

A Yes, Ms. Brownless, I've been here.

Q So you've heard the previous testimony prior to yours, most of it?

A The testimony proffered by --

Q By all the witnesses.

A Oh, yes, ma'am. Yes. I'm sorry.

Q Would Panda's proposed five-year contract term

match the market review period that you've discussed today?

A Unfortunately, I would not be in a real position to answer that one way or the other because I'm not --

Q Well, let me ask you these questions then.

A -- that fully informed about Panda's contract.

Q Panda -- well, let me do that. Panda proposed that it will have a five-year contract term starting in 2003, exercisable up to a period of five years, 2008. Okay. That was one of the options that Panda put on the table to Florida Power Corporation. Accepting that as having been presented in the record in this proceeding, would that contract term match the market review period which you've discussed today --

A Well --

Q -- five years from the in-service date of the unit?

A Five years from the in-service date and given what the conditions are at that time, yes, I would --

Q Okay. So that would be a match then. And so, in essence, if Panda's proposal had been accepted by Florida Power Corp, there would be an automatic market review at the end of five years from the in-service date of the proposed unit; correct?

A With regards to --

Q Power Corp would have had to have gone back out into the market and looked to see what was the most cost-effective alternative available in five years.

A I'm sorry. I'm a bit confused. Are you speaking with regards to the proposal that I've offered?

Q No.

A Or perhaps you could just restate the question for me then.

Q As I understand what your testimony is, you're suggesting that in the year 2008, which is five years after the in-service date --

A Yes.

Q -- of the Hines Unit 2 unit that Power Corp assess the market to determine if that unit continues to be the most cost-effective alternative; is that correct?

A That's correct, yes.

Q Okay. If Panda offered a bid and did offer a bid that would cover that same five-year term, in other words, it would provide capacity from 2003 to 2008, and if the contract terminated in the year 2008, would not, in effect, Power Corp at that time be forced to go back into the market and evaluate what the alternatives were to it at that time?

A Yes. Under my type of framework, this would be part of the periodic review. So I'm sorry I didn't

understand it earlier, but, yes.

Q Sure. I want to follow up on some questions that you were asked about negotiated QF contracts.

A Certainly.

Q As your understanding of both the federal QF law and Florida law implementing that federal law and PSC rules regarding QF contracts, do qualifying facilities have to have steam hosts to meet the definition of a QF?

A Unfortunately, I have no intimate knowledge about that. That's something that I have never studied or considered specifically for this particular testimony.

Q Okay. Except for the purposes of this question that that is in fact true, that in order to qualify under Florida and federal law as a QF, a qualifying facility, one must have a steam host. In other words, that a manufacturing facility, for example, that generates steam that part of that steam must be used by the qualifying facility to turn its turbines in order to get QF status. Let's assume that. If that's true, could one of the purposes for PURPA have been more efficient fuel use because the fossil fuel used to manufacture the steam in a manufacturing process would then be used again a second time to produce electricity?

A Perhaps, and I would not disagree that that was in fact largely the purpose for PURPA. However, within

the guidelines and the parameters that I understand about PURPA and cogen contracts it was used for purposes of my specific testimony. I was only just interested in looking at this current conundrum with regards to how electric utilities are now suddenly here in Florida in a real predicament with respect to the avoidance costs no longer being neutral. As I kind of cryptically referred to it, the ex post price for power is now much lower than it was in the previously negotiated contracts, and I just simply interpreted the specific rulings that have been made by this Commission to grant certain buy-outs as a reflection of those different price signals.

Q I just want to wind this up with one last question. Could it be then that one of the purposes of PURPA was to more efficiently use fossil fuels?

A Yes, ma'am.

Q Are you familiar with avoided cost pricing as it's used in QF contracts?

A I have no -- in my time here at the Commission, I have not worked on any specific docket about avoided costs with QF contracts. My basic knowledge comes from the broad economic literature that I've read about that.

Q Would you agree that avoided cost price was the price that every QF contract had to match or fall below in order to get approved by this Commission?

A Yes, I would.

Q And would you agree that that avoided cost price was based upon the next avoided unit identified in a utility's integrated resource plan?

A Yes. As I understand the literature, that's correct.

Q So the price was directly keyed to the unit that the utility had identified as being the unit it would build in order to implement its own least cost plan?

A Yes, ma'am, that's correct.

Q So QF contracts to the extent power was purchased pursuant to those contracts were in lieu of construction of those units?

A That's correct, yes.

Q Now, if the utility had constructed that unit identified in its least cost plan instead of entered into the QF contract, then one would expect that unit would be at that point in time if declared prudent put into rate base; right?

A That's correct, yes.

Q And put into rate base for 20 years or 25 years or 30 years or some long period of time; correct?

A That's right.

Q Okay. So to the extent that utilities came back and said, look, these QF contracts are higher cost than

the current market, they were in fact taking an after-the-fact analysis of that contract; correct?

A That's an interesting observation because I do share that view which I find evidence about a form of hindsight review that was being used. And if we do find, you know, evidence of electric utilities in fact doing precisely what you've just described, then I think that it's more than reasonable on my part to suggest a type of hindsight review with regards to what I proposed concerning the five-year market review or prudence review. One person's hindsight review, I guess, is another person's 20/20 vision, but still I don't see the two as being fundamentally different.

Q Okay. So basically what you're saying is if this type of review is the type that should be provided for QF contracts, then that type of review is also appropriate for utility built units?

A Yes, ma'am.

Q You were asked some questions about whether it would be prudent for Florida Power Corporation to purchase power in lieu of construct its own unit. Would you agree with me in terms of how that would affect its ability to bring a unit on-line in time? Do you remember those questions?

A Not specifically, but if you could refresh my

memory.

Q Okay. You have -- you were referenced to Page 7 of your testimony, and you were asked some questions about Line 25, assuming Hines 2 was constructed on budget and time.

A Oh, yes.

Q Okay. Questions concerning the risk of not bringing a unit on time into the system.

A Yes.

Q Would it be the most or the least risky strategy or the most prudent strategy from a construction and budget risk standpoint for Florida Power Corporation not to have to come to the Public Service Commission at all, not to have any regulatory review because they could be sure that once they decided to build a unit, without a doubt, it would be constructed when they said they needed it?

A That would be the first best choice, but as we know, we live in a second best world.

Q Because the fact that people can intervene in need determinations and raise issues increases the risk that the unit will not materialize at the in-service date proposed?

A That's all part of the second best world that we live in, yes.

Q But we've already got that regulatory risk; correct?

A That's correct.

Q If the Hines Unit 2 unit is built by Florida Power Corporation, does it present a stranded cost risk at some point in the future?

A Well, I have purposely and intentionally not addressed the issue of stranded cost in my testimony. It is a red herring that's used in discussions about electric regulation/deregulation. For purposes of my testimony, however, I am largely mute on the issue of stranded costs.

Q Okay. To the extent that the capacity provided by Hines Unit 2 is not needed by Florida -- well, let me start by saying, if large retail customers were given an opportunity to chose an electric supplier other than Florida Power Corporation, buy off their system, is it necessarily true that Hines Unit 2 would in fact be needed in year five or year six?

A That, of course, would be contingent on what the type of proposed market review that I'm advocating if --

Q Well, is it a possibility that so much demand could be lost that the need of this unit might be mitigated somewhat in whole or in part?

A Sure, there's a possibility for it, but I would like to think that the definitive word about whether or

not will Hines 2 be, quote, unquote, needed or not is going to rest largely on how the market evaluates that particular technology at sometime in the future T plus five.

Q But that's only true if you assume that Florida Power Corporation's demand will in fact continue to grow over the next 25 years?

A Yes, ma'am. And based on information that I have had a chance to review and study about load growth in this State, that would be true.

Q Okay. But that information is based upon everybody having to buy from their territorial investor-owned utility; correct?

A Correct, yes.

Q To the extent that the capacity associated with Hines Unit 2 is not needed by Power Corp's retail customers and has sold that wholesale by Florida Power Corporation, doesn't Florida Power Corporation get an upside to their risk?

A It could. But I have to be honest that that's a particular scenario that I really didn't factor in.

Q But it is possible?

A But it is possible, yes, but it's not something that I considered.

MS. BROWNLESS: Thank you very much.

THE WITNESS: Thank you.

COMMISSIONER JACOBS: Commissioners.

COMMISSIONER JABER: Yes. Mr. Dickens, let me tell you some concerns of mine, and then I'm going to ask you a question so you can help my understanding of this entire issue. I have concerns with respect to Florida's future energy needs, and I want to make sure that Florida's future demands with respect to electricity is met. We know -- well, you can verify for me, we can tell at least for the next ten years what the demand factors are; correct?

THE WITNESS: Yes, ma'am.

COMMISSIONER JABER: Just by looking at the ten-year site plans, we can take a very good guess; right?

THE WITNESS: Yes, ma'am.

COMMISSIONER JABER: I expect with the state of the law as it exists today and with the market as it exists today and on top of that with the fact that we have agreed that the IOUs will increase their reserve margins from 15 to close to 20 percent that companies will be able to meet that demand, not just today or tomorrow but forward looking; right?

THE WITNESS: Yes, ma'am.

COMMISSIONER JABER: How do I balance those concerns and those missions that I think the Commissioners

have to meet with your recommendation that we need to review the cost-effectiveness of the construction of this plant in five years? I can't -- it's not coming together for me. I need you to help me understand how I can balance those policy concerns with the state of the law and the market as it exits today and what I expect from them today with what you think might happen to the market five years from now.

THE WITNESS: Certainly. My particular proposal, even though it does focus on a short-term five-year review, in order to, you know, assure our ratepayers that they are the beneficiaries of the best state-of-the-art technology and the most appropriate fuel choice mix does not in any way abdicate any alternative, you know, providers of power to make sure that the type of power that we also are receiving is power that will, you know, hopefully be right at that type of threshold level that this body has already set with regards to our reserve margin requirements.

In other words, I'm not decupling or separating, you know, concerns about reliability on one hand versus meeting this type of requirement for cost-effectiveness. Although my testimony does not address the issue of reliability, I only just have my own private views about that. But I do believe and I would like to think that if

it was implemented, then, you know, whoever is going to be the company that's going to be continuing, in this case Florida Power Corp or someone else, that we will have the type of adequate reserves that we need in order to meet those reliability conditions.

COMMISSIONER JABER: But to accomplish that, don't we have to at least assure the company regardless of who it is that the costs associated with meeting that demand will be recovered?

THE WITNESS: Yes, that would be a component of it. After all the smoke clears and we see that the company has met and exceeded the expectations that you and your colleagues have set, a cost recovery would be more than fair and appropriate.

COMMISSIONER JABER: Okay. So in two months from now if we find that the cost -- that the facility was prudently constructed and the need was justified, why would that finding that we might make two months from now be different five years from now just because something outside of what we expect today with respect to demand has changed? Do you understand my question?

THE WITNESS: Yes, yes, I understand your question. I understand your deep scepticism and apprehension about what's being suggested on my part too, and I appreciate that. The short answer is I don't know.

I don't know, but, you know, I'm --

COMMISSIONER JABER: I don't know either.

THE WITNESS: I have just been -- my work in this Commission is one which essentially -- you know, looking at probabilistic events about the future has been a big chunk. I mean, I came here, you know, under the office that Paul Stallcup directs, Office of Economic Forecasting. Forecasting, that's what we do. We don't pretend to be able to, you know, provide forecasts with standard errors close to zero, but we recognize that there is some, you know, margin of error.

Commissioner Jaber, honestly, I just don't know, but what I do know is this: Times are changing, and if times are changing, if this advent of electric generation restructuring continues at the rate which I think it could, then I just believe that you and your colleagues would be in a position -- a better position, I think, to have a chance to now look at how generation is being provided based on what the market signals are essentially communicating at that time. But it could be -- again, it could be the case whereby the scenario that I provided would be off. This is why in my analytical training you are always taught to have best case, worst case, and something in the middle.

COMMISSIONER JABER: Thank you.

COMMISSIONER JACOBS: Let me walk you through a scenario and see how it suits with your proposal. And so that we don't get too much into this case, let's use your analogy with the QFs. Okay? The QF contract is established based on a snapshot of what avoided costs would be.

THE WITNESS: Yes, sir.

COMMISSIONER JACOBS: As I understand it, what you might propose is that in five years, we would reopen those QF contracts and take a look at what the then stated avoided costs would be, and essentially that would be a renegotiation?

THE WITNESS: Yes, that type of model being applied to the case that we have before us with regards to need determination.

COMMISSIONER JACOBS: And in that instance, a QF would rebid based on what -- and I guess they would argue what they think avoided costs would be, and then the utility would then rebut that.

THE WITNESS: Yes, sir.

COMMISSIONER JACOBS: And then we may get a chance to come to some kind of conclusion on what avoided cost is, and then we would force that QF contract to ratchet down to what we would then resolve the avoided costs to be?

THE WITNESS: That would be a possibility, yes.

COMMISSIONER JACOBS: Okay. And in that event, would the -- would we always favor the QF? Because again -- and this is where it gets kind of difficult. That legislation was intended specifically to favor the QFs, alternative Qs and QFs with that, but in your analogy, I don't think that that holds true. I suspect, and correct me if I'm wrong, your focus rather than favoring a particular technology says, let's make sure that the benefits of innovation and of improvements work their way through to the assumptions built into the recovery of costs for a plant.

THE WITNESS: Yes, Commissioner Jacobs, that is the kind of spirt whereby my testimony is crafted. It is not at all biased to a particular adopted or better technology.

COMMISSIONER JACOBS: Right.

THE WITNESS: It's only just biased to having some type of reasonable prudence review and some short-term framework whereby we can more or less kind of sit and look at where we are now five, ten years from now and see whether or not is everything, you know, going the way in which we had originally conceived.

COMMISSIONER JACOBS: Now, of course, the challenge in regard to applying that strategy or that

analysis in this regard is that the capital is pretty much laid out up front for building a plant, and once that capital is laid out and the companies argue that it's laid out under the regulatory compact, i.e., there is some assurance of the opportunity to recover that capital, then when we come back down the road and we reshape what the present view of the world is, it doesn't take into account the real dollars that were put out up front. Are you following me?

THE WITNESS: Yes, sir, I follow you.

COMMISSIONER JACOBS: And so we can get into a whole host of issues with regard to, you know, due process, constitutional issues, and all that sort of thing that I would not want to discuss now. Let me suggest this to you: Holding constant the idea that this capital that was put out up front should be recovered, aren't there a whole host of other issues and factors and ingredients in the cost of providing power from that plant which in fact do vary over time?

THE WITNESS: Yes, sir, that's correct.

COMMISSIONER JACOBS: And so if indeed you would hold constant the idea that there was this capital put out and, of course, some carrying costs for that, but the whole host of other fact orders that do vary with time -- for instance, you know, we have seen the evolution of

capital markets. We have seen the evolution of fuel markets. We have seen the evolution of transmission issues that all play into the operational costs of generation, and so it would occur to me then if we take that analogy that we just discussed with regard to QFs, then we could come five years down the road and look at how these other factors have evolved outside of the initial capital and make determinations about where those relative costs stand as opposed to at the beginning, and then make the rest of the market demonstrate -- well, maybe that's not a good way to describe it. Again, kind of offer up this rebidding, this renegotiating process is really what I'm thinking of.

THE WITNESS: Yes. I understand that fully well, and this is precisely why I believe given the QF experience in this State what really provides for the type of flexibility that I'm recommending is that within the way in which these QF contracts have been in a sense renegotiated because of -- there is an opportunity for, you know, the company, in this case Florida Power Corp or Florida Power & Light, to exercise kind of a market out. You know, I mean, that's -- I think that's important. I believe it promotes a type of efficient arrangement, because if there were no provisions for having some type of, you know, legally provided market out, then in the

case of Florida Power Corp, ratepayers would be not necessarily benefiting, but there would be some potential adverse consequences if they be in the -- Florida Power Corp had been committed to that avoided cost.

COMMISSIONER JACOBS: Very well. Any other questions, Commissioners?

COMMISSIONER BAEZ: I have one question, for starters anyway. Based on your proposal, would you ever contemplate or could it ever be contemplated for a utility, for an investor-owned utility now to engage in self-building, to actually invest in building its own plant?

THE WITNESS: Commissioner Baez, I do believe that there are conditions that exist now and that would also exist in the future whereby the self-build option would be more than appropriate. And, again, it's going to be based -- or at least it would just be submerged within the type of framework that I'm suggesting, that when you look at the situation and you see that the self-build, you know, what result and cost advantage over power purchased, then that would be the right direction to take. I'm not in any way advocating or suggesting that self-build options are always the most economically inefficient way to go.

COMMISSIONER BAEZ: Okay. Thank you.

COMMISSIONER JABER: With a periodic review of the cost-effectiveness of the construction of a plant, do we run the risk of sending the wrong signal to a company that construction of the plant will only be for -- that the demand should only be met for five years, let's say? Do we run that risk?

THE WITNESS: There is a possibility of that risk.

COMMISSIONER JABER: All right. Saying that then, the difference -- the capital costs associated with constructing a plant that's going to meet demand for five years versus a plant that will meet demand going forward is really not great, capital costs --

THE WITNESS: Yes, capital costs.

COMMISSIONER JABER: -- constructing a plant.

THE WITNESS: Right.

COMMISSIONER JABER: Five years versus an extended amount of time, the capital costs up front probably are not significantly different.

THE WITNESS: Yes. And this is why for at least purposes of my testimony the primary concern has been -- I'm sorry, the primary concern with the risk that I address is largely on the fuel side. I mean, this is where I do believe that it could offer some challenges, again depending on how, you know, the fuel forecast shapes

up. But, I mean, this is something with which, you know, has largely been a work in progress. It's much -- things need to be kind of straightened out before, you know, your specific concerns can be adequately addressed so that you could be comfortable.

COMMISSIONER JABER: I guess here is my concern, Billy, that the other inadvertent and correct signal would be that the company start asking for a cost recovery of a huge capital outlay for five years instead of spreading it out over time.

COMMISSIONER BAEZ: That or the unintended consequence, I guess, of forcing an investor-owned utility to not -- to separate generation --

THE WITNESS: Yes.

COMMISSIONER BAEZ: -- or to -- you know, you've eliminated the generation option for a utility, and certainly I should have qualified before, to serve at least retail. And I guess my follow-up question would be is, how much did you consider -- I guess since you were focussing on fuel, you know, perhaps changes in fuel costs of having a review of fuel costs only and not -- I don't know if that's even possible, but perhaps, you know, instead of an overall approach, which is what you're suggesting or seem to be suggesting --

THE WITNESS: Yes, sir.

COMMISSIONER BAEZ: -- something with a more limited scope.

THE WITNESS: Yes. My analysis and framework has primarily just focussed on a combination of both in terms of the generation technology and the risk that imposes as well as the fuel. The fuel risk, however, is something which I think could very well represent the biggest problem only because of, you know, what we are currently looking at now in the market for natural gas and, you know, all of us, we're aware of those type of upward price movements and what that could possibly look like at sometime in the future if those type of trends go unabated.

But at the same time, you know, that kind of also feeds into the electric generation side with regards to the technology adopted too, because if the relative price in this case for natural gas continues to go unabated and if some type of generation technology emerges like, you know, microturbines or, you know, hydrogen fuel sales, if the price is right for microturbines and hydrogen fuel sales, then that's a possibility. And I think the only way in which one can really see that is by having this type of short-term review period that I'm -- short-term review prudence that I am offering.

COMMISSIONER JACOBS: Do you have much cross to

ask -- I mean, redirect?

MS. HART: Yes, I do, Mr. Chairman.

COMMISSIONER JACOBS: How long?

MS. HART: Much, no.

COMMISSIONER JACOBS: Very short?

MS. HART: Very short.

COMMISSIONER JACOBS: Okay. Go ahead.

REDIRECT EXAMINATION

BY MS. HART:

Q Mr. Dickens, earlier Mr. Sasso suggested that utilities are the best equipped to know their own businesses. Do you remember that?

A Yes, I do.

Q If the nature of Florida's electric market evolves to a more competitive environment, do you believe that those market factors could diminish that knowledge advantage and that ratepayers would then be subject to a larger degree of risk?

A Yes, I would generally agree with that. Although, I can see some situations where that may not always hold true. Only because when -- as the market evolves, the information that's going to be made available is information that will be consumed and utilized by essentially the two primary actors, the producers and the consumers.

Q Sticking with this idea that utilities know their own business, does that preclude this Commission from establishing some kind of a checkpoint as the State begins to see the effects of federal law like the Energy Policy Act of '92 and FERC Order 88 and Order 2000?

A Not at all. It does not preclude that. There is a responsible and reasonable role for those type of oversight regulatory agencies.

Q Mr. Sasso also made an interesting analogy saying that FPC has stepped up to the plate in proposing to build Hines 2. Do you remember him using that phrase?

A Yes, I do.

Q Okay. Under FPC's proposal, who will pay the costs of the Hines 2 unit?

A As I understand it, if the unit is accepted and approved by this body, then ultimately that would be paid by FPC's ratepayers.

Q So wouldn't you agree that it's FPC's ratepayers who are stepping up to the plate?

A In this sense the two are indistinguishable, yes.

Q Would you agree that it's a utility's obligation to manage its resources prudently?

A Absolutely.

Q And would you also agree that it's this

Commission's responsibility to assure that a utility is managing its resources prudently?

A Absolutely.

Q And, finally, is it your suggestion that the only way the Commission might address these concerns is through your proposal that you've made?

A Not at all. That would be far too presumptuous on my part.

MS. HART: Thank you. That's all I have.

COMMISSIONER JACOBS: Exhibits. I have Exhibit 18.

MS. HART: We would move that.

COMMISSIONER JACOBS: Show it admitted.

(Exhibit 18 admitted into the record.)

COMMISSIONER JACOBS: We'll take a break. Thank you, Mr. Dickens. You're excused.

MR. DICKENS: Thank you, Chairman.

(Witness excused.)

COMMISSIONER JACOBS: We'll take a break and come back at 2:45.

(Brief recess.)

COMMISSIONER JACOBS: We're back on the record. I believe that takes us back to rebuttal witnesses.

MR. SASSO: Correct. Mr. Chairman, we had initially identified two rebuttal witnesses, but in the

interest of trying to conclude today and to avoid cumulative testimony, we're going to withdrawal the prefiled testimony of John Flynn which will also moot out Items 4, 5, and 6 in our request for official notice or judicial notice. Those were exhibits that were referred to in Mr. Flynn's testimony, so we will no longer be relying on those.

COMMISSIONER JACOBS: Very well.

MR. SASSO: And we would now call Dr. Charles Cicchetti.

COMMISSIONER JACOBS: Very well.

CHARLES J. CICCHETTI

was called as a witness on behalf of Florida Power Corporation and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. SASSO:

Q Dr. Cicchetti, you have already been sworn; correct?

A I have.

Q Would you state your name, your position, and your business address for the record, please.

A Yes. My name is Charles J. Cicchetti, and I'm the Jeffrey J. Miller Professor of Government Business and the Economy at the University of Southern California, and

I'm a partner in a consulting firm called Pacific Economics Group. And my business address is 201 South Lake Avenue, Pasadena, California.

Q Dr. Cicchetti, did you prepare prefiled rebuttal testimony in this proceeding?

A I did.

Q If I were to ask you the questions contained in that prefiled testimony today, would your answers be the same?

A They would.

Q Do you have any changes or corrections to make to that testimony?

A Yes.

Q You do. And what are they?

A The first is at Page 2, Line 2. After the name of the organization, "Environmental Defense Fund," the phrase "from 1972 until 1975" should be inserted, and the second is on Page 10, Line 21. At the end of that line is the word "be," B-E, it should be "by," B-Y.

Q Any other changes or corrections?

A No, that's it.

Q Do you adopt this testimony as your sworn testimony before the Commission in this proceeding?

A I do.

MR. SASSO: Mr. Chairman, I request that

Dr. Cicchetti's testimony be entered into the record as though read.

COMMISSIONER JACOBS: Without objection, show the testimony entered as though read.

BY MR. SASSO:

Q Dr. Cicchetti, have you also included an exhibit with your prefiled testimony?

A I have.

Q Labeled CJC-1, consisting of your CV or your resume?

A Yes, it is.

MR. SASSO: And we would like to mark this as the next exhibit, please, which I think is 19.

COMMISSIONER JACOBS: Yes, correct. Show that marked as Exhibit 19.

(Exhibit 19 marked for identification.)

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles J. Cicchetti. My address is Pacific Economics Group, 201 South Lake Street, Suite 400, Pasadena, California 91101.

Q. WHAT IS YOUR POSITION WITH PACIFIC ECONOMICS GROUP?

A. I am a Co-Founding Member of Pacific Economics Group.

Q. WHAT ARE YOUR DUTIES AS A MEMBER OF PACIFIC ECONOMICS GROUP?

A. I actively consult with clients on price, costs, environmental, natural gas and electricity market issues and antitrust policies, particularly as those policies relate to regulated industries.

Q. DO YOU HOLD ANY OTHER POSITIONS?

A. I am the Jeffrey J. Miller Professor of Government, Business and the Economy at the University of Southern California.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I attended the United States Air Force Academy and I received a B.A. degree in Economics from Colorado College in 1965 and a Ph.D. degree in Economics from Rutgers University in 1969. From 1969 to 1972 I engaged in post-doctoral research at Resources for the Future.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. I served as chief economist for the Environmental Defense Fund from 1972 until 1975 and was a faculty member at the University of Wisconsin from 1972 to 1985, ultimately earning the title of Professor of Economics and Environmental Studies. From 1975 through 1976 I served as the Director of the Wisconsin Energy Office and as Special Energy Counselor for the Governor. In 1977 I was appointed by the Governor as Chairman of the Public Service Commission of Wisconsin and held that position until 1979 and served as a Commissioner until 1980. In 1980 I co-founded the Madison Consulting Group, which was sold to Marsh & McLennan Companies in 1984. In 1984 I was named Senior Vice President of National Economic Research Associates and held that position until 1987. From 1987 until 1990 I served as Deputy Director of the Energy and Environmental Policy Center at the John F. Kennedy School of Government at Harvard University and from 1988 to 1992 I was a Managing Director and ultimately Co-Chairman of the economic and management consulting firm, Putnam, Hayes & Bartlett, Inc. In 1992 I formed Arthur Andersen Economic Consulting, a division of Arthur Andersen, LLP. In 1996, I left Arthur Andersen to co-found Pacific Economics Group.

Q. HAVE YOU PUBLISHED ANY PAPERS OR ARTICLES?

A. Yes. I have published a number of articles on energy and environmental

issues, public utility regulation, competition and antitrust. A complete listing of my publications is included in Exhibit____(CJC-1).

Q. HAVE YOU EVER GIVEN EXPERT TESTIMONY IN A COURT OR ADMINSTRATIVE PROCEEDING?

A. Yes. A list of the proceedings in which I have provided expert testimony since 1980 is also included in Exhibit____(CJC –1).

Q. WHO RETAINED YOU FOR THIS TESTIMONY?

A. Florida Power Corporation (FPC) has retained me.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked to analyze the testimony and recommendations made by Florida Public Service Commission (FPSC or Commission) staff economist Billy R. Dickens. I will address Mr. Dickens' discussion of the proposed Hines 2 generating station and whether it should be included in FPC's rate base for surveillance purposes upon its commercial in-service date. I will also discuss his ideas concerning a prudence review every five years based on then current market conditions to determine whether FPC should be allowed continued rate base tariff recovery of the plant. In my testimony, I explain why Mr. Dickens' conclusions and asymmetrical recommendations are contrary to both regulatory principles and

competitive markets, and fail to achieve best cost. Therefore, I conclude that his proposals should not be followed by the FPSC.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I review briefly the essential facts underlying FPC's proposal with regard to Hines 2 and Mr. Dickens' related conclusions and policy recommendations. Second, I discuss the applicable economic and regulatory principles that lead me to conclude that the FPSC should not follow Mr. Dickens' recommendation. Finally, I summarize my conclusions.

Q. WHAT IS YOUR UNDERSTANDING OF WHAT FPC WANTS TO DO?

A. The Hines 2 power plant will be a state-of-the-art, natural gas-fired, combined cycle power plant with a nominal rating of 530 MW. FPC proposes to build the plant at the Hines Energy Complex (HEC) site in Polk County, Florida. The plant would be operational by November 30, 2003. The plant will have dual fuel capability, using distillate oil as a backup fuel source. The plant will be highly energy efficient, with a projected average heat rate of 6,975 Btu/kWh. The estimated total direct cost for building Hines 2 is $197.5 million. Estimated transmission and interconnection costs are $5.6 million. It is my understanding that FPC is not making any cost recovery proposals at this time.

Q. DOES MR. DICKENS OPPOSE FPC'S PROPOSAL TO CONSTRUCT THE HINES 2 PLANT?

A. No. The bulk of Mr. Dickens' testimony focuses on, however, the supposed "advent of electric generation restructuring" and the potential risks he perceives for consumers related to placing Hines 2 in rate base. Specifically, Mr. Dickens is concerned that if customers are committed to long-term assets, they might miss out on more efficient alternatives in the future. He asserts "Inferior choices typically result in sub-optimal outcomes and unnecessary burdens for ratepayers." He apparently would find it advantageous to make shorter-term decisions and thereby avoid long-term risks associated with "markets turning south."

I find his conclusions to be at odds with the very real possibility that market values can both "rise and fall." Accordingly, Mr. Dickens focuses falsely on outcomes where technology, fuel choice, location, etc. might cause a generating station to be worth less in the future than it was projected to be worth at that future point in time. He fails to consider, either in his example or his logic, that some generating stations may, in the future, be worth more than their original cost less depreciation values.

I do not question that economic and rate base depreciation rates may not match up consistently. I do, however, question the perception that any differences are asymmetric, and always favor lower future market values relative to their underlying original cost less depreciation value.

Q. DOES MR. DICKENS ALLEGE THAT HINES 2 IS AN INFERIOR CHOICE?

A. No. He does not seem to quarrel with FPC's characterization of Hines 2 as a state-of-the-art generating plant. Thus, he seems to agree that this generating station currently is not an inferior choice. He does, however, identify what he perceives to be three risks associated with according Hines 2 traditional full regulatory treatment (i.e., effectively placing Hines 2 in rate base). These are: (1) cost overruns or failure to meet in-service dates; (2) plant under-performance; and (3) risks associated with building a long-lived asset, as well as having fuel costs exceed forecast scenarios.

Mr. Dickens then admits that the first two risks are either minimal and/or that incentives are readily available to protect consumers from these risks. It is the third risk that seems to trouble him the most. In essence, Mr. Dickens is concerned that in the future with new technology and/or competition, the Hines 2 plant might not be the least cost alternative for customers and that if allowed in rate base, the customers will be "liable" for these costs. He does not use the term "stranded costs". Nevertheless, Mr. Dickens seems to worry that the Hines 2 unit might have stranded costs in the future. This would mean that the Hines 2 unit's future economics or market value might turn out to be lower than its original cost less depreciation (i.e., rate base). Mr. Dickens is, therefore, worried that if Hines 2 is allowed in rate base, retail customers would be "liable" for these costs.

Q. DO YOU CONCUR WITH MR. DICKENS' CONCLUSIONS ASSOCIATED WITH FUTURE MARKET RISK?

A. No. Long-term assets can be good for customers. No one can predict with absolute certainty what the future will hold for fuel prices. Not long ago, national decisions were made based on oil price projections that exceeded $100 per barrel. Those high prices never materialized. Instead, world oil prices have generally fluctuated in the $10 to $40 per barrel range. Indeed, oil and natural gas prices over the last twelve months have experienced swings that match this twenty-year range in energy prices

Mr. Dickens admirably would like to protect consumers from the risk of long-run decisions that with perfect "20/20" hindsight turn out to be more costly that they needed to be. The problem with this approach is that it is equally necessary to guard against price movements that swing in the opposite direction. Competitive markets often provide a combination of symmetric hedges and levels of return commensurate with any inherently unavoidable risks. Regulation performs a similar task by combining integrated resource planning and contemporaneous or current prudence reviews.

Q. MR. DICKENS ASSERTS THAT LONG TERM FIXED-PRICE CONTRACTS RETARD MARKET EFFICIENCY. DO YOU AGREE WITH HIM?

A. No. Mr. Dickens' entire premise appears to be based on electric industry restructuring and the advent of a competitive market. Such a market does not yet exist in Florida. Thus, I find Mr. Dickens' suggestion that granting Hines 2 rate base treatment would retard competition is inapplicable in Florida.

Q. DOES MR. DICKENS RECOMMEND THAT THE COMMISSION NOT ALLOW FPC TO PLACE HINES 2 IN RATE BASE?

A. No. Even though Mr. Dickens advocates short-run contracts because he thinks that such contracts minimize the risks associated with future changes in technology and fuel costs, as I understand Mr. Dickens' proposal, he would have FPC build Hines 2. He would then permit FPC to recover the "prudent costs" of Hines 2 in rate base or regulated tariffs for about five years. After this relatively brief cost recovery, Mr. Dickens would require FPC to show that Hines 2 and any related fuel cost, technology, etc. is still the prudent choice. If the answer remains "yes", he would recommend that the Commission reauthorize the "still prudent" cost recovery.

However, if the future brings forth less costly alternatives, he would recommend a "buyers' market-out clause" and refuse to permit FPC to recover the annual revenue requirements for Hines 2 based on traditional cost-of-service principals (i.e., the original cost less depreciation regulatory standard).

Apparently, over a 35 to 40 year plant life, Mr. Dickens would repeat these future "prudence" reviews every five years. If the plant fails to sustain its original approval, Mr. Dickens would disallow full cost recovery in the future. Presumably, if the opposite conditions occur and the future market value of Hines 2 exceeds its cost-of-service value, these "savings" would asymmetrically flow to ratepayers.

Q. DO YOU AGREE WITH MR. DICKENS SUGGESTION THAT A "BUYER-OUT" CLAUSE MIGHT BE APPROPRIATE IF THE FPSC WERE TO ALLOW HINES 2 INTO RATE BASE?

A. No. Mr. Dickens, as I have already explained, ignores the fact that markets go up and markets go down. Mr. Dickens proposes a long-term contract where only the buyer has the option to opt out. One-way market-out clauses only occur when one party has vastly unequal bargaining power. For example, in the early 1970s, natural gas supply was critically short. Producers had a great advantage over pipelines desperate to secure long-term natural gas supplies. In those situations, the producers were able to insert market-out clauses where they could effectively demand higher gas prices for their product when and if natural gas was deregulated. Pipelines had little option but to accept these asymmetric contract clauses. Fundamentally, such symmetry was only available in contracts for the very highest priced natural gas. In Florida, demand is growing and new generation must be built to meet this need. Mr. Dickens

suggests a long-term lease where the buyer gets to decide at a specific point whether the deal originally signed is still a good one. This is totally one-sided and asymmetric.

Merchant plant owners that possess a needed commodity that is in short supply are not likely to accept such conditions. Consequently, it is not reasonable to foist such an unacceptable contract clause upon the incumbent utility. Florida remains a regulated cost-of-service jurisdiction. It is imperative that the FPSC keep this clearly in sight as they balance consumer and shareholder interests. My advice is that deregulation, if it comes, should not ignore the relationship between supply, demand, and entry. In the meantime, consumers' needs must be met in a fair and balanced manner. Hines 2, built under cost-of-service regulation, would do just that.

Neither competitive markets nor regulation typically allow one-sided (i.e., buyer-only) market-out rights. If they did, the price paid to willing sellers that might freely accept such risks would be very costly.

Consider an automobile lease. The car buyer and seller agree on a purchase price, a turn in or residual value, and finance costs (i.e., interest rate and term of the lease). No automobiles with which I am familiar are leased without stipulating a residual value. The residual value, once agreed to by the lessor and lessee, cannot be changed unilaterally ~~be~~ by either party. It is not possible to imagine an automobile dealer accepting a lease contract that allowed the lessee to unilaterally reset the residual

value to reflect the car's then current market value at the end of the lease, allowing the lessee to capture all the potential upside of changing market conditions.

Similarly no bank would ever lend money to a home purchaser if the purchaser demanded the right to continue living in the home while unilaterally reducing the amount of the loan if home values drop at some point in the future. Similarly, no one would sell a house to a buyer that could demand a refund if the buyer's requirements change and a house with different characteristics turns out to be better in the future. Mr. Dickens' proposal would result in such treatment for Hines 2.

Q. ARE THERE ANY CONDITIONS UNDER WHICH A MERCHANT PLANT OWNER MIGHT ACCEPT A ONE-WAY MARKET OUT CLAUSE IN FAVOR OF THE BUYER IN FLORIDA?

A. In a marketplace with supply shortages, a generating plant owner not obligated to serve might accept such a one-sided contract clause, but only if the owner is well compensated for the additional one-sided risk such a contract clause engenders. Such additional compensation would mean that prices to consumers would be higher than they would otherwise be under traditional cost-of-service regulation because the required rate of return necessary to compensate for the increased risk is higher. There is no reason a regulated utility should also not receive a higher rate of return to compensate it for this increased risk if it were forced to accept such an

asymmetrical contract clause. This would serve to increase unnecessarily the price paid by customers.

Q. SHOULD THE COMMISSION ACCEPT MR. DICKENS' RECOMMENDATION TO ALLOW HINES 2 IN RATE BASE WITH PERIODIC PRUDENCE REVIEWS?

A. No. First, Mr. Dickens' recommendation effectively to reopen a prudence review every five years or so is out of sync with his testimony, which primarily touts the consumer benefits associated with short-term contracts for power. Mr. Dickens seems to assume that Florida is moving towards a more competitive environment for generation. This issue is far from decided. And given the troubles currently roiling the California retail market, I suspect that legislators in Florida and elsewhere will be extremely cautious in moving forward to deregulate markets that are functioning well and protecting consumers from the vicious price spikes that were present in San Diego this past summer. At the very least, Florida would benefit by taking the time to determine what went wrong in California, a state with similar location issues and needs, transmission and capacity needs and how to remedy the problems.

Second, Mr. Dickens assumes that electricity prices will fall with both competition and advances in technology. Thus, he is opposed to putting long-term assets, such as Hines 2, into rate base because he believes this would foreclose the opportunity for consumers to take

advantage of these lower prices and new technology. Prices respond to supply and demand. The only relative certainty is that excess supply, not tight markets, will push prices to fall. Prices go up and prices go down in competitive markets. Inexplicably, Mr. Dickens seems willing to let consumers bear the risks of this volatility in competitive markets, but not under the less volatile traditional regulatory system.

Third, Mr. Dickens also assumes that plants built today will be less economic than plants built in the future. This is not necessarily true. As plants are depreciated throughout their useful life, they can become extremely valuable assets to consumers. For example, consider the value of older, depreciated coal-fired base and intermediate plants now that natural gas prices are heading north of $5/mmcf. Mr. Dickens' proposal would trade this solid value for the speculative upside potential associated with new technology and competition. Worse, he would appear to support asymmetry in which consumers would always win and shareholders would always lose.

Regulation believes in both the interests of consumers and utilities. The principle doctrine of the regulatory concept is achieving a "just and reasonable" or "fair and balanced" outcome. If regulation veers too much in one direction, the result is almost always higher future costs and prices and/or poor service quality.

Markets perform a similar balancing between producers (supply) and consumers (demand). No competitive market would or could give one

group the power to dominate the other for any sustained period. Regardless of the conceptual or organizational framework, the policy Mr. Dickens proposes is not economically efficient, fair or reasonable.

Q. IS IT EVEN NECESSARY FOR ANY BUSINESS, REGULATED OR NOT, TO HOLD AND USE AN ASSET IN THE FACE OF A BETTER, MORE PRODUCTIVE/PROFITABLE TECHNOLOGY?

A. No. Competitive business, as the saying goes, "knows when to fold them and knows when to hold them." I include a lecture in the finance course I teach at the University of Southern California that explains precisely how businesses make this decision with, and without, technological and other changes (e.g., load factors, factor input price changes, location, inflation, efficiency, etc.).

Regulation uses integrated resource planning, demand side management, and utility diversity/coordination to consider very much the identical set of things. Hines 2 would not, as Mr. Dickens avers, simply lock Florida into what now would be a state-of-the-art, efficient combined cycle natural gas fired unit. If other technologies become available, Hines 2 would slip down in the supply stack. But it would still be used under either regulation or competition.

Given current technological advantages, competitive producers would recover much of their investment on the front end. Traditional original cost straight-line depreciation recovers more of the plant's return

"on" and "of" investment in the early years, while establishing a fixed annual charge, or "of" component (i.e., depreciation expense) equal to the plant's original cost divided by the plant's expected life. Other methods of cost recovery such as sinking fund depreciation can also be used by regulators if they think it is more appropriate to recover a plant's investment sooner.

Q. ARE THERE ANY OTHER REASONS WHY YOU DISAGREE WITH MR. DICKENS' RECOMMENDATION TO REVISIT PERIODICALLY, BASED ON THEN CURRENT MARKET CONDITIONS, THE PRUDENCE OF INCLUDING HINES 2 IN RATE BASE?

A. Yes. Mr. Dickens is proposing an *ex post* prudence review. There is absolutely no regulatory precedent for such an approach. Rates should reflect the prudent investment standard and the regulatory compact:

1. Risk should be consistent with rewards: and
2. "Best-cost" generation policies should be pursued.

Under the prudent investment standard, a regulated firm is entitled to recover from its ratepayers costs that the firm prudently incurs to fulfill its service obligations to those customers. In evaluating whether an expense should be reflected in rates, the prudent investment standard requires determining whether a "reasonable person" would have pursued the same course of action, considering the information known or

reasonably knowable at the time the decision was made, and taking into account the prevailing industry opinions and practices.

It is possible that, in retrospect, some decision other than the one actually made by the regulated firm would have produced a more (or less) favorable outcome. Nonetheless, the possibility that a different decision might have produced a more (or less) favorable outcome should not be the test of whether the regulated firm will be allowed to recover less (or more) than the costs actually expended for its customers. To require a regulated firm to suffer the consequences of reasonable decisions that turn out, *ex post,* to be less (more) advantageous to consumers violates the bargain inherent in the conventional regulatory system. Under this regulatory system, regulated firms realize neither the "upside" gain nor the "downside" loss for decisions that turn out to be more (or less) beneficial than anticipated. From an economic or consumer cost viewpoint, any one sided. asymmetrical regulation where consumers always win would increase the underlying risk to investors and the cost of capital required by investors, to the direct detriment of consumers.

This does not mean that all decisions made by a utility manager are acceptable. Rather, utility managers should be held responsible for their decisions. Both fairness to consumers and sound economic incentives for regulated firms require that the cost consequences of an imprudent decision not be reflected in rates. Conversely, fairness to investors and the desirability to consumers for the utility to obtain capital at a reasonable

cost imply that the costs associated with a decision that "made sense" at the time it was made, considering the prevailing conditions at the time the decision was made, should not result in financial penalties to shareholders. This is true even where hindsight demonstrates that a different decision or course of conduct would have resulted in a better outcome for consumers. To do otherwise would violate the regulatory compact and would lead to uneconomic decisions.

Included within the regulatory compact is the principle that regulators do not use hindsight to judge outcomes of past prudent decisions made by utility managers. This principle protects both customers and shareholders.

The example of past problems that Mr. Dickens discusses is the prices some utilities paid under the Public Utility Regulatory Policies Act (PURPA). I find this example to be a noteworthy exception. In my opinion, the fault does not lie with failed regulation. I place the blame on legislation that went too far and required "buyers" to purchase qualifying energy (QF power) regardless of the underlying economics of the transaction. Neither competitive markets nor regulation as I know it would have condoned this outcome, tied as it was to flawed legislation, not regulation, gone awry.

Q. WHAT DO YOU MEAN BY "BEST COST" GENERATION POLICIES?

A. Under the regulatory compact, regulated firms like FPC have a regulatory, economic, and ethical responsibility to generate electricity in a way that best suits the interests of their customers. This implies that their forecast policies should adhere to a "best cost" rather than a "least cost" approach. Best cost planning means that sometimes it is necessary to pay more to lock in some factors (e.g., a long-term fuel supply) in order to avoid the risk associated with shortages and/or higher future spot prices. Of course, businesses, families, and regulators do this. When they do not do this, they often learn the lesson that "markets go up as well as down." Hines 2 will represent the state-of-the-art in generation plants when it is constructed. As is clear from the Need Petition filed by FPC, the planned capacity is needed in Florida. The decision to build Hines 2 is certainly the best-cost solution that exists for FPC and its customers at this time.

Q. **WHO SHOULD BEAR THE RISK THAT, IN THE FUTURE, A LOWER PRICED POWER SUPPLY MIGHT BECOME AVAILABLE?**

A. Any risk that at some unspecified time in the future there might be a more economical power source should be borne by those who now receive the benefits of reliable, low-priced sources of supply. The direct and major beneficiaries are the customers. Therefore, it is appropriate that customers bear a portion of the slim potential risk that this plant might be more costly than newer technology at some point in the future. Mr. Dickens' recommendation raises the specter that the FPSC would deny

FPC that right to recover costs that were prudent when made. This would impose the downside risks on FPC while keeping the upside gains for customers. This asymmetrical risk allocation would violate the economic principle that risk and reward should be symmetrical.

Q. WOULD YOU SUMMARIZE YOUR CONCLUSIONS?

A. Yes. Mr. Dickens performs a very useful service by reminding everyone that regulation needs to protect consumers. However, he goes too far in this direction when he proposes to abandon the regulatory prudence and "just and reasonable" principles. His approach is one sided and asymmetric. If consumers paid the price necessary to compensate investors for these assurances and proposed rights, the prices consumers would pay would be much more expensive than traditional cost-of-service prices.

FPC has demonstrated the need for additional capacity and relied upon traditional integrated least cost planning to demonstrate this need. The objectives are well known. The current process is built on making the "best" decisions while incorporating relative certainty and minimal risk. Mr. Dickens seems to believe that this well-honed balance can be nudged in one direction, making the outcome take on some characteristics that he generally believes a competitive market would have. However, Mr. Dickens' regulatory concepts and ideas are in direct conflict with widely accepted regulatory principles and practices, and therefore, should be

rejected. Further, Mr. Dickens' notion of competitive markets ignores the important symmetry that exists in such markets (e.g., prices go up and down). He bases much of what he proposes on an unreasonable asymmetric view of competition in which the market always improves on the past. He is wrong about competitive market performance; and, therefore these ideas should be given short shrift.

Mr. Dickens also overlooks the fact that even if new future technology is less expensive than Hines 2, the Hines 2 plant will simply move down a notch in the supply stack. It will still be used and useful to Florida consumers. Further, as Hines 2 is depreciated under traditional cost-of-service regulatory principles, its revenue requirement will be reduced, likely offsetting future modest technological advances. Mr. Dickens also overlooks this fact.

Finally, Mr. Dickens may be suggesting a mix of these two systems: regulation and competition. Some attempts to do so are in vogue. Nevertheless, there are numerous examples in which such mongrelized experiments go bad and consumers lose. The FPSC should stay the course and not be tempted to follow such an ill-fated path.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MR. SASSO:

Q Do you have a summary of your testimony?

A I do.

Q Would you please give it to the Commissioners.

A Yes. I'd like to begin by explaining that I've been doing this kind of expert testimony in electric power issues for a little bit over 30 years, and in addition to that experience, I've had two positions that are particularly relevant to the points of view that I want to express today.

The first is that I was chairman of the Public Service Commission of Wisconsin from 1977 to 1980, and the second is that while chairman of the Commission, I was also the chairman of the NARUC Committee on implementing the Public Utility Regulatory Policy Act. So I'm fairly familiar with those kinds of topics and subjects.

Essentially my career had been a mixture of government service and working as a private consultant and teaching at various universities around the country. My area is specialization has been energy regulation, environmental issues, and antitrust. And so it's with that background that I come before the Commission today to sort of express my views on the proposals that have been made that I think would, in fact, fundamentally change the regulatory compact as we know it and as Florida practices

it at least to the extent that I know Florida practices it.

Let me begin by making, in terms of a summary, three general points, and then I want to turn to the specific reasons on why I reached the conclusions that I do. The first general point that needs to be made is that three words are used a lot these days in the electric utility industry: Competition, deregulation, and restructuring. First, I think that it's important to note those words are not synonyms, and second, more importantly, there's no unique or specific definition really that's attached to each of those words or any of those words. And, in fact, my experience is that every political jurisdiction, whether it be a state or different countries, that practices something under the heading of deregulation or competition or restructuring does it a very unique way. And until the rules and purpose are laid out, it's really almost impossible to speculate or to address what it is that people in a particular political jurisdiction when they ultimately write the laws or implement the regulations have in mind under those words. And I think we'll see that this is going to be one of the key points of differences between myself and Professor Dickens in talking about these kinds of issues.

I guess the simplest way to say that is that one

size doesn't fit all when it comes to the different ways states are thinking about these matters that we're going to be talking about. Some states, of course, are pursuing retail competition. Some states are looking at wholesale competition. A good number of states have decided to stand still and wait and see what happens. And we are getting now with California, we're starting to hear states taking serious looks at what I'll call re-regulation. We're attempting to reverse some of the experiments that they participated in.

I guess it's safe to say that from an industry perspective, the industry is in a state of flux. When I come in to examine the issues that I've been asked to examine today into the state of Florida, I reach the conclusion that Florida is a state that is a traditional regulatory environment practicing cost-of-service principles. And I think that my position is going to be to try to explain why using that traditional regulatory approach is the policy that should be followed in trying to determine the need for the Hines Electric Station Number 2.

The traditional regulatory approach is built upon the interaction and the integration of three very significant principles. These principles are that prices and rates of return should be just and reasonable, that

prudently incurred costs should be collectible in a reasonable way by the customers -- by the companies that undertake those prudent investments and expenditures to provide service to their customers. In all of these issues, just and reasonable prudence come together into a regulatory compact that has with it the purpose -- has a very important purpose associated with it, and that purpose is to try to deliver quality service, reliable service at the lowest reasonably achievable cost. And that's really -- that last part is the part that I think I particularly want to emphasize in my presentation today.

The third general comment that I need to make is that Mr. Dickens deviates, I think, in a profound way from this regulatory compact. I don't think he's talking about amending that compact. I think he's talking effectively about ending or vitiating that contract. And he does it, I think, by doing three things. The first is that he recognizes, as I think we all do, that the future is uncertain. Nobody can be certain about the future. It is fundamentally uncertain. The different between his treatment of uncertainty and the treatment of traditional regulation is that I believe when he thinks about uncertainty, he will actually be creating new levels and elements of risk that will increase the cost of money for the regulated firms in Florida. And when you increase the

cost of money for regulated firms, you will raise the price that consumers will pay under regulation.

The second part of his notion is that he would introduce periodic five-year prudence reviews, which I think are based upon nearly -- if they're going to serve any purpose at all, they are based on a requirement that hindsight must be used, and therefore, he would totally reject what has been for more than 50 years the regulatory standard of a prudent person or a prudent investment standard. And by that I mean what were the facts, what were the conditions at the time the decision was made, not at some point in the future. And so I think that there are some major differences between the way in which Mr. Dickens would treat prudence, the way in which he'd treat the regulatory compact, and the role that he would attach to the use of hindsight to take into account the fact that the future is uncertain.

Now, let me explain the four major things that I think are fundamentally wrong with that approach and, therefore, why I am here to urge the Commission to reject it. The first is symmetry. Symmetry is an idea or a concept that essentially says regulation and markets should attempt to be fair and balanced in the sense that they tend to -- if they are going to treat upside favorably for one group or one group of players, that they

will treat downside similarly for that same group of players. What Mr. Dickens is proposing, I think, is that he's attempting to suppress what I'll call the downside risk for consumers, but in so doing, he will have the effect of raising the cost of capital for the people who have to make the investments to supply consumers, and therefore, in this way, I think that he's going to have the undesirable effect of hurting regulated retail consumers in Florida.

The second reason which I think he's wrong is that he seems to agree, and from what I know I would agree with his assessment, that the starting point is that the Hines Electric Station for a variety of reasons that we've all been hearing about over the last couple of days and we've read in the prefiled testimony, for a variety reasons, the Hines Electric Station is the most cost-effective means for Florida Power to go out and meet the needs of its consumers over a reasonable planning horizon. The problem with where we start to disagree is that Mr. Dickens really only thinks that the future can be one-sided in the sense that he worries about the possibility that in the future the Hines station may, in fact, have lower value relative to the market or what we expect it to be today. I think there is very reasonable conditions to think that the future might make that plant

more available. And as far as I can see it, he's not building into his analysis any possibility for a situation where, in fact, the upside benefits for consumers of the Hines station would somehow translate into a corresponding symmetric benefit for the shareholders who would be investing their money. Which brings us to the third distinction between myself and --

COMMISSIONER JABER: Mr. Cicchetti, did he not agree on the stand just a few minutes ago that there are two sides to that theory?

THE WITNESS: He agreed that there were two sides to it, Madam Commissioner, but I don't believe that he would allow a return to be increased for the shareholders. Instead, I think what I heard him say and certainly in his testimony in his deposition is that cost-of-service standards would be used when market values were greater than the remaining original cost less depreciation rate base values, or if market values were less, he would then disallow some of the recovery or all of the recovery of the plant, or he would accelerate the write-off of that plant.

So I think that he had in mind -- he agrees that the future could be up or down, but his policy only takes into account an adjustment in one direction when it works out that the future turns out to make Hines, if it does,

less valuable relative to the market.

And it's really this one-sided periodic prudence review which is key to understanding his general philosophy. And it's in that general philosophy where I think he is making his major policy error, and it's that I don't think he's taking into account the fact that there's a cost to changing the policy. There's a reason why for 50 years we have kept the regulatory compact for states and for jurisdictions that have cost-of-service regulation, and that's to try to take uncertainty and the risk associated with it out of the equation in the financing of utilities.

And by trying to reduce some uncertainty and spread the risk -- or suppress the risk that's inherent in all uncertainty through an agreement that on the one hand utilities could get their prudently incurred original costs less depreciation plus a reasonable return on it. That's made it possible to find a group of investors who would put their money into utility companies in a way that they are not seeking the same level of return and earnings as people invest in unregulated businesses. And in that way, regulators have believed and built their decisions on the notion that this would be in the best interest of the consumes because it could bring about a lower price by trying to take some of the risk, up and downside risk, of

recovery of investments in the future.

And the fourth reason for disagreeing with Mr. Dickens is the notion that I don't believe any non-utility generation -- I don't think any NUG or EWG or IPP or whatever we want to call -- acronym we want to use to apply, I don't believe any non-utility generator would accept one-sided risk of the kind that Mr. Dickens is proposing Florida Power should accept unless they were receiving a much higher price or higher rate of return associated with accepting such one-sided risk.

And, again, I see there being a major difference between what's being tentatively proposed for non-utility generators; that is, they would not be called upon to accept one-sided risk, but they would, in fact, be able to charge a higher price for engaging in the activity of building power plants over and above the cost that would be spent by a regulated company using regulated capital structures and taking advantage of some of its built-in scale and other economies associated with this particular site.

So my conclusion is that I think that this Commission should stick with regulatory symmetry. I think it should continue to adopt the issue associated with a regulatory bargain as a reasonable way of achieving the lowest possible price for regulated customers. I think

that ex post prudence reviews should be rejected as only adding cost and risk and not adding any particular advantage over the best decision that could be made today, and therefore, I believe that the Commission should approve the Hines electric station under cost-of-service regulation. Thank you.

COMMISSIONER JACOBS: Thank you. Ms. Brownless.

CROSS EXAMINATION

BY MS. BROWNLESS:

Q Good afternoon, Dr. Cicchetti. How are you?

A Good afternoon.

Q I'd like to ask a few follow-up questions on your comments concerning regulatory risk.

A All right.

Q My understanding is that financial analysts when looking at utility companies, investor-owned utility companies, or others calculate at this time a certain amount of regulatory risk associated with every financing; is that correct?

A Yes. In fact, regulatory Commissions are often graded in terms of the degree of risk.

Q Okay. And when a Wall Street agency is trying to come up a grade for regulatory risk, what is the comparison that's done? In other words, how do you -- what would be considered to be more risky activity versus

less risky activity?

A Well, markets don't like change and uncertainty, and actually prefer states that continue to follow a consistent policy over time. And they tend to grade states on the basis of their performance vis-a-vis themselves; that is, are they changing things or keeping things more or less on an even keel from their own past as well as to consider differences across states and jurisdictions.

And regulation is something that can have adjustments. It can have ways of accommodating differences that occur, but for the most part, the simple story is that markets don't like change, and therefore, they tend to reward regulatory Commissions that more or less either stay where they have been, or the changes they make are viewed as balanced in the sense that they are symmetrical. They don't particularly favor one group of people who are stakeholders than another. They don't particularly favor consumers. They don't particularly favor shareholders. They tend to be evenhanded in their approach.

Q Okay. So would it be fair to say that if at this point in time Florida did have retail deregulation -- if right now the 50-year policy had been retail deregulation, you can buy electricity from whomever you

want, that Wall Street would consider keeping that policy a less risky state than changing that policy to a regulated policy? In other words, sticking with whatever you've got.

A Well, there's no question that regulation or regulatory commissions and environments are graded on the basis of stability and predictability. I don't know that I could be certain of how the investor-owned community would react to essentially a competitive market being regulated de novo for the first time. I don't have enough experience with seeing that actually happening. But I do know when people are talking about re-regulation in California that there are financial consequences for the utilities in California that are negative when those re-regulatory ideas are being debated and considered in the Legislature.

Q So the bottom line is change of any type is viewed as increasing regulatory risk? It's always better to stick with what you've got.

A Change without a good purpose and with the balance and symmetry built into it is always viewed as bad. Good change or change that is essentially brought and sold to the market, that is, you explain where you're coming from and why you are doing it, is also generally favorably reacted to. I know when I was a Commissioner I

was considered a radical, and every time I did something different or the Commission was about to do something different, I felt it was important to communicate why we were doing it and the nature of the change to the financial community either in person or by conference call.

Q And when you were able to make those communications, then you could mitigate the effect of the fact that you were changing your policy; correct?

A Yes, that was the purpose of the calls. It was to sell the policy, if you will, and to explain the policy.

Q Okay. Is the most conservative action always never to change any policy?

A I don't know what -- I'm a reactionary now, so I don't know what you mean by most conservative policy. Maybe I put you off by telling you I once was a radical. So maybe you can change the question in a way that's more -- I'm more comfortable with.

Q Is it always the most conservative approach to keep your same policy? Is that always the most conservative approach?

A I wouldn't characterize it as most conservative.

Q Less risky, stick with what you are doing?

A It's less risky to keep doing what you have been

doing. It's predictable, and in that sense, risk is always about unpredictability and uncertainty.

Q Okay. If you can be completely consistent, then you absolutely minimize risk in that sense?

A Yes. But I don't think any public policy should simply minimize risk. That's -- but I'm happy answering the questions dealing with risk as opposed to cost or whatever the first word you were using.

Q Okay. Would you agree that if the Commission explored Mr. Dickens' suggestion that investor-owned utilities in Florida would be less likely to construct their own generation?

A I think they would either less likely or if they did construct them and they had to finance them, which is what I assume they would have to do is go to the market to finance them, they would have to pay much interest cost and higher cost of equity, so therefore, I think the prices would go up regardless of whether they built the plants or not.

Q All right. Would you agree that in a tight market where there were fewer capacity alternatives, the price of capacity would tend to be higher than in a market where there were more capacity alternatives --

A Well --

Q -- assuming supply -- I mean, demand stays the

same?

A You asked that question yesterday, and I thought that the answer you got was a little bit -- well, it was correct, but it didn't go far enough. And let me explain what my thinking was. When you talk about a market, you have to talk about the geography or the relative size of the market. And what we now know is that power systems are becoming much more interconnected. They are no longer simply a jurisdiction of a single investor-owned utility or even a collection of investor-owned utilities in a single state.

Power markets are being regionalized and probably in the foreseeable future nationalized in the sense that the market will cover collections of regions, if not the entire country. And in those context, when you talk about tightness of supply, you have to talk to about tightness of supply in a locality and what it might or might not do relative to the integrated regional markets that are forming all around us. And so I think you can't really answer your question simply. Economists have a way of making a simple answer, and that's to use the latin expression ceteris paribus or other things being equal.

And other things being equal if demand goes up and supply stays still, prices go up, and the reverse is also true. If demand goes down and supply stays the same,

then prices go down. But when you bring into -- when you take into account that demand and supply in Florida might be different than demand and supply in Georgia, even in the same winter season or summer season because of weather patters, then you can't make such a simple answer because there are more factors that are involved in determining the market and what power does and where it goes and how it responds to price differences that can be connected or delivered across what's becoming more of a -- of certainly a regional transmission system.

Q Are you aware of whether Florida has interconnections with Georgia, Alabama, and other southeastern states?

A Yes.

Q And of the capability of those interconnections?

A I don't have them in my notes for today, but I've certainly looked at them in the context of other proceedings.

Q Do we have a great deal of interconnection capacity with the southeast peninsular Florida?

A You have some. It flows in both directions, but I didn't take your question to be a question about Florida. I took your question to be a question about if markets are tight.

Q Well, let me ask --

A And I wanted to explain --

Q Sure.

A -- that it's more complicated than a market being tight. It's a regional difference that you have to take into account. And the world is changing, and in a changing world, transmission, construction, and access is also changing, and you can't ignore those facts in terms of the principle that other things are not equal; they are changing.

Q Okay. So you wouldn't know whether Florida was considered to be its own peninsular power market for all practical purposes or not?

A I don't agree with that statement. I've heard it stated, and I have even heard the people who say it almost immediately when confronted with other questions and facts run away from it, so it's not an island. It's not Hawaii, but it's also not Maryland sitting in the middle of the Northeast.

Q Okay.

COMMISSIONER JABER: Isn't the fact that the world is changing that access, generation, and transmission is changing and that Commissioners shouldn't look at the world in a one-sided view the whole purpose of Billy Dickens' testimony?

THE WITNESS: I think his whole purpose of his

testimony is to bring to the attention to the Commission -- I think he did a very good service in doing this -- that the future is uncertain and that there is change. So we know that the forces have changed coming from federal legislation and coming from neighboring states and maybe even coming from people who are studying the issue here in Florida that change is inevitable, and therefore, the future is uncertain. Those are good statements and those are valid statements.

The problem I have with Mr. Dickens' policy solution for that is that I think he believes that you could take some of the risk of that change away from consumers and do it without any consequences that will be bad for consumers. And I think there are two bad consequences that are likely for retail consumers in Florida if you follow his policy conclusion. One is the point I made about raising the cost of money for a current set of rules that effectively mean that investor-owned utilities have to build power plants, and if they have to build them at a higher cost of money, that's going to be bad for consumers.

And the second change is that his one-sided approach, I think, will have an effect on denying, or not denying, but reducing the likelihood that investor-owned utilities will want to build, and therefore, you'll have

to find a way to turn to non-utility generators who can only build power plants in Florida, as I understand it, is if they do it in conjunction with a investor-owned utility.

Now, if that's true, then the only relationships you'll see develop will be non-utility generators who will come forward and know they have a desperate buyer on their hands, somebody who can't build themselves because they can't finance it, and raise their rates to collect the money, and they will only get them to build -- or they will only come up in agreement where they come in at prices that are by any standard of comparison too expensive with much higher implicit rate of returns with these kinds of offerings coming forward like we've seen laid out for us by Panda. That is just really expensive alternatives for short-term duration, and that's not good for the Florida consumer as well.

So I think any way if you follow his policy, you will see more of what you are seeing here which are a bad set of IPPs coming forward and when utilities decide they can't build because they can't finance it because of these five-year prudence reviews, I think that's the bad policy idea. He's right to worry about uncertainty in the future in the transition and the fact that you're trying to make regulatory policies in an environment in which you know

the Legislature and others are thinking about changing the rules of which you operate, but you have to make a decision today that's going to be around for 25 years.

COMMISSIONER JABER: All right. So if you agree that the future is very uncertain and that there are costs associated with any change and as a former Commissioner you understand the policy decisions that are made every day by the Public Service Commission, how do you minimize the effect to the retail ratepayer?

THE WITNESS: Well, I think the answer is that you try to avoid making the risk and uncertainty greater, and I think that if you had five-year periodic prudence reviews, you would be doing just the opposite. You would be making today's level of risk and uncertainty much greater.

I think that if I had to deal with the issue here, I'd be very encouraged by the fact that Hines 2 is not just a good build option, it's one of the best build options I've seen because of adding on to an existing site that already has the transmission and environmental investments made would rely on natural gas which Florida under various proposals is going to be getting increasing amounts of, particularly from the power industry, and it would be benefiting from the fact that it's lucked out on this deal to get a source of generating equipment at a

very favorable price because of negotiations that took place in the past.

So you have a really ideal cost option here, and I think that it's one of those things that as a regulator I'd try to find a way to grab it. I'd try to find a way to make it happen.

COMMISSIONER JABER: So in my attempt to try to grab onto those benefits that might be associated with the economies of scale, the benefits that your client and you believe that will be afforded to the retail ratepayer, how do those benefits associated with the economies of scale flow through to the retail ratepayer?

THE WITNESS: Well, they flow through because it's a lot less expensive to take electricity with straight line original cost depreciation out of Hines 2 built under the cost of money and the capital structure and with these built-in construction advantages, construction cost advantages. That's a lot cheaper than you are going to get an IPP to ever build a plant for.

COMMISSIONER JABER: So --

THE WITNESS: And an IPP that only offers a plant for a short duration because they want to essentially be able to go to the market, then that kind of an IPP really isn't meeting the long-term needs, and it's subjecting the citizens and the retail consumers in

Florida to much higher upside prices in the future. And since they have no duty or interest in serving the market, you have to worry about them rushing even under the limited transmission system to higher price markets if those prices become available. So this --

COMMISSIONER JABER: Okay. I really appreciate that. It's educational to me, but I'm not talking about the IPP. I'm talking about your client. If I want to make sure that the benefits associated with the economies of scale from this plant flow through to the retail ratepayer, I think what you're -- inherent in what you're saying is, in a rate proceeding, the retail ratepayer should see the economies of scale flow through?

THE WITNESS: Well, not only that, but as I understand Florida regulation, it wouldn't even go into a rate case until the earnings of Florida Power with this plant now included in its cost were to exceed some band of rate of return so that in fact the reliability could conceivably be achieved and the efficiency of the unit could conceivably be achieved and the credits going through to the consumers of any excess capacity could be sold off at certain times. Although, I don't think those are very big, but there could be some. Those could also flow through to the consumer, and finally the fuel diversity benefits could flow through to the consumer. So

you would have about four benefits without it triggering any increase in the retail rates in Florida.

COMMISSIONER JABER: But absent a rate proceeding --

THE WITNESS: That's without a rate proceeding. That's under the current surveillance report accounting.

COMMISSIONER JABER: You're saying that those economies of scale would be included for surveillance purposes?

THE WITNESS: Yes. Well, the operating economies of scale would be included for surveillance purposes.

COMMISSIONER JABER: Okay. So then it would be included in the earnings of the company is what you're saying. It would offset the earnings of the company.

THE WITNESS: It would drive the earnings up. It might trigger you to have a rate case if everything else stayed the same where you would be reducing rates. I don't think my client wants to hear that, but that could happen and we understand the way it works. It's more likely that it would trigger a rate reduction because it's such a good plant than a rate increase.

BY MS. BROWNLESS:

Q I'd like to follow up on --

A Excuse me?

Q I'd like to follow up on some of Commissioner Jaber's questions concerning -- where you told her that your client would be less likely to invest in generation facilities under this proposal, is that correct?

A This proposal is the --

Q The five-year prudence review.

A -- five-year prudence review every five years? Yes.

Q Yeah. Okay.

A Yes, they would be less likely --

Q Less likely to do that.

A And so would every other investor-owned utility in Florida.

Q Okay. And you also, I think, mentioned that that would be -- that under current Florida regulation, as you understand it, an independent power producer has to have a contract with an investor-owned utility to build a power plant?

A That's my understanding.

Q Okay. Would your analysis change of the benefits of this prudence review if an independent power producer did not have to have a contract with an investor-owned utility or in point of fact did not have to come to this decision for a need determination but could

go out and construct wholesale capacity in the state of Florida based upon its own forecast of what the market was?

A Well, I think there you are getting into an area where you have provided answers to most of the questions but not all of them. The next question would be: What wholesale market are we talking about?

Q The Florida wholesale market is the only market I'm talking about, peninsular Florida.

A Well, let me finish. I hadn't finished.

Q Excuse me.

A I mean, you can answer my question, but I haven't finished my question.

Q Sure.

A The first thing I'd ask myself is, what wholesale power market are we talking about, and second, what are the pricing or other rules of exchange of electricity within those markets. And I know that the independent power producers, some of them in Florida, have proposed selling against the marginal price in the stack as opposed to other means of selling electricity. I'd have to know what those rules are, what the rights were, and I would have to know whether the new rules had must-buy provisions kind of like the avoided cost rules in PURPA. Unless I know the rules, I can't really answer

your question whether or not even under your hypothetical I would change my mind because there is no way of combining regulation, which we're going to still have some of every place that we restructure, and markets without telling me the rules between those two forces that we are trying to integrate in some fundamental way. So there is no simple answer to the questions.

Q But you would agree that there could be a set of rules under which allowing wholesale generators to construct power plants without committed capacity contracts to investor-owned utilities and without having to come to this Commission for need determinations would, in fact, be beneficial for Florida ratepayers in the Florida market?

A I'd have to see the rules.

Q Well, it's a probability they could be drafted, is it not?

A Well, I'm not the kind of a witness who will say, oh, everything is possible; therefore, I will always say yes if you say is it a possibility. I don't know. It's plausible that you could design a conceptual argument that would make the argument yes, but I just won't say it. I think that it's -- what I see is the reality of what is likely, and the reality of what's happening in lots of other places is that the answer is more likely to be a no

under the rules that are often put forward. But the rules are so fundamental that the question really can't be answered. You can't say yes or no to those kind of questions because you have left out the rules, and the rules will decide whether or not it's good or bad for consumers.

Q So you can only render an opinion about the regulatory scheme that's in effect today because you know the rules associated with that?

A No, but I can't answer questions about an alternative regulatory or market regulatory mix without knowing the rules that you have in mind when you pose the question.

MS. BROWNLESS: Thank you, Dr. Cicchetti.

COMMISSIONER JACOBS: Staff.

CROSS EXAMINATION

BY MS. HART:

Q Dr. Cicchetti, I've only got really one question for you. You were present in the room, weren't you, when Mr. Dickens testified throughout the course of his testimony?

A Yes, I was.

Q Do you recall him suggesting that his proposed review -- that if his proposed review determined that the Hines 2 unit was a superior economic asset to -- superior

to the other available alternatives at the point of subsequent review that the shareholders could receive a pecuniary award?

A I think he said -- the way -- I heard him say something like that, but the way I interpreted it was that the Commission could do anything it wanted in the future about raising rates of return, and if it thought that a Commission had done a particularly lucky thing in the past, it was reasonable if this Commission wanted to do it to raise their rate of return. Now, I didn't view that as enough of a change from what he was really proposing, which was a regularized periodic prudence review where if the outcome was the other way, the choices would be either to disallow recovery of the plant in its entirety, which I think would be extraordinarily extreme, or alternatively to allow for accelerated depreciation of the plant.

Now, that policy is something that is intriguing because that might actually be a good policy because it would allow a company to get really a lot of cash flow assuming they could collect it in their rates. So again that policy I'm not so sure that what he had in mind and what I have in mind when I read those words are the same thing, but the policy that he's put forward as far as I could see it was a policy that said if the Commission wants to reward companies who have done better than other

companies, it can always do that. And I suspect most of us who have been regulators, whether we say it or not, have done that.

On the other hand, I view this periodic review as changing something very fundamentally. I completely disagreed when you said this was just an amendment to it. I viewed it as a total rejection of the regulatory compact, and I still think that that's the case. I don't think he changed it enough to come even close to making me nudge from that conclusion.

MS. HART: Thank you.

COMMISSIONER JACOBS: Commissioners. I have a question. We have an interesting development here where we have this fleet of essentially peaking plants that are being built which don't require siting approval. Most of them are over 300 megawatts. In fact, some of them are 800, 500, 600, 800 megawatts, and it's an interesting development to me because I'm wondering how they are going to make it. And at the same time, we have a fleet of peaking plants that some of them are running oil, and in the summer, we will likely see -- and winter, in fact, we will likely see an increasing peak.

The argument that I heard, and I believe is being expressed, is that in the face of electric market power, you will likely see those oil peakers running in

the face of these 800-megawatt gas plants out there, and we have very little, if any, opportunity to exercise any scrutiny about whether or not those decisions were reasonable and on terms with the present market. If we don't do something on the order of what's being proposed, how do we ever exercise any scrutiny about those operational decisions?

THE WITNESS: Well, I don't know that I can give you a complete answer to your question, but let me first agree that I think that your premise of tightening peaks in states like Florida and California and Texas are right on, and they are for a surprising reason. We have discovered in California that as we become more whetted to computers and DSL lines and all those things, we are leaving them on. We're not turning them off. And they are drawing power 24 hours a day, 7 days a week which is pushing up the base, which along with our improved incomes and economic growth, we want cooler houses, warmer houses, and therefore, the peak is getting worse on top of the base going up.

So the growth in electricity, in my opinion, particularly in the three warmer and high growing economic states, California, Texas, and Florida, elsewhere perhaps as well, but those three states in particular I think are having a round of unprecedented growth that is pushing up

demand relative to supply. So there is a supply constraint that translates into higher prices, and regulators and/or markets have to think about what's the best solution to tightening demand relative to supply. And we have three -- those three states are in three different places on that issue.

Texas is making it up now. California tried something and didn't have it completely worked out and has had the prospect of prices which are now averaging during the week 25 cents a kilowatt hour, so that's not necessarily a model to be found. And then here you have Florida which is trying to decide what to do not in real time but on a more debilitate time, and in the middle of that, you have to deal with the fact that there is this pressure to meet capacity requirements in the next three years. And I think you have to make the best decision you can. It can't be a perfect decision. It can just be the best decision that you can. I don't think you can make -- there's a phrase that I used to use when I was a regulatory: Don't let perfect be the enemy of the good.

You have to make a good decision. And right now I think a good decision is one that says, let's not make the cost of what we have to do, which is to build plants, greater than what it otherwise will be. And unfortunately, while I think Mr. Dickens raised the right

issue, an issue that I share, what do you do? I don't have the answer, but I also don't think he has the answer. His proposal, in my opinion, would make the cost of doing what you have to do a good decision. Hines 2 is a really good decision. You can go home and sleep on that one and not worry that it's a bad decision any way you look at it.

Now, the idea is, how do you get that good decision at the best cost or most reasonable cost? And I would put to you that from what I've seen and what I've heard and what I've thought about in reading his proposals, you don't get that in the -- you don't get Hines 2 a good decision in a cost-effective way by making it riskier. If you make it riskier, you increase the cost. And so if you think the plant really is needed, that those 20 percent reserve requirements really are kind of an important target given what's happening on the DSM side and you need that plant and it's the most cost-effective plant, then I think you should try to get it built and put into your portfolio or fleet of plants at the lowest cost, which is not to take his recommendation but to instead stay with the current system that you have, and realize that by the time the next two or three of these plants might be coming along, your legislative task force will be making decisions. You can import the lessons learned from California, New York and elsewhere

and make again a better decision than I think you can make today about what the future mix of policy should be for Florida.

COMMISSIONER BAEZ: Doctor, I have a question. You mentioned -- you spoke about risk and making certainly a project like Hines 2 a lot riskier for the company. Why or why not isn't that risk shifted also onto an IPP coming into this market with this regulatory, you know, proposed intermittent regulatory review, why is that risk -- or might that risk also be applicable to independent power producers?

THE WITNESS: I think the uncertainty, that is, what's the value of electricity in five years, whether it would be Panda or Florida Power, the same risk. We don't -- neither one of them knows the answer to that question. They may have the same opinion. They may have a different opinion, but neither one knows what the price will be. So in that sense the price risk is the same. The difference is that an IPP could charge a higher price if electricity is more valuable or have a lower price if electricity in the market is less valuable. There is symmetry in a competitive market up and down.

What regulation tries to do is to take the same idea of symmetry that a market has but suppress it to say, let's keep the cost that we know today. If it's our best

decision, let's keep it around for as long as we can with original cost straight-line depreciation or rate base treatment, and in that way, we can guarantee price stability. We can guarantee consumers they won't have to pay more than we think that they would have to pay now, and if it's a good decision now, it's a pretty good deal, realizing that upside and downside adjustments are available in the market. But then so is the -- when you go to a market, there's more equity and less debt. There's a higher cost of capital, and there is the possibility to make really big profits in markets.

There are companies who are IPPs in California who are proudly saying, we've been here a year, and we've got all our money back in one year at these ridiculously high prices. Well, those are things that markets like to hear. There will years in the future when everybody loses their shirt in California, but that's a market. And I think that until you have the rules of the market worked out and until you know what you are doing, the best decision you can make is to use your current rules in a way that get this good plant built at the lowest possible cost and to do that means to avoid putting risk on a cost-of-service plant.

And if that's the only choice you can make or the choices that an IPP might present are only available

at a high price, a higher price, then go ahead with the best choice you can make now on what's on the table with some reasonably open bidding process and review process and go with it, but don't take your good choice and make it more costly if it's your choice.

If it's your choice, lock it in like you've done in the past, and recognize that if in the future you have to decide to look at things, you're going to have to look at all the plants that are currently in the portfolio in the fleet and decide the transition rules, or your Legislature is going to have to do that, or your courts are going to have to do that, but some group is going to have to address these issues. And in my way of thinking, it would be a mistake to bring Hines 2 out and say, let's treat it completely different. It's not going to make your future life that much easier, if at all, because you're going to have to do whatever you do for everything.

COMMISSIONER JACOBS: Redirect.

MR. SASSO: We have no redirect, Mr. Chairman. We would like to move in Mr. Cicchetti's resume, which is Exhibit 19.

COMMISSIONER JACOBS: You can call it CV now. I know what it means.

MR. SASSO: Okay. I just can't say it clearly enough.

COMMISSIONER JACOBS: Very well. Show Exhibit 19 admitted.

(Exhibit 19 admitted into the record.)

COMMISSIONER JACOBS: Thank you very much, Mr. Cicchetti. You're excused.

(Witness excused.)

MR. ELIAS: Mr. Chairman, I have got two housekeeping matters. The first is Panda's opportunity to object to the introduction of Mr. Dickens' testimony was specifically reserved.

COMMISSIONER JACOBS: Right.

MS. BROWNLESS: And we certainly have no objection to his testimony.

COMMISSIONER JACOBS: Very well.

MR. ELIAS: Okay. And the second concerns the confidential information that was inadvertently verbalized on the record during the cross of Witness Major, and I want to put on the transcript exactly how we propose to treat that. It was stricken by ruling of the Prehearing Officer. We will place the original page of the transcript in a confidential file and maintain it as we ordinarily do confidential information. The public copy and all copies that are distributed will have that information redacted.

COMMISSIONER JACOBS: Very well.

MS. BROWNLESS: Can I just ask a housekeeping question here --

COMMISSIONER JACOBS: Sure.

MS. BROWNLESS: -- about the treatment of the confidential materials that have been discussed?

COMMISSIONER JACOBS: Other than that?

MS. BROWNLESS: Yes, sir.

COMMISSIONER JACOBS: Okay.

MS. BROWNLESS: And it's with regard to how they will be treated in the briefs. I assume that we will be able to write a brief with use of all the information, both confidential and nonconfidential in it, and that can be provided under seal to everybody to the Commission and the other parties, and that we would have a brief that was redacted that would be the public record brief.

MR. ELIAS: That's been the procedure in the past when individuals have felt compelled to refer to confidential information in the argument, and I don't see any reason to deviate from it here.

MR. SASSO: As I understand what you are suggesting, Suzanne, we basically use the same procedure that we did with exhibits.

MS. BROWNLESS: And the testimony.

MR. SASSO: And the testimony, which will be fine.

MS. BROWNLESS: Thank you.

COMMISSIONER JACOBS: Clear enough. I did not -- I remember we talked about the Late-Filed Exhibit 16. It's Staff's request for the treatment of -- did we admit that?

MR. ELIAS: We would move its admission subject to objection of the parties once it's distributed.

COMMISSIONER JACOBS: Okay. Show that --

MS. BROWNLESS: And do we have a date by which those late-filed exhibits will be provided?

COMMISSIONER JACOBS: Yes. We do need a date.

MR. SASSO: May we have until the end of next week?

MS. HART: Sure. That's fine.

COMMISSIONER JACOBS: Very well.

MR. SASSO: And we'll certainly -- we'll work to get you something sooner. I'm going to be out of town most of next week, and I'm just concerned about logistics.

MS. BROWNLESS: Can you just give it a date for the record? Because I don't have a calendar here.

MS. HART: November 3rd.

MS. BROWNLESS: Thank you.

COMMISSIONER JACOBS: Very well. That's next Friday. That works.

MR. SASSO: Thank you.

COMMISSIONER JACOBS: Anything else to come before the Commission today?

MS. HART: Mr. Chairman, I just thought for the record I would express the upcoming dates that are relevant for everybody in this matter according to the CASR. Transcripts of this hearing are due November 3rd. Briefs are due November 15th. Staff's recommendation is due December 7th. It's scheduled to be heard at agenda on December 19th. And that's all I have to say. Thank you.

COMMISSIONER JACOBS: Very well. If there's nothing else then, thank you very much. Show this hearing adjourned.

(Hearing concluded at 3:50 p.m.)

- - - - -

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that the Hearing in Docket No. 001064-EI was heard by the Florida Public Service Commission at the time and place herein stated.

It is further certified that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 649 pages, Volume 5 constitutes a true transcription of my notes of said proceedings.

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

DATED this 2nd day of November, 2000.

Tricia DeMarte

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

FILED
THOMAS D. HALL
MAY 25 2001
CLERK, SUPREME COURT
BY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Hines Unit 2 Power Plant by Florida Power Corporation.	DOCKET NO. 001064-EI DATE: OCTOBER 25, 2000

STAFF'S REQUEST FOR OFFICIAL RECOGNITION

Pursuant to Sections 90.201, 90.202, and 120.569(2)(i), Florida Statutes, Staff requests that the Commission take official recognition of the following:

FLORIDA PUBLIC SERVICE COMMISSION ORDERS

Orders on QF Buyouts

1. ORDER NO. PSC-96-0889-FOF-EU
ISSUED: July 9, 1996
DOCKET NO. 960182-EQ
Petition for approval of agreement to buy out Cypress Energy Company standard offer contract by Florida Power & Light Company

2. ORDER NO. PSC-96-0898-AS-EQ
ISSUED: July 12, 1996
DOCKET NO. 960193-EQ
Petition for expedited approval of settlement agreement between Florida Power Corporation and Orlando Cogen, L.P.

3. ORDER NO. PSC-96-1217-FOF-EQ
ISSUED: September 24, 1996
DOCKET NO. 960604-EQ
Joint Petition for Expedited Approval of Settlement Agreement by Florida Power Corporation and Ridge Generating Station, L.P.

4. ORDER NO. PSC-97-0086-FOF-EQ
ISSUED: January 27, 1997
DOCKET NO. 961184-EQ
Petition for approval of early termination amendment to negotiated qualifying facility contract with Orlando Cogen Limited, Ltd. by Florida Power Corporation.

5. ORDER NO. PSC-97-0523-FOF-EQ
ISSUED: May 7, 1997
DOCKET NO. 961407-EQ
Petition for expedited approval of settlement agreement, regarding negotiated contract for purchase of firm capacity and energy from a qualifying facility, with Pasco Cogen, Ltd. by Florida Power

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 1
COMPANY/ WITNESS: FPSC Staff

Corporation.

6. ORDER NO. PSC-97-1437-FOF-EQ
ISSUED: November 14, 1997
DOCKET NO. 961477-EQ
Petition for expedited approval of settlement agreement with Lake Cogen, Ltd., by Florida Power Corporation.

7. ORDER NO. PSC-98-0400-FOF-EQ
ISSUED: March 16, 1998
DOCKET NO. 961184-EQ
Petition for approval of early termination amendment to negotiated qualifying facility contract with Orlando Cogen Limited, Ltd. by Florida Power Corporation.

8. ORDER NO. PSC-99-1956-PAA-EQ
ISSUED: October 5, 1999
DOCKET NO. 990723-EQ
Petition by Florida Power Corporation for approval of an agreement with El Paso Power Services Company to restructure existing cogeneration contracts with Polk Power Partners, L.P. and Orange Cogeneration Limited Partnership.

9. ORDER NO. PSC-00-1166-PAA-EQ
ISSUED: June 27, 2000
DOCKET NO. 000184-EQ
Petition by Florida Power Corporation, Miami-Dade County, and Montenay-Dade, Ltd. for approval of settlement agreement, for confirmation that negotiated contract continues to qualify fully for cost recovery, and to allow Florida Power Corporation cost recovery of historic settlement payment made to Dade County pursuant to settlement agreement.

Hines 1 Order

10. ORDER NO. 25805
ISSUED: February 25, 1992
DOCKET NO. 910759-EI
Petition for Determination of Need for Proposed Electrical Power Plant and Related Facilities, Polk County Units 1-4 by Florida Power Corporation

All Orders approving waiver/variance of 10 year minimum term in the standard offer contract rule.

11. ORDER NO. PSC-99-1519-AS-EI
ISSUED: March 17, 1999
DOCKET NO. 990067-EI
Petition by the Citizens of the State of Florida for a full revenue requirements rate case for Florida Power & Light Company.

12. ORDER NO. PSC-99-1713-TRF-EG
ISSUED: September 2, 1999
DOCKET NO. 990249-EG
Petition by Florida Power & Light Company for approval of a standard offer contract and revised COG-2 tariff.

13. ORDER NO. PSC-00-0265-PAA-EG
ISSUED: February 8, 2000
DOCKET NO. 991526-EQ
Petition of Florida Power Corporation for Approval of Standard Offer Contract and Accompanying Rate Schedule COG-2.

14. ORDER NO. PSC-00-0504-PAA-EQ
ISSUED: March 7, 2000
DOCKET NO. 991973-EQ
Petition of Florida Power Corporation for Approval of Standard Offer Contract Based on a 2003 Combined Cycle Avoided Unit and Accompanying Rate Schedule.

15. ORDER NO. PSC-00-1773-PAA-EQ
ISSUED: September 27, 2000
DOCKET NO. 000684-EQ
Petition for approval of standard offer contract for qualifying cogeneration and small power production facilities by Tampa Electric Company.

16. ORDER NO. PSC-00-1748-PAA-EI
ISSUED: September 26, 2000
DOCKET NO. 000868-EI
Petition by Florida Power & Light Company for approval of standard offer contract.

Court Decisions

17. Tampa Electric Co., et al. v. Garcia, et al., (Duke) Nos. SC95444, SC95445, SC95446 (Fla. Apr. 20, 2000)(revised opinion).

FERC Filings

~~18. Filings made by FPC, individually or jointly, in response to~~ FERC Order No. 2000.

FPSC Filings

19. Projected Residential Fuel Factors for the period January 2001 - December 2001, filed by IOU's in Dockets Nos. 000001-EI, 000002-EG, and 000007-EI.

Respectfully submitted this 25th day of October, 2000.

DEBORAH D. HART
Fla. Bar No. 305022
KATRINA D. WALKER
Fla. Bar No. 277400
Staff Counsel
FLORIDA PUBLIC SERVICE COMMISSION
2540 Shumard Oak Boulevard
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(850) 413-6199

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Hines Unit 2 Power Plant by Florida Power Corporation.	DOCKET NO. 001064-EI FILED: OCTOBER 25, 2000

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of Staff's Request for Official Recognition has been furnished by U.S. Mail and via facsimile this 25th day of October, 2000, to the following:

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

Florida Power Corporation
James A. McGee, Esquire
Post Office Box 14042
St. Petersburg, Florida 33733-4042

Suzanne Brownless, Esq.
1311-B Paul Russell Rd., Suite 201
Tallahassee, Florida 32301

Deborah D. Hart

DEBORAH D. HART
Fla. Bar No. 305022
KATRINA D. WALKER
Fla. Bar No. 277400
Staff Counsel
FLORIDA PUBLIC SERVICE COMMISSION
2540 Shumard Oak Boulevard
Gerald L. Gunter Building - Room 370
Tallahassee, Florida 32399-0863
(850) 413-6199

EXH. 2

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines Unit 2 Power Plant.	)	DOCKET NO. 001064-EI
	)	Submitted for Filing: October 25, 2000

FLORIDA POWER CORPORATION'S
REQUEST FOR OFFICIAL RECOGNITION

Pursuant to Sections 90.202 and 90.203, Fla.Stats., Florida Power Corporation ("FPC" or the "Company") requests that the Florida Public Service Commission ("PSC" or the "Commission") take judicial notice of the items listed below, consisting of the following:

1. Review of Electric Utility 1999 Ten-Year Site Plans, December, 1999, Florida Public Service Commission, Division of Electric and Gas; Division of Auditing and Financial Analysis.

2. Hearing Transcript of the August 18, 1999 Agenda Conference in Docket No. 980783-EI, In Re: Petition by Gulf Power Company for waiver of portions of Rule 25-22.082(4)(a), F.A.C., Selection of Generation Capacity.

3. Hearing Transcript Volumes I-VI, In the Matter of Proposed Amendment of Rule 25-22.081, F.A.C.; and Proposed New Rule 25-22.082, F.A.C., Selection of Generating Capacity: Wednesday September 9, 1993; Thursday September 30, 1993; October 1, 1993.

4. New York Times article, *A Dwindling Faith in Deregulation*, by Neela Banerjee, Friday, September 15, 2000, Section C1.

5. New York Times article, *One Choice Too Many in Electricity's New Free Market*, by Kirk Johnson, August 17, 2000, New York Report.

6. Power Markets Week article, *High-Priced California Market Allows Dynegy To Recover Plant Investments*, September 11, 2000.

7. Final Order Approving Certification, In Re: Application for Power Plant Certification of Florida Power Corporation Polk County Site, Before the Governor and Cabinet

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 2
COMPANY/ WITNESS: Florida Power Corporation
DATE: 10-26 & 27-00

DOCUMENT NUMBER-DATE
13661 OCT 25 00
FPSC-RECORDS/REPORTING

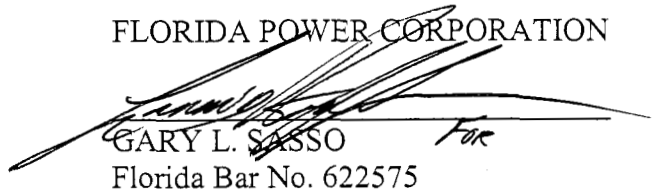
Sitting as the Florida Siting Board, dated January 25, 1994. (separate request made on Aug. 7, 2000).

The foregoing items are public records, transcripts of public Commission hearings, and/or self-authenticating newspaper or periodical articles pursuant to Fla. Stat. 90.902(6), and FPC believes that the Commission has full authority and ability to consider these items in connection with this proceeding.

WHEREFORE, FPC requests that the Commission take judicial notice of the foregoing items.

Respectfully submitted,

FLORIDA POWER CORPORATION



GARY L. SASSO
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EMMANUEL, SMITH & CUTLER, P.A.
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ROBERT A. GLENN
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FLORIDA POWER CORPORATION
P.O. Box 14042
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
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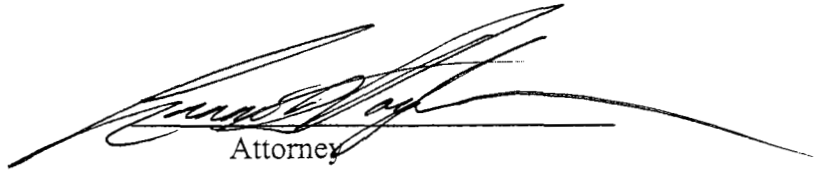
CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT a true and correct copy of the foregoing have been furnished by facsimile to Deborah Hart, Esq., as counsel for the Florida Public Service Commission and to Suzanne Brownless, as counsel for Panda Energy International, Inc. and has been furnished by U.S. Mail to all other interested parties of record as listed below on this 25th of October, 2000.



Attorney

PARTIES OF RECORD:

Deborah Hart, Esq.
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Gunter Building
2540 Shumard Oak Boulevard
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Senior Assistant General Counsel
Department of Environmental Protection
2600 Blairstone Road
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Exh. 3

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines Unit 2 Power Plant.

Docket No. 001064-EI

PANDA ENERGY INTERNATIONAL, INC.'S
REQUEST FOR JUDICIAL NOTICE

Pursuant to Sections 90.202 and 90.203, Fla.Stats., Panda Energy International, Inc. (PEII) requests that the Florida Public Service Commission (FPSC) take judicial notice of the item attached to this pleading, consisting of the following:

1. Notice of Proposed Agency Action Order Denying Petition for Fee Waiver, Order PSC-99-0232-FOF-EI, issued on February 9, 1999.

The foregoing item is a recorded decision of the FPSC and PEII has full authority and ability to consider it in the proceeding without a request for judicial notice. In an abundance of caution, however PEII is filing this request for judicial notice since the foregoing item is also a matter of which the Commission may, upon request be any party, take judicial notice.

WHEREFORE, PEII requests that the Commission take judicial notice of the foregoing item.

Respectfully submitted,
PANDA ENERGY INTERNATIONAL , INC.

Suzanne Brownless, Esq.
FL Bar No. 309591

Suzanne Brownless, P.A.
1311-B Paul Russell Road
Suite 201
Tallahassee, FL 32301
Phone: (850) 877-5200
Fax: (850) 878-0090

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 3
COMPANY/ WITNESS: Panda Energy
DATE 10-26-00

DOCUMENT NUMBER-DATE
13645 OCT 25 8
FPSC-RECORDS/REPORTING

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing was furnished via United States Mail and by Facsimile (*) or Hand Delivery (**) on this 25th day of October, 2000, to the following persons:

(*)Gary L. Sasso, Esq.
James Michael Walls
Carlton & Fields Law Firm
One Progress Plaza
Suite 2300
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St. Petersburg, Florida 33701

(*) Robert A. Glenn, Esq.
Director, Regulatory Counsel
Group
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One Progress Plaza, Suite 1500
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St. Petersburg, Florida 33701

(**)Deborah D. Hart, Esq.
Katrina D. Walker, Esq.
Florida Public Service Comm.
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Suzanne Brownless, Esq.

request, FPC cites to Rule 25-22.082(9), Florida Administrative Code, as well as Section 120.542, Florida Statutes. As required by Section 120.542, Florida Statutes, notice of FPC's waiver request was published in Florida Administrative Weekly on November 13, 1998. Rule 28-104.003, Florida Administrative Code, provides for written comments on the petition for waiver to be filed within 14 days after the notice is published in Florida Administrative Weekly. Thus, the comment period was over on November 27, 1998. Since Friday, November 27, 1998 was a state holiday, the comment period expired November 30, 1998. Two interested persons filed comments. On November 30, 1998, the Electric Power Supply Association filed comments. On December 1, 1998, the Florida Industrial Cogeneration Association also filed comments. Both entities opposed the waiver request.

II. TIMELINESS OF FLORIDA INDUSTRIAL COGENERATION ASSOCIATION'S COMMENTS

On December 1, 1998, the Florida Industrial Cogeneration Association (FICA) filed comments requesting denial of the petition. By letter dated December 10, 1998, FPC suggested that FICA's comments were untimely and not entitled to consideration in this proceeding. FPC claimed the due date was November 30, 1998. In response to FPC's letter, FICA provided a Federal Express waybill showing that its comments were forwarded in time to be filed on the 30th. A delivery error appears to be responsible for the one-day delay.

We believe that the one day's lateness is not fatal to our ability to consider the comments. The comments are technically late under the Uniform Rule. However, in our opinion, the comment date is not a jurisdictional date. Further, the Federal Express waybill shows FICA's effort to assure that the comments would be timely filed. Finally, this matter is being considered as Proposed Agency Action. Thus, any interested person, including FICA, could address the Commission at the agenda conference. Having apparently acted in good faith to assert its rights, we find therefore, it is appropriate to consider FICA's comments as timely filed.

III. WAIVER OF RULE 25-22.082, FLORIDA ADMINISTRATIVE CODE

FPC has requested a waiver of Rule 25-22.082, Florida Administrative Code, in order to proceed with the certification of Hines 2, a second 500 MW combined cycle unit to be built at its existing Hines Energy complex in Polk County. In addressing the public interest aspects of their request for rule waiver, FPC has alleged that:

1. Hines 2 will be an advanced technology 500 MW combined cycle unit similar in design to Hines 1.

2. Because of concerns with recent record high summer temperatures, practical limitations experienced with the company's reliance on dispatchable DSM programs (direct load control), and the adequacy of reserves statewide, FPC has decided to accelerate the in-service date of Hines 2 from late 2004 to the summer of 2001.

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Gainesville, FL 32602

3. As the second unit at an existing developed site, Hines 2 will have a scheduling and cost advantage over other supply side alternatives.

4. Hines 2 will improve the balance between company-owned generation and purchased power. Because of FPC's relatively high percentage of purchased power and the practice of major bond rating agencies to impute a portion of a utility's long-term purchased power obligations to the debt component of its capital structure, Hines 2 will help maintain the utility's debt/equity ratio.

In addition to these factors, FPC has committed not to initiate any proceeding to increase its current base rates for a period of at least five years from the unit's commercial in-service date (or through mid-2006 based on the unit's current in-service schedule).

Waiver pursuant to Section 120.542, Florida Statutes

Section 120.542, Florida Statutes, mandates threshold proofs and notice provisions for variances and waivers from agency rules. Subsection (2) of the statute states:

> Variances and waivers shall be granted when the person subject to the rule demonstrates that the purpose of the underlying statutes will be or has been achieved by other means by the person and when application of the rule would create a substantial hardship or would violate principles of fairness. For purposes of this section, "substantial hardship" means a demonstrated economic, technological, legal, or other type of hardship to the person requesting the variance or waiver. For purposes of this section, "principles of fairness" are violated when literal application of a rule affects a particular person in a manner significantly different from the way it affects other similarly situated persons who are subject to the rule.

FPC asserts that the application of the rule in this instance creates a substantial hardship for FPC and its customers. FPC further argues that the purpose of the underlying statute will be achieved if FPC's petition is granted.

Statewide Reliability

Planned generating reserves have become questionable because of a series of unforeseen reliability modeling questions that arise primarily from the recent higher generating unit availabilities and an unprecedented reliance on load management and other non-firm loads.

Generating unit availabilities have increased from about 80 percent in 1988 to 89 percent in 1997 because of improved maintenance and spare parts practices. The higher the generating unit availabilities, the lower the reserve margin required for a given overall generating reliability. This has led to planned reserve margins being much lower than

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FPC has relied on load management more than any other electric utility in the nation. Load management has been viewed as the functional equivalent of a peaking type generating unit. These units have a low installed cost, a lower fuel efficiency than a combined-cycle unit, and are operated only a few hundred hours per year. The 1998 summer heat wave caused the use of load management to exceed customer tolerance levels. About 46,000 FPC residential customers opted out of load management during the 1998 heat wave. This drop out translated to about 50 MW of Summer capacity. While over reliance on load management is a critical issue for FPC, we are also concerned with the extensive reliance on load management and other non-firm loads on a Peninsular Florida basis. On a Peninsular Florida basis, load management and other non-firm loads currently range from 44 to 58 percent of the reserve margin. The uncertainty as to what the reserve margin should be is exacerbated by the fact that a high percentage of the planned reserve margin is in the form of load management and other non-firm loads.

Winter 1999-2000 and winter 2000-01 have been previously identified as periods when the adequacy of state-wide reserves is uncertain. Since this facility is not expected to come on-line until approximately June 2001, it does not address these potential concerns.

Comments of Interested Persons

On November 30, 1998, the Electric Power Supply Association (EPSA) filed comments requesting that the Commission deny FPC's requested waiver. EPSA states "there is no assurance that Florida Power's construction will provide the best price for existing Florida ratepayers, who will, after Florida Power's proposed five year rate freeze, be asked to foot the bill for this project..." EPSA does not believe FPC can be assured of procuring the lowest cost reliable supply of energy absent a competitive solicitation. EPSA also believes FPC's proposal increases risk for FPC's ratepayers, exacerbates FPC's market power in the wholesale generation market and increases the possibility that FPC's ratepayers will subsidize FPC's participation in the competitive market.

On December 1, 1998, the Florida Industrial Cogeneration Association (FICA) filed comments. FICA states that Rule 25-22.082, Florida Administrative Code, was adopted at a time when the Commission amended its Cogeneration rules so that standard offers would only be available to solid waste facilities and small cogenerators (ie., no more than 100kw). FICA claims the bidding rule was intended to provide opportunities for cogenerators to sell power to utilities. FICA believes the proposed waiver is contrary to long-standing federal and state policy. FICA also suggests the absence of competitive bidding for this resource addition could create "stranded costs" or otherwise burden the ratepayers.

Decision and Analysis

As detailed below, we deny FPC's request because we do not believe FPC has demonstrated that the lowest cost generation alternative will be selected by FPC. This is one underlying purpose of Section 403.519, Florida Statutes. Although it appears the proposed

plant may represent a low cost supply of electricity and stands to increase FPC's reliability, FPC has not sufficiently demonstrated the unavailability of other equally reliable less costly utility or non-utility options. Therefore, FPC has not met the requirements of Section 120.542, Florida Statutes. Moreover, for the reasons discussed below, we also believe that it would not be in the public interest and would further be contrary to the intent of the bidding rule to approve the requested waiver.

We recognize that Peninsular Florida is facing generation reliability concerns and the proposed five year rate commitment has some potential benefit. However, the same result may be equally achieved via other utility and non-utility alternatives. It is unclear exactly how FPC would become aware of such proposals absent soliciting the market.

Rate Commitment

FPC's commitment to "not initiate any proceeding to increase its current base rates which includes the capital costs and non-fuel operating and maintenance expenses associated with Hines 2 for a period of at least five years from the unit's commercial operation date" has value, but it is limited. The company can still ask for a base rate increase through a limited proceeding for other items. The company further states that the "commitment is conditioned upon the understanding that these capital costs and non-fuel O&M expenses will be considered legitimate utility expenditures for surveillance reporting purposes when Hines 2 is placed in commercial operation." Under FPC's commitment, Hines 2 will be included for all earnings purposes except a full-fledged rate proceeding initiated by FPC. Earnings tracked by the Commission's surveillance program will include Hines 2. If any other party were to initiate a proceeding with FPC to review base rates, Hines 2 costs would also be included.

Purpose of Rule 25-22.082, Florida Administrative Code

FPC still must demonstrate the cost-effectiveness of Hines 2 relative to other alternatives during a need-determination proceeding. Recognizing this obligation, absent completing the RFP process, a utility undertakes an increased risk of having to prove the worthiness of its project during a need determination proceeding. In that situation, since the RFP process was not used to preclude likely intervenors and so-called eleventh-hour proposals, the utility and Commission alike stand to endure the same lengthy litigation experienced during the Cypress case[1].

The Cypress proceeding prompted in part the adoption of Rule 25-22.082, Florida Administrative Code. In that case, Florida Power & Light Company presented what it believed to be the most cost-effective generation alternative based on a limited selection process. Through the course of the proceeding, two additional projects contested FPL's

[1] Joint Petition to Determine Need by Cypress Energy Partners, L.P. and Florida Power and Light Company, Docket 920520-EQ, Order No. PSC-92-1355-FOF-EQ, issued 11/23/92.

A Publication of FALR, Inc. P.O. Box 385,
Gainesville, FL 32602: (352) 375-8036, WWW.FALR.COM

choice and offered alternatives. The Commission expressed frustration that the limited selection process used by FPL to select Cypress did not facilitate the Commission's statutory responsibility to determine the most cost-effective generating unit under Section 403.519, Florida Statutes. In part the Commission stated:

> In this case we find that FPL's selection process was less than optimal. FPL did not ensure that all interested parties had an equal opportunity to submit capacity proposals, but instead considered one project left over from a 1989 request for proposals (RFP) and 14 unsolicited proposed projects. As a result, FPL did not adequately consider all potential purchased power options. (Order page 16)

> Any non-utility generator, having seen the price in FPL's next need petition, will be able to intervene in the need proceeding and put a better price on the table. If a need is then denied because the proposed plant is not the most cost-effective alternative available, the process could repeat itself ad infinitum, with the need never being filled, and with more cost-effective alternatives presented at each successive need determination proceeding. (Order page 17)

While it is appropriate to review generation alternatives in a need determination, it is not the most optimal method of capacity selection. Much like FPL, FPC should consider the advantages of the RFP process and avoid the potential for eleventh-hour proposals and the possibility of an unsatisfied need. Doing so would allow FPC to identify and evaluate all capacity alternatives as well as reaching closure on the issue of cost-effectiveness during the need-determination process due to the intervention preclusion. We believe such an outcome is consistent with the intent of Rule 25-22.082, Florida Administrative Code, and more importantly, is in the public interest.

FPC previously requested a certification of need for the Hines 2 unit (formerly Polk Unit 3 and 4) in Docket 910759-EI. In Order No. 25550, we held that FPC indeed had a need to construct the first two of the four requested units but that a need for the last two was premature at that time. The granted need for the first two units came in part due to FPC having "evaluated ten alternative generating plans in its Integrated Resource Study. These plans included various generating technologies, as well as purchased power options from other utilities." (page 37) In addressing the final two units, now known as Hines 2, the Hearing officer stated:

> At this time, I will not make a finding on how Florida Power should meet the needs of its third and fourth units. I will not require bidding for purchased power to avoid construction of these units for two reasons: the need for the third unit is not mature, and we have no policy or rules requiring bidding. However, Florida Power should reevaluate all of the options for meeting the needs of the third and fourth units before requesting

certification in order to ensure that it chooses the most cost-effective option. (page 40)

But for the maturity of the need and the lack of a bidding rule, it is our belief the Hearing officer had every intention to require FPC to "reevaluate all of the options" before granting the second part of FPC's requested need. This requirement is still appropriate. According to its petition, FPC now believes that the need for the remaining two units is mature. Likewise, since 1994, this Commission has had a rule requiring bidding.

As a general matter of policy, we believe that bypassing the RFP process ultimately contributes to stifling the economic benefits of competitive generation in Florida. If in fact Hines Unit 2 is the most cost-effective alternative for FPC's ratepayers, this would be confirmed during the initial stages of the RFP process. However, if this is not the case, this too would be confirmed and the process will have worked as originally intended.

We also note that our decision rendered in this matter is, and must be, issued as proposed agency action. If the waiver request were granted, persons whose substantial interests are affected by the decision could request a hearing pursuant to Sections 120.569 and 120.57, Florida Statutes. This process could reasonably be expected to take between four and six months. This would, in large measure, eliminate any time advantage obtained via the waiver.

Moreover, Rule 25-22.082(8) Florida Administrative Code, precludes participation in the subsequent need determination proceeding by non-bidders in a RFP process. Granting the requested waiver would render that provision inapplicable, thus making the need determination proceeding potentially more complex.

Timing

Though presented as new information, it appears that FPC has known of its near-term need for additional capacity resources since the early part of this year. An RFP solicitation procedure takes about six to nine months to complete, thereby delaying the in-service date of a generating unit by at least one summer or winter peak demand season. This realization should have prompted FPC to start the RFP process at that point in time. Having done so, finalization would be very near complete and FPC would be concentrating its efforts on a determination of need instead of requesting the instant waiver.

FPC's current Ten Year Site Plan (TYSP) filed in April of 1998 indicated that its next planned generation addition, known as Hines 2, was a 487 MW combined cycle unit to be ready for commercial operation by November 2004. FPC's TYSP also indicated that it expected to drop below its 15 percent winter reserve margin criterion in the year 2000/01. FPC explained that it intended on covering this shortfall with short-term power purchases. FPC was also aware of the potential termination of the 75 MW Panda-Kathleen, L.P. standard offer contract.[2] Furthermore, it was negotiating with the City of Barrow in early May for,

[2] Florida Power Corporation notified the Commission on July 20, 1998 that it had officially terminated the standard offer contract with Panda-Kathleen, L.P. due to Panda

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the most cost-effective option.

k of a bidding rule, it is our belief the
o "reevaluate all of the options" before
This requirement is still appropriate.
ıe need for the remaining two units is
had a rule requiring bidding.
ıt bypassing the RFP process ultimately
›etitive generation in Florida. If in fact
› for FPC's ratepayers, this would be
ss. However, if this is not the case, this
vorked as originally intended.
ı this matter is, and must be, issued as
ere granted, persons whose substantial
ıearing pursuant to Sections 120.569 and
bly be expected to take between four and
ıte any time advantage obtained via the

ıinistrative Code, precludes participation
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Commission on July 20, 1998 that it h
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and has subsequently signed, a five year full-requirements power supply contract beginning in 1999.

With this information, we believe that FPC was aware during the early part of this year that additional capacity would be needed beginning in the year 2000. Nonetheless, placing Hines 2 into service in the Summer of 2001 will do nothing to increase FPC's capacity reserves during the Winter 2000/01.

For these reasons we deny FPC's request for a waiver of the requirements of Rule 25-22.082, Florida Administrative Code. This will assure that its ratepayers benefit from the most economical resource addition and to avoid the potential for extensive litigation during the later need determination process. Of the alternatives presented, we believe this is most consistent with the public interest. FPC has failed to demonstrate that the purposes of the underlying statute will be achieved by other means. Therefore, FPC has not met the requirements of Section 120.542, Florida Statutes.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the comments of the Florida Industrial Cogeneration Association shall be accepted as timely. It is further

ORDERED that Florida Power Corporation's request for a waiver of the requirements of Rule 25-22.082, Florida Administrative Code, shall be denied.

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings or Judicial Review" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket shall be closed.

By ORDER of the Florida Public Service Commission this 9th day of February, 1999.

BLANCA S. BAYÓ, Director
Division of Records and Reporting

Kathleen's failure to perform.

ORIGINAL 001064-EI Legal

AFFIDAVIT OF PUBLICATION
THE LEDGER
Lakeland, Polk County, Florida

Case No .....

Attach Notice Here

STATE OF FLORIDA)
COUNTY OF POLK)

Before the undersigned authority personally appeared Nelson Kirkland, who on oath says that he is Classified Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

Public Hearing

in the matter of Power Plant

in the

Court, was published in said newspaper in the issues of

9-10; 2000

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

APP
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Signed

Nelson Kirkland
Classified Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this 13TH day of SEPTEMBER A.D. 20 00

Notary Public
DONALD RAY JENKINS

DONALD RAY JENKINS
MY COMMISSION # CC 586345
EXPIRES September 18, 2000
Bonded Thru Notary Public Underwriters

(Seal)

My Commission Expires

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 4
COMPANY/ WITNESS: FPC
DATE: 10-[illegible]-00

DOCUMENT NUMBER-DATE
11817 SEP 20 00

235383 E459 K Flynn

ON PROPOSED ELECTRICAL POWER PLANT
TO
FLORIDA POWER CORPORATION
DEPARTMENT OF COMMUNITY AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
ELECTRIC AND GAS UTILITIES
AND
ALL INTERESTED PERSONS

IN RE: DOCKET NO. 001064-EI - PETITION FOR DETERMINATION OF NEED OF HINES UNIT 2 POWER PLANT.

ISSUED: September 10, 2000

NOTICE is hereby given that the Florida Public Service Commission will hold a public hearing in the above docket. The time and location of the hearing are listed below. All persons who wish to be heard are urged to be present at the beginning of the hearing on Thursday, October 26, 2000.

October 26 and 27, 2000, 9:30 a.m. each day
Commission Hearing Room 148
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

Any person requiring some accommodation at the hearing or prehearing conference because of a physical impairment should call the Division of Records and Reporting at (850) 413-6770 at least 48 hours prior to the hearing or prehearing conference. Any person who is hearing or speech impaired should contact the Florida Public Service Commission by using the Florida Relay Service, which can be reached at 1-800-955-8771 (TDD).

PURPOSE AND PROCEDURE

The purpose of this hearing will be for the Commission to take final action to determine the need, pursuant to Sections 403.501-519, Florida Statutes, for the construction of a power plant and related facilities in Polk County, Florida. This proceeding shall: 1) allow Florida Power Corporation to present evidence and testimony in support of their petition for a determination of need for their proposed plant and related facilities in Polk County, Florida; 2) allow any intervenors to present testimony and exhibits concerning this matter; 3) allow members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and, 4) allow for such other purposes as the Commission may deem appropriate. All witnesses shall be subject to cross-examination at the conclusion of their testimony.

The proceedings will be governed by the provisions of Chapter 120, Florida Statutes, Section 403.519, Florida Statutes, Chapter 25-22, Florida Administrative Code, and Chapter 28-106, Florida Administrative Code.

Under Section 403.519, Florida Statutes, the Commission is the sole forum for the determination of need for the electrical power plant and associated facilities. In making its determination, the Commission must take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available. The Commission must also expressly consider the conservation measures taken by or reasonably available to the petitioners which might mitigate the need for the proposed plant, and other matters within its jurisdiction which it deems relevant. The Commission's determination of need for the Polk County facility shall create a presumption of public need and necessity and shall serve as the Commission's report as required by Section 403.507 (2)(a) (2), Florida Statutes. An order entered by the Commission pursuant to this hearing shall constitute final agency action.

Only issues relating to the need for the power plant and its associated facilities will be heard at the October 26 and 27, 2000, hearing. Separate public hearings will be held before the Division of Administrative Hearings to consider environmental and other impacts of the proposed plant and associated facilities.

Members of the public who are not parties to the need determination proceeding will have an opportunity to present testimony regarding the need for the proposed plant and associated facilities. All members of the public who wish to offer testimony should be present at the beginning of the hearing. All witnesses will be sworn and will be subject to cross-examination at the conclusion of their testimony.

Written comments regarding the need for the proposed plant and associated facilities may be sent to the Commission at the following address:

Blanca S Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0870
Re: Docket No. 001064-EI

Anyone wishing to become a party to the need determination proceeding should file an appropriate petition pursuant to Rule 25-22.039, Florida Administrative Code with the Director of the Commission's Division of Records and Reporting at the address listed above. Copies of the petition should be sent by mail to all parties. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be a qualified representative pursuant to Chapter 120, Florida Statutes, and Rule 28-106.106, Florida Administrative Code. Petitions for leave to intervene must be filed at least five (5) days before the final hearing, must conform with Rule 28-106.201 (2), Florida Administrative Code, and must include allegations sufficient to demonstrate that the intervenor is entitled to participate in the proceeding as a matter of constitutional or statutory right or pursuant to Commission rule, or that the substantial interests of the intervenor are subject to determination or will be affected through the hearing.

GENERAL LOCATION AND PROJECT DESCRIPTION

The proposed electric power plant will be a gas-fired, combined cycle electrical power plant with a nominal rating of 530 MW. The plant will consist of a 2 on 1 combined cycle unit. It will use low sulfur (0.05 percent) distillate oil as backup fuel. Natural gas will be delivered by pipeline to the plant, and distillate oil will be transported by truck to the Haines Energy Complex. Florida Power Corporation will place the plant in service by November 30, 2003.

PREHEARING CONFERENCE

A prehearing conference will be held at the following time and place:

October 11, 2000, 9:30 a.m.
Commission Hearing Room 152
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

The purpose of the prehearing conference will be to consider: (1) the simplification of the issues; (2) the identification of the positions of the parties on the issues; (3) the possibility of obtaining admissions of fact and of documents which will avoid unnecessary proof; (4) the identification of exhibits; (5) the establishment of an order of witnesses; and (6) such other matters as may aid in the disposition of the action.

JURISDICTION

Jurisdiction over this determination of need is vested in the Commission by Chapter 366 and Section 403.519, Florida Statutes. This proceeding will be governed by the provisions of Chapter 120, Florida Statutes, as well as Chapter 25-22 and Chapter 28-106, Florida Administrative Code.

APPLICATION

A copy of the Petition for Determination of Need and supporting exhibits are available for public inspection during normal business hours at the following location:

Florida Public Service Commission
Division of Records and Reporting
Room 110, Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

By Direction of the Florida Public Service Commission this 10th day of September, 2000.

BLANCA S. BAYÓ, Director
Division of Records and Reporting

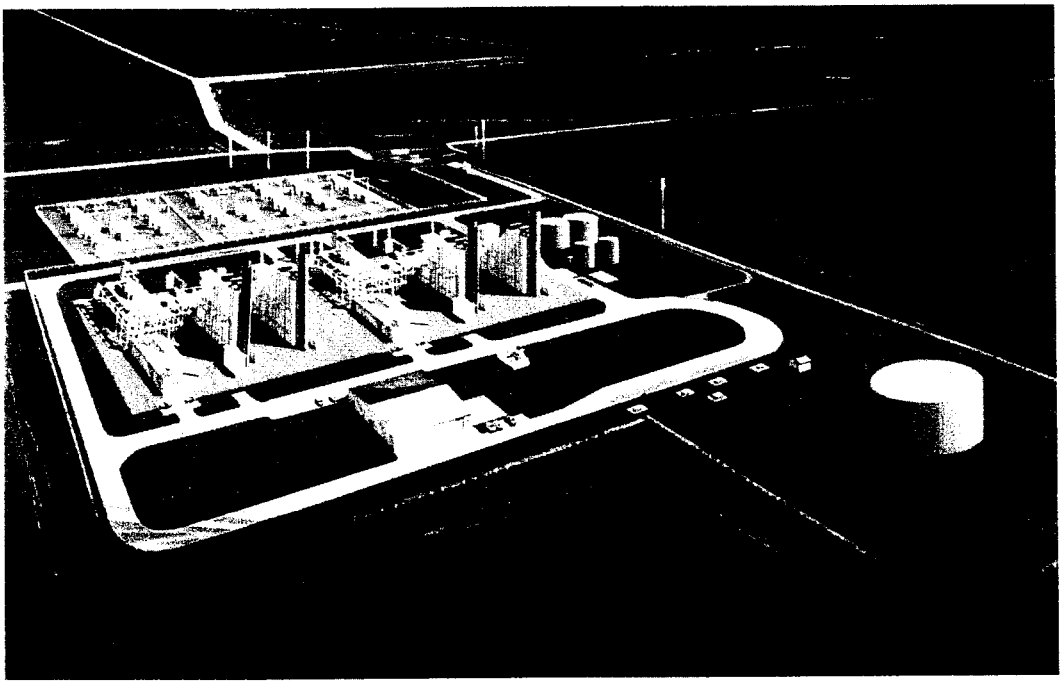
(SEAL)

by: 9-10-2000

THE NEED STUDY

In Support of

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



BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

August 7, 2000

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 5 (Part 1 of 3)
COMPANY/ WITNESS: Crisp
DATE: 10-26-27-00

FLORIDA POWER CORPORATION
NEED STUDY

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THE NEED STUDY

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

I. Executive Summary.

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

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

generating capacity (1) to achieve and maintain system reliability and integrity; (2) to continue to provide adequate electricity at a reasonable cost; and (3) to add diversity to the Company's supply-side resource mix.

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

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

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

II. The Company and its Existing Resources.

A. Description of the Company.

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

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

B. Generation Facilities.

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

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

TABLE 1

FLORIDA POWER CORPORATION
TOTAL CAPACITY RESOURCE
Power Plants And Purchased Power

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

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

TABLE 2

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

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

C. Transmission and Distribution Facilities.

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

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

A. Introduction.

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

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

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

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

other utilities. The standard LOLP reliability threshold value in the electric utility industry, and the criterion used by FPC, is a maximum of 0.1 days per year.

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

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

C. Key Planning Forecasts and Assumptions.

As the Company moves forward along its planning horizon, the Company seeks to make significant resource selection decisions based on the best information available to the Company at the time. Accordingly, the Company updates key factors and assumptions in the course of

evaluating its overall resource plan. These factors are addressed in the ensuing sections of this report covering energy sales, customer demand, fuel prices, economic and financial assumptions, a summary of the existing supply-side and demand-side resources currently available, and an assessment of cost and performance of new resource alternatives available to the Company.

1. Demand and Energy Forecast.

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

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

With respect to this forecasting activity, there are a number of assumptions that serve as inputs to the forecasts based on economic and demographic factors, such as weather conditions, population growth trends, economic growth trends, and the regulatory environment. The assumptions underlying FPC's energy load and sales forecasts used in the IRP process are

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

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

TABLE 3	
ECONOMIC & DEMOGRAPHIC SUMMARY	
(1999 – 2009)	
AVERAGE ANNUAL GROWTH RATE	
Real GDP	2.3%
Fl. Employment	2.1%
Fl. Personal Income	5.6%
FPC Service Area Population	1.6%

FPC uses several statistical models in developing its long-term forecasts. The models incorporate multiple forecasting techniques, such as time-series analysis, ordinary least squares

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

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

Customer Load Forecasts. Population projections for each of the 32 Florida counties served by FPC drive the forecasts of FPC's residential and commercial customers, who together comprise 98 percent of FPC's total customers. Population increases in FPC's service area translate directly into a greater number of residential electric customers and, as a further consequence, a greater number of commercial establishments to serve them. FPC relies on the BEBR at the University of Florida for population estimates and projections in its service area. The BEBR relies primarily on a cohort component computer model that uses demographic data to develop high, low, and medium cases for its population projections. FPC uses the BEBR

medium case as the basis for its residential and commercial class customer forecasts. FPC then uses time-series models to project industrial, street and highway lighting, and public authority customers because they follow relatively stable historical growth trends and make up only two percent of FPC's total customers on its system. A more complete discussion of the customer load forecasts and the methodologies behind them can be found in FPC's 2000 TYSP. See Appendix D, Chapter 2.

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

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

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

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

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

One significant industrial sector is modeled separately, outside the end-use model. That

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

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

Energy sales to the governmental ("Public Authority") and street and highway lighting users are also projected. An econometric approach is used for public authority energy sales to account for population growth and the state of the economy, which together impact the level of local governmental service, and thus the level of governmental energy consumption. Historically, government employment has been the best single indicator of increases or decreases

in local government service due to changes in the population and economy. The model, accordingly, uses local government employment, weather impacts on governmental energy use, and variations in energy use when school is in and out of session, to develop the public authority energy sales projections.

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

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

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

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

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

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

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

Wholesale demand, as noted above, comprises supplemental, partial, and full requirements service. Supplemental load is based on sales to SECI, FPC's supplemental requirements customer. Demand for partial requirements services is based on historical ratios of

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

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

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

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

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

2. FPC's Fuels Forecast.

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

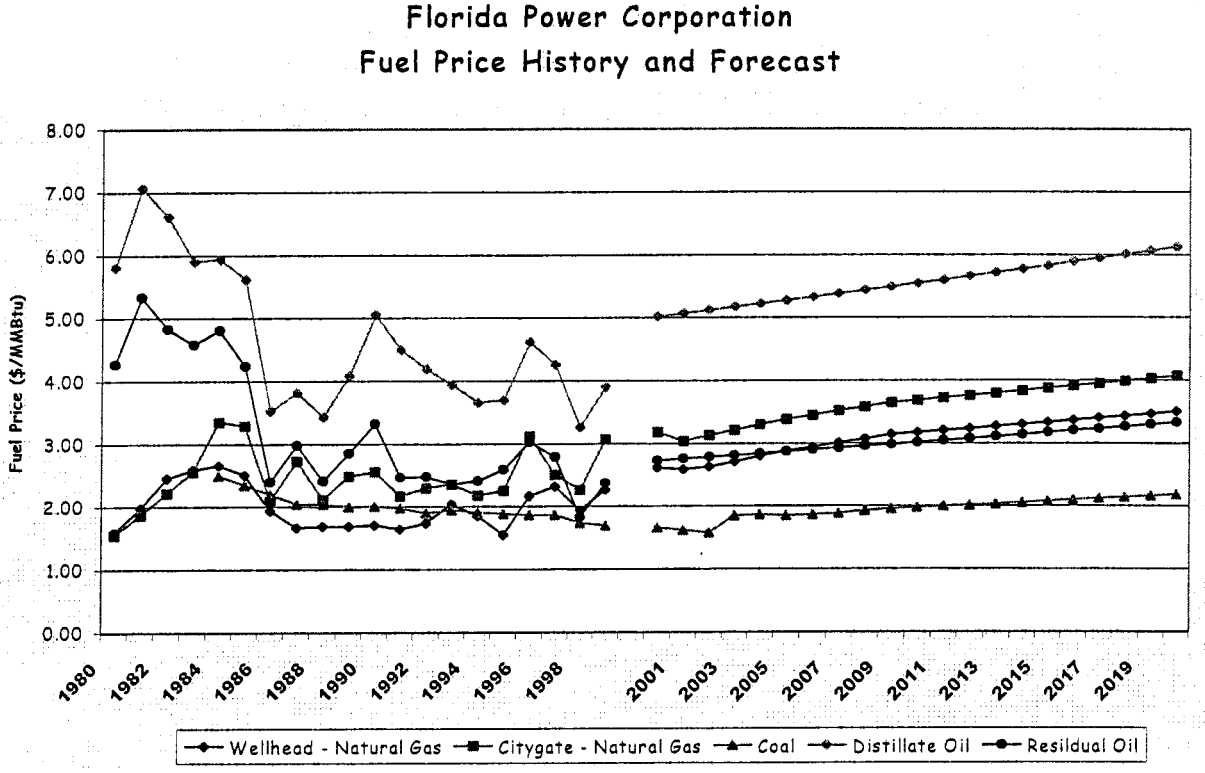
FPC's natural gas forecast was derived from price estimates for the Gulf Coast market area, specifically the Henry Hub and Mobile Bay. FPC also uses Petroleum Industry Research Associates as a forecasting consultant service. In addition, FPC contacts suppliers who are willing to enter into long-term contracts for gas supplies, and quotes by these companies are used

as an additional input in developing FPC's natural gas price forecast. Data from public agencies such as the Energy Information Administration are also considered as a reference source by FPC in developing its natural gas price forecast. The final natural gas price forecast is an estimate based upon all these inputs, as well as transportation costs for natural gas. Transportation costs, including fixed and variable components, were estimated based upon the prevailing tariff rate for service on the Florida Gas Transmission ("FGT") pipeline system and the expected rates available from the various proposed new pipelines into peninsular Florida.

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

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

TABLE 4



3. Economic and Financial Assumptions.

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

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

TABLE 5

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

Base year 2000

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

Base Case Cap Structure

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

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

4. Existing Supply-Side Resources.

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

5. Existing and Planned Demand-Side Resources.

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

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

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

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

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

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

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

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

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

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

6. Cost and Performance Projections for New Resource Alternatives.

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

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

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

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

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

D. The Integrated Resource Planning Process.

1. Introduction.

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

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

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

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

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

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

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

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

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

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

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

Company's IRP process, as described herein.

2. Supply-Side Screening of Generation Alternatives.

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

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

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

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

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

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

this Need Study.

TABLE 6

SCREENING EVALUATION OF GENERATION TECHNOLOGIES

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

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

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

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

and performance factors for these conventional generation technology alternatives are listed below in Tables 7 and 8 in this Need Study.

TABLE 7

SUPPLY-SIDE ALTERNATIVES

SUMMARY OF ESTIMATED COST AND PERFORMANCE FOR CONVENTIONAL GENERATION ALTERNATIVES

(Year 2000 $)

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

TABLE 8

SUPPLY-SIDE ALTERNATIVES

SUMMARY OF ESTIMATED CAPITAL COST RANGE FOR CONVENTIONAL GENERATION ALTERNATIVES

(Year 2000 $)

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

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

3. Demand-Side Screening.

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

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

4. Resource Integration.

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

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

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

TABLE 9

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

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

5. Sensitivity Analyses.

In the process of evaluating and selecting the Integrated Optimal Plan, FPC tests the planning results under different sensitivity scenarios to identify variances, if any, that would warrant reconsideration of any of the basic plan assumptions. These "sensitivities" are run with the PROVIEW model using high, medium (base), or low forecast ranges for demand and energy, fuel prices, and critical economic and financial assumptions. High, medium, and low forecasts are developed based on FPC's experience and its ongoing review and analysis of industry trends

and forecasts in the key areas underlying each of these Company forecasts. In addition, FPC reviews a special fuel sensitivity where the differential between oil/gas and coal is maintained constant over time.

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

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

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

As expected, all of the high sensitivity cases indicated an increase in total revenue requirements while the low sensitivities indicated lower total revenue requirements. The results

of these sensitivity studies confirm that a robust plan had been chosen for further consideration and that there would be no need to depart from the base assumptions used in this assessment.

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

A. Introduction.

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

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

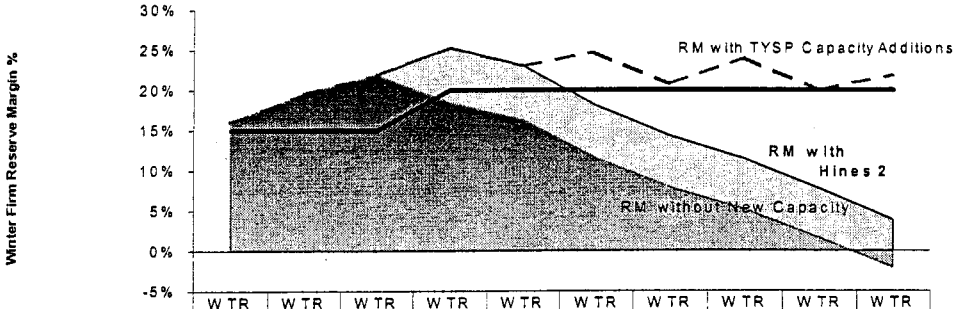
B. Electric System Reliability and Integrity.

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

TABLE 10

FPC Winter Firm Reserve Margin (RM) %

Impact of Hines 2 on Reserve Margin



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

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

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

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

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

firm) would be much lower. Specifically, FPC would have only 367 MW of firm supply-side capacity reserves in excess of estimated total load.

TABLE 11

Reserve Levels With and Without Hines 2
Winter 2003/2004

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

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

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

C. Provide Adequate Electricity at a Reasonable Cost.

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

addition, the projected installed cost for Hines 2 is well below the current market estimates for equivalent units because of previously negotiated favorable equipment option terms.

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

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

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

A. Introduction.

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

B. Hines 2 Contract Advantages.

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

C. Adequacy of Supply and Transportation of Fuels.

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

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

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

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

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

D. Environmental and Site Benefits.

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

the use of a clean fuel, efficient plants reduce the exposure of FPC to new environmental rules, constraints, or taxes.

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

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

The proposed new unit will be located adjacent to the Hines 1 unit. The existing infrastructure – including extensive site development (excavation, fill, access roads), a 722 acre

cooling pond, a fully sized natural gas lateral pipeline, as well as all common facilities and manpower requirements needed to support two-unit operations at the site – provides Hines 2 with significant site-development and construction-cost advantages over any other generation alternative available to FPC.

E. Fuel Savings and Fuel Diversity.

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

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

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

VI. FPC's Request for Proposals.

A. Introduction

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

B. Development and Distribution of the RFP.

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

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

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

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

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

C. Conclusion and Resource Selection.

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

VII. The Proposed Plant: Hines 2.

A. Introduction.

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

B. The Hines Energy Complex.

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

C. Hines Unit 2 Description.

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

D. Projected Unit Performance.

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

E. Fuel Transportation and Supply.

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

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

be expected to be completed and capable of providing natural gas transportation service to FPC for Hines 2 in the next two to three years.

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

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

for either short- or long-term gas supplies long before the plant's in-service date and before the Company has received regulatory authorization for Hines 2.

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

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

F. Transmission Requirements.

With the addition of the proposed Hines 2 unit at the HEC in November 2003, the projected total net generation at the HEC with the Hines 1 and 2 units will be 977 MW in the summer and 1,096 MW in the winter. There are three existing 230kv transmission circuits from the HEC that were installed to connect the Hines 1 unit to the transmission grid, two circuits to FPC's Fort Meade substation, and a single circuit constructed on double circuit structures to FPC's Barcola substation. Transmission facility upgrades and additions at an estimated total cost of $5.6 million will be required for the connection of the Hines 2 unit to the FPC transmission

system and the operation of Hines 2 at the HEC (and for other, future generation additions in the same area by other utilities). These facility upgrades and additions will include the substation interconnection requirements (busswork, breakers, controls) and upgrade work on two of the circuits.

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

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

single 954 kcm ACSR conductor to bundled 954 kcm ACSR conductor per phase. FPC and TECO will be negotiating the upgrade of this interconnection in 2000, with the final scope and responsibility for the work on this upgrade finalized by a Transmission Interconnection and Operating Agreement between FPC and TECO.

G. Environmental Considerations.

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

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

The HEC is a zero surface water discharge facility with respect to the National Pollution Discharge Elimination System program for industrial wastewaters. Process wastewater streams are treated on-site and are used as makeup for the cooling pond. Water consumption and loss

occur primarily through evaporation from the cooling pond. Accordingly, a key feature of the HEC design for zero surface water discharge is the existing 722 acre cooling pond, which will serve not only as the heat dissipation device but also as a water storage device. Hines 2 will use treated effluent and storm water for cooling with no discharge offsite.

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

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

H. Hines 2 Costs.

1. Project Cost.

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

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

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

2. O&M Costs.

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

3. Associated Facilities.

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

4. Transmission Interconnection Facilities.

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

VIII. Consequences of Delay of Hines 2.

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

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

IX. Conclusion.

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

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

THE NEED STUDY

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

LIST OF APPENDIX ITEMS.

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B. FPC's Electric System Map.

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

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

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F. FPC's Load Forecast Model Documentation.

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

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

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

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

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

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

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

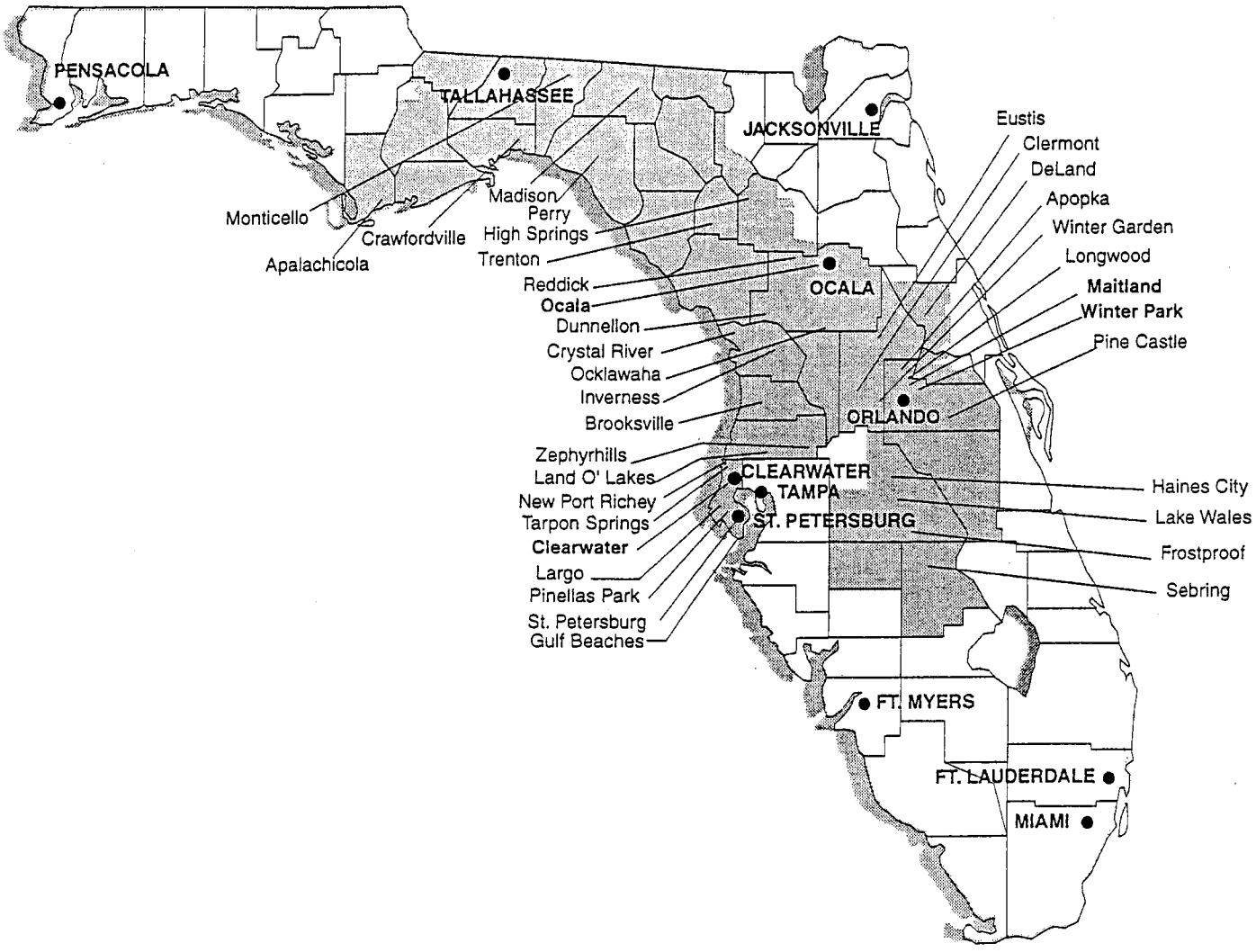
N. Cost and Operational Factors for Non-Conventional Generation Technologies.

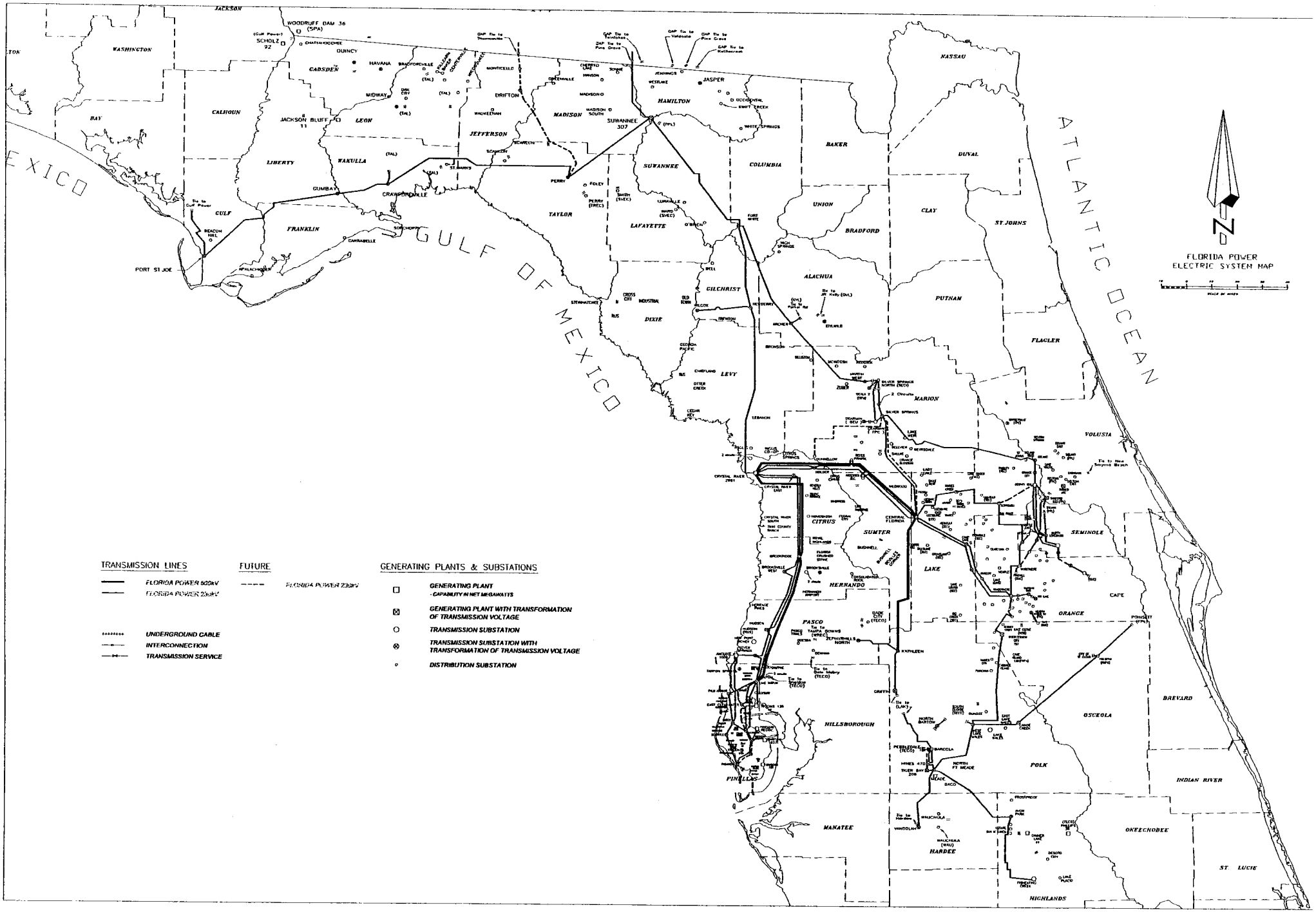
O. FPC's 2000 TYSP Analysis With and Without Capacity Additions.

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

Florida Power
CORPORATION

Florida Power Corporation • Area of Service




FLORIDA POWER
ELECTRIC SYSTEM MAP
ATLANTIC OCEAN
GULF OF MEXICO
TRANSMISSION LINES
FLORIDA POWER 500kV
FLORIDA POWER 230kV
FUTURE
FLORIDA POWER 230kV
UNDERGROUND CABLE
INTERCONNECTION
TRANSMISSION SERVICE
GENERATING PLANTS & SUBSTATIONS
GENERATING PLANT
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GENERATING PLANT WITH TRANSFORMATION OF TRANSMISSION VOLTAGE
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DISTRIBUTION SUBSTATION
JACKSON
WASHINGTON
BAY
CALHOUN
LIBERTY
GULF
FRANKLIN
GADSDEN
LEON
WAKULLA
JEFFERSON
MADISON
TAYLOR
LAFAYETTE
SUWANNEE
HAMILTON
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BAKER
NASSAU
DUVAL
CLAY
UNION
BRADFORD
ST JOHNS
ALACHUA
GILCHRIST
DIXIE
LEVY
PUTNAM
FLAGLER
MARION
VOLUSIA
CITRUS
SUMTER
LAKE
SEMINOLE
HERNANDO
PASCO
ORANGE
OSCEOLA
BREVARD
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HARDEE
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BEACON HILL
CARRABELLE
ST MARKS
SCANLON
WHITE SPRINGS
FORT WHITE
HIGH SPRINGS
LAKE BUTLER
STARKE
KEYSTONE HEIGHTS
GREEN COVE SPRINGS
ORANGE PARK
DAYTONA BEACH
NEW SMYRNA BEACH
PONCE DE LEON
CRYSTAL RIVER 2901
CRYSTAL RIVER 3903
CRYSTAL RIVER SOUTH
CRYSTAL RIVER EAST
HOMOSASSA
FLORIDA CRUSHED STONE
BROOKSVILLE
BROOKSVILLE WEST
HUDSON
HUDSON (PASCO)
NEW PORT RICHEY
SILVER SPRINGS
SILVER SPRINGS NORTH (SECO)
OCALA
OCALA (OUC)
OCALA (FPC)
LAKE WEIR
WEIRSDALE
SUMTER
CENTRAL FLORIDA
DOUBLE OAKS
BUSHNELL
BUSHNELL (OUC)
LEESBURG
LEESBURG (OUC)
LEESBURG (FPC)
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HOOKERS POINT (TECO)
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DAVIS (TECO)
PEBBLEDALE (TECO)
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HINES 470
TIGER BAY 208
NORTH FT MEADE
FT MEADE
BACO
WAUCHULA
WAUCHULA (WAU)
VANDOLAH
PRINCETON
PRINCETON (FPC)
DESOTO CITY
LAKE PLACID
PROSPERITY
PROSPERITY (TECO)
SUWANNEE
SUWANNEE (FPL)
PERRY (TREC)
SMITH (SVEC)
LULLWOOD (SVEC)
MAYO (SVEC)
O'BRIEN
O'BRIEN (SVEC)
CROSS CITY
CROSS CITY INDUSTRIAL
OLD TOWN
WILCOX
STEINHATCHEE
JASPER
JENNINGS
WESTLAKE
OCCIDENTAL
EMMET CREEK
GREENVILLE
MADISON
MADISON SOUTH
MONTICELLO
WALKERHAM
SCANLON
CHATTAHOOCHEE
QUINCY
BRADFORDVILLE
MIDWAY
HAVANA
GADSDEN
CHATTAHOOCHEE
GULF POWER
BEACON HILL
SOUTHPORT
CARRABELLE
ST MARKS
PORT ST JOE
APALACHICOLA
GEORGIA PACIFIC
CHIEFLAND
OTTER CREEK
CEDAR KEY
LEBANON
TRENTON
ARCHER
BRONSON
WILLISTON
MORRISTON
REDDICK
DUNNELLON
HOLDER
HOLDER (FPC)
INGLIS
CITRUS SPRINGS
CITRUS SPRINGS (FPC)
LAKE WEIR
WEIRSDALE
SILVER SPRINGS
SILVER SPRINGS NORTH (SECO)
SILVER SPRINGS (FPC)
LAKE WEIR (FPC)
SUMTER (FPC)
CENTRAL FLORIDA (FPC)
LEESBURG (FPC)
LAKE HARRIS (FPC)
LAKE GRIFFIN (FPC)
LAKE YALE (FPC)
LAKE MINNEOLA (FPC)
CLERMONT (FPC)
CLERMONT EAST (FPC)
GROVELAND (FPC)
MONTVERDE (FPC)
MOUNT DORA (FPC)
TAVARES (FPC)
EUSTIS (FPC)
EUSTIS EAST (FPC)
ZELLWOOD (FPC)
APOPKA (FPC)
APOPKA EAST (FPC)
APOPKA NORTH (FPC)
WINDERMERE (FPC)
WINTER GARDEN (FPC)
WINTER GARDEN EAST (FPC)
WINTER GARDEN SOUTH (FPC)
WINTER GARDEN WEST (FPC)
WINTER PARK (FPC)
WINTER PARK EAST (FPC)
WINTER PARK SOUTH (FPC)
WINTER PARK WEST (FPC)
ORLANDO (FPC)
ORLANDO EAST (FPC)
ORLANDO NORTH (FPC)
ORLANDO SOUTH (FPC)
ORLANDO WEST (FPC)
SILVER SPRINGS NORTH (SECO)
OCALA (FPC)
OCALA (OUC)
Tie to Gulf Power
Tie to Jim Kelly (OAK)
Tie to Hilltop Rd
Tie to New Smyrna Beach
Tie to (TECO)
Tie to (LAK)
Tie to Hardee
Tie to (TECO)
Tie to (WAU)
Tie to (FPC)
Tie to (SECO)
Tie to (OUC)
Tie to (TAL)
Tie to (SVEC)
Tie to (TREC)
Tie to (FPL)
Tie to (LAK)
Tie to (WAU)
Tie to (FPC)
Tie to (SECO)
Tie to (OUC)
Tie to (TECO

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

The following Commissioners participated in the disposition of this matter:

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

APPEARANCES:

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

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

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

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

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

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

DOCUMENT NUMBER-DATE
15628 DEC 22 99
FPSC-RECORDS/REPORTING

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

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

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

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

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

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

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

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

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

ORDER APPROVING STIPULATION

BY THE COMMISSION:

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

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

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

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

At the continued hearing, we considered both proposals. After discussion, FPL, FPC, and TECO agreed to further modifications to their proposal. A document incorporating these agreed-upon changes was filed on December 15, 1999. A copy of this document (hereinafter the "Stipulation") is included in this Order as Attachment A and is incorporated herein by reference. FPL, FPC, and TECO have each agreed to achieve a planned twenty percent

reserve margin by the summer of 2004. In response to concerns expressed by some of the other parties, each utility has agreed to make a good faith effort to notify the Commission if it opts to modify the twenty percent criterion. The three utilities signing the Stipulation further acknowledge in paragraph 9 at page 4 that

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

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

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

Based on the foregoing, it is therefore

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

ORDERED that this docket shall be closed.

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

BLANCA S. BAYÓ, Director
Division of Records and Reporting

(S E A L)

RVE

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

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

filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Docket No. 981890-EU

/

STIPULATION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AGREED this 14th day of December 1999.

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Charles A. Guyton
Steel Hector
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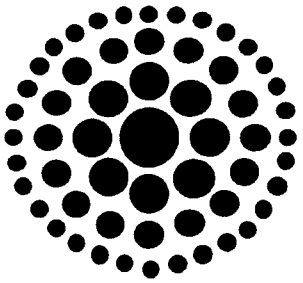

Florida Power
CORPORATION

Ten-Year Site Plan

2000-2009

Submitted To:

State of Florida
Public Service Commission

APRIL, 2000

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FLORIDA POWER CORPORATION
CODE IDENTIFICATION SHEET

Generating Unit Type

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

Fuel Type

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

Fuel Transportation

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

Future Generating Unit Status

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

INTRODUCTION

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

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

The TYSP document contains four chapters as described below:

CHAPTER 1

Description of EXISTING FACILITIES

CHAPTER 2

Forecast of ELECTRICAL POWER DEMAND and ENERGY CONSUMPTION

CHAPTER 3

Forecast of FACILITIES REQUIREMENTS

CHAPTER 4

ENVIRONMENTAL and LAND USE INFORMATION

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

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CHAPTER 1

Description of EXISTING FACILITIES

CHAPTER 1 Description of EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

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

AREA OF SERVICE

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

TRANSMISSION/DISTRIBUTION

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

ENERGY MANAGEMENT

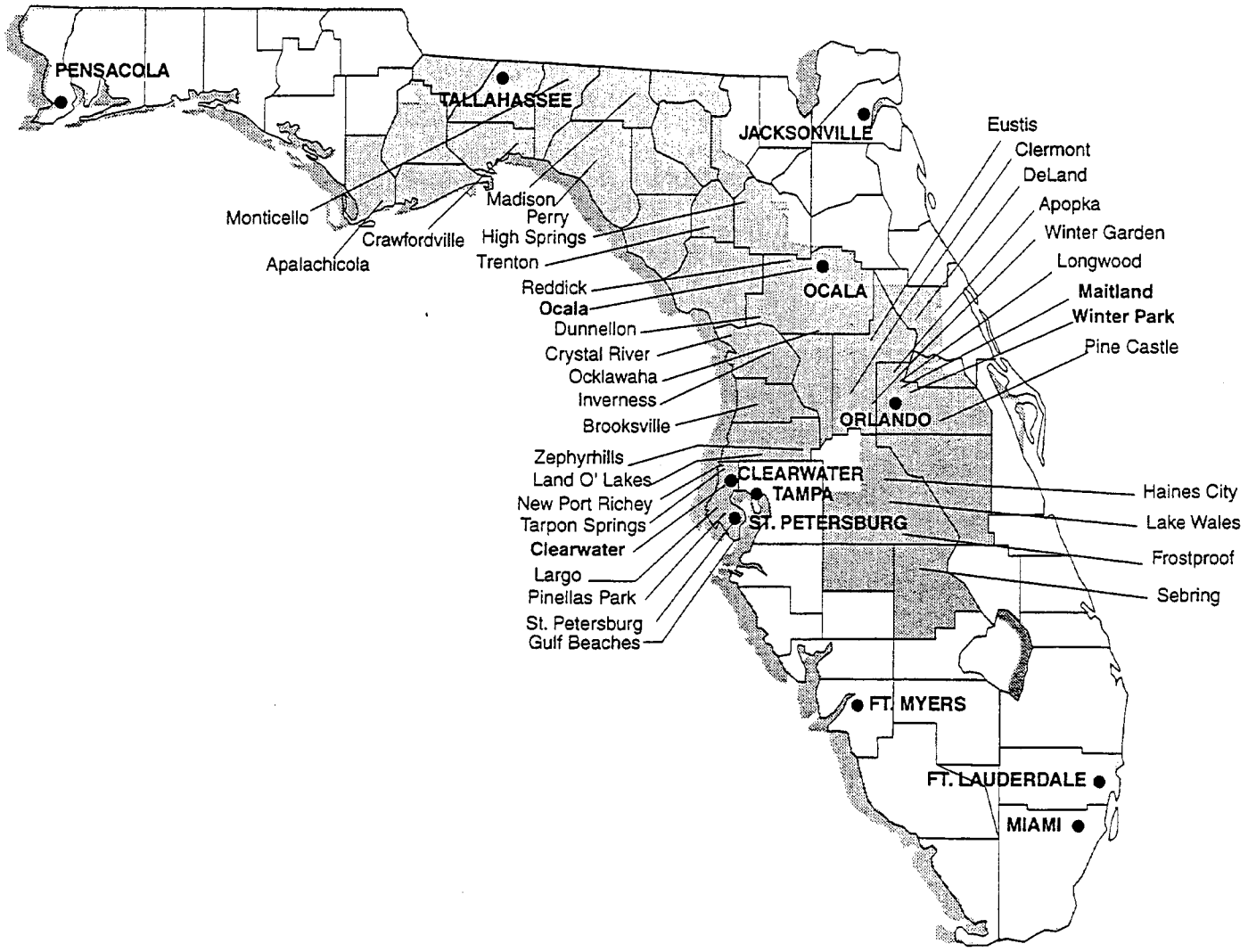
Florida Power customers participating in the company's Energy Management program are managing future growth and costs. Over 475,000 customers participated in the Energy Management program during the year. This excellent participation level provides over 870,000 KW of peak shaving capacity for use during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

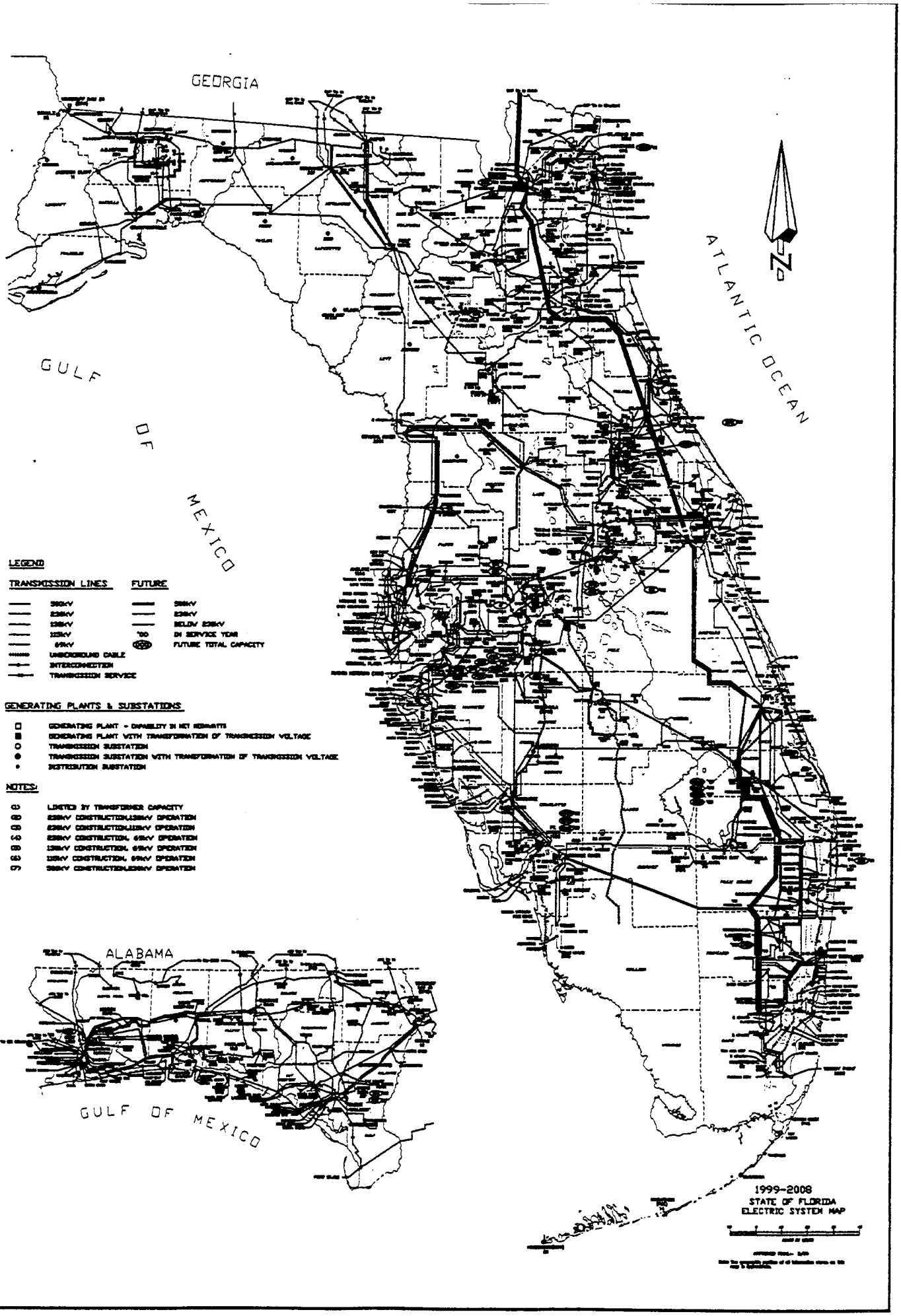
TOTAL CAPACITY RESOURCE

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

Florida Power
CORPORATION

Florida Power Corporation • Area of Service




GEORGIA
ATLANTIC OCEAN
GULF OF MEXICO
ALABAMA
GULF OF MEXICO
LEGEND
TRANSMISSION LINES
FUTURE
GENERATING PLANTS & SUBSTATIONS
NOTES:
1999-2008
STATE OF FLORIDA
ELECTRIC SYSTEM MAP

FLORIDA POWER CORPORATION

SCHEDULE 1
EXISTING GENERATING FACILITIES
AS OF DECEMBER 31, 1999

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

* REPRESENTS 91.8 % FPC OWNERSHIP OF UNIT

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CHAPTER 2

Forecast of ELECTRIC POWER DEMAND and ENERGY CONSUMPTION

CHAPTER 2 Forecast of ELECTRIC POWER DEMAND and ENERGY CONSUMPTION

OVERVIEW

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

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

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

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

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

ENERGY CONSUMPTION SCHEDULES

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

FORECAST OF ELECTRIC POWER DEMAND SCHEDULES

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

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

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

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

FLORIDA POWER CORPORATION

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

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

FLORIDA POWER CORPORATION

SCHEDULE 2.2

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND

NUMBER OF CUSTOMERS BY CUSTOMER CLASS

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

FLORIDA POWER CORPORATION

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

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

FLORIDA POWER CORPORATION

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
EAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
990	6,096	632	5,464	198	342	35	24	49	136	5,312
991	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
993	6,913	833	6,080	272	502	48	27	70	155	5,839
994	6,880	787	6,093	262	527	52	30	81	154	5,774
995	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
997	7,786	874	6,912	288	555	78	41	131	170	6,523
998	8,367	943	7,424	291	438	97	42	142	182	7,175
999	9,039	1,520	7,519	292	505	113	45	153	183	7,747
000	8,633	1,277	7,356	327	464	126	48	155	75	7,439
001	8,840	1,343	7,497	308	414	136	49	156	75	7,701
2002	8,518	867	7,651	305	351	149	50	157	75	7,431
2003	8,337	506	7,831	328	305	162	51	158	75	7,258
004	8,421	436	7,985	329	269	175	52	160	75	7,361
005	8,574	433	8,141	335	238	190	54	161	75	7,522
2006	8,782	493	8,289	339	210	204	55	162	75	7,737
2007	8,988	555	8,433	343	185	218	57	163	75	7,947
008	9,191	618	8,573	346	163	232	59	164	75	8,152
009	9,394	681	8,713	349	144	246	61	165	75	8,354

Historical Values (1990-1999):

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

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

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

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

ected Values (2000 - 2009):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2009):

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

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

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

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

FLORIDA POWER CORPORATION

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
AR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
90	6,096	632	5,464	198	342	35	24	49	136	5,312
91	6,079	674	5,405	192	313	36	25	53	136	5,324
1992	6,519	813	5,706	150	287	39	25	58	141	5,819
1993	6,913	833	6,080	272	502	48	27	70	155	5,839
94	6,880	787	6,093	262	527	52	30	81	154	5,774
95	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
98	8,367	943	7,424	291	438	97	42	142	182	7,175
99	9,039	1,520	7,519	292	505	113	45	153	183	7,747
2000	8,444	1,277	7,167	327	464	126	48	155	75	7,250
01	8,629	1,343	7,286	308	414	136	49	156	75	7,490
02	8,299	867	7,432	305	351	149	50	157	75	7,212
2003	8,068	506	7,562	328	305	162	51	158	75	6,989
04	8,134	436	7,698	329	269	175	52	160	75	7,074
05	8,251	433	7,818	335	238	190	54	161	75	7,199
06	8,422	493.	7,929	339	210	204	55	162	75	7,377
2007	8,589	555	8,034	343	185	218	57	163	75	7,548
08	8,752	618	8,134	346	163	232	59	164	75	7,713
09	8,916	681	8,235	349	144	246	61	165	75	7,876

istorical Values (1990-1999):

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

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

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

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

ected Values (2000 - 2009):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2010):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

orical Values (1990-1999):

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

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

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

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

ected Values (2000 - 2010):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2010):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

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

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

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

FLORIDA POWER CORPORATION

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

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

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

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

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

FLORIDA POWER CORPORATION

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

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

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

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

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

FLORIDA POWER CORPORATION

SCHEDULE 4

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

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

FUEL REQUIREMENTS and ENERGY SOURCES

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

FLORIDA POWER CORPORATION

SCHEDULE 5

FUEL REQUIREMENTS

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

FLORIDA POWER CORPORATION

SCHEDULE 6.1

ENERGY SOURCES (GWh)

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

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

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

FLORIDA POWER CORPORATION

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

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

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

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

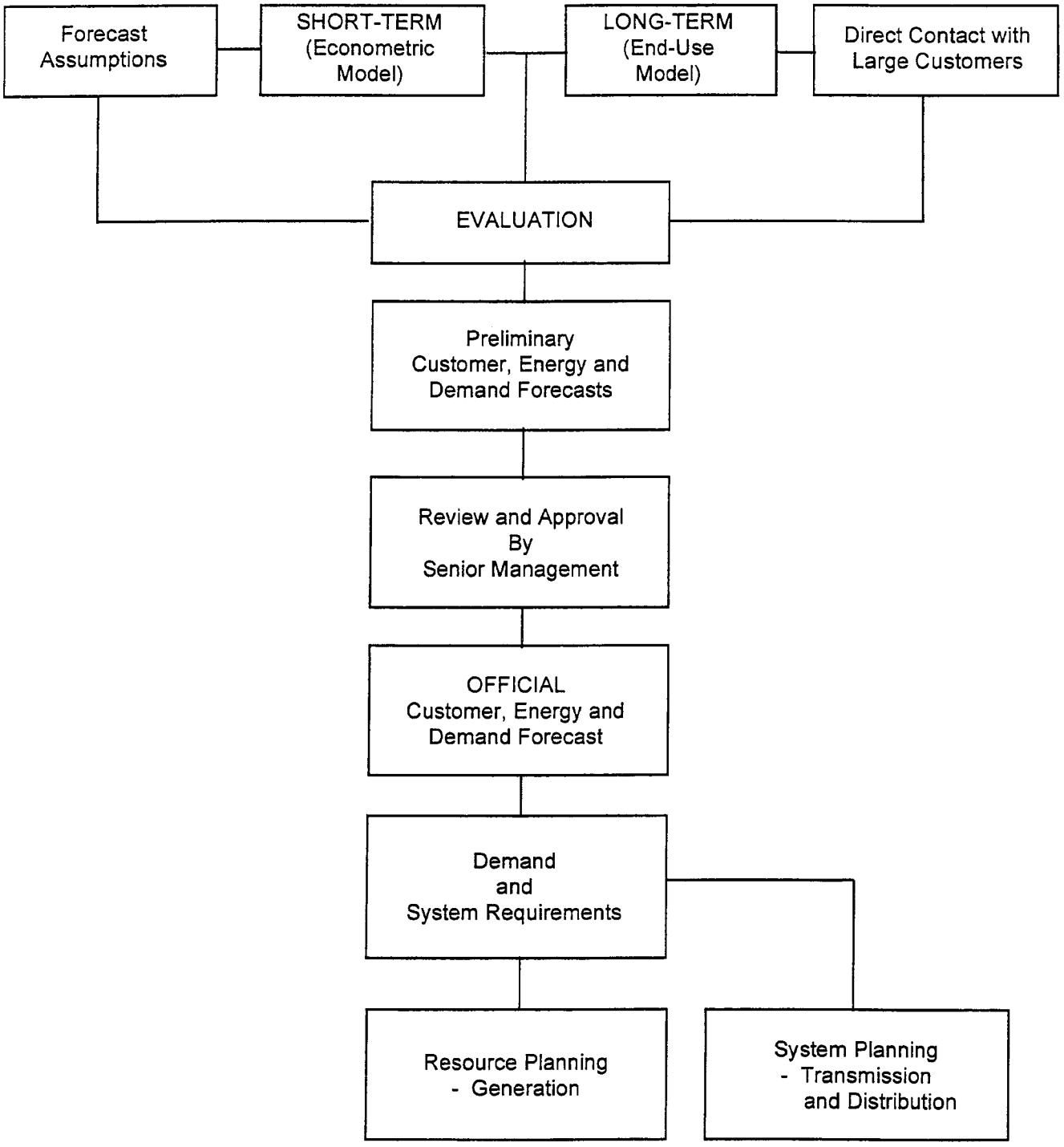
FORECASTING METHODS AND PROCEDURES

INTRODUCTION

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

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

CUSTOMER, ENERGY AND DEMAND FORECAST



SHAPESPC.PPT

FORECAST ASSUMPTIONS

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

GENERAL ASSUMPTIONS

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

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

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

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

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

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

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

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

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

SHORT-TERM ECONOMIC ASSUMPTIONS

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

The national unemployment rate has reached a 30-year low of 4 percent. This has resulted in greater spending power for the consumer and a high level of optimism in the economy. Looking ahead however, growth will taper off due to constraints upon the economy, which

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

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

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

growth in hourly earnings as well as transfer payments should also hold down income growth in the years ahead.

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

LONG-TERM ECONOMIC ASSUMPTIONS

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

Population Growth Trends

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

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

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

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

Economic Growth Trends

- Florida's rapid population growth of the 1980s created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also significant numbers of corporations migrating to Florida capitalizing on the low cost, low tax business environment. In this situation, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract

businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period. A cause for concern, however, is the passage of the North American Free Trade Agreement (NAFTA) as well as future trade agreements. At risk here is the bypassing of Florida by companies looking to relocate to a lower cost foreign environment. Mexico is expected to attract a formidable share of American manufacturing jobs that may have moved to Florida. Also, the stability of Florida's citrus and vegetable industry may be threatened when faced with greater competition from Mexico as tariffs are eliminated.

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

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

FORECAST METHODOLOGY

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

SHORT-TERM ECONOMETRIC MODEL

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

impacts (conservation program reductions) and direct load control reductions are also incorporated into the forecast. Specific sectors are modeled as follows:

Residential Sector

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

Commercial Sector

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

Industrial Sector

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

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

Other Retail Sectors

Street Lighting

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

Public Authorities

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

Sales For Resale Sector

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

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

agreement. Beginning in the year 2000, FPC will supply 150 MW of stratified peaking demand. The amount of load increases to 300 MW in 2001 and 2002. This load is not projected to be served by FPC beyond the contract term.

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

last contract year determines the load upon the FPC system for the remaining years of the forecast horizon, unless the customer has notified FPC of their intention to not renew the contract.

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

Demand-Side Management

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

LONG-TERM SHAPES-PC MODEL

Energy Forecast

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

Residential Sector

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

The last factor in the demand equation is the probability of the appliance operating at a given time. This term is called the use factor. It is necessary to distinguish between temperature, or

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

Industrial Sector

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

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

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

Commercial Sector

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

price on energy usage decisions as well as expected end-use saturation levels. Projections of KWh usage per square foot along with projected square footage for each building type yield commercial sector energy sales.

Customer Forecast

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

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

Peak Demand Forecast

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

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

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

Potential firm retail load refers to projections of FPC retail hourly seasonal net peak demand (excluding interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of FPC's Load Management program. The historical values of this series are constructed to show the size of FPC's firm retail net peak demand if no utility-induced conservation or load control had ever taken place. The value of constructing such

a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to total system customer levels at the time of the peak and coincident weather conditions without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data, regardless of which month the peak occurred. The projections become the potential retail demand projection for the months of January (winter) and August (summer), since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the month being projected.

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

Sales For Resale demand projections represent load supplied by FPC to other electric utilities, such as SECI, FMPA and other electric distribution companies. The SECI supplemental demand projection is based on their forecast of their service area within the FPC control area. The level of MW to be served by FPC is dependent upon the amount of resources SECI supplies to itself or contracts with others. An assumption has been made that beyond 2005 - the last year of committed capacity declaration - SECI will hold constant their level of self-serve resources. For the partial requirements customers demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels. Demand requirements continue out at the level indicated by the final year in their respective contracts. The full requirements

municipal demand forecast is estimated for individual cities using linear econometric equations modeling both weather and economic impacts specific to each locale. The seasonal (winter and summer) projections become the January and August peak values, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month (November to March) relative to the winter peak, and each summer month (April to October) in relation to the summer peak demand.

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

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

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

HIGH AND LOW FORECAST SCENARIOS

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

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

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

CONSERVATION

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

Historical Residential Conservation Goals and Achievements

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

Historical Commercial/Industrial Conservation Goals and Achievements

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

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

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

Residential Programs

Home Energy Check Program

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

Home Energy Improvement Program

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

Residential New Construction Program

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

Residential Energy Management Program

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

Commercial/Industrial (C/I) Programs

Business Energy Check Program

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

Better Business Program

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

Commercial/Industrial New Construction Program

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

Innovation Incentive Program

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

Commercial Energy Management Program (Rate Schedule GSLM-1)

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

Standby Generation Program

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

Interruptible Service Program

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

Curtailable Service

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

Research and Development Program

Technology Development Program

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

CHAPTER 3

Forecast of FACILITIES REQUIREMENTS

CHAPTER 3 Forecast of FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

Overview of the Current Forecast

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

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

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

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

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

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

TABLE 3.1

FLORIDA POWER CORPORATION
TOTAL CAPACITY RESOURCE
Power Plants And Purchased Power

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

TABLE 3.2

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

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

FLORIDA POWER CORPORATION

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

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

FLORIDA POWER CORPORATION

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF WINTER PEAK

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

FLORIDA POWER CORPORATION

SCHEDULE 8

PLANNED AND PROSPECTIVE GENERATING FACILITY

ADDITIONS AND CHANGES

(JANUARY 1, 2000 THROUGH DECEMBER 31, 2009)

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

NOTES :

1 / CAPABILITY INCREASE (TURBINE EFFICIENCY UPGRADE).

2 / CAPABILITY INCREASE (INLET FOGGING INSTALLATION).

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

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

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

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

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

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

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

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

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

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

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

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

FLORIDA POWER CORPORATION

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

HINES ENERGY COMPLEX SITE

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

INTEGRATED RESOURCE PLANNING OVERVIEW

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

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

The Integrated Resource Plan provides FPC with substantial guidance in assessing and optimizing the Company's overall resource mix on both the supply side and the demand side. When a decision supporting a significant resource commitment is being developed (e.g. plant construction, power purchase, DSM program implementation), the Company will move forward

with directional guidance from the IRP and delve much further into the specific levels of examination required. This more detailed assessment will typically address very specific technical requirements and cost estimates, detailed corporate financial considerations and the most current dynamics of the business and regulatory environments.

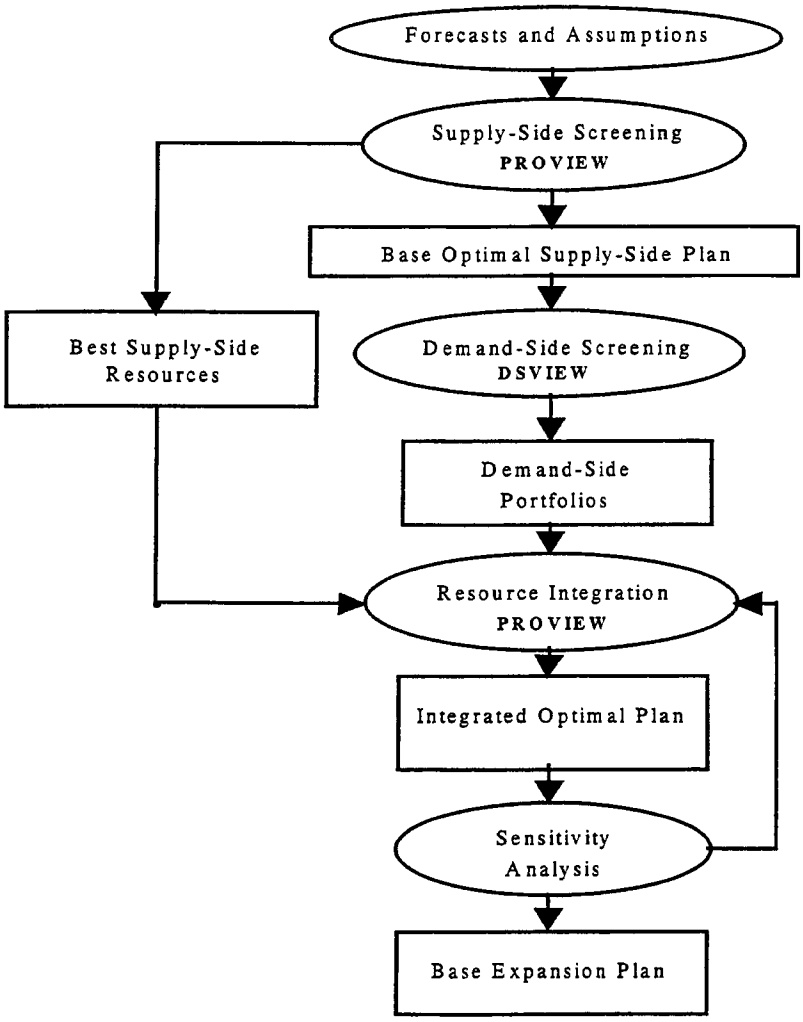


Figure 1: IRP Process Overview

THE IRP PROCESS

Forecasts and Assumptions

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

Reliability Criteria

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

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

Supply-Side Screening

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

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

Demand-Side Screening

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

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

Resource Integration And The Integrated Optimal Plan

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

Developing the Base Expansion Plan

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

KEY CORPORATE FORECASTS

Fuel Forecast

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

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

High Fuel Case: FPC's high case fuel forecast is based on the premise that fuel prices are high in a relatively high inflation economic environment on a worldwide basis. The forecast is based on an approximate probability of 25 percent (vs. 50 percent for the base case). Coal prices in the high case were developed based on the effect the coal market and inflation have on contract supply, spot supply, quality differences and the various transportation cost drivers. FPC developed the high case oil and natural gas forecast based on the same general market environment and inflation levels as those used for coal. Since oil and natural gas supply are

primarily purchased at market prices, consideration for current contract escalation was not required. Any expected increase in transportation cost is also included in the overall projected price increases.

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

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

Financial Forecast

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

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

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

CURRENT PLANNING RESULTS

TYSP Supply-Side Resources

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

Plan Sensitivities

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

The high and low fuel forecast sensitivity results did not suggest any significant reconsideration of the base plan. The low fuel forecast did not point to any changes to the base plan. The high fuel forecast indicated a potential increase in benefits for future advanced technology combined cycle units (as the technologies mature) versus the current state-of-the-art combined cycle units. The additional sensitivity, holding the current differential price of oil

and gas to coal constant over time, pointed toward a slight decrease in the value for combined cycle units. However, the variances resulting from these fuel sensitivities were not significant enough to consider departure from the base plan.

Request for Proposals

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

TRANSMISSION PLANNING

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

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

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

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

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

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

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

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

FLORIDA POWER CORPORATION
LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS
2000-2009

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

* Rebuild existing circuit

CHAPTER 4

ENVIRONMENTAL and LAND USE INFORMATION

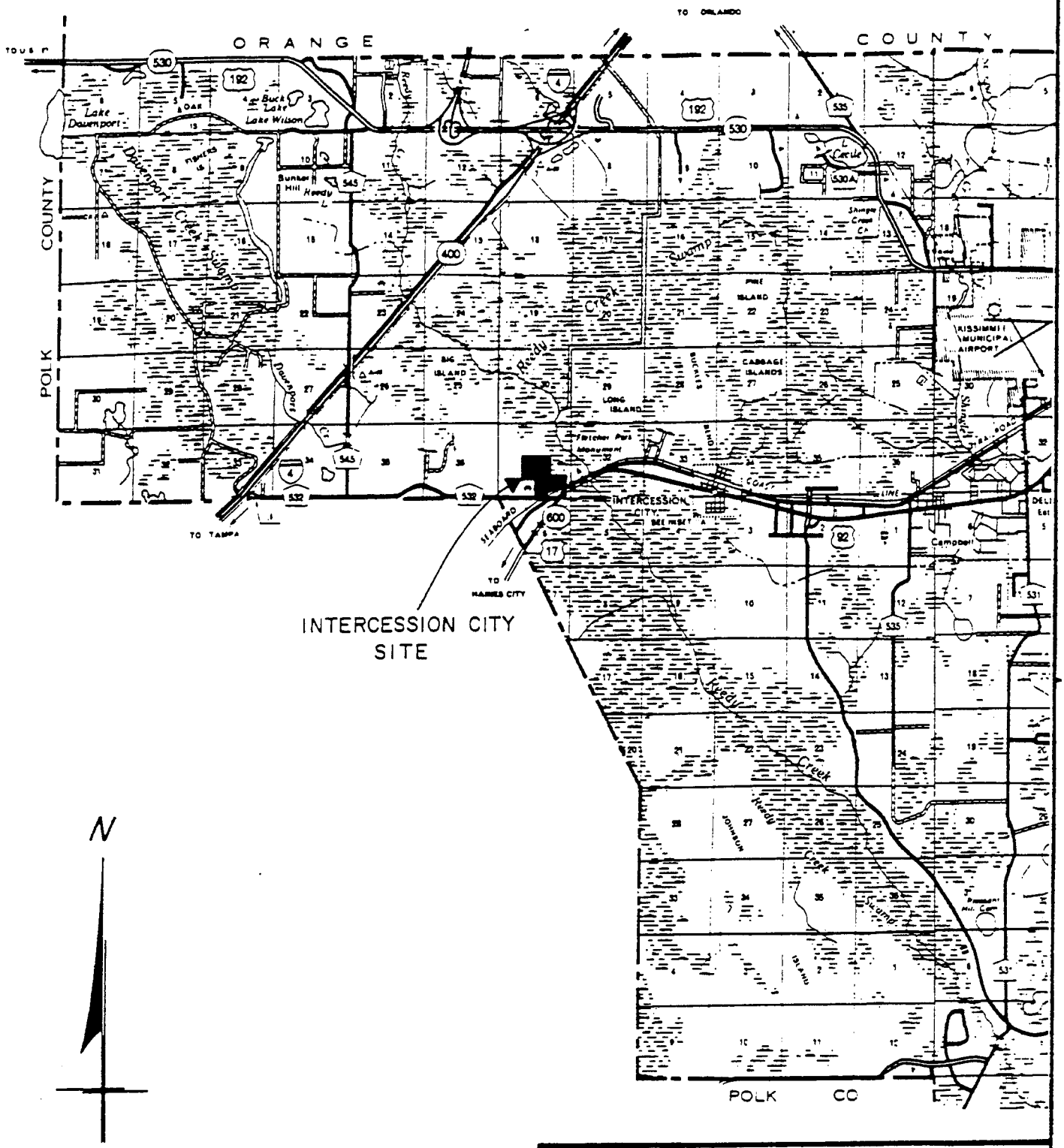
CHAPTER 4 ENVIRONMENTAL and LAND USE INFORMATION

PREFERRED SITES

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

INTERCESSION CITY SITE

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



PRODUCTION ENGINEERING DEPARTMENT		
PARTIAL AREA MAP OSCEOLA CO. FL.		
Florida Power	DRAWN BY G.S.K. DATE 2-27-90	SCALE NONE
	CHECKED BY DATE	DISCIPLINE
	APPROVED BY DATE	PLANT/UNIT
	DATA PROCESS NO.	SHEET
	DWG. NO. IV-4	

NO.	DESCRIPTION

HINES ENERGY COMPLEX SITE

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

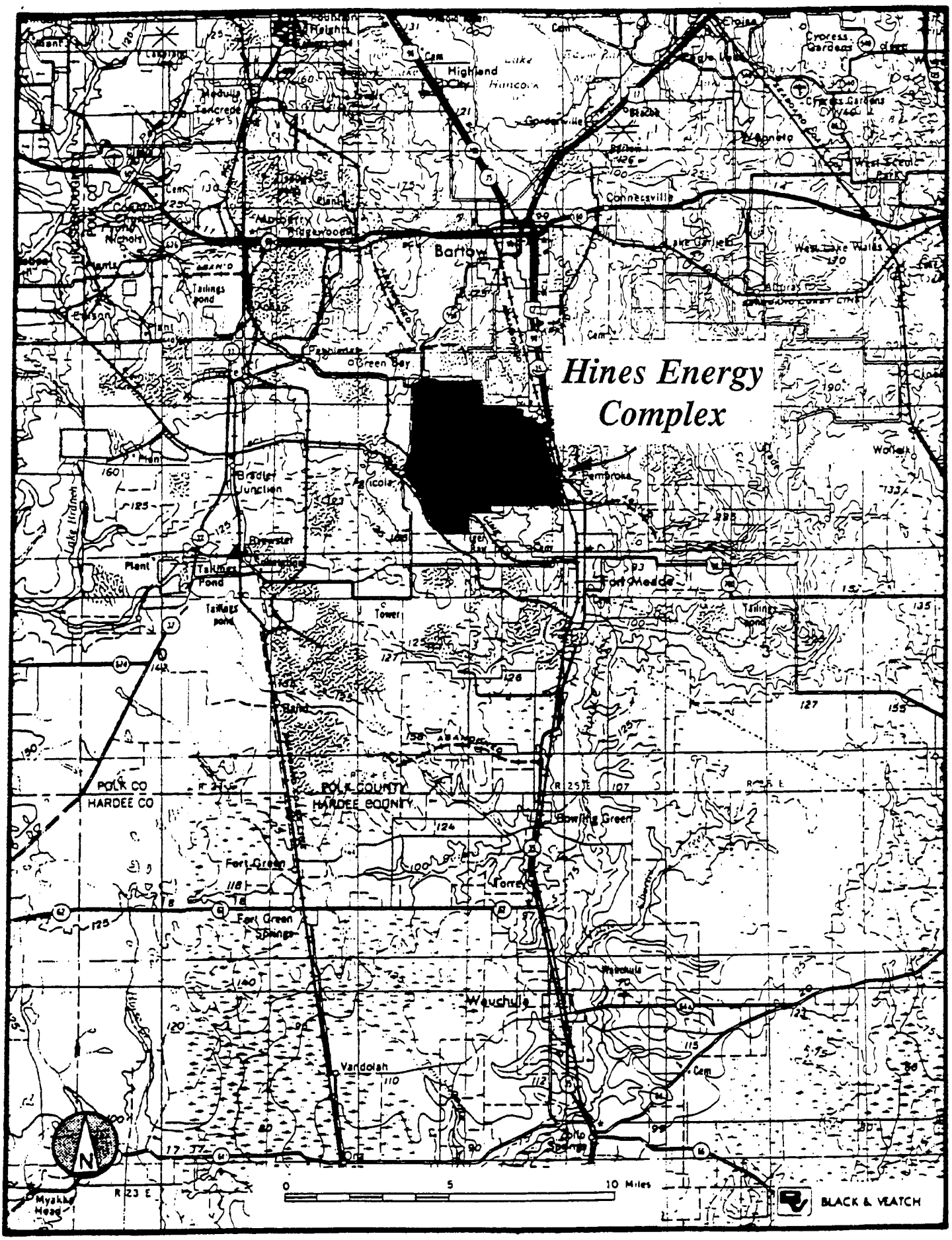
The governor and cabinet approved site certification for ultimate site development and construction of the first 470 MW increment on January 25, 1994, in accordance with the rules of the Power Plant Siting Act. Due to the thorough screening during the selection process, and the disturbed nature of the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

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

The first combined cycle unit at this site, with a capacity of 482 MW summer and 529 MW winter, began commercial operation in April 1999. The transmission improvements associated

with this first unit were the rebuilding of the 230/115 kV double circuit Barcola to Ft. Meade line by increasing the conductor sizes and converting the line to double circuit 230 kV operation.

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



Hines Energy Complex (Polk County)

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

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

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

FORECAST ASSUMPTIONS

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

GENERAL ASSUMPTIONS

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

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

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

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

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

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

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

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

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

SHORT-TERM ECONOMIC ASSUMPTIONS

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

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

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

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

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

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

LONG-TERM ECONOMIC ASSUMPTIONS

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

Population Growth Trends

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

- Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. This will continue to occur, but at less than historic rates for two reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Sixty years later, there now exists a smaller pool of retirees capable of migrating to Florida. Second, the enormous growth in population and corresponding development of the 1980s and 1990s made portions of Florida less

desirable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

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

Economic Growth Trends

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

manufacturing jobs that may have moved to Florida. Also, the stability of Florida's citrus and vegetable industry may be threatened when faced with greater competition from Mexico as tariffs are eliminated.

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

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

FORECAST METHODOLOGY

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

SHORT-TERM ECONOMETRIC MODEL

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

direct load control reductions are also incorporated into the forecast. Specific sectors are modeled as follows:

Residential Sector

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

Commercial Sector

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

Industrial Sector

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

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

Other Retail Sectors

Street Lighting

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

Public Authorities

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

Sales For Resale Sector

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

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

stratified peaking demand. The amount of load increases to 300 MW in 2001 and 2002. This load is not projected to be served by FPC beyond the contract term.

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

system for the remaining years of the forecast horizon unless the customer has notified FPC of a willingness to not renew their contract.

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

Demand-Side Management

Each projection of every retail class-of-business MWh energy sales forecast is reduced by estimated future energy savings due to FPC-sponsored and Florida Public Service Commission (FPSC)-approved dispatchable and non-dispatchable Demand-Side Management programs. Estimated energy savings for every non-dispatchable DSM program are calculated on a program-by-program basis and aggregated for each class-of-business on the program. Dispatchable DSM program energy savings are estimated within the Resource Planning Department's production costing

models. These models determine the most cost-effective means to meet system requirements, including load control. The DSM projections incorporated in this demand and energy forecast meet the new conservation goals established by the FPSC in Order No. PSC-99-1942-FOF-EG, issued October 1, 1999 in Docket No. 971005-EG.

LONG-TERM SHAPES-PC MODEL

Energy Forecast

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

Residential Sector

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

The last factor in the demand equation is the probability of the appliance operating at a given time. This term is called the use factor. It is necessary to distinguish between temperature, or weather

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

Industrial Sector

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

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

Commercial Sector

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

Customer Forecast

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

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

Peak Demand Forecast

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

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

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

Potential firm retail load refers to projections of FPC retail hourly seasonal net peak demand (excluding interruptible/curtailable/standby services) before the cumulative effects of any conservation activity or the activation of FPC's Load Management program. The historical values of this series are constructed to show the size of FPC's firm retail net peak demand had no utility-induced conservation or load control ever taken place. The value of constructing such a "clean" series enables the forecaster to observe and correlate the underlying trend in retail peak demand to

total system customer levels at the time of the peak and coincident weather conditions without the impacts of year-to-year variation in conservation activity or load control reductions. Seasonal peaks are projected using historical seasonal peak data regardless to which month the peak occurred. The projections become the potential retail demand projection for the month of January (winter) and August (summer) since this is typically when the seasonal peaks occur. The non-seasonal peak months are projected the same as the seasonal peaks, but the analysis is limited to the month being projected.

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

Sales For Resale demand projections represent load supplied by FPC to other electric utilities such as Seminole Electric Cooperative, Incorporated, the Florida Municipal Power Agency, and other electric distribution companies. The SECI supplemental demand projection is based on their forecast of their service area within the FPC control area. The level of MW to be served by FPC is dependent upon the amount of resources SECI supplies to itself or contracts with others. An assumption has been made that beyond 2005 - the last year of committed capacity declaration - SECI will hold constant their level of self-serve resources. For the partial requirements customers demand projections, historical ratios of coincident-to-contract levels of demand are applied to future MW contract levels. Demand requirements continue out at the level indicated by the final year in their respective contracts. The full requirements municipal demand forecast is estimated for

individual cities using linear econometric equations modeling both weather and economic impacts specific to each locale. The seasonal (winter and summer) projections become the January and August peak values, respectively. The non-seasonal peak months are calculated using monthly allocation factors derived from applying the historical relationship between each winter month (November to March) relative to the winter peak, and each summer month (April to October) in relation to the summer peak demand.

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

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

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

HIGH AND LOW FORECAST SCENARIOS

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

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

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

MODEL DOCUMENTATION

SHORT TERM ECONOMETRIC MODELS

RESIDENTIAL CLASS:

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

where:

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

COMMERCIAL CLASS:

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

where:

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

INDUSTRIAL CLASS: NON-PHOSPHATE SUBSECTOR

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

where:

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

PUBLIC AUTHORITY CLASS:

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

where:

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

STREET & HIGHWAY LIGHTING CLASS:

SHL = F(BMLTHR, RES_CUSA, SHL_DUM)

where:

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

SHL_DUM	=	Intercept shift variable to account for the impacts of the new customer service system
AR(1)	=	1st order autoregressive error term
SAR(1)	=	1st order seasonal autoregressive error term

SHAPES END-USE MODEL

RESIDENTIAL END USE APPLIANCES:

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

INDUSTRIAL CATEGORIES:

Manufacturing Industries Modeled in SHAPES-PC Industrial Model:

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

COMMERCIAL BUILDING TYPES:

Commercial Building Types Modeled in SHAPES-PC Commercial Model:

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

FLORIDA POWER CORPORATION

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

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

FLORIDA POWER CORPORATION

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

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

FLORIDA POWER CORPORATION

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2009):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2009):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2009):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2010):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2010):

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

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

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

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

FLORIDA POWER CORPORATION

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

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

Historical Values (1990-1999):

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

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

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

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

Projected Values (2000 - 2010):

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

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

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

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

DEMAND-SIDE MANAGEMENT PLAN

OF

FLORIDA POWER CORPORATION

DECEMBER 29, 1999

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INTRODUCTION

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

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

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

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

I. PROGRAM GOALS AND CUMULATIVE IMPACT

I. PROGRAM GOALS AND CUMULATIVE IMPACT

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

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

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

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

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

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

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

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

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

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

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

II. PROGRAM INTRODUCTION

II. PROGRAM INTRODUCTION

A. PROGRAM OPERATION

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

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

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

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

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

B. COST-EFFECTIVENESS

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

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

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

Table II-1

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

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

NOTES:

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

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

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

C. PROGRAM MONITORING AND EVALUATION

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

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

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

D. COST-RECOVERY

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

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

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

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

III. RESIDENTIAL CONSERVATION PROGRAMS

III. RESIDENTIAL CONSERVATION PROGRAMS

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

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

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

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

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

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

Each program is described in detail in the following sections.

A. HOME ENERGY CHECK PROGRAM

Program Start Date: ▸ 1995

Policies and Procedures

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

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

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

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

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

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

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

Program Participation

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

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

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

Savings Estimates

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

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

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

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

Impact Evaluation Plan

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

B. HOME ENERGY IMPROVEMENT PROGRAM

Program Start Date: ▸ 1995

▸ Proposed modification for 2000

Policies and Procedures

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

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

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

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

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

Attic Insulation Upgrade

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

Duct Test and Repair

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

High Efficiency Electric Heat Pumps

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

High Efficiency Alternate Water Heating

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

Supplemental Incentive Bonus

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

Financing

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

Program Participation

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

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

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

Savings Estimates

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

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

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

Impact Evaluation Plan

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

Cost-Effectiveness

The economic results of the program are as follows:

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

PROGRAM: Home Energy Improvement

PARTICIPANT TEST

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

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

PROGRAM: Home Energy Improvement

TOTAL RESOURCE COST TEST

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

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.64

PROGRAM: Home Energy Improvement

RATE IMPACT MEASURE TEST

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

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

C. NEW CONSTRUCTION

Program Start Date: ▸ 1995

▸ Proposed modification for 2000

Policies and Procedures

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

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

The objectives of the program include the following goals:

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

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

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

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

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

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

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

High Efficiency Electric Heat Pumps

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

High Efficiency Alternate Electric Water Heating

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

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

Program Participation

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

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

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*
2. *Total number of eligible new homes constructed in FPC's territory.*
3. *Annual Number of Measure Participants is the projected number of cumulative measure applications from all measures promoted by this program. Because customer can install multiple measures, the actual number of participants will be less.*

Savings Estimates

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

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	470	0.864	0.425	3,083,000	5,670	2,786
2001	469	0.870	0.426	7,011,000	12,995	6,370
2002	469	0.875	0.428	11,826,000	22,059	10,788
2003	469	0.879	0.429	17,500,000	32,814	16,018
2004	468	0.882	0.430	23,937,000	45,075	21,972
2005	468	0.884	0.431	31,006,000	58,578	28,520
2006	468	0.886	0.431	38,569,000	73,054	35,537
2007	468	0.888	0.432	46,465,000	88,186	42,868
2008	468	0.889	0.432	54,554,000	103,691	50,379
2009	468	0.890	0.432	62,715,000	119,337	57,959

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	493	0.902	0.450	3,238,074	5,918	2,949
2001	492	0.908	0.451	7,363,653	13,564	6,743
2002	492	0.913	0.453	12,420,847	23,025	11,421
2003	492	0.918	0.454	18,380,250	34,251	16,958
2004	491	0.921	0.455	25,141,031	47,049	23,261
2005	491	0.923	0.456	32,565,601	61,143	30,194
2006	491	0.925	0.456	40,509020	76,253	37,623
2007	491	0.927	0.457	48,802,189	92,048	45,384
2008	491	0.928	0.457	57,298,066	108,232	53,336
2009	491	0.929	0.457	65,869,564	124,563	61,361

Impact Evaluation Plan

The Residential New Construction program includes the installation of varied types of measures. As such, the impact evaluation plan should address interactive effects of multiple measures. In order to capture the impacts of these measures, engineering simulations and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts, although the specific method may vary depending on measure-specific participation levels. These analyses may be supported by residential end-use metering data, where feasible.

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	45,795	40,630	5,165	1.13
Participant	35,305	11,740	23,565	3.01
Total Resource Cost	45,795	17,065	28,730	2.68

PROGRAM: New Construction

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	227	107	0	334	1075	0	1075	-741
2001	509	110	0	619	1299	0	1299	-680
2002	879	112	0	991	1527	0	1527	-536
2003	1309	113	0	1422	1745	0	1745	-323
2004	1789	113	0	1902	1937	0	1937	-35
2005	2321	114	0	2435	2093	0	2093	342
2006	2887	114	0	3001	2223	0	2223	778
2007	3471	116	0	3587	2304	0	2304	1283
2008	4091	117	0	4208	2358	0	2358	1850
2009	4781	117	0	4898	2377	0	2377	2521
2010	4859	0	0	4859	0	0	0	4859
2011	4940	0	0	4940	0	0	0	4940
2012	5025	0	0	5025	0	0	0	5025
2013	5108	0	0	5108	0	0	0	5108
2014	5191	0	0	5191	0	0	0	5191
2015	5279	0	0	5279	0	0	0	5279
2016	5365	0	0	5365	0	0	0	5365
2017	5454	0	0	5454	0	0	0	5454
2018	5542	0	0	5542	0	0	0	5542
2019	5634	0	0	5634	0	0	0	5634
2020	5726	0	0	5726	0	0	0	5726
2021	5821	0	0	5821	0	0	0	5821
2022	5917	0	0	5917	0	0	0	5917
2023	6018	0	0	6018	0	0	0	6018
2024	6115	0	0	6115	0	0	0	6115
2025	6217	0	0	6217	0	0	0	6217
2026	6317	0	0	6317	0	0	0	6317
2027	6422	0	0	6422	0	0	0	6422
2028	6526	0	0	6526	0	0	0	6526
NOMINAL	129740	1133	0	130873	18938	0	18938	111935
NPV	34568	737	0	35305	11740	0	11740	23565

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 3.01

PROGRAM: New Construction

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	117	145	0	0	262	1075	0	0	0	534	1609	-1347
2001	312	332	0	0	644	1299	0	0	0	619	1918	-1274
2002	402	564	348	0	1314	1527	0	0	0	708	2235	-921
2003	627	830	523	0	1980	1745	0	0	0	793	2538	-558
2004	907	1144	0	0	2051	1937	0	0	0	869	2806	-755
2005	2214	1489	804	0	4507	2093	0	0	0	932	3025	1482
2006	4302	1859	1331	0	7492	2223	0	0	0	982	3205	4287
2007	1630	2244	1412	0	5286	2304	0	0	0	1013	3317	1969
2008	3177	2640	267	0	6084	2358	0	0	0	1034	3392	2692
2009	2323	3038	522	0	5883	2377	0	0	0	1041	3418	2465
2010	2855	3038	551	0	6444	0	0	0	0	0	0	6444
2011	2378	3038	555	0	5971	0	0	0	0	0	0	5971
2012	2439	3038	55	0	5532	0	0	0	0	0	0	5532
2013	2459	3038	19	0	5516	0	0	0	0	0	0	5516
2014	2467	3038	54	0	5559	0	0	0	0	0	0	5559
2015	2489	3038	638	0	6165	0	0	0	0	0	0	6165
2016	2526	3038	679	0	6243	0	0	0	0	0	0	6243
2017	2550	3038	678	0	6266	0	0	0	0	0	0	6266
2018	2544	3038	719	0	6301	0	0	0	0	0	0	6301
2019	2567	3038	721	0	6326	0	0	0	0	0	0	6326
2020	2631	3038	767	0	6436	0	0	0	0	0	0	6436
2021	2657	3038	766	0	6461	0	0	0	0	0	0	6461
2022	3226	3038	812	0	7076	0	0	0	0	0	0	7076
2023	2772	3038	1600	0	7410	0	0	0	0	0	0	7410
2024	2775	3038	1637	0	7450	0	0	0	0	0	0	7450
2025	2808	3038	1701	0	7547	0	0	0	0	0	0	7547
2026	3298	3038	1746	0	8082	0	0	0	0	0	0	8082
2027	2893	3038	1808	0	7739	0	0	0	0	0	0	7739
2028	2947	3038	1850	0	7835	0	0	0	0	0	0	7835
NOMINAL	67292	72007	22563	0	161862	18938	0	0	0	8525	27463	134399
NPV	19643	20336	5817	0	45795	11740	0	0	0	5325	17065	28730

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.68

PROGRAM: New Construction

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	117	145	0	0	262	0	0	0	534	107	227	868	-606
2001	312	332	0	0	644	0	0	0	619	110	509	1238	-594
2002	402	564	348	0	1314	0	0	0	708	112	879	1699	-385
2003	627	830	523	0	1980	0	0	0	793	113	1309	2215	-235
2004	907	1144	0	0	2051	0	0	0	869	113	1789	2771	-720
2005	2214	1489	804	0	4507	0	0	0	932	114	2321	3367	1140
2006	4302	1859	1331	0	7492	0	0	0	982	114	2887	3983	3509
2007	1630	2244	1412	0	5286	0	0	0	1013	116	3471	4600	686
2008	3177	2640	267	0	6084	0	0	0	1034	117	4091	5242	842
2009	2323	3038	522	0	5883	0	0	0	1041	117	4781	5939	-56
2010	2855	3038	551	0	6444	0	0	0	0	0	4859	4859	1585
2011	2378	3038	555	0	5971	0	0	0	0	0	4940	4940	1031
2012	2439	3038	55	0	5532	0	0	0	0	0	5025	5025	507
2013	2459	3038	19	0	5516	0	0	0	0	0	5108	5108	408
2014	2467	3038	54	0	5559	0	0	0	0	0	5191	5191	368
2015	2489	3038	638	0	6165	0	0	0	0	0	5279	5279	886
2016	2526	3038	679	0	6243	0	0	0	0	0	5365	5365	878
2017	2550	3038	678	0	6266	0	0	0	0	0	5454	5454	812
2018	2544	3038	719	0	6301	0	0	0	0	0	5542	5542	759
2019	2567	3038	721	0	6326	0	0	0	0	0	5634	5634	692
2020	2631	3038	767	0	6436	0	0	0	0	0	5726	5726	710
2021	2657	3038	766	0	6461	0	0	0	0	0	5821	5821	640
2022	3226	3038	812	0	7076	0	0	0	0	0	5917	5917	1159
2023	2772	3038	1600	0	7410	0	0	0	0	0	6018	6018	1392
2024	2775	3038	1637	0	7450	0	0	0	0	0	6115	6115	1335
2025	2808	3038	1701	0	7547	0	0	0	0	0	6217	6217	1330
2026	3298	3038	1746	0	8082	0	0	0	0	0	6317	6317	1765
2027	2893	3038	1808	0	7739	0	0	0	0	0	6422	6422	1317
2028	2947	3038	1850	0	7835	0	0	0	0	0	6526	6526	1309
NOMINAL	67292	72007	22563	0	161862	0	0	0	8525	1133	129740	139398	22464
NPV	19643	20336	5817	0	45795	0	0	0	5325	737	34568	40630	5165

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.13

D. LOW INCOME WEATHERIZATION ASSISTANCE PROGRAM

Program Start Date: ▸ 2000

Policies and Procedures

The Low-Income Weatherization Assistance program (LIWAP) is the umbrella program to improve energy efficiency for low-income customers in existing residential housing. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program seeks to meet the following goals:

- Integrate FPC's LIWAP procedures with the Department of Community Affairs (DCA) and local weatherization providers to deliver energy efficiency measures to low-income families.
- Identify and educate contractors and low income customers about energy saving opportunities to improve home energy efficiency.
- Increase low-income families' participation in FPC's DSM programs.
- Minimize "lost opportunities" in the existing marketplace.

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

- The residence must be in FPC's service area and be a residential FPC metered customer.
- Must meet Florida's weatherization low-income criteria in addition to income requirements required by DCA.
- Homes must be greater than two years old.
- Homes having previously received FPC incentives for listed measures are not eligible for the same measure. Attic insulation and duct repairs have special exemptions as outlined in the Home Energy Improvement Program.
- A DCA approved provider or their approved contractors must perform all work. FPC approved contractors may be used.

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

Attic Insulation Upgrade

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

Duct Test and Repair

This portion of the program is designed to encourage eligible customers to improve their central duct system by reducing the air leakage rate. This is accomplished by performing a duct leakage test, then offering to repair the leakage that is discovered by the duct test. The home must have central ducted electric cooling and electric heat to participate in this measure. For a duct test, FPC will pay up to a maximum of $30 for the first unit and $20 for each additional unit at the same address. For the duct repair, FPC will pay an incentive of up to $100 per unit.

Reduced Air Infiltration

The weatherization provider must demonstrate a minimum reduction of air infiltration into the home of 1500 cfm at 50 pascals to receive a $75 incentive. The home must not exceed ASHRAE Standard 92.2-1989 for acceptable indoor air quality.

Water Heater Wrap/Replacement

The weatherization provider will wrap the water heater with an insulation value of at least R-6 side and R-8 top and insulate the pipes a minimum of 3 feet extending from the tank. The temperature will be set down to 120 degrees. To defray the cost of purchasing a high efficiency water heater, in lieu of installing an insulating jacket, the same $25 incentive would apply.

High Efficiency Electric Heat Pumps

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

High Efficiency Alternate Water Heating

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

Heating and Air Conditioning Maintenance

To maximize efficiency a $40 incentive will be provided for a Heating & Air Conditioning contractor to perform service/tune-up maintenance on existing electric central heating and air conditioning systems.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2000	1,230,736	1,500	293	20%
2001	1,252,598	3,030	768	25%
2002	1,274,213	4,591	1,293	28%
2003	1,295,656	6,183	1,818	29%
2004	1,316,791	7,808	2,343	30%
2005	1,337,264	9,466	2,868	30%
2006	1,357,066	11,157	3,393	30%
2007	1,376,186	12,882	3,918	30%
2008	1,394,931	14,642	4,443	30%
2009	1,413,612	16,437	4,968	30%

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*
2. *Total number of Eligible Customers that are weatherized by local weatherization assistance providers.*
3. *Annual Number of Measure Participants is the projected number of cumulative measure installations from all measures promoted by this program. Because customers can install multiple measures, the actual number of participants will be less.*

Savings Estimates

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

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	354	0.574	0.255	104,000	168	75
2001	360	0.596	0.260	276,000	457	200
2002	354	0.594	0.254	458,000	768	328
2003	352	0.593	0.251	640,000	1,078	457
2004	351	0.592	0.250	822,000	1,388	586
2005	350	0.592	0.249	1,004,000	1,698	714
2006	350	0.592	0.248	1,186,000	2,008	843
2007	349	0.592	0.248	1,369,000	2,318	971
2008	349	0.592	0.248	1,551,000	2,628	1,100
2009	349	0.591	0.247	1,733,000	2,938	1,228

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	371	0.599	0.270	109,231	175	79
2001	378	0.622	0.275	289,882	477	211
2002	371	0.620	0.269	481,037	801	347
2003	369	0.619	0.266	672,192	1,125	483
2004	368	0.618	0.265	863,346	1,448	620
2005	367	0.618	0.264	1,054,501	1,772	755
2006	367	0.618	0.263	1,245,655	2,095	892
2007	366	0.618	0.263	1,437,860	2,419	1,027
2008	366	0.618	0.263	1,629,015	2,743	1,164
2009	366	0.617	0.261	1,820,169	3,066	1,300

Impact Evaluation Plan

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

Cost-Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	1,630	1,602	28	1.02
Participant	1,330	0	1,330	9999
Total Resource Cost	1,630	272	1,358	5.99

PROGRAM: Low Income Weatherization Assistance

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	8	29	0	37	0	0	0	37
2001	21	48	0	69	0	0	0	69
2002	34	52	0	86	0	0	0	86
2003	48	52	0	100	0	0	0	100
2004	62	52	0	114	0	0	0	114
2005	76	52	0	128	0	0	0	128
2006	90	52	0	142	0	0	0	142
2007	103	52	0	155	0	0	0	155
2008	117	52	0	169	0	0	0	169
2009	133	52	0	185	0	0	0	185
2010	135	0	0	135	0	0	0	135
2011	138	0	0	138	0	0	0	138
2012	145	0	0	145	0	0	0	145
2013	142	0	0	142	0	0	0	142
2014	145	0	0	145	0	0	0	145
2015	147	0	0	147	0	0	0	147
2016	149	0	0	149	0	0	0	149
2017	152	0	0	152	0	0	0	152
2018	154	0	0	154	0	0	0	154
2019	157	0	0	157	0	0	0	157
2020	159	0	0	159	0	0	0	159
2021	162	0	0	162	0	0	0	162
2022	166	0	0	166	0	0	0	166
2023	167	0	0	167	0	0	0	167
2024	170	0	0	170	0	0	0	170
2025	173	0	0	173	0	0	0	173
2026	176	0	0	176	0	0	0	176
2027	179	0	0	179	0	0	0	179
2028	181	0	0	181	0	0	0	181
NOMINAL	3689	493	0	4182	0	0	0	4182
NPV	1013	317	0	1330	0	0	0	1330

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Low Income Weatherization Assistance

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	4	6	0	0	10	0	0	0	0	36	36	-26
2001	11	16	0	0	27	0	0	0	0	41	41	-14
2002	15	26	12	0	53	0	0	0	0	43	43	10
2003	23	36	16	0	75	0	0	0	0	43	43	32
2004	31	47	24	0	102	0	0	0	0	43	43	59
2005	36	57	22	0	115	0	0	0	0	43	43	72
2006	111	68	45	0	224	0	0	0	0	43	43	181
2007	48	78	42	0	168	0	0	0	0	43	43	125
2008	53	89	49	0	191	0	0	0	0	43	43	148
2009	60	99	58	0	217	0	0	0	0	43	43	174
2010	62	99	59	0	220	0	0	0	0	0	0	220
2011	62	99	61	0	222	0	0	0	0	0	0	222
2012	60	99	0	0	159	0	0	0	0	0	0	159
2013	64	99	64	0	227	0	0	0	0	0	0	227
2014	65	99	67	0	231	0	0	0	0	0	0	231
2015	66	99	68	0	233	0	0	0	0	0	0	233
2016	68	99	71	0	238	0	0	0	0	0	0	238
2017	68	99	73	0	240	0	0	0	0	0	0	240
2018	70	99	75	0	244	0	0	0	0	0	0	244
2019	105	99	77	0	281	0	0	0	0	0	0	281
2020	72	99	79	0	250	0	0	0	0	0	0	250
2021	73	99	82	0	254	0	0	0	0	0	0	254
2022	67	99	85	0	251	0	0	0	0	0	0	251
2023	75	99	87	0	261	0	0	0	0	0	0	261
2024	77	99	90	0	266	0	0	0	0	0	0	266
2025	78	99	93	0	270	0	0	0	0	0	0	270
2026	80	99	96	0	275	0	0	0	0	0	0	275
2027	81	99	99	0	279	0	0	0	0	0	0	279
2028	83	99	101	0	283	0	0	0	0	0	0	283
NOMINAL	1768	2403	1695	0	5866	0	0	0	0	421	421	5445
NPV	507	700	422	0	1630	0	0	0	0	272	272	1358

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 5.99

PROGRAM: Low Income Weatherization Assistance

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	4	6	0	0	10	0	0	0	36	29	8	73	-63
2001	11	16	0	0	27	0	0	0	41	48	21	110	-83
2002	15	26	12	0	53	0	0	0	43	52	34	129	-76
2003	23	36	16	0	75	0	0	0	43	52	48	143	-68
2004	31	47	24	0	102	0	0	0	43	52	62	157	-55
2005	36	57	22	0	115	0	0	0	43	52	76	171	-56
2006	111	68	45	0	224	0	0	0	43	52	90	185	39
2007	48	78	42	0	168	0	0	0	43	52	103	198	-30
2008	53	89	49	0	191	0	0	0	43	52	117	212	-21
2009	60	99	58	0	217	0	0	0	43	52	133	228	-11
2010	62	99	59	0	220	0	0	0	0	0	135	135	85
2011	62	99	61	0	222	0	0	0	0	0	138	138	84
2012	60	99	0	0	159	0	0	0	0	0	145	145	14
2013	64	99	64	0	227	0	0	0	0	0	142	142	85
2014	65	99	67	0	231	0	0	0	0	0	145	145	86
2015	66	99	68	0	233	0	0	0	0	0	147	147	86
2016	68	99	71	0	238	0	0	0	0	0	149	149	89
2017	68	99	73	0	240	0	0	0	0	0	152	152	88
2018	70	99	75	0	244	0	0	0	0	0	154	154	90
2019	105	99	77	0	281	0	0	0	0	0	157	157	124
2020	72	99	79	0	250	0	0	0	0	0	159	159	91
2021	73	99	82	0	254	0	0	0	0	0	162	162	92
2022	67	99	85	0	251	0	0	0	0	0	166	166	85
2023	75	99	87	0	261	0	0	0	0	0	167	167	94
2024	77	99	90	0	266	0	0	0	0	0	170	170	96
2025	78	99	93	0	270	0	0	0	0	0	173	173	97
2026	80	99	96	0	275	0	0	0	0	0	176	176	99
2027	81	99	99	0	279	0	0	0	0	0	179	179	100
2028	83	99	101	0	283	0	0	0	0	0	181	181	102
NOMINAL	1768	2403	1695	0	5866	0	0	0	421	493	3689	4603	1263
NPV	507	700	422	0	1630	0	0	0	272	317	1013	1602	28

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.02

E. RESIDENTIAL ENERGY MANAGEMENT PROGRAM

Program Start Date:
- 1981
- Program modified in 1995
- Proposed modification for 2000

Policies and Procedures

Residential Energy Management is a voluntary customer program that allows FPC to reduce peak demand and defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customers premises. These controlled interruptions are at FPC's option, during specified time periods, and coincident with hours of peak demand.

FPC has recently determined that it is no longer cost-effective under the RIM test to continue adding new participants to the current Residential Energy Management program, as described in rate schedule RSL-1. (Pages III-33 through III-35 present the results of all three Commission-approved tests of cost-effectiveness.) The Company also recognizes and seeks to balance the broad range of issues associated with a program whose participation rate is about forty-percent of it's entire residential customer base. As a result, FPC is proposing to modify the program in such a way as to improve program cost-effectiveness, ensure adequate near-term reserve margins, minimize customer reaction and inconvenience, and optimize reserve margin mix in the long-term. This proposal involves modifying the current program into two components.

Year-Round Energy Management

The Year-Round Energy Management component of the program will be the current Residential Energy Management Program (rate schedule RSL-1). However, because it is no longer cost-effective to add new participants to the existing program, FPC is proposing to close this component of the program to all customers who are not current participants. All existing Residential Energy Management program participants will be allowed to remain on the year-round program if they do not change their control schedule. Therefore, no existing participants will be affected by this change, as long as they remain on their existing control schedule. Also, prior to April 1, 2001 all new occupants of an active Energy Management equipped residence will be treated as an existing participant and allowed on the year-round component, if they maintain the same Energy Management control schedule as the previous occupants and do not require a service trip. Any participant that alters their current control schedule such that it requires a service trip, will no longer be eligible to continue on this Year-Round component of the program.

Maintaining existing program participants on the Energy Management program through the winter of 2001 is especially important given the relatively large amount of non-firm load provided by this program, as well as the need to provide a minimum fifteen percent reserve margin. Any significant loss of program participation directly increases firm load, and reduces FPC's already tight near-term planned reserve margins. This is the primary reason behind allowing new occupants of an active Energy Management equipped home to automatically continue service under the previous occupants Year-Round Energy Management rate schedule prior to April 1, 2001. In addition, this transition period will provide the time needed to organize and complete the operational components required to actually implement these proposed changes (i.e., contractor support and training, systems programming, etc.). However, the Company also recognizes the need to begin shifting program participation away from the Year-Round Energy Management Component. To meet both of these objectives, FPC proposes to substantially reduce the number of existing participants on the year-round component of the program beginning April 1, 2001. As of this date, FPC expects to have sufficient reserves to allow a ramping down of the year-round program component with no deleterious effects on reserve margins. The ramp-down will be accomplished by no longer offering new occupants of an active Energy Management equipped residence the ability to continue the previous occupant's service under the Year-Round Energy Management rate schedule. This strategy is expected to minimize any negative customer reaction, since it does not affect existing participants that do not change their occupancy status or control schedule.

Proposed changes to the RSL-1 rate schedule (in legislative format) are presented in the Appendix to this document.

Winter-Only Energy Management

The proposed Winter-Only Energy Management component of the program represents a modified, cost-effective version of the current Residential Energy Management program, and is outlined in the proposed new rate schedule RSL-2 (see Appendix). It provides for winter only (November through March) direct load control of customer's electric water heating and central electric heating appliances. Eligible participants must have both appliances on the program and will receive monthly credits during the potential control months. The amount of the credits are identical to those under the current Residential Energy Management program (rate schedule RSL-1) except that they are payable only during the winter months.

Since no new participation will be eligible for the Year-Round Energy Management component, this new Winter Only Energy Management component will enable FPC to continue to provide customers a cost-effective alternative to standard residential service that can help lower their electric bills as well as reduce FPC's winter peak demand. The program solidly passes the RIM Test, with benefit-cost ratios of 1.24. Pages III-37 through III-39 present the results for all three Commission-approved tests of cost-effectiveness.

There are three primary differences between the current Residential Energy Management Program (i.e., proposed Year-Round Residential Energy Management component) and the proposed Winter-Only Energy Management component:

- The current program offers customers a credit for the ability to exercise direct load control on any combination of their electric pool pump, water heating, central heating, and/or central cooling appliances. The proposed Winter-Only Energy Management component only provides a credit for direct load control of electric water heating and central electric heating appliances.

- The current program allows direct load control to be exercised throughout the year and pays an incentive every month of the year. The proposed Winter-Only Energy Management component allows the use of direct load control only during the five winter months of November through March, and only provides a credit during those winter months.

- The current program offers two possible control schedules for electric central heating equipment: 10 minutes maximum control or 16.5 minutes maximum control in any 30 minute period. For the proposed Winter-Only Energy Management component, only one heating schedule will be offered: 16.5 minute maximum control in any 30 minute period.

Program Participation

Cumulative program participation estimates beginning in the year 2000 are shown in the following table, and reflect new equipment installations under the Winter-Only Energy Management component of the program. There are no new participants (i.e., new Energy Management installations) projected for the Year-Round Energy Management component.

Winter-Only Energy Management

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Program Participants [3]	Cumulative Penetration Level (%)
2000	1,230,736	605,337	5,000	.008%
2001	1,252,598	622,827	10,625	.017%
2002	1,274,213	640,119	16,875	.026%
2003	1,295,656	657,273	23,750	.036%
2004	1,316,791	674,181	31,250	.046%
2005	1,337,264	690,560	38,750	.056%
2006	1,357,066	706,401	45,625	.065%
2007	1,376,186	721,697	51,875	.072%
2008	1,394,931	736,693	57,500	.078%
2009	1,413,612	751,638	62,500	.083%

1. *Total Number of Customers is the forecast of all residential customers, from the June 1999 Forecast.*

2. *Total numbers of eligible customers are all residential customers not already on the Residential Energy Management program.*

Savings Estimates

The total program savings shown in the following tables reflect the demand and energy savings associated with the new program participants projected for the Winter-Only Energy Management component of the program. Since there will be no new participants or savings from the Year-Round Energy Management component, only the savings from the Winter-Only component will be used to meet FPC's Commission approved conservation goals.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	2.110	0	0	10,550	0
2001	0	2.110	0	0	22,419	0
2002	0	2.110	0	0	35,606	0
2003	0	2.110	0	0	50,113	0
2004	0	2.110	0	0	65,938	0
2005	0	2.110	0	0	81,763	0
2006	0	2.110	0	0	96,269	0
2007	0	2.110	0	0	109,456	0
2008	0	2.110	0	0	121,325	0
2009	0	2.110	0	0	131,875	0

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	2.202	0	0	11,012	0
2001	0	2.202	0	0	23,400	0
2002	0	2.202	0	0	37,165	0
2003	0	2.202	0	0	52,307	0
2004	0	2.202	0	0	68,826	0
2005	0	2.202	0	0	85,344	0
2006	0	2.202	0	0	100,485	0
2007	0	2.202	0	0	114,250	0
2008	0	2.202	0	0	126,639	0
2009	0	2.202	0	0	137,651	0

Impact Evaluation Plan

FPC is in the process of conducting a residential end-use metering study that will be used to estimate the appliance level, and duty-cycle impacts of residential load control. This end-use metering data will be used to perform engineering and statistical analysis to estimate the impacts of the program.

Cost-Effectiveness

1. The following economic results for the current year-round Residential Energy Management program:

Current Year-Round Residential Energy Management Program

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	82,516	98,117	-15,601	0.81
Participant	69,545	2	69,543	9999
Total Resource Cost	82,514	28,572	53,942	2.76

PROGRAM: Current (Year-Round) Residential Energy Management

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	5	701	0	706	0	0	0	706
2001	0	1490	0	1490	0	2	2	1488
2002	20	2366	0	2386	0	0	0	2386
2003	21	3331	0	3352	0	0	0	3352
2004	58	4382	0	4440	0	0	0	4440
2005	207	5434	0	5641	0	0	0	5641
2006	377	6398	0	6775	0	0	0	6775
2007	837	7275	0	8112	0	0	0	8112
2008	1327	8063	0	9390	0	0	0	9390
2009	1439	8764	0	10203	0	0	0	10203
2010	1482	8764	0	10246	0	0	0	10246
2011	1486	8764	0	10250	0	0	0	10250
2012	1538	8764	0	10302	0	0	0	10302
2013	1535	8764	0	10299	0	0	0	10299
2014	1583	8764	0	10347	0	0	0	10347
2015	1584	8764	0	10348	0	0	0	10348
2016	1641	8764	0	10405	0	0	0	10405
2017	1637	8764	0	10401	0	0	0	10401
2018	1690	8764	0	10454	0	0	0	10454
2019	1691	8764	0	10455	0	0	0	10455
2020	1729	8764	0	10493	0	0	0	10493
2021	1747	8764	0	10511	0	0	0	10511
2022	1803	8764	0	10567	0	0	0	10567
2023	1804	8764	0	10568	0	0	0	10568
2024	1845	8764	0	10609	0	0	0	10609
2025	1864	8764	0	10628	0	0	0	10628
2026	1927	8764	0	10691	0	0	0	10691
2027	1926	8764	0	10690	0	0	0	10690
2028	1969	8764	0	10733	0	0	0	10733
NOMINAL	36772	214720	0	251492	0	2	2	251490
NPV	8831	60714	0	69545	0	2	2	69543

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Current (Year-Round) Residential Energy Management

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	151	0	0	153	0	0	0	0	1863	1863	-1710
2001	0	320	0	0	320	0	29	0	0	2166	2195	-1875
2002	0	508	1488	0	1996	0	1398	0	0	2482	3880	-1884
2003	0	715	1476	0	2191	0	1385	0	0	2813	4198	-2007
2004	0	941	2987	0	3928	0	2514	0	0	3160	5674	-1746
2005	0	1167	3085	0	4252	0	869	0	0	3289	4158	94
2006	0	1374	4131	0	5505	0	1315	0	0	3191	4506	999
2007	0	1562	4104	0	5666	0	752	0	0	3090	3842	1824
2008	3522	1732	5950	0	11204	0	0	0	0	2986	2986	8218
2009	3048	1882	7103	0	12033	0	0	0	0	2877	2877	9156
2010	2809	1882	7219	0	11910	0	0	0	0	1122	1122	10788
2011	2863	1882	7551	0	12296	0	0	0	0	1165	1165	11131
2012	2815	1882	7654	0	12351	0	0	0	0	1211	1211	11140
2013	2779	1882	7937	0	12598	0	0	0	0	1258	1258	11340
2014	2401	1882	8098	0	12381	0	0	0	0	1307	1307	11074
2015	2962	1882	8437	0	13281	0	0	0	0	1358	1358	11923
2016	3062	1882	8664	0	13608	0	0	0	0	1411	1411	12197
2017	3170	1882	8968	0	14020	0	0	0	0	1466	1466	12554
2018	3171	1882	9167	0	14220	0	0	0	0	1523	1523	12697
2019	3358	1882	9532	0	14772	0	0	0	0	1583	1583	13189
2020	3198	1882	9484	0	14564	0	0	0	0	1644	1644	12920
2021	3584	1882	10133	0	15599	0	0	0	0	1709	1709	13890
2022	3804	1882	10357	0	16043	0	0	0	0	1775	1775	14268
2023	3832	1882	10770	0	16484	0	0	0	0	1850	1850	14634
2024	3573	1882	10716	0	16171	0	0	0	0	1927	1927	14244
2025	4015	1882	11449	0	17346	0	0	0	0	2008	2008	15338
2026	4660	1882	11723	0	18265	0	0	0	0	2093	2093	16172
2027	4329	1882	12169	0	18380	0	0	0	0	2181	2181	16199
2028	4078	1882	12108	0	18068	0	0	0	0	2272	2272	15796
NOMINAL	71035	46110	212460	0	329605	0	8262	0	0	58780	67042	262563
NPV	15963	13585	52966	0	82514	0	5450	0	0	23122	28572	53942

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.76

PROGRAM: Current (Year-Round) Residential Energy Management

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	151	0	0	153	0	0	0	1863	701	5	2569	-2416
2001	0	320	0	2	322	29	0	0	2166	1490	0	3685	-3363
2002	0	508	1488	0	1996	1398	0	0	2482	2366	20	6266	-4270
2003	0	715	1476	0	2191	1385	0	0	2813	3331	21	7550	-5359
2004	0	941	2987	0	3928	2514	0	0	3160	4382	58	10114	-6186
2005	0	1167	3085	0	4252	869	0	0	3289	5434	207	9799	-5547
2006	0	1374	4131	0	5505	1315	0	0	3191	6398	377	11281	-5776
2007	0	1562	4104	0	5666	752	0	0	3090	7275	837	11954	-6288
2008	3522	1732	5950	0	11204	0	0	0	2986	8063	1327	12376	-1172
2009	3048	1882	7103	0	12033	0	0	0	2877	8764	1439	13080	-1047
2010	2809	1882	7219	0	11910	0	0	0	1122	8764	1482	11368	542
2011	2863	1882	7551	0	12296	0	0	0	1165	8764	1486	11415	881
2012	2815	1882	7654	0	12351	0	0	0	1211	8764	1538	11513	838
2013	2779	1882	7937	0	12598	0	0	0	1258	8764	1535	11557	1041
2014	2401	1882	8098	0	12381	0	0	0	1307	8764	1583	11654	727
2015	2962	1882	8437	0	13281	0	0	0	1358	8764	1584	11706	1575
2016	3062	1882	8664	0	13608	0	0	0	1411	8764	1641	11816	1792
2017	3170	1882	8968	0	14020	0	0	0	1466	8764	1637	11867	2153
2018	3171	1882	9167	0	14220	0	0	0	1523	8764	1690	11977	2243
2019	3358	1882	9532	0	14772	0	0	0	1583	8764	1691	12038	2734
2020	3198	1882	9484	0	14564	0	0	0	1644	8764	1729	12137	2427
2021	3584	1882	10133	0	15599	0	0	0	1709	8764	1747	12220	3379
2022	3804	1882	10357	0	16043	0	0	0	1775	8764	1803	12342	3701
2023	3832	1882	10770	0	16484	0	0	0	1850	8764	1804	12418	4066
2024	3573	1882	10716	0	16171	0	0	0	1927	8764	1845	12536	3635
2025	4015	1882	11449	0	17346	0	0	0	2008	8764	1864	12636	4710
2026	4660	1882	11723	0	18265	0	0	0	2093	8764	1927	12784	5481
2027	4329	1882	12169	0	18380	0	0	0	2181	8764	1926	12871	5509
2028	4078	1882	12108	0	18068	0	0	0	2272	8764	1969	13005	5063
NOMINAL	71035	46110	212460	2	329607	8262	0	0	58780	214720	36772	318534	11073
NPV	15963	13585	52966	2	82516	5450	0	0	23122	60714	8831	98117	-15601

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 0.81

Cost-Effectiveness (Cont'd)

2. The following economic results are for the proposed new Winter-Only Energy Management program component:

Winter-Only Energy Management

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	37,282	28,800	8,482	1.24
Participant	11,277	0	11,277	9999
Total Resource Cost	37,282	17,524	19,759	2.05

PROGRAM: Winter-Only Residential Energy Management

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	1	124	0	125	0	0	0	125
2001	0	264	0	264	0	0	0	264
2002	4	419	0	423	0	0	0	423
2003	2	589	0	591	0	0	0	591
2004	21	775	0	796	0	0	0	796
2005	19	961	0	980	0	0	0	980
2006	49	1132	0	1181	0	0	0	1181
2007	51	1287	0	1338	0	0	0	1338
2008	84	1426	0	1510	0	0	0	1510
2009	78	1550	0	1628	0	0	0	1628
2010	88	1550	0	1638	0	0	0	1638
2011	81	1550	0	1631	0	0	0	1631
2012	88	1550	0	1638	0	0	0	1638
2013	81	1550	0	1631	0	0	0	1631
2014	94	1550	0	1644	0	0	0	1644
2015	84	1550	0	1634	0	0	0	1634
2016	97	1550	0	1647	0	0	0	1647
2017	87	1550	0	1637	0	0	0	1637
2018	102	1550	0	1652	0	0	0	1652
2019	89	1550	0	1639	0	0	0	1639
2020	105	1550	0	1655	0	0	0	1655
2021	92	1550	0	1642	0	0	0	1642
2022	109	1550	0	1659	0	0	0	1659
2023	95	1550	0	1645	0	0	0	1645
2024	113	1550	0	1663	0	0	0	1663
2025	99	1550	0	1649	0	0	0	1649
2026	116	1550	0	1666	0	0	0	1666
2027	102	1550	0	1652	0	0	0	1652
2028	122	1550	0	1672	0	0	0	1672
NOMINAL	2153	37977	0	40130	0	0	0	40130
NPV	540	10737	0	11277	0	0	0	11277

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Winter-Only Residential Energy Management

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	1	90	0	0	91	0	0	0	0	976	976	-885
2001	0	191	0	0	191	0	5	0	0	1087	1092	-901
2002	0	304	780	0	1084	0	770	0	0	1203	1973	-889
2003	0	427	882	0	1309	0	808	0	0	1324	2132	-823
2004	0	562	1652	0	2214	0	1588	0	0	1450	3038	-824
2005	0	697	1582	0	2279	0	1467	0	0	1496	2963	-684
2006	18	821	2343	0	3182	0	0	0	0	1459	1459	1723
2007	0	933	2767	0	3700	0	508	0	0	1420	1928	1772
2008	0	1034	3380	0	4414	0	729	0	0	1381	2110	2304
2009	0	1124	3804	0	4928	0	693	0	0	1340	2033	2895
2010	0	1124	3869	0	4993	0	682	0	0	692	1374	3619
2011	0	1124	4044	0	5168	0	661	0	0	708	1369	3799
2012	0	1124	4125	0	5249	0	638	0	0	724	1362	3887
2013	0	1124	4303	0	5427	0	603	0	0	741	1344	4083
2014	0	1124	4401	0	5525	0	602	0	0	758	1360	4165
2015	0	1124	4574	0	5698	0	563	0	0	777	1340	4358
2016	0	1124	4674	0	5798	0	543	0	0	796	1339	4459
2017	0	1124	4862	0	5986	0	518	0	0	815	1333	4653
2018	0	1124	4979	0	6103	0	475	0	0	836	1311	4792
2019	0	1124	5168	0	6292	0	444	0	0	857	1301	4991
2020	0	1124	5295	0	6419	0	406	0	0	879	1285	5134
2021	0	1124	5493	0	6617	0	389	0	0	902	1291	5326
2022	0	1124	5625	0	6749	0	373	0	0	926	1299	5450
2023	0	1124	5839	0	6963	0	333	0	0	953	1286	5677
2024	0	1124	5983	0	7107	0	110	0	0	981	1091	6016
2025	0	1124	6207	0	7331	0	271	0	0	1010	1281	6050
2026	0	1124	6356	0	7480	0	240	0	0	1040	1280	6200
2027	0	1124	6598	0	7722	0	210	0	0	1071	1281	6441
2028	217	1124	6769	0	8110	0	0	0	0	1104	1104	7006
NOMINAL	236	27539	116354	0	144129	0	14629	0	0	29706	44335	99794
NPV	31	8114	29137	0	37282	0	6100	0	0	11424	17524	19759

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.05

PROGRAM: Winter-Only Residential Energy Management

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	1	90	0	0	91	0	0	0	976	124	1	1101	-1010
2001	0	191	0	0	191	5	0	0	1087	264	0	1356	-1165
2002	0	304	780	0	1084	770	0	0	1203	419	4	2396	-1312
2003	0	427	882	0	1309	808	0	0	1324	589	2	2723	-1414
2004	0	562	1652	0	2214	1588	0	0	1450	775	21	3834	-1620
2005	0	697	1582	0	2279	1467	0	0	1496	961	19	3943	-1664
2006	18	821	2343	0	3182	0	0	0	1459	1132	49	2640	542
2007	0	933	2767	0	3700	508	0	0	1420	1287	51	3266	434
2008	0	1034	3380	0	4414	729	0	0	1381	1426	84	3620	794
2009	0	1124	3804	0	4928	693	0	0	1340	1550	78	3661	1267
2010	0	1124	3869	0	4993	682	0	0	692	1550	88	3012	1981
2011	0	1124	4044	0	5168	661	0	0	708	1550	81	3000	2168
2012	0	1124	4125	0	5249	638	0	0	724	1550	88	3000	2249
2013	0	1124	4303	0	5427	603	0	0	741	1550	81	2975	2452
2014	0	1124	4401	0	5525	602	0	0	758	1550	94	3004	2521
2015	0	1124	4574	0	5698	563	0	0	777	1550	84	2974	2724
2016	0	1124	4674	0	5798	543	0	0	796	1550	97	2986	2812
2017	0	1124	4862	0	5986	518	0	0	815	1550	87	2970	3016
2018	0	1124	4979	0	6103	475	0	0	836	1550	102	2963	3140
2019	0	1124	5168	0	6292	444	0	0	857	1550	89	2940	3352
2020	0	1124	5295	0	6419	406	0	0	879	1550	105	2940	3479
2021	0	1124	5493	0	6617	389	0	0	902	1550	92	2933	3684
2022	0	1124	5625	0	6749	373	0	0	926	1550	109	2958	3791
2023	0	1124	5839	0	6963	333	0	0	953	1550	95	2931	4032
2024	0	1124	5983	0	7107	110	0	0	981	1550	113	2754	4353
2025	0	1124	6207	0	7331	271	0	0	1010	1550	99	2930	4401
2026	0	1124	6356	0	7480	240	0	0	1040	1550	116	2946	4534
2027	0	1124	6598	0	7722	210	0	0	1071	1550	102	2933	4789
2028	217	1124	6769	0	8110	0	0	0	1104	1550	122	2776	5334
NOMINAL	236	27539	116354	0	144129	14629	0	0	29706	37977	2153	84465	59664
NPV	31	8114	29137	0	37282	6100	0	0	11424	10737	540	28800	8482

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.24

IV. COMMERCIAL/INDUSTRIAL CONSERVATION PROGRAMS

IV. COMMERCIAL/INDUSTRIAL CONSERVATION PROGRAMS

Florida Power Corporation's DSM Plan includes eight (8) commercial/industrial programs:

A. **Business Energy Check** - C/I energy audits

B. **Better Business** - "umbrella" program for existing facilities

C. **C/I New Construction** - "umbrella" program for new construction facilities

D. **Innovation Incentive** - custom measures

E. **Commercial Energy Management** - C/I load control: Rate Tariff GSLM-1

F. **Standby Generation** - Rate Tariff GSLM-2

G. **Interruptible Service** - Rate Tariff IS-2

H. **Curtailable Service** - Rate Tariff CS-2

Each program is described in detail in the following sections.

A. BUSINESS ENERGY CHECK PROGRAM

Program Start Date: ▸ 1995

Policies and Procedures

The Business Energy Check is FPC's energy audit program. It provides commercial and industrial (C/I) customers with an assessment of the current energy usage at their facility and information on low-cost energy efficiency measures. This program serves as the foundation for FPC's other DSM programs targeted toward existing C/I construction and, in most cases, it is a prerequisite for participation in the other C/I programs.

The Business Energy Check consists of two types of audits:

Level 1: Free Walk-Through Audit (Inspection)

Level 2: Paid Walk-Through Audit (Energy Analysis)

All commercial, industrial, and governmental retail customers of FPC are eligible to have either level conducted on any of their buildings located in FPC's service territory. There is no charge for the Level 1 inspection, while there is a nominal customer charge for the Level 2 energy analysis. When a customer requests a Business Energy Check, they will be given the option of scheduling a Level 1 inspection or a Level 2 energy analysis. The specific details on the procedures for each level of audit will be presented in the Program Participation Standards.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants [2]	Cumulative Penetration Level (%)
2000	163,576	145,483	1,000	1%
2001	166,984	148,335	2,000	1%
2002	170,356	151,155	3,000	2%
2003	173,705	153,952	4,000	3%
2004	177,016	156,710	5,000	3%
2005	180,239	159,380	6,000	4%
2006	183,373	161,963	7,000	4%
2007	186,419	164,456	8,000	5%
2008	189,416	166,901	9,000	5%
2009	192,406	169,338	10,000	6%

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*
2. *Annual Number of Program Participants is the cumulative number of audits thatare projected to be conducted.*

Savings Estimates

The total program savings were developed based on historical FPC audits and a review of C/I audit impacts. These estimates include impacts directly resulting from the standard audit recommendations, including the installation of low-cost energy efficiency measures. In addition, customer-specific savings may result from site-specific recommendations that the auditor makes at the time of the audit, but which are not included in the standard audit form. These impacts will be calculated on a case-by-case basis and added to the standard impacts. The total program savings are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	300	0.14	0.14	300,000	140	140
2001	300	0.14	0.14	600,000	280	280
2002	300	0.14	0.14	900,000	420	420
2003	300	0.14	0.14	1,200,000	560	560
2004	300	0.14	0.14	1,500,000	700	700
2005	300	0.14	0.14	1,800,000	840	840
2006	300	0.14	0.14	2,100,000	980	980
2007	300	0.14	0.14	2,400,000	1,120	1,120
2008	300	0.14	0.14	2,700,000	1,260	1,260
2009	300	0.14	0.14	3,000,000	1,400	1,400

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	315	0.15	0.15	315,270	146	148
2001	315	0.15	0.15	630,540	293	295
2002	315	0.15	0.15	945,810	439	443
2003	315	0.15	0.15	1,261,080	586	591
2004	315	0.15	0.15	1,576,350	732	739
2005	315	0.15	0.15	1,891,620	879	886
2006	315	0.15	0.15	2,206,890	1,025	1,034
2007	315	0.15	0.15	2,522,160	1,172	1,182
2008	315	0.15	0.15	2,837,430	1,318	1,330
2009	315	0.15	0.15	3,152,700	1,465	1,477

Impact Evaluation Plan

The range of possible recommendations resulting from the audit, and the inclusion of both technological and behavioral recommendations suggests the need to carefully survey participants to determine what specific actions have been undertaken due to the completed audit. Initially, the use of site-specific engineering estimates is likely to be the most cost-effective method of estimating program impacts, although the use of statistical analysis technique may also be considered, depending on the participation levels actually achieved.

B. BETTER BUSINESS PROGRAM

Program Start Date: ▸ 1995

▸ Proposed modification for 2000

Policies and Procedures

The Better Business program is the umbrella efficiency program for existing commercial and industrial customers. Better Business builds on the Business Energy Check by using the audit to initiate FPC involvement in the customer's facility (participating in Business Energy Check is a prerequisite for receiving most of the incentives). This program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to FPC and its customers. Better Business promotes energy efficient heating, ventilation, air conditioning, motors, and some building retrofit measures (in particular, roof insulation upgrade, duct leakage test and repair, and window film retrofit). FPC proposes to remove incentives for Heat Recovery Units, which have previously been offered through this program.

The general eligibility requirements are as follows:

- The participant must be a FPC commercial, industrial, or governmental customer.
- Equipment must be installed in facilities located in the FPC service territory and served by a metered FPC account.
- A Business Energy Check audit (Level 1 or 2) must be completed prior to the purchase or installation of all measures (with the exception of motors).
- The participant must be willing to allow FPC to inspect the installation of all measures and equipment prior to receiving any incentive payments.
- All equipment installations shall meet manufacturers' instructions and specifications.

Incentive levels and specific eligibility requirements for each measure promoted in this program will be presented in the Program Participation Standards and will be subject to revision based on changes in market conditions, such as baseline or code revisions, evaluation findings, or technological advances.

HVAC Equipment

The HVAC equipment component of Better Business provides customers with information on high efficiency HVAC equipment and financial incentives for the purchase of very high efficiency unitary heat pumps and air conditioners, packaged rooftop units, packaged terminal heat pumps (PTHPs), and water-cooled and air-cooled chillers. The incentive is calculated for each unit based on the kW difference between the high efficiency unit and the program-specified baseline efficiency (at ARI Standard Test Rating Conditions) and is calculated using a dollar per kW reduced incentive up to a maximum of $100/kW reduced.

Motors

The program promotes the installation of high efficiency polyphase motors through a simple incentive structure. The incentive for any given motor is calculated based on the motor size and a specified $/hp. The maximum incentive amount will be $2.00 per hp and the specific incentive amount will be a function of the motor size. To maintain cost-effectiveness, a minimum number of motors per application will be established for motors that are 25 hp and smaller. The Business Energy Check is not required to receive this incentive.

Roof Insulation Upgrade

This portion of the program encourages customers who have electric space heat to add insulation to the roof area by paying for a portion of the installed cost. The facility must have an existing roof insulation level less than R-12 to participate and must be heated by electricity in order to receive the incentive. Heat loss and heat gain calculations must show that the additional insulation would result in heating and/or cooling energy use reductions in order to be eligible for an incentive. The maximum incentive amount will be $100 per customer and the specific incentive amount that a customer is eligible to receive will be a function of the resulting insulation level.

Duct Leakage Test and Repair

This portion of the program is designed to promote energy efficiency through improved duct system sealing. Through the use of an inspection tool, such as a blower-door, duct leaks can be identified and repaired. This program component applies to HVAC equipment and systems that are no larger than 65,000 Btu/h. A customer must have electric heating (no facilities with combustion appliances are allowed to participate) and a centrally-ducted cooling system, either air conditioning or heat pump, to be eligible for this program. If a building has excess ventilation such that the building can not be pressurized, the building may not be eligible for participation. For the duct test, FPC will pay an incentive of up to a maximum of $30 for the first unit tested and $20 for each additional unit tested. For the duct repair, FPC will pay an incentive of up to a maximum of $100 per unit. The duct repair incentive amount is dependent on the type of electric heating system.

Window Film

FPC will provide customers with an incentive to install window film having a shading coefficient of 0.45 or less on existing east or west windows with shading coefficients of 0.84 or higher. The maximum incentive will be a flat amount per square-foot of window film installed. The total incentive per customer can not exceed $125. An exception to this limitation will be made for facilities with multiple guest rooms, such as hotels, motels, hospitals, and assisted-care living facilities, which may receive incentives up to a maximum of $50 per room.

Financing

FPC is also offering interest-free installment billing (over a 12-month period). As an alternative to receiving an incentive payment, customers may opt to finance up to $500 through installment billing. Installment billing allows the customer to spread the cost over 12 months at no interest. The installment billing payments will be billed monthly.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Measure Participants [2]	Cumulative Penetration Level (%)
2000	938,991	938,991	4,123	0.4%
2001	966,999	966,999	8,151	1%
2002	996,029	996,029	12,347	1%
2003	1,026,116	1,026,116	16,571	2%
2004	1,048,843	1,048,843	20,756	2%
2005	1,072,198	1,072,198	24,947	2%
2006	1,096,103	1,096,103	28,693	3%
2007	1,120,653	1,120,653	32,260	3%
2008	1,139,300	1,139,300	35,714	3%
2009	1,158,339	1,158,339	39,001	3%

1. *Total Number of Customers is the forecast of commercial floorspace (in 000s of sq.ft.).*
2. *Annual Number of Measure Participants is the cumulativefloorspace (in 000s sq.ft.) projected to participate, assuming no measure overlap.*

Savings Estimates

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

At the Meter						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	337	0.14	0.19	1,390,261	560	787
2001	302	0.13	0.16	2,464,851	1,049	1,297
2002	290	0.12	0.15	3,575,760	1,532	1,847
2003	283	0.12	0.14	4,695,076	2,019	2,400
2004	281	0.12	0.14	5,830,782	2,514	2,962
2005	281	0.12	0.14	7,013,017	3,016	3,561
2006	281	0.12	0.14	8,076,121	3,471	4,094
2007	284	0.12	0.14	9,162,477	3,932	4,647
2008	282	0.12	0.14	10,082,487	4,374	5,021
2009	288	0.12	0.14	11,228,961	4,841	5,628

At the Generator						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	354	0.14	0.20	1,460,973	586	831
2001	318	0.13	0.17	2,590,312	1,098	1,368
2002	304	0.13	0.16	3,757,766	1,603	1,949
2003	298	0.13	0.15	4,934,055	2,113	2,533
2004	295	0.13	0.15	6,127,569	2,631	3,126
2005	295	0.13	0.15	7,369,980	3,156	3,758
2006	296	0.13	0.15	8,487,196	3,632	4,321
2007	298	0.13	0.15	9,628,847	4,114	4,904
2008	297	0.13	0.15	10,595,686	4,576	5,299
2009	303	0.13	0.15	11,800,515	5,066	5,940

Per measure impacts for 2000-2009 are per 1000 sq.ft., assuming no overlap.

Per measure impacts vary from year to year because of the changing mix of measures assumed to be installed in any given year.

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach given the number and type of measures being promoted. Some measures provide large per unit impacts while others yield relatively smaller impacts. The total impact from all smaller-impact measures could potentially be less than the uncertainty around an impact estimate of just one large-impact measure. Consequently, the impact evaluation will place greater emphasis on the larger-impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts. On-site metering may also be used where feasible and cost-effective.

Cost Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	6,537	5,776	761	1.13
Participant	5,602	1,963	3,639	2.85
Total Resource Cost	6,537	2,137	4,400	3.06

PROGRAM: Better Business

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	77	55	0	132	524	0	524	-392
2001	134	54	0	188	251	0	251	-63
2002	201	58	0	259	293	0	293	-34
2003	266	53	0	319	231	0	231	88
2004	332	54	0	386	235	0	235	151
2005	402	58	0	460	277	0	277	183
2006	465	52	0	517	237	0	237	280
2007	531	54	0	585	255	0	255	330
2008	600	58	0	658	294	0	294	364
2009	677	60	0	737	316	0	316	421
2010	687	0	0	687	0	0	0	687
2011	698	0	0	698	0	0	0	698
2012	709	0	0	709	0	0	0	709
2013	720	0	0	720	0	0	0	720
2014	731	0	0	731	0	0	0	731
2015	742	0	0	742	0	0	0	742
2016	754	0	0	754	0	0	0	754
2017	765	0	0	765	0	0	0	765
2018	777	0	0	777	0	0	0	777
2019	789	0	0	789	0	0	0	789
2020	801	0	0	801	0	0	0	801
2021	814	0	0	814	0	0	0	814
2022	827	0	0	827	0	0	0	827
2023	839	0	0	839	0	0	0	839
2024	852	0	0	852	0	0	0	852
2025	866	0	0	866	0	0	0	866
2026	879	0	0	879	0	0	0	879
2027	893	0	0	893	0	0	0	893
2028	906	0	0	906	0	0	0	906
NOMINAL	18734	556	0	19290	2913	0	2913	16377
NPV	5239	363	0	5602	1963	0	1963	3639

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 2.85

PROGRAM: Better Business

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	43	37	0	0	80	524	0	0	0	26	550	-470
2001	107	59	0	0	166	251	0	0	0	26	277	-111
2002	102	87	26	0	215	293	0	0	0	28	321	-106
2003	143	112	38	0	293	231	0	0	0	26	257	36
2004	186	138	24	0	348	235	0	0	0	26	261	87
2005	1332	165	54	0	1551	277	0	0	0	27	304	1247
2006	312	189	40	0	541	237	0	0	0	26	263	278
2007	286	214	45	0	545	255	0	0	0	27	282	263
2008	1468	241	46	0	1755	294	0	0	0	28	322	1433
2009	366	268	55	0	689	316	0	0	0	28	344	345
2010	500	268	55	0	823	0	0	0	0	0	0	823
2011	374	268	59	0	701	0	0	0	0	0	0	701
2012	377	268	0	0	645	0	0	0	0	0	0	645
2013	382	268	63	0	713	0	0	0	0	0	0	713
2014	362	268	63	0	693	0	0	0	0	0	0	693
2015	391	268	67	0	726	0	0	0	0	0	0	726
2016	398	268	66	0	732	0	0	0	0	0	0	732
2017	399	268	72	0	739	0	0	0	0	0	0	739
2018	406	268	71	0	745	0	0	0	0	0	0	745
2019	407	268	76	0	751	0	0	0	0	0	0	751
2020	413	268	75	0	756	0	0	0	0	0	0	756
2021	415	268	81	0	764	0	0	0	0	0	0	764
2022	417	268	80	0	765	0	0	0	0	0	0	765
2023	425	268	86	0	779	0	0	0	0	0	0	779
2024	435	268	84	0	787	0	0	0	0	0	0	787
2025	437	268	91	0	796	0	0	0	0	0	0	796
2026	446	268	92	0	806	0	0	0	0	0	0	806
2027	448	268	97	0	813	0	0	0	0	0	0	813
2028	457	268	95	0	820	0	0	0	0	0	0	820
NOMINAL	12234	6602	1701	0	20537	2913	0	0	0	268	3181	17356
NPV	4113	1970	454	0	6537	1963	0	0	0	174	2137	4400

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 3.06

PROGRAM: Better Business

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	43	37	0	0	80	0	0	0	26	55	77	158	-78
2001	107	59	0	0	166	0	0	0	26	54	134	214	-48
2002	102	87	26	0	215	0	0	0	28	58	201	287	-72
2003	143	112	38	0	293	0	0	0	26	53	266	345	-52
2004	186	138	24	0	348	0	0	0	26	54	332	412	-64
2005	1332	165	54	0	1551	0	0	0	27	58	402	487	1064
2006	312	189	40	0	541	0	0	0	26	52	465	543	-2
2007	286	214	45	0	545	0	0	0	27	54	531	612	-67
2008	1468	241	46	0	1755	0	0	0	28	58	600	686	1069
2009	366	268	55	0	689	0	0	0	28	60	677	765	-76
2010	500	268	55	0	823	0	0	0	0	0	687	687	136
2011	374	268	59	0	701	0	0	0	0	0	698	698	3
2012	377	268	0	0	645	0	0	0	0	0	709	709	-64
2013	382	268	63	0	713	0	0	0	0	0	720	720	-7
2014	362	268	63	0	693	0	0	0	0	0	731	731	-38
2015	391	268	67	0	726	0	0	0	0	0	742	742	-16
2016	398	268	66	0	732	0	0	0	0	0	754	754	-22
2017	399	268	72	0	739	0	0	0	0	0	765	765	-26
2018	406	268	71	0	745	0	0	0	0	0	777	777	-32
2019	407	268	76	0	751	0	0	0	0	0	789	789	-38
2020	413	268	75	0	756	0	0	0	0	0	801	801	-45
2021	415	268	81	0	764	0	0	0	0	0	814	814	-50
2022	417	268	80	0	765	0	0	0	0	0	827	827	-62
2023	425	268	86	0	779	0	0	0	0	0	839	839	-60
2024	435	268	84	0	787	0	0	0	0	0	852	852	-65
2025	437	268	91	0	796	0	0	0	0	0	866	866	-70
2026	446	268	92	0	806	0	0	0	0	0	879	879	-73
2027	448	268	97	0	813	0	0	0	0	0	893	893	-80
2028	457	268	95	0	820	0	0	0	0	0	906	906	-86
NOMINAL	12234	6602	1701	0	20537	0	0	0	268	556	18734	19558	979
NPV	4113	1970	454	0	6537	0	0	0	174	363	5239	5776	761

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.13

C. COMMERCIAL/INDUSTRIAL NEW CONSTRUCTION PROGRAM

Program Start Date: ▸ 1995

▸ Proposed modification for 2000

Policies and Procedures

The primary goal of the FPC's Commercial/Industrial (C/I) New Construction program is to foster the design and construction of energy efficient buildings. The new construction program will: 1) provide education and information to the design community on all aspects of energy efficient building design; 2) require that the building design, at a minimum, surpass the state energy code; 3) provide financial incentives for specific energy efficient equipment; and 4) provide energy design awards to building design teams. The program will simultaneously target building developers/owners and the building design community and will work one-on-one with them throughout a new construction project. FPC will focus on developing relationships with the key decision-makers of commercial and industrial new construction so as to be able to get involved early in the design process. FPC proposes to remove incentives for Duct Leakage Testing and Repair, which have previously been offered through this program.

The general eligibility requirements are as follows:

- The new construction project location must be established within FPC's service territory.
- The new construction building must be served by a FPC account prior to the issuance of any incentive payment.
- The participant must be willing to allow FPC to inspect the installation of all measures and equipment prior to receiving any incentive payments.
- All equipment installations shall meet manufacturers' instructions and specifications.

Incentives will be provided for high efficiency HVAC equipment, motors, and heat recovery units. Incentive levels and specific eligibility requirements for each of the measures promoted in this program will be presented in the Program Participation Standards and will be subject to revision based on changes in market conditions, such as baseline or code revisions, evaluation findings, or technological advances.

HVAC Equipment

The HVAC equipment component of C/I New Construction provides customers with information on high efficiency HVAC equipment and financial incentives for the purchase of very high efficiency unitary heat pumps and air conditioners, packaged rooftop units, packaged terminal heat pumps (PTHPs), and water-cooled and air-cooled chillers. The incentive is calculated for

each unit based on the kW difference between the high efficiency unit and the program-specified baseline efficiency (at ARI Standard Test Rating Conditions) and is calculated using a dollar per kW reduced incentive up to $100/kW reduced.

Motors

The program promotes the installation of high efficiency polyphase motors through a simple incentive structure. The incentive for any given motor is calculated based on the motor size and a specified $/hp. The maximum incentive amount will be up to $2.00 per hp and the specific incentive amount will be a function of the motor size. To maintain cost-effectiveness, a minimum number of motors per application will be established for motors that are 25 hp and smaller.

Heat Recovery Units

The program promotes the installation of heat recovery units for water heating by providing an incentive for each unit installed. FPC will pay a maximum incentive of up to $100 per unit when installed on heat pumps or straight air units that are five tons or less.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2}	Annual Number of Measure Participants [3]	Cumulative Penetration Level (%)
2000	938,991	27,037	1,613	6%
2001	966,999	55,045	3,154	6%
2002	996,029	84,075	4,912	6%
2003	1,026,116	114,162	6,892	6%
2004	1,048,843	136,889	9,085	7%
2005	1,072,198	160,245	11,464	7%
2006	1,096,103	184,149	13,811	7%
2007	1,120,653	208,700	16,248	8%
2008	1,139,300	227,346	18,777	8%
2009	1,158,339	246,385	21,349	9%

1. *Total Number of Customers is the forecast of commercial floorspace (in 000s of sq.ft.).*
2. *Total Number of Eligible Customers is the forecast of cumulative commercialfloorspace additions after 1999 (in 000s of sq.ft.),*
3. *Annual Number of Measure Participants is the cumulativefloorspace (in 000s of sq.ft.) projected to participate, assuming no measure overlap.*

Savings Estimates

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

At the Meter						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	226	0.13	0.15	364,326	214	248
2001	216	0.13	0.14	679,977	395	455
2002	207	0.12	0.14	1,016,653	584	669
2003	199	0.11	0.13	1,374,479	782	889
2004	193	0.11	0.12	1,753,030	989	1,116
2005	188	0.11	0.12	2,150,031	1,204	1,349
2006	183	0.10	0.11	2,531,132	1,408	1,569
2007	180	0.10	0.11	2,922,778	1,618	1,793
2008	177	0.10	0.11	3,325,734	1,833	2,022
2009	175	0.10	0.11	3,736,460	2,052	2,256

At the Generator						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	237	0.14	0.16	382,870	2245	261
2001	227	0.13	0.15	714,588	413	480
2002	218	0.12	0.14	1,068,401	611	706
2003	210	0.12	0.14	1,444,440	818	938
2004	203	0.11	0.13	1,842,259	1,036	1,178
2005	197	0.11	0.12	2,259,468	1,260	1,423
2006	193	0.11	0.12	2,659,967	1,474	1,655
2007	189	0.10	0.12	3,071,547	1,693	1,892
2008	186	0.10	0.11	3,495,014	1,918	2,134
2009	184	0.10	0.11	3,926,646	2,147	2,381

Per measure impacts for 2000-2009 are per 1000 sq.ft., assuming no overlap.

Per measure impacts vary from year to year because of the changing mix of measures assumed to be installed in any given year.

Impact Evaluation Plan

The impact evaluation plan for an "umbrella" program such as this requires a varied approach, given the number and type of measures being promoted. Some measures provide large per unit impacts while others yield relatively smaller impacts. The total impact from all smaller-impact measures could potentially be less than the uncertainty around an impact estimate of just one large-impact measure. Consequently, the impact evaluation will place greater emphasis on the larger-impact measures. The method of impact evaluation may vary depending on the participation levels actually achieved for each measure. Engineering analysis and statistical billing analysis will represent the primary methods used to estimate demand and energy impacts. On-site metering may also be used, where feasible and cost-effective.

Cost Effectiveness

The economic results of the program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	1,948	1,855	93	1.05
Participant	1,727	448	1,279	3.86
Total Resource Cost	1,948	576	1,372	3.38

PROGRAM: Commercial/Industrial New Construction

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	20	9	0	29	73	0	73	-44
2001	38	7	0	45	63	0	63	-18
2002	57	8	0	65	65	0	65	0
2003	78	8	0	86	67	0	67	19
2004	100	9	0	109	69	0	69	40
2005	123	9	0	132	71	0	71	61
2006	146	9	0	155	68	0	68	87
2007	169	9	0	178	69	0	69	109
2008	194	9	0	203	70	0	70	133
2009	221	9	0	230	72	0	72	158
2010	225	0	0	225	0	0	0	225
2011	228	0	0	228	0	0	0	228
2012	232	0	0	232	0	0	0	232
2013	235	0	0	235	0	0	0	235
2014	239	0	0	239	0	0	0	239
2015	243	0	0	243	0	0	0	243
2016	246	0	0	246	0	0	0	246
2017	250	0	0	250	0	0	0	250
2018	254	0	0	254	0	0	0	254
2019	258	0	0	258	0	0	0	258
2020	262	0	0	262	0	0	0	262
2021	266	0	0	266	0	0	0	266
2022	270	0	0	270	0	0	0	270
2023	274	0	0	274	0	0	0	274
2024	279	0	0	279	0	0	0	279
2025	283	0	0	283	0	0	0	283
2026	287	0	0	287	0	0	0	287
2027	292	0	0	292	0	0	0	292
2028	296	0	0	296	0	0	0	296
NOMINAL	6065	86	0	6151	687	0	687	5464
NPV	1672	55	0	1727	448	0	448	1279

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 3.86

PROGRAM: Commercial/Industrial New Construction

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	12	12	0	0	24	73	0	0	0	20	93	-69
2001	24	22	0	0	46	63	0	0	0	19	82	-36
2002	30	32	8	0	70	65	0	0	0	19	84	-14
2003	43	43	11	0	97	67	0	0	0	20	87	10
2004	57	54	7	0	118	69	0	0	0	20	89	29
2005	191	66	18	0	275	71	0	0	0	20	91	184
2006	96	77	10	0	183	68	0	0	0	20	88	95
2007	93	88	15	0	196	69	0	0	0	20	89	107
2008	134	100	15	0	249	70	0	0	0	20	90	159
2009	121	111	19	0	251	72	0	0	0	20	92	159
2010	123	111	19	0	253	0	0	0	0	0	0	253
2011	123	111	20	0	254	0	0	0	0	0	0	254
2012	126	111	20	0	257	0	0	0	0	0	0	257
2013	126	111	21	0	258	0	0	0	0	0	0	258
2014	102	111	22	0	235	0	0	0	0	0	0	235
2015	129	111	23	0	263	0	0	0	0	0	0	263
2016	132	111	22	0	265	0	0	0	0	0	0	265
2017	132	111	24	0	267	0	0	0	0	0	0	267
2018	134	111	24	0	269	0	0	0	0	0	0	269
2019	134	111	25	0	270	0	0	0	0	0	0	270
2020	137	111	26	0	274	0	0	0	0	0	0	274
2021	137	111	27	0	275	0	0	0	0	0	0	275
2022	140	111	28	0	279	0	0	0	0	0	0	279
2023	141	111	29	0	281	0	0	0	0	0	0	281
2024	144	111	28	0	283	0	0	0	0	0	0	283
2025	144	111	31	0	286	0	0	0	0	0	0	286
2026	147	111	31	0	289	0	0	0	0	0	0	289
2027	148	111	33	0	292	0	0	0	0	0	0	292
2028	151	111	32	0	294	0	0	0	0	0	0	294
NOMINAL	3351	2714	588	0	6653	687	0	0	0	198	885	5768
NPV	991	801	156	0	1948	448	0	0	0	128	576	1372

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 3.38

PROGRAM: Commercial/Industrial New Construction

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	12	12	0	0	24	0	0	0	20	9	20	49	-25
2001	24	22	0	0	46	0	0	0	19	7	38	64	-18
2002	30	32	8	0	70	0	0	0	19	8	57	84	-14
2003	43	43	11	0	97	0	0	0	20	8	78	106	-9
2004	57	54	7	0	118	0	0	0	20	9	100	129	-11
2005	191	66	18	0	275	0	0	0	20	9	123	152	123
2006	96	77	10	0	183	0	0	0	20	9	146	175	8
2007	93	88	15	0	196	0	0	0	20	9	169	198	-2
2008	134	100	15	0	249	0	0	0	20	9	194	223	26
2009	121	111	19	0	251	0	0	0	20	9	221	250	1
2010	123	111	19	0	253	0	0	0	0	0	225	225	28
2011	123	111	20	0	254	0	0	0	0	0	228	228	26
2012	126	111	20	0	257	0	0	0	0	0	232	232	25
2013	126	111	21	0	258	0	0	0	0	0	235	235	23
2014	102	111	22	0	235	0	0	0	0	0	239	239	-4
2015	129	111	23	0	263	0	0	0	0	0	243	243	20
2016	132	111	22	0	265	0	0	0	0	0	246	246	19
2017	132	111	24	0	267	0	0	0	0	0	250	250	17
2018	134	111	24	0	269	0	0	0	0	0	254	254	15
2019	134	111	25	0	270	0	0	0	0	0	258	258	12
2020	137	111	26	0	274	0	0	0	0	0	262	262	12
2021	137	111	27	0	275	0	0	0	0	0	266	266	9
2022	140	111	28	0	279	0	0	0	0	0	270	270	9
2023	141	111	29	0	281	0	0	0	0	0	274	274	7
2024	144	111	28	0	283	0	0	0	0	0	279	279	4
2025	144	111	31	0	286	0	0	0	0	0	283	283	3
2026	147	111	31	0	289	0	0	0	0	0	287	287	2
2027	148	111	33	0	292	0	0	0	0	0	292	292	0
2028	151	111	32	0	294	0	0	0	0	0	296	296	-2
NOMINAL	3351	2714	588	0	6653	0	0	0	198	86	6065	6349	304
NPV	991	801	156	0	1948	0	0	0	128	55	1672	1855	93

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.05

D. INNOVATION INCENTIVE PROGRAM

Program Start Date: ▸ 1992

▸ Modified in 1995

Policies and Procedures

The Innovation Incentive program promotes a reduction in kW and kWh by subsidizing energy conservation projects for customers in the FPC service territory. The intent of the program is to encourage legitimate energy efficiency measures that reduce peak kW demand and/or kWh energy, but which are not addressed by other programs.

Energy efficiency opportunities are identified by FPC representatives during a Business Energy Check audit and are presented to the customer as part of the Business Energy Check report. Requirements for participation in this program are also explained to the customer at that time. If the customer chooses to implement modifications to effect energy efficiency improvements that are not addressed in other FPC energy efficiency programs, the modifications would be eligible for consideration under this program.

Representative examples of energy efficient technologies that would be considered under this program include, but are not limited to, refrigeration equipment replacements to improve efficiency, thermal energy storage systems, microwave drying systems, and inductive heating systems to replace resistance heating systems.

The program is available to all business customers in FPC's territory for projects that reduce peak demand by a minimum of 10 kW.

Program eligibility requirements to qualify for participation are as follows:

- Participant must be located in the FPC service territory and be a metered business customer.
- The customer is required to have an audit (any level) completed by FPC prior to participation in the program, except in the case of new construction projects.
- Projects must reduce or shift peak demand by a minimum of 10 kW.
- The participant must be willing to allow FPC to inspect the installations of all measures and equipment.

If the described project meets the program specifications, FPC will provide project approval and projected incentive payment amounts. Engineering designs, cost estimates, and energy savings projections must be submitted under a professional seal, when necessary. The customer may be required to monitor the project after completion to verify kW and kWh savings. Monitoring methods shall be approved by FPC. Costs for monitoring equipment should be included in the overall project cost estimate.

FPC will perform a customer-specific cost-effectiveness analysis for each project being considered under the Innovation Incentive program, using the Commission-approved cost-effectiveness tests described in Rule 25-17.008, Florida Administrative Code. To receive an incentive, each project must pass the Rate Impact Measure (RIM) and Participant tests of cost-effectiveness. The customer's incentive shall be based upon the RIM results, with the maximum allowable rebate being $150 per peak kW reduced or shifted to an off peak period.

After FPC has reviewed and approved the project, a contract will be executed between FPC and the customer, in which FPC agrees to subsidize the customer upon completion of the project.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	3,333	1	0
2001	166,984	3,398	3	0
2002	170,356	3,463	4	0
2003	173,705	3,527	6	0
2004	177,016	3,590	7	0
2005	180,239	3,651	8	0
2006	183,373	3,710	9	0
2007	186,419	3,767	10	0
2008	189,416	3,823	11	0
2009	192,406	3,879	12	0

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*
2. *Total Number of Eligible Customers is based on the total number of customers whose peak monthly demand exceeds 100 kW.*

Savings Estimates

The total program savings are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	120,047	70	70	120,047	70	70
2001	120,047	70	70	360,141	210	210
2002	120,047	70	70	480,188	280	280
2003	120,047	70	70	720,282	420	420
2004	120,047	70	70	840,329	490	490
2005	120,047	70	70	960,376	560	560
2006	120,047	70	70	1,080,423	630	630
2007	120,047	70	70	1,200,470	700	700
2008	120,047	70	70	1,320,517	770	770
2009	120,047	70	70	1,440,564	840	840

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	126,157	73	73	126,157	73	74
2001	126,157	73	73	378,472	220	222
2002	126,157	73	73	504,630	293	295
2003	126,157	73	73	456,944	439	443
2004	126,157	73	73	883,102	513	517
2005	126,157	73	73	1,009,259	586	591
2006	126,157	73	73	1,135,417	659	665
2007	126,157	73	73	1,261,574	732	739
2008	126,157	73	73	1,387,731	806	813
2009	126,157	73	73	1,513,889	879	886

Impact Evaluation Plan

To verify the estimated savings for each project, an engineering/billing analysis based on customer-specific site and usage data will be performed. Monitoring will continue until FPC has reasonable assurance that the project will remain in place and produce cost-effective energy savings for its estimated life. An incentive will not be issued to the customer until FPC is reasonably sure of the projected savings.

Cost Effectiveness

Each individual project will be analyzed for cost-effectiveness at the time of project submittal to FPC, using the Commission-approved tests of cost-effectiveness. Therefore, total program cost-effectiveness results are not shown. All projects must achieve a benefit-cost ratio of at least 1.0 ~~on the RIM and Participant tests to receive an incentive under this program.~~

E. COMMERCIAL ENERGY MANAGEMENT PROGRAM

Program Start Date:
- 1983
- Modified in 1995
- Proposed modification for 2000

Policies and Procedures

The Commercial Energy Management program is a direct load control program that reduces FPC's demand during peak or emergency conditions. FPC will have direct control of the customer's selected participating equipment. The customer will receive a monthly credit on their bill depending on the interruption schedule and the devices which are participating in the program. *(Please refer to the GSLM-1 tariff for details.)*

The program is available to FPC customers eligible for service under the GS-1, GST-1, GSD-1, or GSDT-1 rate schedules, and who elect service under the GSLM-1 rate schedule and have electric space cooling equipment suitable for interruptible operation. The program is also applicable to customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: (1) water heater(s), (2) central electric heating system(s), (3) central electric cooling system(s), and/or (4) swimming pool pump(s). Customers must be within the range of the Company's load management system in order to be eligible for the program.

Like the Residential Energy Management Program, FPC has determined that it is no longer cost-effective under the RIM test to continue adding new participants to the Commercial Energy Management program. (Pages IV-28 through IV-30 present the results of all three Commission-approved tests of cost-effectiveness.) As a result, the Company is proposing to close the program to new participants.

Domestic Commercial Energy Management

Currently, for domestically utilized equipment (i.e., the domestic (household) commercial portion of the Commercial Energy Management program), the GSLM-1 rate schedule simply references the Residential Energy Management's RSL-1 tariff in regard to control schedules and credit structure. FPC's proposed domestic commercial modifications will continue this direct link, as well as include a reference to the proposed new RSL-2 (Winter-Only) rate schedule, for all existing buildings that have an active Energy Management installation. The primary changes to the Domestic Commercial Energy Management portion of the program are as follows:

- The program will be closed to new participation, such that there will be no new domestic Commercial Energy Management installations.

- All existing domestic commercial Energy Management participants will be allowed to remain on the existing year-round program as long as they do not change their current control schedule.

- Prior to April 1, 2001, all new customer accounts associated with an active Energy Management-equipped building will be treated as an existing participant and allowed on the existing year-round program, if they maintain the same control schedules as the previous customer and do not require a service trip. If any changes in control schedule are made, then the customer will only be eligible for the proposed new Winter-Only RSL-2 rate schedule. (For details on this Winter-Only rate schedule, please see the Residential Energy Management Program, and the proposed RSL-2 rate schedule.)

- Beginning April 1, 2001, new customer accounts associated with an active Energy Management equipped building will no longer be eligible to continue the previous participant's service under the existing year-round Energy Management rate schedule. However, they will be eligible for the proposed new Winter-Only RSL-2 rate schedule.

Non-Domestic Commercial Energy Management

The non-domestic portion of the Commercial Energy Management Program is a summer-only component that offers an incentive for direct load control of electric cooling equipment. This is opposite of the direction FPC seeks to move the Residential Energy Management program, which would only allow new participants on a winter-only control schedule. FPC is, therefore, proposing that this non-domestic portion of the program be closed to new participation. All existing non-domestic commercial Energy Management participants will be allowed to remain on the existing program, as long as they do not change their current control schedule such that it requires a service trip. However, new customer accounts will not be eligible to continue a previous participant's service under this program.

Proposed changes to the GSLM-1 rate schedule (in legislative format) are presented in the Appendix to this document.

Program Participation

Given FPC's proposal to close the Commercial Energy Management Program to new participants, there are not projected to be any new participation during the 2000-2009 period.

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	145,483	0	0%
2001	166,984	148,335	0	0%
2002	170,356	151,155	0	0%
2003	173,705	153,952	0	0%
2004	177,016	156,710	0	0%
2005	180,239	159,380	0	0%
2006	183,373	161,963	0	0%
2007	186,419	164,456	0	0%
2008	189,416	166,901	0	0%
2009	192,406	169,338	0	0%

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*

Savings Estimates

The total program savings for the Winter-Only Energy Management component of the program are shown in the following tables. Since there will be no new participants or savings from the Commercial Energy Management component, this program will not be used to meet FPC's Commission-approved conservation goals.

At the Meter						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

At the Generator						
Year	Per Measure kWh Reduction	Per Measure Winter kW Reduction	Per Measure Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

Impact Evaluation Plan

Since FPC is proposing to close this program to all new participation, and allow attrition to slowly end the existing program, FPC plans to maintain only a minimal evaluation effort that will use existing resources to address the domestic (household) portion of this program. As noted in the Residential Energy Management Program, FPC is in the process of conducting a residential end-use metering study that will be used to estimate the appliance level, and duty-cycle impacts of residential load control. This same data will be applied to the domestic portion of the Commercial Energy Management program to improve program impact estimates.

Cost Effectiveness

The following economic results are for the current Commercial Energy Management Program:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	144	187	-43	0.79
Participant	56	0	56	9999
Total Resource Cost	144	131	13	1.13

PROGRAM: Commercial Energy Management

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	0	1	0	1	0	0	0	1
2001	0	1	0	1	0	0	0	1
2002	0	2	0	2	0	0	0	2
2003	0	3	0	3	0	0	0	3
2004	0	3	0	3	0	0	0	3
2005	3	4	0	7	0	0	0	7
2006	0	5	0	5	0	0	0	5
2007	0	6	0	6	0	0	0	6
2008	0	6	0	6	0	0	0	6
2009	0	7	0	7	0	0	0	7
2010	1	7	0	8	0	0	0	8
2011	1	7	0	8	0	0	0	8
2012	1	7	0	8	0	0	0	8
2013	1	7	0	8	0	0	0	8
2014	1	7	0	8	0	0	0	8
2015	1	7	0	8	0	0	0	8
2016	1	7	0	8	0	0	0	8
2017	1	7	0	8	0	0	0	8
2018	1	7	0	8	0	0	0	8
2019	1	7	0	8	0	0	0	8
2020	1	7	0	8	0	0	0	8
2021	1	7	0	8	0	0	0	8
2022	1	7	0	8	0	0	0	8
2023	1	7	0	8	0	0	0	8
2024	1	7	0	8	0	0	0	8
2025	1	7	0	8	0	0	0	8
2026	1	7	0	8	0	0	0	8
2027	1	7	0	8	0	0	0	8
2028	1	7	0	8	0	0	0	8
NOMINAL	22	171	0	193	0	0	0	193
NPV	6	50	0	56	0	0	0	56

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Commercial Energy Management

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	11	11	-11
2001	0	0	0	0	0	0	0	0	0	11	11	-11
2002	0	0	1	0	1	0	1	0	0	11	12	-11
2003	0	0	1	0	1	0	1	0	0	11	12	-11
2004	0	0	2	0	2	0	1	0	0	11	12	-10
2005	0	0	194	0	194	0	20	0	0	11	31	163
2006	2	0	2	0	4	0	0	0	0	11	11	-7
2007	0	0	2	0	2	0	1	0	0	11	12	-10
2008	0	0	4	0	4	0	1	0	0	11	12	-8
2009	0	0	4	0	4	0	1	0	0	11	12	-8
2010	0	0	4	0	4	0	1	0	0	10	11	-7
2011	0	0	5	0	5	0	1	0	0	10	11	-6
2012	0	0	3	0	3	0	1	0	0	10	11	-8
2013	0	0	3	0	3	0	0	0	0	10	10	-7
2014	0	0	3	0	3	0	1	0	0	10	11	-8
2015	0	0	3	0	3	0	1	0	0	10	11	-8
2016	0	0	3	0	3	0	1	0	0	10	11	-8
2017	0	0	4	0	4	0	0	0	0	10	10	-6
2018	0	0	4	0	4	0	0	0	0	10	10	-6
2019	0	0	4	0	4	0	1	0	0	10	11	-7
2020	0	0	4	0	4	0	0	0	0	10	10	-6
2021	0	0	4	0	4	0	1	0	0	10	11	-7
2022	0	0	4	0	4	0	0	0	0	10	10	-6
2023	0	0	4	0	4	0	0	0	0	10	10	-6
2024	0	0	4	0	4	0	0	0	0	10	10	-6
2025	0	0	4	0	4	0	0	0	0	10	10	-6
2026	0	0	5	0	5	0	0	0	0	10	10	-5
2027	0	0	5	0	5	0	0	0	0	10	10	-5
2028	0	0	5	0	5	0	0	0	0	10	10	-5
NOMINAL	2	0	285	0	287	0	34	0	0	300	334	-47
NPV	1	0	143	0	144	0	18	0	0	113	131	13

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 1.13

PROGRAM: Commercial Energy Management

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	11	1	0	12	-12
2001	0	0	0	0	0	0	0	0	11	1	0	12	-12
2002	0	0	1	0	1	1	0	0	11	2	0	14	-13
2003	0	0	1	0	1	1	0	0	11	3	0	15	-14
2004	0	0	2	0	2	1	0	0	11	3	0	15	-13
2005	0	0	194	0	194	20	0	0	11	4	3	38	156
2006	2	0	2	0	4	0	0	0	11	5	0	16	-12
2007	0	0	2	0	2	1	0	0	11	6	0	18	-16
2008	0	0	4	0	4	1	0	0	11	6	0	18	-14
2009	0	0	4	0	4	1	0	0	11	7	0	19	-15
2010	0	0	4	0	4	1	0	0	10	7	1	19	-15
2011	0	0	5	0	5	1	0	0	10	7	1	19	-14
2012	0	0	3	0	3	1	0	0	10	7	1	19	-16
2013	0	0	3	0	3	0	0	0	10	7	1	18	-15
2014	0	0	3	0	3	1	0	0	10	7	1	19	-16
2015	0	0	3	0	3	1	0	0	10	7	1	19	-16
2016	0	0	3	0	3	1	0	0	10	7	1	19	-16
2017	0	0	4	0	4	0	0	0	10	7	1	18	-14
2018	0	0	4	0	4	0	0	0	10	7	1	18	-14
2019	0	0	4	0	4	1	0	0	10	7	1	19	-15
2020	0	0	4	0	4	0	0	0	10	7	1	18	-14
2021	0	0	4	0	4	1	0	0	10	7	1	19	-15
2022	0	0	4	0	4	0	0	0	10	7	1	18	-14
2023	0	0	4	0	4	0	0	0	10	7	1	18	-14
2024	0	0	4	0	4	0	0	0	10	7	1	18	-14
2025	0	0	4	0	4	0	0	0	10	7	1	18	-14
2026	0	0	5	0	5	0	0	0	10	7	1	18	-13
2027	0	0	5	0	5	0	0	0	10	7	1	18	-13
2028	0	0	5	0	5	0	0	0	10	7	1	18	-13
NOMINAL	2	0	285	0	287	34	0	0	300	171	22	527	-240
NPV	1	0	143	0	144	18	0	0	113	50	6	187	-43

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 0.79

F. STANDBY GENERATION PROGRAM

Program Start Date: ▸ 1993
▸ Modified in 1995

Policies and Procedures

The Standby Generation program is a demand control program that will reduce FPC's demand based upon the indirect control of customer equipment. The program is a voluntary program available to all commercial and industrial customers who have on-site generation capability and are willing to reduce their FPC demand when FPC deems it necessary. The program is offered through the General Service Load Management-2 (GSLM-2) rate schedule.

FPC will have no direct control of the customer's equipment, but will rely upon the customer to initiate the generation upon being notified by FPC and continue running it until FPC notifies the customer that the generation is no longer needed. FPC does not restrict other use of the equipment by the customer.

Standby Generation program participants will receive a monthly credit on their energy bill according to the demonstrated ability of the customer to reduce demand at FPC's request. The credit will be based upon the load served by the customer's generator, which would have been served by FPC if the Standby Generation program were not in operation. By compensating the customer for the use of their on-site generation, FPC can impact the commercial and industrial market while minimizing rate impacts.

The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the GS-1, GST-1, GSD-1 or GSDT-1 Rate Schedules.
- Customer must have standby generation that will allow facility demand reduction at the request of FPC.
- Customer's Standby Generation Capacity calculation must be at least 50 kW.
- Customer must be within the range of FPC's load management system.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers [2]	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	538	5	1%
2001	166,984	549	10	2%
2002	170,356	559	15	3%
2003	173,705	570	20	4%
2004	177,016	580	25	4%
2005	180,239	590	30	5%
2006	183,373	599	35	6%
2007	186,419	608	40	7%
2008	189,416	618	45	7%
2009	192,406	627	50	8%

1. *Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.*
2. *Total Number of Eligible Customers is based on the total number of customers having on-site generation.*

Savings Estimates

The kW and kWh savings estimates for this program were determined from historical data and are presented below.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	5,910	600	600	29,550	3,000	3,000
2001	5,910	600	600	59,100	6,000	6,000
2002	5,910	600	600	88,650	9,000	9,000
2003	5,910	600	600	118,200	12,000	12,000
2004	5,910	600	600	147,750	15,000	15,000
2005	5,910	600	600	177,300	18,000	18,000
2006	5,910	600	600	206,850	21,000	21,000
2007	5,910	600	600	236,400	24,000	24,000
2008	5,910	600	600	265,950	27,000	27,000
2009	5,910	600	600	295,500	30,000	30,000

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	6,211	628	633	31,054	3,139	3,166
2001	6,211	628	633	62,108	6,278	6,332
2002	6,211	628	633	93,162	9,418	9,498
2003	6,211	628	633	124,216	12,557	12,664
2004	6,211	628	633	155,270	15,696	15,830
2005	6,211	628	633	186,325	18,835	18,995
2006	6,211	628	633	217,379	21,974	22,161
2007	6,211	628	633	248,433	25,114	25,327
2008	6,211	628	633	279,487	28,253	28,493
2009	6,211	628	633	310,541	31,392	31,659

Impact Evaluation Plan

FPC uses on-site metering to measure the generation capability of each Standby Generation program participant to reduce load at the time they join the program. The customer and a FPC representative will observe the metering tests to determine the load that the standby generator carries. This system testing will also determine the initial readings that will be recorded in order to determine the incentive that the customer will receive on their bill each month. Engineering analysis is used to estimate on-going program savings for each participant based upon monitoring their generator usage.

Cost Effectiveness

The economic results of the program are as follows.

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	7,226	6,323	903	1.14
Participant	5,598	0	5,598	9999
Total Resource Cost	7,226	725	6,501	9.97

PROGRAM: Standby Generation

PARTICIPANT TEST

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	2	75	0	77	0	0	0	77
2001	5	149	0	154	0	0	0	154
2002	6	224	0	230	0	0	0	230
2003	5	298	0	303	0	0	0	303
2004	13	373	0	386	0	0	0	386
2005	12	447	0	459	0	0	0	459
2006	14	522	0	536	0	0	0	536
2007	18	596	0	614	0	0	0	614
2008	15	671	0	686	0	0	0	686
2009	30	745	0	775	0	0	0	775
2010	37	745	0	782	0	0	0	782
2011	29	745	0	774	0	0	0	774
2012	37	745	0	782	0	0	0	782
2013	30	745	0	775	0	0	0	775
2014	36	745	0	781	0	0	0	781
2015	28	745	0	773	0	0	0	773
2016	32	745	0	777	0	0	0	777
2017	27	745	0	772	0	0	0	772
2018	35	745	0	780	0	0	0	780
2019	28	745	0	773	0	0	0	773
2020	31	745	0	776	0	0	0	776
2021	29	745	0	774	0	0	0	774
2022	32	745	0	777	0	0	0	777
2023	30	745	0	775	0	0	0	775
2024	33	745	0	778	0	0	0	778
2025	30	745	0	775	0	0	0	775
2026	34	745	0	779	0	0	0	779
2027	31	745	0	776	0	0	0	776
2028	35	745	0	780	0	0	0	780
NOMINAL	724	18255	0	18979	0	0	0	18979
NPV	199	5400	0	5598	0	0	0	5598

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Standby Generation

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	25	0	0	27	0	0	0	0	10	10	17
2001	6	50	0	0	56	0	0	0	0	10	10	46
2002	0	75	142	0	217	0	116	0	0	10	126	91
2003	0	100	149	0	249	0	136	0	0	10	146	103
2004	0	125	273	0	398	0	158	0	0	10	168	230
2005	650	150	446	0	1246	0	0	0	0	10	10	1236
2006	261	175	322	0	758	0	0	0	0	10	10	748
2007	0	200	293	0	493	0	51	0	0	10	61	432
2008	0	225	553	0	778	0	95	0	0	10	105	673
2009	0	250	635	0	885	0	81	0	0	10	91	794
2010	0	250	653	0	903	0	80	0	0	10	90	813
2011	0	250	675	0	925	0	77	0	0	10	87	838
2012	0	250	695	0	945	0	70	0	0	10	80	865
2013	0	250	718	0	968	0	69	0	0	10	79	889
2014	0	250	739	0	989	0	65	0	0	10	75	914
2015	0	250	764	0	1014	0	64	0	0	10	74	940
2016	0	250	785	0	1035	0	59	0	0	10	69	966
2017	0	250	812	0	1062	0	57	0	0	10	67	995
2018	0	250	835	0	1085	0	46	0	0	10	56	1029
2019	0	250	863	0	1113	0	45	0	0	10	55	1058
2020	0	250	887	0	1137	0	39	0	0	10	49	1088
2021	0	250	917	0	1167	0	35	0	0	10	45	1122
2022	0	250	943	0	1193	0	33	0	0	10	43	1150
2023	0	250	975	0	1225	0	25	0	0	10	35	1190
2024	0	250	1002	0	1252	0	19	0	0	10	29	1223
2025	0	250	1036	0	1286	0	15	0	0	10	25	1261
2026	0	250	1066	0	1316	0	12	0	0	10	22	1294
2027	0	250	1102	0	1352	0	4	0	0	10	14	1338
2028	4	250	1132	0	1386	0	0	0	0	10	10	1376
NOMINAL	923	6125	19412	0	26460	0	1451	0	0	290	1741	24719
NPV	552	1811	4863	0	7226	0	619	0	0	106	725	6501

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 9.97

PROGRAM: Standby Generation

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	2	25	0	0	27	0	0	0	10	75	2	87	-60
2001	6	50	0	0	56	0	0	0	10	149	5	164	-108
2002	0	75	142	0	217	116	0	0	10	224	6	356	-139
2003	0	100	149	0	249	136	0	0	10	298	5	449	-200
2004	0	125	273	0	398	158	0	0	10	373	13	554	-156
2005	650	150	446	0	1246	0	0	0	10	447	12	469	777
2006	261	175	322	0	758	0	0	0	10	522	14	546	212
2007	0	200	293	0	493	51	0	0	10	596	18	675	-182
2008	0	225	553	0	778	95	0	0	10	671	15	791	-13
2009	0	250	635	0	885	81	0	0	10	745	30	866	19
2010	0	250	653	0	903	80	0	0	10	745	37	872	31
2011	0	250	675	0	925	77	0	0	10	745	29	861	64
2012	0	250	695	0	945	70	0	0	10	745	37	862	83
2013	0	250	718	0	968	69	0	0	10	745	30	854	114
2014	0	250	739	0	989	65	0	0	10	745	36	856	133
2015	0	250	764	0	1014	64	0	0	10	745	28	847	167
2016	0	250	785	0	1035	59	0	0	10	745	32	846	189
2017	0	250	812	0	1062	57	0	0	10	745	27	839	223
2018	0	250	835	0	1085	46	0	0	10	745	35	836	249
2019	0	250	863	0	1113	45	0	0	10	745	28	828	285
2020	0	250	887	0	1137	39	0	0	10	745	31	825	312
2021	0	250	917	0	1167	35	0	0	10	745	29	819	348
2022	0	250	943	0	1193	33	0	0	10	745	32	820	373
2023	0	250	975	0	1225	25	0	0	10	745	30	810	415
2024	0	250	1002	0	1252	19	0	0	10	745	33	807	445
2025	0	250	1036	0	1286	15	0	0	10	745	30	800	486
2026	0	250	1066	0	1316	12	0	0	10	745	34	801	515
2027	0	250	1102	0	1352	4	0	0	10	745	31	790	562
2028	4	250	1132	0	1386	0	0	0	10	745	35	790	596
NOMINAL	923	6125	19412	0	26460	1451	0	0	290	18255	724	20720	5740
NPV	552	1811	4863	0	7226	619	0	0	106	5400	199	6323	903

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.14

G. INTERRUPTIBLE SERVICE PROGRAM

Program Start Date: ▸ 1996 for the IS-2 and IST-2 rate schedules.

Policies and Procedures

The Interruptible Service (IS) program is a direct load control program that reduces FPC's demand at times of capacity shortage during peak or emergency conditions. The program is available throughout the entire territory served by FPC to any non-residential customer who is willing to have their power interrupted. The program is currently offered through the Interruptible General Service (IS-2) and Interruptible General Service Time of Use (IST-2) rate schedules. The IS-1 and IST-1 rate schedules were closed to new customers in 1996, but remain active for those customers that were grandfathered onto the rate.

FPC will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. If purchased power is available at the time of potential interruption, customers who choose not to have their load interrupted will be assessed at the price of that purchased power supplied. Customers participating in the Interruptible Service program will receive a monthly interruptible demand credit based on their billing demand and billing load factor. The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the IS-2 or IST-2 Rate Schedules.
- Average billing demand must be 500 kW or more.
- Available at primary, transmission, and secondary service voltages.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	869	0	0
2001	166,984	891	0	0
2002	170,356	913	1	0
2003	173,705	936	1	0
2004	177,016	959	1	0
2005	180,239	983	1	0
2006	183,373	1,008	2	0
2007	186,419	1,033	2	0
2008	189,416	1,059	2	0
2009	192,406	1,086	2	0

1. Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.

Savings Estimates

Savings estimate for the Interruptible Service program are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	4,250	500	440	0	0	0
2001	4,250	500	440	0	0	0
2002	4,250	500	440	4,250	500	440
2003	4,250	500	440	4,250	500	440
2004	4,250	500	440	4,250	500	440
2005	4,250	500	440	4,250	500	440
2006	4,250	500	440	8,500	1000	880
2007	4,250	500	440	8,500	1000	880
2008	4,250	500	440	8,500	1000	880
2009	4,250	500	440	8,500	1000	880

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	4,466	523	464	0	0	0
2001	4,466	523	464	0	0	0
2002	4,466	523	464	4,466	523	464
2003	4,466	523	464	4,466	523	464
2004	4,466	523	464	4,466	523	464
2005	4,466	523	464	4,466	523	464
2006	4,466	523	464	8,933	1,046	929
2007	4,466	523	464	8,933	1,046	929
2008	4,466	523	464	8,933	1,046	929
2009	4,466	523	464	8,933	1,046	929

Impact Evaluation Plan

Program impacts are evaluated through on-site interval metering data of all Interruptible Service customers.

Cost-Effectiveness

The cost-effectiveness results of the Interruptible Service program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	272	270	2	1.00
Participant	190	0	190	9999
Total Resource Cost	272	80	192	3.39

PROGRAM: Interruptible Service

PARTICIPANT TEST

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0
2002	0	10	0	10	0	0	0	10
2003	0	10	0	10	0	0	0	10
2004	0	10	0	10	0	0	0	10
2005	1	10	0	11	0	0	0	11
2006	4	21	0	25	0	0	0	25
2007	7	21	0	28	0	0	0	28
2008	5	21	0	26	0	0	0	26
2009	5	21	0	26	0	0	0	26
2010	6	21	0	27	0	0	0	27
2011	6	21	0	27	0	0	0	27
2012	6	21	0	27	0	0	0	27
2013	6	21	0	27	0	0	0	27
2014	6	21	0	27	0	0	0	27
2015	6	21	0	27	0	0	0	27
2016	6	21	0	27	0	0	0	27
2017	6	21	0	27	0	0	0	27
2018	6	21	0	27	0	0	0	27
2019	6	21	0	27	0	0	0	27
2020	6	21	0	27	0	0	0	27
2021	6	21	0	27	0	0	0	27
2022	7	21	0	28	0	0	0	28
2023	7	21	0	28	0	0	0	28
2024	7	21	0	28	0	0	0	28
2025	7	21	0	28	0	0	0	28
2026	7	21	0	28	0	0	0	28
2027	7	21	0	28	0	0	0	28
2028	7	21	0	28	0	0	0	28
NOMINAL	143	523	0	666	0	0	0	666
NPV	36	154	0	190	0	0	0	190

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Interruptible Service

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	5	5	-5
2001	0	0	0	0	0	0	0	0	0	5	5	-5
2002	0	4	8	0	12	0	6	0	0	6	12	0
2003	0	4	6	0	10	0	5	0	0	5	10	0
2004	0	4	8	0	12	0	8	0	0	5	13	-1
2005	56	4	35	0	95	0	0	0	0	5	5	90
2006	0	9	14	0	23	0	1	0	0	6	7	16
2007	0	9	11	0	20	0	1	0	0	5	6	14
2008	0	9	19	0	28	0	3	0	0	5	8	20
2009	0	9	20	0	29	0	3	0	0	5	8	21
2010	0	9	20	0	29	0	3	0	0	5	8	21
2011	0	9	21	0	30	0	3	0	0	5	8	22
2012	0	9	22	0	31	0	2	0	0	5	7	24
2013	0	9	22	0	31	0	2	0	0	5	7	24
2014	0	9	23	0	32	0	2	0	0	5	7	25
2015	0	9	24	0	33	0	2	0	0	5	7	26
2016	0	9	24	0	33	0	2	0	0	5	7	26
2017	0	9	25	0	34	0	2	0	0	5	7	27
2018	0	9	26	0	35	0	2	0	0	5	7	28
2019	0	9	27	0	36	0	2	0	0	5	7	29
2020	0	9	28	0	37	0	1	0	0	5	6	31
2021	0	9	29	0	38	0	1	0	0	5	6	32
2022	0	9	30	0	39	0	1	0	0	5	6	33
2023	0	9	30	0	39	0	1	0	0	5	6	33
2024	0	9	31	0	40	0	1	0	0	5	6	34
2025	0	9	32	0	41	0	0	0	0	5	5	36
2026	0	9	34	0	43	0	0	0	0	5	5	38
2027	0	9	34	0	43	0	0	0	0	5	5	38
2028	0	9	35	0	44	0	0	0	0	5	5	39
NOMINAL	56	223	638	0	917	0	54	0	0	147	201	716
NPV	34	66	172	0	272	0	25	0	0	55	80	192

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 3.39

PROGRAM: Interruptible Service

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	5	0	0	5	-5
2001	0	0	0	0	0	0	0	0	5	0	0	5	-5
2002	0	4	8	0	12	6	0	0	6	10	0	22	-10
2003	0	4	6	0	10	5	0	0	5	10	0	20	-10
2004	0	4	8	0	12	8	0	0	5	10	0	23	-11
2005	56	4	35	0	95	0	0	0	5	10	1	16	79
2006	0	9	14	0	23	1	0	0	6	21	4	32	-9
2007	0	9	11	0	20	1	0	0	5	21	7	34	-14
2008	0	9	19	0	28	3	0	0	5	21	5	34	-6
2009	0	9	20	0	29	3	0	0	5	21	5	34	-5
2010	0	9	20	0	29	3	0	0	5	21	6	35	-6
2011	0	9	21	0	30	3	0	0	5	21	6	35	-5
2012	0	9	22	0	31	2	0	0	5	21	6	34	-3
2013	0	9	22	0	31	2	0	0	5	21	6	34	-3
2014	0	9	23	0	32	2	0	0	5	21	6	34	-2
2015	0	9	24	0	33	2	0	0	5	21	6	34	-1
2016	0	9	24	0	33	2	0	0	5	21	6	34	-1
2017	0	9	25	0	34	2	0	0	5	21	6	34	0
2018	0	9	26	0	35	2	0	0	5	21	6	34	1
2019	0	9	27	0	36	2	0	0	5	21	6	34	2
2020	0	9	28	0	37	1	0	0	5	21	6	33	4
2021	0	9	29	0	38	1	0	0	5	21	6	33	5
2022	0	9	30	0	39	1	0	0	5	21	7	34	5
2023	0	9	30	0	39	1	0	0	5	21	7	34	5
2024	0	9	31	0	40	1	0	0	5	21	7	34	6
2025	0	9	32	0	41	0	0	0	5	21	7	33	8
2026	0	9	34	0	43	0	0	0	5	21	7	33	10
2027	0	9	34	0	43	0	0	0	5	21	7	33	10
2028	0	9	35	0	44	0	0	0	5	21	7	33	11
NOMINAL	56	223	638	0	917	54	0	0	147	523	143	867	50
NPV	34	66	172	0	272	25	0	0	55	154	36	270	2

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.00

H. CURTAILABLE SERVICE PROGRAM

Program Start Date: ▸ 1996 for the CS-2 and CST-2 rate schedules.

Policies and Procedures

The Curtailable Service (CS) program is a direct load control program that will reduce FPC's demand at times of capacity shortage during peak or emergency conditions. The program is available throughout the entire territory served by FPC to any non-residential customer who agrees to curtail 25% of their average monthly billing demand. The program is currently offered through the Curtailable General Service (CS-2) and Curtailable General Service Time of Use (CST-2) rate schedules. The CS-1 and CST-1 rate schedules were closed to new customers in 1996, but remain active for those customers that were grandfathered onto the rate.

FPC will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. If purchased power is available at the time of potential curtailment, customers who choose not to reduce their load will be assessed at the price of that purchased power. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit based on their curtailable demand and billing load factor. The general program eligibility requirements to qualify for participation are as follows:

- Customer must be eligible for service under the CS-2 or CST-2 Rate Schedules.
- Average billing demand must be 500 kW or more.
- Available at primary, transmission, and secondary service voltages.

Program Participation

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

Year	Total Number of Customers [1]	Total Number of Eligible Customers	Annual Number of Program Participants	Cumulative Penetration Level (%)
2000	163,576	869	0	0
2001	166,984	891	0	0
2002	170,356	913	0	0
2003	173,705	936	0	0
2004	177,016	959	0	0
2005	180,239	983	0	0
2006	183,373	1,008	0	0
2007	186,419	1,033	0	0
2008	189,416	1,059	0	0
2009	192,406	1,086	0	0

1. Total Number of Customers is the forecast of all commercial and industrial customers, from the June 1999 forecast.

Savings Estimates

Savings estimate for the Curtailable Service program are shown in the following tables.

At the Meter						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

At the Generator						
Year	Per Customer kWh Reduction	Per Customer Winter kW Reduction	Per Customer Summer kW Reduction	Total Annual kWh Reduction	Total Annual Winter kW Reduction	Total Annual Summer kW Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

Impact Evaluation Plan

Program impacts are evaluated through on-site interval metering data of all Curtailable Service customers.

Cost-Effectiveness

Even though FPC is projecting no new participants for the Curtailable Service Program, in order to evaluate the program for cost-effectiveness a minimal level of participation (one participant every other year) was assumed. The cost-effectiveness results of the Curtailable Service program are as follows:

Cost-Effectiveness Test	NPV Benefits (000$)	NPV Costs (000$)	NPV Net Benefits (000$)	B/C Ratio
Rate Impact Measure	634	479	154	1.32
Participant	251	0	251	9999
Total Resource Cost	634	228	405	2.77

PROGRAM: Curtailable Service

PARTICIPANT TEST

YEAR	BENEFITS (1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	COSTS (5) PARTICIPANT'S COSTS $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
1999	0	0	0	0	0	0	0	0
2000	0	4	0	4	0	0	0	4
2001	0	4	0	4	0	0	0	4
2002	0	9	0	9	0	0	0	9
2003	0	9	0	9	0	0	0	9
2004	1	13	0	14	0	0	0	14
2005	1	13	0	14	0	0	0	14
2006	7	17	0	24	0	0	0	24
2007	14	17	0	31	0	0	0	31
2008	23	22	0	45	0	0	0	45
2009	23	22	0	45	0	0	0	45
2010	24	22	0	46	0	0	0	46
2011	13	22	0	35	0	0	0	35
2012	13	22	0	35	0	0	0	35
2013	13	22	0	35	0	0	0	35
2014	14	22	0	36	0	0	0	36
2015	14	22	0	36	0	0	0	36
2016	14	22	0	36	0	0	0	36
2017	14	22	0	36	0	0	0	36
2018	15	22	0	37	0	0	0	37
2019	15	22	0	37	0	0	0	37
2020	7	22	0	29	0	0	0	29
2021	7	22	0	29	0	0	0	29
2022	7	22	0	29	0	0	0	29
2023	7	22	0	29	0	0	0	29
2024	8	22	0	30	0	0	0	30
2025	7	22	0	29	0	0	0	29
2026	8	22	0	30	0	0	0	30
2027	7	22	0	29	0	0	0	29
2028	8	22	0	30	0	0	0	30
NOMINAL	284	548	0	832	0	0	0	832
NPV	86	164	0	250	0	0	0	250

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 4/COL. 7): 9999.00

PROGRAM: Curtailable Service

TOTAL RESOURCE COST TEST

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COSTS $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	4	0	0	4	0	0	0	0	15	15	-11
2001	0	4	0	0	4	0	0	0	0	15	15	-11
2002	0	8	18	0	26	0	15	0	0	15	30	-4
2003	0	8	14	0	22	0	13	0	0	15	28	-6
2004	0	12	32	0	44	0	21	0	0	15	36	8
2005	0	12	26	0	38	0	2	0	0	15	17	21
2006	29	16	35	0	80	0	0	0	0	15	15	65
2007	0	16	28	0	44	0	4	0	0	15	19	25
2008	0	19	60	0	79	0	11	0	0	15	26	53
2009	0	19	62	0	81	0	8	0	0	15	23	58
2010	0	19	64	0	83	0	9	0	0	15	24	59
2011	0	19	65	0	84	0	8	0	0	15	23	61
2012	0	19	67	0	86	0	7	0	0	15	22	64
2013	0	19	69	0	88	0	7	0	0	15	22	66
2014	0	19	71	0	90	0	7	0	0	15	22	68
2015	0	19	74	0	93	0	6	0	0	15	21	72
2016	0	19	76	0	95	0	6	0	0	15	21	74
2017	0	19	78	0	97	0	5	0	0	15	20	77
2018	0	19	81	0	100	0	5	0	0	15	20	80
2019	0	19	84	0	103	0	4	0	0	15	19	84
2020	0	19	84	0	103	0	4	0	0	15	19	84
2021	0	19	87	0	106	0	3	0	0	15	18	88
2022	0	19	90	0	109	0	4	0	0	15	19	90
2023	0	19	92	0	111	0	3	0	0	15	18	93
2024	0	19	95	0	114	0	2	0	0	15	17	97
2025	0	19	98	0	117	0	2	0	0	15	17	100
2026	0	19	101	0	120	0	1	0	0	15	16	104
2027	0	19	104	0	123	0	1	0	0	15	16	107
2028	0	19	108	0	127	0	0	0	0	15	15	112
NOMINAL	29	479	1863	0	2371	0	158	0	0	435	593	1778
NPV	16	147	470	0	633	0	70	0	0	160	230	403

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 11): 2.77

PROGRAM: Curtailable Service

RATE IMPACT MEASURE TEST

	BENEFITS					COSTS							
YEAR	(1) FUEL & O & M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) TOTAL BENEFITS $(000)	(6) FUEL & O & M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) TOTAL COSTS $(000)	(13) NET BENEFITS TO ALL CUSTOMERS $(000)
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	4	0	0	4	0	0	0	15	4	0	19	-15
2001	0	4	0	0	4	0	0	0	15	4	0	19	-15
2002	0	8	18	0	26	15	0	0	15	9	0	39	-13
2003	0	8	14	0	22	13	0	0	15	9	0	37	-15
2004	0	12	32	0	44	21	0	0	15	13	1	50	-6
2005	0	12	26	0	38	2	0	0	15	13	1	31	7
2006	29	16	35	0	80	0	0	0	15	17	7	39	41
2007	0	16	28	0	44	4	0	0	15	17	14	50	-6
2008	0	19	60	0	79	11	0	0	15	22	23	71	8
2009	0	19	62	0	81	8	0	0	15	22	23	68	13
2010	0	19	64	0	83	9	0	0	15	22	24	70	13
2011	0	19	65	0	84	8	0	0	15	22	13	58	26
2012	0	19	67	0	86	7	0	0	15	22	13	57	29
2013	0	19	69	0	88	7	0	0	15	22	13	57	31
2014	0	19	71	0	90	7	0	0	15	22	14	58	32
2015	0	19	74	0	93	6	0	0	15	22	14	57	36
2016	0	19	76	0	95	6	0	0	15	22	14	57	38
2017	0	19	78	0	97	5	0	0	15	22	14	56	41
2018	0	19	81	0	100	5	0	0	15	22	15	57	43
2019	0	19	84	0	103	4	0	0	15	22	15	56	47
2020	0	19	84	0	103	4	0	0	15	22	7	48	55
2021	0	19	87	0	106	3	0	0	15	22	7	47	59
2022	0	19	90	0	109	4	0	0	15	22	7	48	61
2023	0	19	92	0	111	3	0	0	15	22	7	47	64
2024	0	19	95	0	114	2	0	0	15	22	8	47	67
2025	0	19	98	0	117	2	0	0	15	22	7	46	71
2026	0	19	101	0	120	1	0	0	15	22	8	46	74
2027	0	19	104	0	123	1	0	0	15	22	7	45	78
2028	0	19	108	0	127	0	0	0	15	22	8	45	82
NOMINAL	29	479	1863	0	2371	158	0	0	435	548	284	1425	946
NPV	16	147	470	0	633	70	0	0	160	164	86	480	153

UTILITY DISCOUNT RATE: 8.53%
BENEFIT/COST RATIO (COL. 5/COL. 12): 1.32

V. TECHNOLOGY DEVELOPMENT PROGRAM

V. TECHNOLOGY DEVELOPMENT PROGRAM

Program Start Date: • 1995

Policies and Procedures

The purpose of this program is to establish a system for meeting the goals in Section 366.82(2), Florida Statutes, and Rule 25-17, Florida Administrative Code. Specifically, the following is stated in Rule 25-17.001, {5}(f): "Aggressively pursue research, development, and demonstration projects jointly with others as well as individual projects in individual service areas."

Florida Power Corporation will undertake certain development and demonstration projects which have promise to become cost-effective demand and energy efficiency programs. In general, each research and development project that is proposed and investigated will proceed as follows:

1. Project concept or idea development
2. Project research and design, including estimated costs and benefits
3. Conduct field test or pilot program
4. Evaluation of field test or pilot program, including cost-effectiveness
5. Acceptance or rejection of project for continuation as a program
6. If accepted in Item #5 above, application to the FPSC for approval to implement the program

Eligible customers will be determined during the project research and design phase, which will be dependent on the type of project being proposed and investigated. However, it is anticipated that only retail customers will be involved.

Each project that is proposed and investigated will have to meet one or more of the goals identified in Section 366.82(2), Florida Statutes, and Rule 25-17, Florida Administrative Code. If not, it will not proceed beyond the project concept or idea phase in Item #1 above.

Program Participation

In most cases, each demand reduction and energy efficiency project that is proposed and investigated under this program will require field testing with actual customers. These projects will offer services or products to eligible customers, after being defined in the project research and design phase, on a voluntary basis.

Examples of potential projects that may be funded under this program include demand reduction energy efficiency techniques, market transformation initiatives, indoor air quality measures, thermal energy storage technologies, and innovative metering approaches. All costs including incentives and rebates that are offered will be included as part of the pre-approved project expenditures under this program.

At the discretion of the Company, expenditures up to $800,000 annually may be made and recovered through the conservation cost recovery clause for all energy efficiency and conservation projects that are proposed and investigated. If any single project's expenditures exceed $100,000, a status report will be filed as a component of the Conservation Cost Recovery Projection and True-Up filings. The status report will identify each project under investigation with disbursements exceeding $100,000, the scope and purpose of the project, its development schedule identifying accomplishments and projections, and the project's actual and proposed expenditures for FPSC staff review. If any project (or combination of projects) expenditures are projected to exceed the $800,000 annual limit available under this program and are sufficiently worthy of special consideration, the Company will apply to the FPSC staff for approval to proceed.

Finally, the Company will account for and maintain records of all expenses for each project in accordance with Rule 25-17.015, Florida Administrative Code.

Savings Estimates

This program makes it possible to obtain and use actual data from field tests, instead of relying heavily on engineering assumptions, model results, estimates, and so forth. Benefit and cost figures derived from these projects will be more reliable and projectable, allowing better assessment of future demand reduction and energy efficiency programs submitted to the FPSC for approval.

A second benefit resulting from this development program is that the procedure uncovers benefits, costs, and disadvantages that may be overlooked by an engineering estimate or evaluation. During field tests, not only planned elements, but also unplanned elements are encountered. Actual experience on a small scale is obtained. This should facilitate the decision-making process and improve the success rate of approved programs.

Consequently, program savings were not estimated during the planning stage and are not included in the DSM Plan totals. Any impacts obtained by this program will be calculated for each individual project and will be reported to the FPSC to be counted toward achieving FPC's conservation goals.

Impact Evaluation Plan

The methodology for monitoring and evaluating a project that is submitted to the FPSC for approval as a program shall be determined during the project research and design phase and shall be refined during the field test or pilot program phase. Since projects will normally include a

field test or pilot program, the data will be actual rather than estimated. In the event a project does not involve a field test or pilot program, the estimated or modeled savings will be fully documented with the methodology used.

Cost-Effectiveness

The cost-effectiveness of each project submitted to the FPSC for approval to be implemented as a program shall be analyzed and reported using the Commission-approved cost-effectiveness tests.

Planned Projects

FPC agreed to pursue the following as part of the Commission approved stipulation between FPC and the Legal Environmental Assistance Foundation (LEAF):

1. New Construction "Energy Star" Initiative -- HVAC Diagnostics

FPC proposed in the stipulation with LEAF to "Research and evaluate the energy impacts from required HVAC airflow and proper refrigerant charging through year-end 2000." This research will determine the feasibility of any future enhancement to the New Construction program involving these measures.

2. Photovoltaic Initiative – R&D Project

This proposed R&D project under FPC's Technology Development Program is designed to standardize pre-packaged, roof-mounted photovoltaic (PV) systems for manufactured buildings. The PV systems will be connected to the utility grid. The primary objective is to reduce the labor costs associated with the installation of PV systems in the field. This would be accomplished by installing PV system hardware and a balance of system components in a factory environment where the processes can be streamlined. The project will install an estimated 8 kWp of PV arrays in total. The system will be between 1 and 2 kWp each and will be installed on six to eight buildings. The proposed project will be responsive to the Federal Government's Million Solar Roofs initiative and current goals of the Florida Energy Office and Sandia National Labs and will provide the following benefits:

- The proposed PV project will provide education and develop efficiencies in the expanding manufactured building trade for the increased use of PV in the future.
- The proposed project will allow FPC to add a component of "green" power to its generation mix.
- With the assistance of the Florida Solar Energy Center, FPC will have the opportunity to monitor the proposed project and gain insight into the impact of distributed generation on FPC's grid.

APPENDIX -- PROPOSED TARIFF REVISIONS AND ADDITIONS

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT

Availability:

Available only within the range of the Company's load management system.

~~As of _____, available only to customers whose premises have active load management devices installed.~~

~~As of April 1, 2001, available only to customers taking service hereunder on this date.~~

Applicable:

To Customers eligible for residential service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh (based on the most recent 12 months or, where not available, a projection for 12 months), and utilizing any of the following electrical equipment:

1. Water Heater
2. Central Electric Heating System
3. Central Electric Cooling System
4. Swimming Pool Pump

Character of Service:

Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations."

Limitation of Service:

Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the Customer's premises.

For new service requests after ~~the effective date of this tariff~~ April 1, 1995, customers who select the swimming pool pump schedule must also select at least one other schedule.

An installation of an alternative thermal storage heating system under Special Provision No. 7 of this rate schedule is not available after ~~the effective date of this tariff.~~ April 1, 1995.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$8.85
Energy and Demand Charges:	
Non-Fuel Energy Charge:	4.020¢ per kWh
plus Energy Conservation Cost Recovery Factor:	See Sheet No. 6.105
plus Capacity Cost Recovery Factor:	See Sheet No. 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amounts:[1,2]

(a) Load Management Program (monthly credits)

Interruptible Equipment	Interruption Schedule A	B	C	D
Water Heater	-	-	$3.50	-
Central Heating System[3]	$2.00	$8.00	-	-
Central Heating System w/Thermal Storage[3]	-	-	-	$8.00
Central Cooling System[4]	$1.00	$5.00	-	-
Swimming Pool Pump	-	-	$2.50	-

(Continued on Page No. 2)

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 1)

(b) Advanced Load Management Program (per day interrupted credits)

Interruptible Equipment

Central Cooling System[4] = $4.50 x (% - 1)
50

Central Heating System[3] = $3.00 x (% - 1)
50

60 ≤ % ≤ 100

% = Customer selected maximum interruption %

Notes:
(1) Load management credits shall not exceed 40% of the Non-Fuel Charge associated with kWh consumption in excess of 600 kWh/month.
(2) For Central Heating and Cooling Systems, selection of Interruption Schedule A, Schedule B, Advanced Load Management is at the option of the Customer.
(3) For the billing months of November through March only.
(4) For the billing months of April through October only.

Interruption Schedules:

Schedule A — Equipment interruptions will not exceed an accumulated total of 10 minutes during any 30-minute interval within the Company's designated Peak Periods.

Schedule B — Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30-minute interval within the Company's designated Peak Periods.

Schedule C — Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods. Where a thermal storage system has been installed hereunder, additional interruptions to the water heater will be made during periods of charging thermal storage system.

Schedule D — The regular heating system may be interrupted continuously and alternative heating provided by means of a thermal storage system installed hereunder.

Advanced — Under the Advanced Load Management Program, Customers may select from among company determined interruption schedules for the central heating systems and/or central cooling systems ranging from 18 minutes during any 30-minute interval to 30 minutes during any 30-minute interval.

Customers participating in the Advanced Load Management Program must also be Interruption Schedule B participants. Under the Advanced Load Management Program, Customers will receive an Advanced Load Management credit for each day (midnight to midnight) in which this program is implemented. This credit will be in addition to the Customer's monthly load management credits.

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March - All Days: 6:00 a.m. to 11:00 a.m., and 6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October - All Days: 1:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service, (i.e., Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service, and Average Billing Plan), shall apply to service under this rate schedule.

RATE SCHEDULE RSL-1
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 2)

Special Provisions:

1. The Company shall be allowed reasonable access to the Customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the Customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized heating or cooling equipment, or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment type at that premise.

5. The limitation on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its load management system.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the Customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. An alternative thermal storage heating system is available to Customers who (a) have resistance strip heating solely as their central electric heating system, (b) have adequate space and provide access for installation and maintenance of a thermal storage system, (c) have an electric water heater circuit which can be utilized for charging a thermal storage system, and (d) have normal residential water heating and central heating requirements. The Company shall not be required to provide a thermal storage system where the Company deems the installation to be economically unjustified.

   For qualifying Customers, the Company will install, maintain, and operate a thermal storage system consisting of a thermal storage (water) tank, a pump, and a heat exchanging coil. The storage tank will be charged at the option and under the control of the Company. When this option is exercised, heating from this system will be available in place of the Customer's regular heating system. During periods that the storage tank is being charged, electric service to the Customer's regular water heater will be interrupted. An initial incentive payment of $50.00 shall be made to a participating Customer.

8. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A Customer may not change interruption schedules or the selection of electrical equipment installed with load management devices; ~~or~~ The customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. ~~However, in the event of any revision to the interruption schedules that may affect Customer, the Customer shall be allowed ninety (90) days from the effective date of the revision to transfer to another rate schedule.~~

8. If the Company determines that the effect of equipment interruptions has been offset by the Customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the Customer billed for all prior load management credits received over a period not in excess of six (6) months.

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT – WINTER ONLY

Availability:
Available only within the range of the Company's load management system.

Applicable:
To Customers eligible for residential service under Rate Schedule RS-1 or RSS-1 having a minimum average monthly usage of 600 kWh for the months of November through March (based on the most recent billings, where not available, a projection for those months), and utilize **both** electric water heater and central electric heating systems:

Character of Service:
Continuous service, alternating current, 60 cycle, single-phase, at the Company's standard distribution secondary voltage available. Three-phase service, if available, will be supplied only under the conditions set forth in the Company's booklet "Requirements for Electric Service and Meter Installations.

Limitation of Service:
Service to the electrical equipment specified above may be interrupted at the option of the Company by means of load management devices installed on the Customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate Per Month:

Customer Charge:	$8.85
Energy and Demand Charges:	
Non-Fuel Energy Charge:	4.020¢ per kWh
plus Energy Conservation Cost Recovery Factor:	See Sheet No. 6.105
plus Capacity Cost Recovery Factor:	See Sheet No. 6.106

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Load Management Credit Amount:[1]

Interruptible Equipment	Monthly Credit[2]
Water Heater and Central Heating System	$11.50

Notes: (1) Load management credits shall not exceed 40% of the Non-Fuel Charge associated with kWh consumption in excess of 600 kWh/month.
(2) For billing months of November through March only.

Appliance Interruption Schedule:

Heating	Equipment interruptions will not exceed an accumulated total of 16.5 minutes during any 30 minute interval within the Company's designated Peak Periods.
Water Heater	Equipment may be interrupted continuously, not to exceed 300 minutes, and during the Company's designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE RSL-2
RESIDENTIAL LOAD MANAGEMENT
(Continued from Page No. 1)

Peak Periods:

The Peak Periods expressed in terms of prevailing clock time shall be, but are not limited to these as follows:

(1) For the calendar months of November through March - All Days: 6:00 a.m. to 11:00 a.m., and
6:00 p.m. to 10:00 p.m.

Terms and Conditions:

All terms and conditions of Rate Schedule RS-1, Residential Service, i.e., Fuel Charges and other Billing Adjustments, Minimum Monthly Bill, Terms of Payment, Term of Service, and Average Billing Plan, shall apply to service under this rate schedule.

Special Provisions:

1. The Company shall be allowed reasonable access to the Customer's premises to install, maintain, inspect, test and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the Customer's electrical equipment to ensure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment.

3. The Company shall not be required to install load management devices on electrical equipment which would not be economically justified for reasons, such as, excessive installation costs, insufficient load, oversized heating or cooling equipment, or abnormal utilization of equipment, including but not limited to, vacation or other limited occupancy residences or qualifying common use facilities.

4. Multiple units of any electrical equipment specified above must all be installed with load management devices to qualify for the credit attributable to that equipment type at that premise.

5. The limitation on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its load management system.

6. If the Company determines that the load management devices have been tampered with, the Company may discontinue service under this rate schedule and bill for all prior load management credits received by the Customer, unless an earlier tampering date can be established, plus applicable investigative charges.

7. Billing under this Rate Schedule will commence with the first complete billing period following installation of the load management devices. A Customer may transfer to another rate schedule by notifying the Company forty-five (45) days in advance. However, in the event of any revision to the interruption schedules which may affect Customer, the Customer shall be allowed ninety (90) days from the effective date of the revision to change schedules, or equipment, or transfer to another rate schedule. If a customer transfers to another rate schedule they are not eligible to request service under this rate schedule for 12 month from the date of the transfer.

8. If the Company determines that the effect of equipment interruptions has been offset by the Customer's use of supplementary or alternative electrical equipment, or if access cannot be obtained by the Company to inspect, maintain, or remove load management devices, service under this rate schedule may be discontinued and the Customer billed for all prior load management credits received over a period not in excess of six (6) months.

RATE SCHEDULE GSLM-1
GENERAL SERVICE - LOAD MANAGEMENT

Availability:

Available only within the range of the Company's load management system.

Applicable:

To customers who are eligible for service under Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1, excluding those customers served under the General Service transition rates, and who elect service under this rate schedule and have electric space cooling equipment suitable for interruptible operation. Also applicable to those customers who have any of the following electrical equipment installed on permanent residential structures and utilized for domestic (household) purposes: (1) water heater(s), (2) central electric heating system(s), (3) central electric cooling system(s), and/or (4) swimming pool pump(s).

Rate Codes:

~~The assigned Rate Codes for service hereunder as related to its otherwise applicable Rate Schedule are as follows: GS-1 -- 61(Secondary), 63(Primary),___(Transmission); GST-1 -- (Unassigned); GSD-1 -- 71(Secondary), 73(Primary),___(Transmission); GSDT-1 -- 69(Secondary), 45(Primary),___(Transmission).~~

Limitation of Service:

Service to specified electrical equipment may be interrupted at the option of the Company by means of load management devices installed on the Customer's premises.

Standby or resale service not permitted hereunder. Service under this rate is subject to the Company's currently effective and filed "General Rules and Regulations for Electric Service."

Rate per Month:

The rates and all other terms and conditions of Company Rate Schedules GS-1, GST-1, GSD-1, or GSDT-1 (whichever shall otherwise be applicable) shall be applicable to service under this rate schedule, subject to the following:

LOAD MANAGEMENT MONTHLY CREDIT AMOUNT

Interruptible Equipment	Interruption Schedule	Credit Based on Installed Capacity[1]	Applicable Billing Months
Electric Space Cooling[3]	A	$ 0.26 Per kW	April thru October
Electric Space Cooling[3]	B	$ 0.56 Per kW	April thru October
Domestically Utilized Equipment[2]	[Availability, Schedules and Credits of the otherwise applicable Rate Schedule RSL-1 or RSL-2 shall apply]		

Notes:
(1) Credit shall not exceed 50% of the Non-Fuel Energy and Demand Charges; nor, for otherwise applicable Rate Schedule GSDT-1, shall the credit exceed the On-Peak and Base demand charges.
(2) Equipment includes water heaters, central heating systems, central cooling systems, and swimming pool pumps when such equipment is installed on permanent residential structures and utilized for domestic purposes.
(3) Restricted to existing customer as of _____.

Interruption Schedules:

Schedule A Interruptions will not exceed an accumulated total of 10 minutes during any 30-minute interval within the designated Peak Periods.

Schedule B Interruptions will not exceed an accumulated total of 16.5 minutes during any 30-minute interval within the designated Peak Periods.

(Continued on Page No. 2)

RATE SCHEDULE GSLM-1
GENERAL SERVICE - LOAD MANAGEMENT
(Continued from Page No. 1)

Peak Periods:

The designated Peak Periods expressed in terms of prevailing clock time shall be as follows:

(1) For the calendar months of November through March,
All Days: 6:00 a.m. to 11:00 a.m., and
6:00 p.m. to 10:00 p.m.

(2) For the calendar months of April through October,
All Days: 1:00 p.m. to 10:00 p.m.

Special Provisions:

1. The Company shall be allowed reasonable access to the Customer's premises to install, maintain, inspect, test, and remove load management devices on the electrical equipment specified above.

2. Prior to the installation of load management devices, the Company may inspect the Customer's electrical equipment to insure good repair and working condition, but the Company shall not be responsible for the repair or maintenance of the electrical equipment. The Company may, at its option, require a commercial energy audit as a prerequisite to receiving service under this rate. The audit may be used to establish or confirm equipment capacity, operating hours, or to determine the ability of the Company to control electric demand.

3. The Company shall not be required to install load management devices on electrical equipment, which would not be economically justified, for reasons such as excessive installation costs, oversized heating or cooling equipment, or abnormal utilization of equipment, including operating hours which are not considered within the designated Peak Periods.

4. If the Company determines that equipment operating schedules and/or business hours have reduced the ability of the Company to control electric demand during the above designated peak periods, then service under this rate will be discontinued.

5. Where multiple units (including standby or multi-stage) of space conditioning equipment are used to heat or cool a building, all of these units must be equipped with load management devices and normally must be controlled on the same interruption cycle.

6. Billing under this rate schedule will commence with the first complete billing period following installation of the load management devices. During the first year of service, a Customer may transfer to another rate schedule by notifying the Company forty-five days (45) in advance. After the first year of service, the Customer may transfer to another rate schedule by notifying the Company twelve (12) months in advance. However, in the event of any revision to the interruption schedules which may affect Customer, the Customer shall be allowed ninety (90) days from the effective date of the revision to change schedules or equipment or transfer to another rate schedule.

7. The limitations on Interruptible Schedules shall not apply during critical capacity conditions on the Company's system; nor shall limitations apply at times the Company requires additional generating resources to maintain firm power sales commitments or supply emergency interchange service to another utility for its firm load obligations only. The Company may also exercise equipment interruptions at any time for purposes of testing and performance evaluation of its load management system.

8. If the Company determines that the load management devices have been tampered with, or disconnected without notice, the Company may discontinue service under this rate schedule and bill for prior load management credits received by the Customer, plus applicable investigative charges.

9. If the Company determines that the effect of equipment interruptions have been offset by the Customer's use of supplementary or alternative electrical equipment, service under this rate schedule may be discontinued and the Customer billed for all prior load management credits received over a period not in excess of six (6) months.

10. For purposes of determining eligible credits related to domestically utilized equipment, the Customer shall provide the Company actual occupancy rates of permanent residential structures containing each type equipment for the previous winter (November through March) and summer (April through October) periods. Credits for the current billing period shall apply to the number of items of each installed type equipment multiplied by the corresponding previous seasonal period's occupancy rate.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Approval of demand-side management plan of Florida Power Corporation.	DOCKET NO. 991789-EG ORDER NO. PSC-00-0750-PAA-EG ISSUED: April 17, 2000

The following Commissioners participated in the disposition of this matter:

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

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING DEMAND-SIDE MANAGEMENT PLAN

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

The Florida Energy Efficiency and Conservation Act (FEECA), Chapter 366.82, Florida Statutes, requires us to adopt goals to reduce and control the growth rates of electric consumption and weather-sensitive peak demand. In Docket No. 971005-EG (Order No. PSC-99-1942-FOF-EG, issued October 1, 1999), we set numeric demand-side management (DSM) goals for Florida Power Corporation (FPC). The goals were set after we accepted a joint stipulation between FPC and an intervenor, Legal Environmental Assistance Foundation, Inc. (LEAF), in Docket No. 971005-EG.

Rule 25-17.0021(4), Florida Administrative Code, states that within 90 days of a final order establishing goals, a utility shall submit a DSM plan designed to meet its goals. FPC timely filed its DSM Plan on December 29, 1999.

DOCUMENT NUMBER-DATE
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In Order No. 22176, issued November 14, 1989, in Docket No. 890737-PU, we stated that conservation programs will be evaluated using the following criteria:

1. Whether the program advances the policy objectives of Rule 25-17.001, Florida Administrative Code, and Sections 366.80 through 366.85, Florida Statutes, also known as the "Florida Energy Efficiency and Conservation Act" (FEECA);

2. Whether the program is directly monitorable and yields measurable results; and

3. Whether the program is cost-effective.

On December 29, 1999, FPC filed its DSM Plan. FPC's DSM Plan contains five residential programs, eight commercial and industrial (C/I) programs, and one research and development program. These programs are summarized in Attachment A and incorporated herein by reference. The tables in Attachment A, pages 10 and 14, illustrate each DSM program's projected demand and energy savings and contribution towards FPC's numeric DSM goals. Demand savings from FPC's DSM Plan are expected to meet the residential summer and winter peak demand goals set in Order No. PSC-99-1942-FOF-EG. FPC expects to slightly exceed its residential energy savings goal and all three commercial/industrial goals.

FPC's DSM programs are designed to minimize free riders, minimize rate impacts, and to meet our prescribed DSM goals. Accordingly, we find that the programs contained in FPC's DSM plan appear to meet the policy objectives of Rule 25-17.001, Florida Administrative Code, and FEECA. FPC's measurement plan to evaluate assumed demand and energy savings appears reasonable. Each program included in FPC's DSM plan is cost-effective under the rate impact measure (RIM), total resource cost (TRC), and Participants tests. However, it must be emphasized that we are not addressing the prudence of expenditures for the programs contained in FPC's DSM plan; such a review is performed annually in the Energy Conservation Cost Recovery docket.

Most of the programs in FPC's DSM Plan are either unchanged or minimally modified since we approved them in 1995. As discussed below, the only new program contained in FPC's DSM Plan is a Low Income Weatherization Assistance Program. The only substantial DSM program change is to FPC's existing year-round Residential and

Commercial Energy Management programs, which have been closed to new customers and replaced with a winter-only load management program.

FPC's Low Income Weatherization Assistance Program (LIWAP) is offered in response to the stipulation with LEAF in Docket No. 971005-EG. LIWAP is an umbrella program to improve energy efficiency for low-income customers in existing homes. FPC has been involved in conservation activities in the low-income segment for years through some of its other DSM programs. The new LIWAP will continue these activities. The primary goals of the LIWAP are to:

- Continue coordination with the Department of Community Affairs (DCA) and local weatherization providers to deliver energy efficiency measures to low-income families;
- Identify and educate contractors and low-income customers about opportunities to improve home energy efficiency;
- Increase participation of low income families in FPC's other DSM programs; and
- Minimize lost opportunities in the existing marketplace.

LIWAP provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, heating and air conditioning maintenance, high-efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters. FPC forecasts that demand and energy savings from LIWAP will contribute approximately one percent towards FPC's residential DSM goals. Total cost for the program is expected to be far less than one percent of the total cost of FPC's DSM Plan.

FPC's plan also contains substantial changes to the Residential Energy Management Program (RSL-1 tariff) and Commercial Energy Management Program (GSLM-1 tariff). Due to declining cost-effectiveness, these year-round load control programs will no longer be available to new customers. Existing customers can continue to receive monthly credits for year-round interruptions as long as no changes occur to the appliances being controlled or to the interruption schedule. Future residential and small commercial

customers can participate in FPC's Winter-Only Energy Management Program (RSL-2 tariff), which provides for direct load control of electric water heating and central electric heating appliances between November and March. The monthly credit paid for both residential and small commercial participants in the winter-only program is the same as under the existing RSL-1 tariff, but is paid only between November and March. The amount of the credit remains unchanged from when the program was last modified in 1995.

FPC's research & development program, named the Technology Development Program, is essentially unchanged from what was approved by the Commission in 1995. FPC agreed to pursue certain projects in photovoltaics and energy efficiency as part of its stipulation with LEAF in the DSM Goals docket. A summary of the program is contained on page 15. Program expenses are capped at $800,000 per year, with a $100,000 annual cap on expenditures for any single project. FPC does not count any kW and kWh savings from its proposed Technology Development program. The purpose of this program is to research potential DSM programs, determine their estimated kW and kWh savings, and evaluate them for cost-effectiveness. If a legitimate DSM program results from FPC's research efforts, the program would be incorporated into the DSM Plan and its kW and kWh savings would be applied toward the goals.

Upon consideration, we hereby approve Florida Power Corporation's Demand-Side Management Plan, including approval for cost recovery. FPC's program standards shall clearly state the requirements for participation in the programs, customer eligibility requirements, details on how rebates or incentives will be processed, technical specifications on equipment eligibility, and necessary reporting requirements. If these program participation standards conform to the description of the programs contained in FPC's DSM Plan, they shall be approved administratively.

Based on the foregoing, it is therefore

ORDERED by the Florida Public Service Commission that Florida Power Corporation's Demand-Side Management Plan summarized in Attachment A to this Order, and incorporated by reference herein, is approved. It is further

ORDERED that Florida Power Corporation shall file program standards which clearly state the requirements for participation in the programs, customer eligibility requirements, details on how

rebates or incentives will be processed, technical specifications on equipment eligibility, and necessary reporting requirements. If these program participation standards conform to the description of the programs contained in Florida Power Corporation's Demand-Side Management Plan, they shall be approved administratively. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this Docket shall be closed.

By ORDER of the Florida Public Service Commission this 17th day of April, 2000.

Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

(S E A L)

DMC

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

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

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on May 8, 2000.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

FLORIDA POWER CORPORATION
DEMAND-SIDE MANAGEMENT PLAN

RESIDENTIAL PROGRAMS

1. Home Energy Check: Residential energy audit program. Company auditor examines home and makes recommendations on low-cost or no-cost energy-saving practices and measures. Offers four types of audits: *mail-in* (completed by customer), *free walk-through*, *paid walk-through* ($15 cost), and *home energy rating* (BERS audit promoted by DCA).

2. Home Energy Improvement: Umbrella program for existing homes. Combines thermal envelope efficiency improvements with upgraded equipment and appliances. Promotes the following energy-efficiency measures:

   a. Attic Insulation Upgrade: Encourages customers who have electric space heat to add ceiling insulation. FPC pays portion of the installed cost. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $100 per customer.

   b. Duct Leakage Test and Repair: Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. Customer must have electric heating and centrally-ducted cooling system to participate. FPC pays up to $30 per unit for duct leakage test and up to $100 per unit for duct repair.

   c. High Efficiency Electric Heat Pumps: Pays financial incentive, not exceeding $350 per unit, to replace existing electric heating equipment with high-efficiency electric heat pumps. Specific incentive based on minimum heating and/or cooling efficiency levels. Indoor air handler and outdoor condenser must both be replaced to qualify for this rebate.

   d. High-Efficiency Alternate Electric Water Heating: Promotes installation of high-efficiency alternative electric water heating equipment. Provides incentive of up to $100 for each heat recovery unit and up to $200 per unit for each dedicated heat pump water heater unit.

e. Supplemental Incentive Bonus: Encourages adoption of several energy-efficiency measures through an additional incentive of up to $50. Incentive is paid to a participant in FPC's high efficiency electric heat pump program who also implements the ceiling insulation upgrade, duct leakage repair, or both, within 90 days.

Home Energy Improvement program offers two financing options in lieu of rebates mentioned above: interest-free installment billing over 12 months, and financing assistance through participating financial institutions and/or Federal programs.

3. Residential New Construction: Umbrella program for new home construction, multi-family, and manufactured homes. Promotes energy-efficient construction which exceeds the building code. Provides information, education, and advice to home builders and contractors on energy-related issues and efficiency measures. Promotes energy-efficient electric heat pumps and alternate electric water heating units with incentives that are identical to those offered in the Home Energy Improvement program for existing homes.

4. Low Income Weatherization Assistance (LIWAP): Umbrella program for the weatherization of low income family homes. Offered pursuant to stipulation with LEAF in the DSM Goals docket. Efficiency measures and incentives are identical to those offered in FPC's Home Energy Improvement Program, with the following additions:

a. Reduced Air Infiltration: A $75 incentive is paid for work which reduces air infiltration by a minimum specified amount.

b. Water Heater Wrap / Replacement: Provides wrap for water heater and associated piping near the tank. A $25 incentive may be paid towards the purchase of a high-efficiency water heater in lieu of an insulating jacket.

5. Residential Energy Management: Voluntary load control program in which FPC reduces peak demand by interrupting electric service to water heaters and central electric heating units. Program is offered only during winter months (November through March). Existing program also interrupts service to pool pumps and central cooling units during summer months, but is no longer cost-effective and will be closed to new customers. Maximum monthly bill credit is $11.50, but is paid only during winter months when customer usage exceeds 600 kWh per month.

FPC'S RESIDENTIAL DSM PROGRAMS

DSM Program	Summer Peak Demand		Winter Peak Demand		Annual Energy Consumption		B/C Ratio (RIM)
	Savings (MW)	% of Goal	Savings (MW)	% of Goal	Savings (GWH)	% of Goal	
Home Energy Check	20.3	16.3	20.3	5.2	65.9	35.6	N/A
Home Energy Improvement	45.1	36.1	114.8	29.5	63.4	34.3	1.11
Residential New Construction	58.0	46.4	119.3	30.7	62.7	33.9	1.13
Low Income Weatherization Assistance	1.2	1.0	2.9	0.8	1.7	0.9	1.02
Res. Winter-Only Energy Management [1]	0.0	0.0	131.9	33.9	0.0	0.0	1.24
TOTAL SAVINGS	124.6	99.7	389.3	100.1	193.7	104.7	
GOAL	125.0		389.0		185.0		

[1] Winter-only program offered to new participants. Existing participants may continue on the old year-round program as long as there are no changes to the interruption schedule.

COMMERCIAL / INDUSTRIAL (C/I) PROGRAMS

1. Business Energy Check: C/I energy audit program. Offers a *free walk-through audit* (inspection) and a *paid walk-through audit* (energy analysis) whose cost varies based on facility's average monthly energy use.

2. Better Business: Umbrella efficiency program for existing C/I buildings. Gives customers information and advice on energy-related issues and efficiency measures. Provides incentives or financing for the following energy-efficiency measures:

   a. HVAC Equipment: Pays financial incentive, of up to $100 per kW reduced, for the purchase of high-efficiency HVAC equipment such as packaged terminal heat pumps, water-cooled and air-cooled chillers, and unitary heat pumps and air conditioners.

   b. Motors: Promotes installation of high-efficiency poly-phase motors. Incentives paid according to motor size on a per-horsepower basis, with larger motors receiving up to $2 per horsepower.

   c. Roof Insulation Upgrade: Encourages customers who have electric space heat to add roof insulation. FPC pays portion of the installed cost. Eligibility based on demonstration that additional insulation results in heating and/or cooling use reductions. Specific incentive amount based on increase in insulation amount above a maximum of R-12, with maximum incentive amount of $100 per customer.

   d. Duct Leakage Test and Repair: Promotes energy efficiency through improved duct system sealing. Program helps identify and reduce energy loss by measuring air leakage rate through the central duct system. Customer must have electric heating and centrally-ducted cooling system to participate. FPC pays up to $30 per unit for duct leakage test and up to $100 per unit for duct repair.

   e. Window Film: Provides incentive for installation of window film having a shading coefficient of 0.45 or less on an existing window with a shading coefficient of 0.84 or greater. Incentive paid on a per-square foot of

installed film basis; maximum incentive is $125 per customer. Facilities with multiple guest rooms (hotels, hospitals, etc.) are eligible for maximum incentive of $50 per room.

Better Business program offers two financing options in lieu of incentives mentioned above: interest-free installment billing over a 12 month period (amount not to exceed $500), and financing assistance through participating financial institutions and/or Federal programs.

3. C/I New Construction: Umbrella efficiency program for new C/I buildings. Provides information, education, and advice on energy-related issues and efficiency measures. Allows FPC to be involved early in the building's design process. Also provides incentives for energy-efficient equipment, such as HVAC equipment, motors, and heat recovery units, which exceed the building code. Incentive levels are identical to those offered in the Better Business program for existing buildings.

4. Innovation Incentive: Subsidizes demand and energy conservation projects, on a customer-specific basis, where cost-effective to all FPC customers. To be eligible, projects must reduce or shift a minimum of 10 kW. Rebates will be limited to $150 per kW reduced or shifted. Focuses on measures not offered in FPC's other DSM programs. Examples include *refrigeration equipment replacement, thermal energy storage, microwave drying systems,* and *inductive heating* (to replace resistance heat).

5. Commercial Energy Management: Voluntary load control program in which FPC reduces peak demand by interrupting electric service to water heaters and central electric heating units. Program is offered only to small commercial customers during winter months (November through March). Existing program for small commercial customers also interrupts service to pool pumps and central cooling units during summer months, but is no longer cost-effective and will be closed to new customers. Maximum monthly bill credit is $11.50, same as for residential load management participants, and is paid only during the winter months.

6. Standby Generation: Voluntary demand control program available to all C/I customers having on-site generation capability. Customer controls the equipment but operates it when needed by

FPC. Incentive based on the load served by the customer's generator and is based on FPC's GSLM-2 rate schedule.

7. Interruptible Service: Direct load control program. FPC interrupts service by disconnecting electric service at the breaker during peak or emergency conditions. Offered under FPC's IS-1 and IST-1 tariffs. Available to any non-residential customer with an average billing demand of at least 500 kW. Monthly credit paid to customer based on level of billing demand.

8. Curtailable Service: Direct load control program that is similar to interruptible service, only the customer's entire load is not shed. Offered under the CS-1 and CST-1 tariffs. Available to any non-residential customer with an average billing demand of at least 500 kW. Customer must be willing to reduce 25% of its average monthly billing demand upon request by FPC. Monthly credit paid to customer based on level of curtailable demand.

FPC'S COMMERCIAL / INDUSTRIAL DSM PROGRAMS

DSM Program	Summer Peak Demand		Winter Peak Demand		Annual Energy Consumption		B/C Ratio (RIM)
	Savings (MW)	% of Goal	Savings (MW)	% of Goal	Savings (GWH)	% of Goal	
Business Energy Check	1.4	3.7	1.4	3.8	3.0	15.8	N/A
Better Business	5.6	14.8	4.8	13.1	11.2	59.1	1.13
C/I New Construction	2.3	5.9	2.1	5.5	3.7	19.7	1.05
Innovation Incentive	0.8	2.2	0.8	2.3	1.4	7.6	N/A
Commercial Energy Management [2]	0.0	0.0	0.0	0.0	0.0	0.0	0.79
Standby Generation	30.0	78.9	30.0	81.1	0.3	1.6	1.14
Interruptible Service	0.9	2.3	1.0	2.7	8.5	44.7	1.00
Curtailable Service [3]	0.0	0.0	0.0	0.0	0.0	0.0	1.32
TOTAL SAVINGS	41.0	107.9	40.1	108.5	28.2	148.4	
GOAL	38.0		37.0		19.0		

[2] Closed to new participants. Existing participants may continue on the old year-round program as long as there are no changes to the interruption schedule.

[3] FPC does not forecast any new participants in this program.

RESEARCH & DEVELOPMENT PROGRAM

1. Technology Development Program: Program used by FPC to research, develop, and demonstrate potential cost-effective conservation programs. Includes field testing or a pilot program. Program expenses are capped at $800,000 per year. FPC will notify the Commission, through ECCR filings, if any single project's expenditures exceed $100,000.

   Examples of potential projects include demand reduction energy efficiency techniques, market transformation initiatives, indoor air quality measures, thermal energy storage technologies, and innovative metering techniques. FPC will provide a final report on each demonstration project or file and offer a permanent conservation program for each program investigated.

   FPC agreed to pursue the following projects as part of its stipulation with LEAF in the DSM goals docket:

   - New construction "energy star" initiative -- HVAC diagnostics
   - Photovoltaic initiative -- R&D project (including a "green power" component)

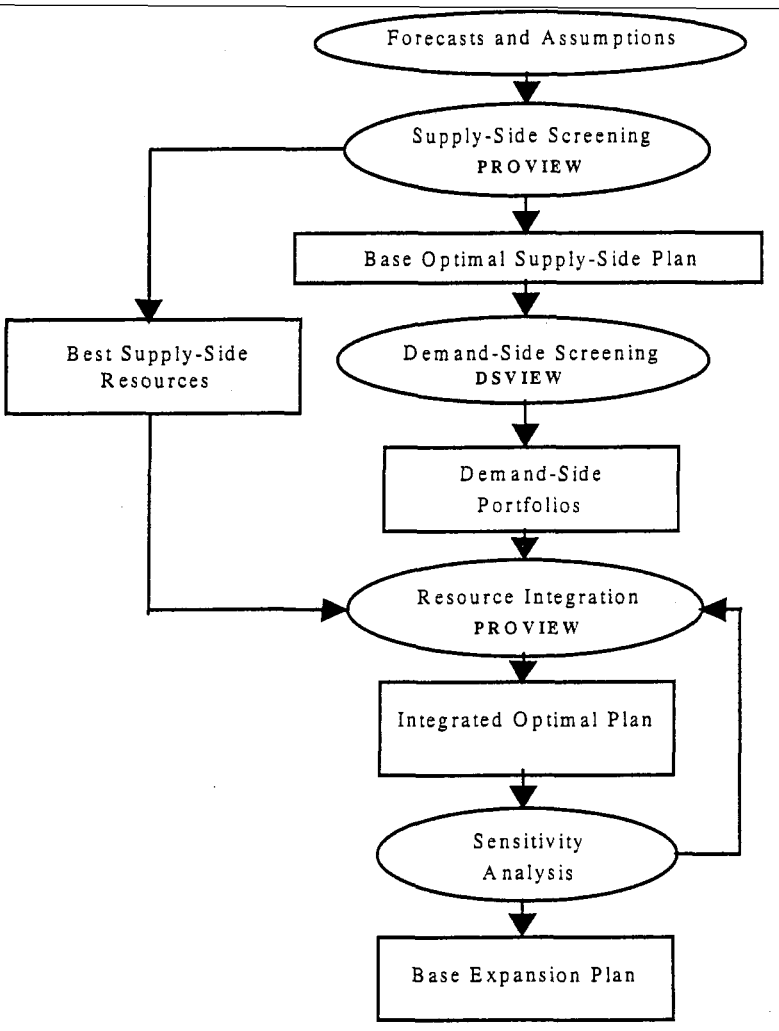

Figure 1: IRP Process Overview

Table 2-1
Wind Energy Conversion
Performance and Costs

Commercial Status	Commercial
Average Wind Speed (mph)	20
Performance:	
Power Capacity (MW_{rated})	10
Power Capacity ($MW_{average}$)	3.5
Energy Production (MWh/yr)	29,000
Capacity Factor (percent)	35
Costs:	
Capital Cost ($/kW$_{rated}$)	1,100
Capital Cost ($/kW$_{average}$)	3,200
O&M Costs:	
Fixed O&M ($/kW-yr$_{average}$)	30
Variable O&M ($/MWh$_{average}$)	5.0
Levelized Cost (cents/kWh)	5.3[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-2
Solar Thermal – Parabolic Trough
Performance and Costs

Commercial Status	Commercial
Duty Cycle	Supplemental
Performance:	
Power Capacity (MW)	80
Energy Production (MWh/yr)	250,000
Capacity Factor (percent)	36
Costs:	
Capital Cost ($/kW)	2,870 - 3,600
O&M Costs:	
Fixed O&M ($/kW-yr)	47
Variable O&M ($/MWh)	4.1
Levelized Cost (cents/kWh)	13.2 – 21.2[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-3
Utility-Scale Photovoltaics
Performance and Costs

Commercial Status	Commercial
Module Type	Single Crystalline
Array Type	Fixed-tilt
Duty Cycle	Supplemental
Performance:	
Module Efficiency (%)	12.0
Power Capacity (MW)	10
Energy Production (MWh/yr)	17,500
Capacity Factor (percent)	20
Costs:	
Capital Cost ($/kW$_{rated}$)	2,000
Capital Cost ($/kW$_{average}$)	10,000
O&M Costs:	
Fixed O&M ($/kW-yr$_{average}$)	14
Variable O&M ($/MWh$_{average}$)	2.0
Levelized Cost (cents/kWh)	13.0 – 19.9[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-4
Wood Chip Combustion
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	50
Net Plant HHV Heat Rate (Btu/kWh)	12,500 to 17,500
Energy Capacity (MWh)	260,000
Capacity Factor (percent)	60
Costs:	
Capital Cost ($/kW)	1,450 - 1,850
O&M Costs:	
Fixed O&M ($/kW-yr)	24 - 48
Variable O&M ($/MWh)	4.0 - 5.0
Levelized Cost (cents/kWh)	6.7 – 13.6[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-5
Geothermal
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	25
Energy Capacity (MWh)	175,000
Capacity Factor (percent)	80
Costs:	
Capital Cost ($/kW)	2,000 - 4,000
O&M Costs:	
Fixed O&M ($/kW-yr)	105
Variable O&M ($/MWh)	7.2
Levelized Cost (cents/kWh)	5.2 - 14.7[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 2-6
Hydroelectric
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	10 to 1,500+
Energy Capacity (MWh)	Resource dependent
Capacity Factor (percent)	Resource dependent
Costs:	
Capital Cost ($/kW)	1,300 - 5,200
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 30
Variable O&M ($/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	5.9 – 13.0[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 3-1
Waste to Energy – Mass Burn Unit
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	15,500
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,000 - 3,000
O&M Costs:	
Fixed O&M ($/kW-yr)	100 - 150
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	7.2 - 12.3[1,2]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.
(2) Excludes tipping fee credit.

Table 3-2
Waste to Energy - RDF Unit
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	17,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,500 - 3,500
O&M Costs:	
Fixed O&M ($/kW-yr)	150 - 200
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	8.2 - 13.4[1,2]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.
(2) Excludes tipping fee credit.

Table 3-3
Landfill Gas - IC Engine Unit
(Gas Collection/Processing Not Included)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	10
Net Plant Heat Rate (Btu/kWh)	8,500
Capacity Factor (percent)	60 - 75
Availability (percent)	93
Costs:	
Capital Cost ($/kW)	825
O&M Costs:	
Fixed O&M ($/kW-yr)	0.9[1]
Variable O&M ($/MWh)	6.7
Levelized Cost (cents/kWh)	2.0 - 4.0[2]

(1) Unstaffed site.
(2) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 3-4
Multi-Fuel CFB
(~10 Percent TDF Co-Fire)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	11,000
TDF Tons per Day	100
Capacity Factor (percent)	60 - 75
Availability (percent)	85
Costs:	
Capital Cost ($/kW)	1,650
O&M Costs:	
Fixed O&M ($/kW-yr)	40
Variable O&M ($/MWh)	3.0
Levelized Cost (cents/kWh)	5.2 – 11.1[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-1
Humid Air Turbine Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	410
O&M Costs:	
Fixed O&M ($/kW-yr)	7 - 9
Variable O&M ($/MWh)	0.10 - 0.60
Levelized Cost (cents/kWh)	3.6 – 5.2[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-2
Kalina Cycle Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,025
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 12
Variable O&M ($/MWh)	0.1 - 0.5
Levelized Cost (cents/kWh)	4.8 – 7.0[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-3
Cheng Cycle Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,025
O&M Costs:	
Fixed O&M ($/kW-yr)	12
Variable O&M ($/MWh)	0.6
Levelized Cost (cents/kWh)	4.3 – 5.5[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-4
Supercritical Pulverized Coal Power Plant
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	350 - 1,300
Net Plant Heat Rate (Btu/kWh)	9,300
Capacity Factor (percent)	60 - 75
Availability (percent)	78
Costs:	
Capital Cost ($/kW)	1,230
O&M Costs:	
Fixed O&M ($/kW-yr)	19 - 23
Variable O&M ($/MWh)	3.3
Levelized Cost (cents/kWh)	5.4 – 6.9[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-5
PCFB Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	80 - 350
Net Plant Heat Rate (Btu/kWh)	8,600 (6,700 2nd generation)
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,300 - 2,050
O&M Costs:	
Fixed O&M ($/kW-yr)	40 – 80
Variable O&M ($/MWh)	3.5
Levelized Cost (cents/kWh)	5.2 – 6.2[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-6
Magnetohydrodynamic Combined Cycle Plant
Conceptual Performance and Costs

Commercial Status	Development/Conceptual
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	10,300
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,300 - 2,500
O&M Costs:	
Fixed O&M ($/kW-yr)	20 - 35
Variable O&M ($/MWh)	1.0 - 3.1
Levelized Cost (cents/kWh)	6.7 - 13.5

Table 4-7
Fuel Cell Power Plant
Performance and Costs

Commercial Status	Commercially Available
Performance:	
Plant Capacity (MW)	0.2
Net Plant Heat Rate (Btu/kWh)	10,000
Capacity Factor (percent)	85
Costs:	
Capital Cost ($/kW)	4,100
O&M Costs:	
Fixed O&M ($/kW-yr)	330
Variable O&M ($/MWh)	0.84
Levelized Cost (cents/kWh)	7.4 – 8.6[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-8
Ocean Wave Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	0.1 - 1.0
Net Plant Heat Rate (Btu/kWh)	N/A
Capacity Factor (percent)	25
Costs:	
Capital Cost ($/kW)	2,450
O&M Costs:	
Fixed O&M ($/kW-yr)	50 - 100
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)	6.7 – 41.4[1]

(1) California Energy Commission, Energy Technology Status Report, adjusted to 2000 dollars.

Table 4-9
Ocean Tidal Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	20 - 240
Annual Energy Capacity (GWh)	35 - 500
Capacity Factor (percent)	20 - 25
Costs:	
Capital Cost ($/kW)	1,000 - 4,000
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 50
Variable O&M ($/MWh)	1.5 - 5.2
Levelized Cost (cents/kWh)	13.3 - 23.2

2000 Ten-Year Site Plan Analysis • No Future "CC" Capacity Additions • No "CC's"

		WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
		Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
New FPC Capacity	MW	323	17	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,890	9,907	9,894	9,748	9,758	9,608	9,507	9,492	9,383	9,242
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	8,394	8,610	8,820	9,029	9,234	9,440
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	1,517	1,364	998	687	462	149	-198
Normal Weather Reserve Margin (After All Load Control)	%	16.0%	19.6%	21.9%	18.4%	16.3%	11.6%	7.8%	5.1%	1.6%	-2.1%

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
New FPC Capacity	MW	0	264	17	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	8,978	8,988	8,853	8,770	8,755	8,646
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	7,439	7,701	7,431	7,258	7,361	7,522	7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	1,617	1,466	1,116	823	603	291
Normal Weather Reserve Margin (After All Load Control)	%	19.0%	18.4%	22.7%	25.7%	22.0%	19.5%	14.4%	10.4%	7.4%	3.5%

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
		Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
New FPC Capacity	MW	323	17	0	567	0	567	0	567	0	567
Total Available Capacity	**MW**	**9,890**	**9,907**	**9,894**	**10,315**	**10,325**	**10,742**	**10,641**	**11,193**	**11,084**	**11,510**
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	**MW**	**8,528**	**8,282**	**8,120**	**8,231**	**8,394**	**8,610**	**8,820**	**9,029**	**9,234**	**9,440**
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	2,132	1,821	2,163	1,850	2,070
Normal Weather Reserve Margin (After All Load Control)	**%**	**16.0%**	**19.6%**	**21.9%**	**25.3%**	**23.0%**	**24.8%**	**20.6%**	**24.0%**	**20.0%**	**21.9%**

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
New FPC Capacity	MW	0	264	17	0	495	0	495	0	495	0
Total Available Capacity	**MW**	**8,853**	**9,117**	**9,121**	**9,121**	**9,473**	**9,483**	**9,843**	**9,760**	**10,240**	**10,131**
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**7,439**	**7,701**	**7,431**	**7,258**	**7,361**	**7,522**	**7,737**	**7,947**	**8,152**	**8,354**
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	2,106	1,813	2,088	1,776
Normal Weather Reserve Margin (After All Load Control)	**%**	**19.0%**	**18.4%**	**22.7%**	**25.7%**	**28.7%**	**26.1%**	**27.2%**	**22.8%**	**25.6%**	**21.3%**

Florida Power
CORPORATION

January 26, 2000

Attention: Interested Parties

Subject: Request for Proposals

Attached, please find a copy of Florida Power Corporation's Request for Proposals and a diskette containing data tables appropriate for your use. Please direct any questions that you may have in writing to:

Michael D. Rib
Director, Resource Planning
Florida Power Corporation
263 13th Avenue South
St. Petersburg, FL 33701

Via Fax: (727) 826-4333
Via E-mail: rfpresponse@fpc.com

Sincerely,

Michael Rib

REQUEST FOR PROPOSALS

January 26, 2000

I. Purpose And Scope

In accordance with Rule 25-22.082, F.A.C., Florida Power Corporation (FPC) issues this request for proposals (RFP) to solicit and screen, for subsequent contract negotiations, competitive proposals for supply-side alternatives to its next planned generating unit. FPC invites proposals that will offer exceptional value to FPC and its customers. Proposals submitted pursuant to this RFP will be considered and evaluated against each other and against FPC's self-build options. FPC's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW (net) to be located at the Hines Energy Complex in Polk County, Florida and available November 30, 2003. For a more detailed description of this planned unit, refer to Attachment D.

Respondents are asked to provide capacity offered in their proposal at a level of firmness that is dedicated solely to FPC's use and subject to dispatch by FPC. For purposes of this solicitation, FPC is interested in long-term proposals with flexible contract options.

II. Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	1/26/2000	
Notice of Intent to Bid (NOI) Due	2/10/2000	NOIs should be received by FPC's RFP Contact by 3:00 P.M. EST
Pre-Bid Meeting	2/18/2000	Tampa Airport Marriott 10:00 A.M. - 12:30 P.M. EST Room To Be Determined
Proposals Due	3/27/2000	Proposals must be received by the RFP Contact by 3:00 P.M. EST

Short-list Determination	5/19/2000	If applicable
Complete Negotiations	8/1/2000	If applicable
File contract(s) with state Public Service Commission for approval	8/15/2000-9/29/2000	If applicable

FPC reserves the right to revise, suspend, or terminate this schedule at its sole discretion. Any changes to the schedule will be provided, as appropriate, to Respondents that have submitted a timely NOI.

III. Proposal Guidelines

A. Instructions for Completing Forms

1. All Respondents are encouraged to submit a written Notice of Intent to Bid (NOI), using the form provided in Attachment A. Please submit the NOIs to the FPC RFP Contact by facsimile, Registered or Certified Mail, Return Receipt Requested, or overnight courier, by 3:00 P.M. EST, February 10, 2000. Voice telephone notices will not be acknowledged.

2. Respondents are also encouraged to attend the February 18, 2000 pre-bid meeting. This meeting is tentatively set to be held from 10:00 A.M. to 12:30 P.M. at the Tampa Airport Marriott (Room TBD). If this time or location change, FPC will notify Respondents who have submitted a NOI.

3. All Respondents must submit with their proposal a Proposal Summary using the form provided in Attachment B.

4. All proposals must be submitted in the format shown in the RFP response forms Attachment C and E. Respondents should, at the time of proposal submittal, supply any additional information not included in the forms if such information may be needed for a thorough understanding or evaluation of the proposal. All responses will be considered commitments to be used in defining any agreement between FPC and the Respondent that may arise from this RFP.

5. Proposals must be signed by a duly authorized officer of the Respondent.

6. A signed original and ten (10) copies of the proposal, including all attachments,

must be submitted along with the electronic forms provided on a 3.5" floppy diskette. The electronic forms may be obtained from FPC on floppy disk or downloaded from the Company website (www.fpc.com). In the event of a discrepancy between the electronic forms and the hard copy, the hard copy will be considered to be correct.

7. All proposals, including all attachments, must be properly completed and returned by overnight courier or Registered or Certified Mail, Return Receipt Requested, in both hard copy and electronic versions, to FPC's RFP Contact:

Michael D. Rib
Director, Resource Planning
Florida Power Corporation
263 13th Avenue South
St. Petersburg, FL 33701
Phone: (727)826-4387
Fax: (727)826-4333
E-mail: rfpresponse@fpc.com

All proposals shall be received by FPC's RFP contact no later than 3:00 P.M. EST on March 27, 2000. Late or incomplete offers may be rejected by FPC. Offers must remain open until at least October 1, 2000. All inquiries and other communications relating in any manner to this RFP must be directed in writing or by facsimile or E-mail to FPC's RFP Contact. FPC may distribute Respondents' questions and FPC's answers to such questions to all other Respondents if FPC deems the question to be of general interest. Unsolicited contact about this process with other FPC personnel or attorneys or consultants retained by FPC may result in disqualification.

8. Complete information is needed to facilitate a timely evaluation. FPC may request clarifying or additional information at any time during the evaluation process, and Respondents will be expected to provide timely responses to facilitate the evaluation and decisionmaking process within the time constraints. Respondents must provide all data requested in the RFP and the applicable attachments. FPC may reject non-specific offers from further consideration.

9. Proposals must reflect any and all of the costs that FPC would be expected to pay for power delivered to FPC's System. If any portion of the total delivered cost of power is not intended to be clearly defined in the pricing outlined in the proposal, then a detailed description of the proposed approach regarding that portion of cost must be clearly delineated in the proposal. Prices and dollar figures quoted must be clearly stated in $US as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.

B. Confidentiality

FPC will take reasonable precautions and use reasonable efforts to protect any proprietary and confidential information contained in a proposal provided that such information is clearly identified by the Respondent as "Proprietary and Confidential" on the page on which proprietary and confidential information appears. Such information may, however, be made available under applicable state or federal law to regulatory commission(s), their staff(s), or other governmental agencies having an interest in these matters. FPC reserves the right to release such information to agents, contractors, or to its parent company or to subsidiaries thereof, for the purpose of evaluating the Respondent's proposal but such companies, agents, or contractors will be required to observe the same care with respect to disclosure as FPC. Under no circumstances will FPC or Florida Progress Corporation or their subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure during or after the solicitation process.

C. Proposal Evaluation Costs

1. To help defray the cost of performing the proposal evaluations, Respondents are required to submit, with the proposal, a non-refundable check payable to Florida Power Corporation for $10,000 for each proposal. Changes in the physical attributes, such as site, output, fuel, or technology changes will require the submission of a separate proposal and payment of another fee.

2. Neither FPC nor its representatives, affiliate companies, or parent company shall be liable for any expenses incurred in connection with preparation of a response to this RFP or for any costs, fees, or lost or foregone profits of unsuccessful Respondents. Respondents should prepare their proposals simply and economically, providing a straightforward and concise description of the Respondent's ability to meet the requirements of the RFP. Any Respondent that submits in its proposal to FPC any information that is determined by FPC to be substantially inaccurate, misleading, exaggerated, or incorrect shall be disqualified from consideration.

D. Regulatory Provisions

1. Any negotiated contract for the purchase of power between FPC and the Respondent will be conditioned upon approval or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation, including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission.

2. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:

Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

Respondents are required to forward copies of these actual published notices to FPC when they are available.

IV. General Specifications

A. Minimum Requirements for Proposals

In addition to the requirements of Section III above, proposals must also meet the minimum requirements set forth below. FPC, in its sole discretion, may reject any proposal that fails to respond adequately or completely to all or any part of this RFP.

1. Capacity offered must be at a level that is dedicated solely to FPC's use and subject to dispatch by FPC. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources will not be evaluated and will be rejected. Proposals must allow FPC the right to use this generating resource, including, but not limited to, electrical transmission services associated with the project, for any purpose that the company deems appropriate in its sole discretion.

2. The capacity must be available no later than November 30, 2003.

3. Proposal prices must reflect any and all costs that FPC will be expected to pay for power delivered to its system, as outlined in this RFP. Further, Respondents shall be responsible for absorbing all charges and costs for firm transmission service (including the cost of all attendant equipment, including but not limited to generator step-up transformers) to deliver each generating resource included in the proposal to the FPC control area, or to interconnect a generating resource to the FPC Transmission System.

4. A Respondent whose proposal is selected shall take all necessary actions to

satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on the Respondent by any federal, state, or local law, or ordinance, rule, or regulation concerning the generation, sale, or delivery of the power. FPC will cooperate with the Respondent to provide information or such other assistance as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise fully support all of FPC's regulatory requirements associated with this potential power supply arrangement.

5. A Respondent whose proposal is selected shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale, or delivery of power for the entire term of the proposed contract, and the Respondent shall include any such costs in its proposal.

6. The proposal must include unit commitment notification and dispatch scheduling provision details for the contract sale. Respondents must describe provisions that can and would be made to allow FPC to dispatch the proposed generating resources directly from FPC's control area energy management control system.

7. The Respondent's proposal must provide a milestone schedule that identifies key dates, including but not limited to dates for regulatory approvals, finalization of transmission and interconnection agreements, finalization of fuel supply arrangements, pre-construction milestones, and construction milestones, along with terms for default.

B. Electrical Transmission Requirements

Respondents are asked to provide the information that is necessary to understand and assess the transmission delivery path(s) and the FPC system impacts of the proposed power supply arrangements. Under the guidelines outlined herein, Attachments C and E provide detailed information requirements for each resource included in the proposal. Respondents who are placed on the "short list" shall provide reasonable assurances that they will be able to provide or secure adequate and reliable firm transmission capability for each generating resource included in the Respondent's proposal for the duration of the term of the power supply to FPC.

1. Definition of Terms

- FPC Transmission System: Transmission facilities owned, controlled, or operated by FPC.

- FPC Control Area: The FPC Transmission System bounded by FPC tie-line metering and telemetry which controls generation directly to maintain

interchange schedules and frequency.

- Resource: Each specific generating resource or system power resource included in the Respondent's proposal.

2. External Resource Information Requirements

   a. For each Resource included in the proposal not directly connected to the FPC Transmission System (External Resource), the Respondent shall describe the location of the External Resource and specify in detail all transmission path(s) that will be utilized, the transmission service that will be purchased, and the name of each transmission provider required to deliver the External Resource to the FPC Control Area. The description of the location of each External Resource should include:

      - For specific generation, the specific delivery point on the transmission system where the generation is located.

      - For a system power offer, the transmission system(s) on which the power resources are located.

   b. Respondents are responsible for paying for and clearly delineating in their price quotes all charges and costs for firm transmission service to deliver power to the FPC Control Area.

   c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current Florida Reliability Coordinating Council (FRCC) load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

   d. For proposals included in the "short list" that include External Resources, the Respondents must demonstrate during the "short list" evaluation phase of this RFP that firm transmission service can be secured on all transmission paths required to deliver the External Resource to the FPC Control Area.

3. Internal Resource Information Requirements

   a. For each Resource included in the proposal that is directly connected to the FPC Transmission System (Internal Resource), the Respondent must

describe the specific delivery point on the FPC Transmission System where the Resource is or is proposed to be located.

b. The Respondent shall include in the proposal the costs of all generation equipment up to and including the generator step-up transformer(s).

c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current FRCC load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

4. Transmission System Impact Study

During the "short list" evaluation phase of this RFP, FPC will perform a transmission system impact study to evaluate all proposals on the "short list" at the same time. All required information to conduct this study must have already been provided to FPC in accordance with the schedule provisions of this RFP. The cost of this study shall be pro-rated among all Respondents whose proposals are included on the "short list." Coincident with the determination by FPC of the "short list," FPC will issue System Impact Study Agreements to each Respondent included on the "short list."

C. Non-Price Attributes

1. At this time, FPC would view more favorably proposals that:

- Offer a greater degree of firmness and reliability;
- Offer shorter unit commitment notification and greater dispatch flexibility;
- Offer greater contract flexibility through creative proposal options potentially including, but not limited to:
  - The right for FPC to terminate early,
  - Supplemental capacity call options
  - Options to buy the generating asset at pre-determined prices.

  (Respondents must provide discrete cost or fee structures for proposed contract flexibility attributes.)

- Offer greater supplier performance assurances through parent guarantees, securities, deposits, or other means;

- Promote FPC transmission system reliability and integrity;
- Utilize commercially proven technologies;
- Minimize potential adverse environmental impacts; and
- Offer larger megawatt block sizes.

2. FPC will consider the following additional non-price attributes in its evaluation of proposals:

- Respondent's qualifications and experience;
- Technical and financial viability of the proposal;
- Project location (for example: grid location, zoning, community acceptance);
- Resource scheduling and dispatchability;
- Deliverability (interconnection and transmission), including system reliability and transmission related issues;
- Fuel supply, including, but not limited to:
    - Firmness of fuel supply,
    - Backup fuel supply,
    - Dual fuel capability,
    - Transportation flexibility,
    - Fuel management or tolling requirements;
- Water supply;
- Environmental compliance;
- Operational and maintenance plans;
- Performance criteria;
- Pricing structure;

- Potential for increases or decreases in FPC's cost of capital;

- The effect of Respondent's financing arrangements on FPC's system reliability;

- Any competitive advantage the financing arrangement may give the Respondent; and

- All factors that must be considered or discussed by FPC pursuant to F.A.C. Rule 25-22.081, .082.

3. This list of attributes is not intended to be all inclusive. Other innovative and cost effective offerings, which provide value to FPC and its customers, will be viewed favorably.

D. Performance Assurances

FPC will rely on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement and should be included in the Respondent's proposal. Performance guarantees and financial credit assurances will also be required of the Respondents, subject to negotiation, at FPC's discretion, and also should be included in Respondent's proposal.

V. Proposal Evaluation

A. Proposal Evaluation Procedure

1. FPC and/or independent consultants will evaluate proposals and recommend proposals, if any, which provide the most value to FPC and its customers. FPC reserves the right to evaluate the proposals in a manner that ultimately produces the most competitive responses from which to begin negotiations. Proposals that offer less than 530 MW may be combined with other proposals as supply-side alternatives to FPC's next planned generating unit. FPC shall determine in its sole discretion the value of any proposals and of any resulting agreement to FPC and its customers.

2. Information provided from each Respondent by the proposal due date will be used to develop a short list of proposals from which selection(s) could be made for direct negotiations. No additional information will be accepted after the proposal due date, except for clarifications requested by FPC and possible

transmission study results. FPC will evaluate the proposals in terms of price and non-price attributes.

3. FPC will perform an initial screening evaluation to identify and eliminate any proposals that are not responsive to the RFP, do not meet the minimum requirements set forth in the RFP, are clearly not economically competitive with other proposals, or are submitted by Respondents that lack appropriate creditworthiness or sufficient financial resources or qualifications to provide dependable and reliable service.

4. The proposals that pass the initial evaluation screen will be further evaluated based on qualitative and non-price attributes, as discussed at Section IV. C above, and using production costing methods and other models so that all reasonable cost impacts can be quantified. A selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will compete with each other and with any self-build options before FPC makes any final selection.

B. Reservation of Rights

1. FPC reserves the right, without qualification and in its sole discretion, to accept or reject any or all proposals for any reason or to make the award to that Respondent, who, in the opinion of FPC, will provide the most value to FPC and its customers. FPC also reserves the right to make an award to other than the lowest price offer or to the proposal evidencing the greatest technical ability if FPC determines that to do so would result in the greatest value to FPC and its customers. FPC may make an award of contract without further discussion.

2. FPC reserves the right to reject any, all, or portions of the proposals received for failure to meet any criteria set forth in this RFP. FPC also may decline to enter into a power purchase arrangement with any Respondent, or to abandon the project in its entirety. FPC reserves the right to revise the capacity needs forecast at any point during the RFP process or during negotiations and any such change may reduce, eliminate, or increase the amount of power sought.

3. Respondents should be aware that the following, without limitation, will be classified as non-responsive and will not be considered or evaluated if submitted:

   - proposals offering non-firm capacity or energy;
   - demand-side proposals;
   - incomplete, inaccurate, conditional, deceptive, misleading, ambiguous,

exaggerated, or non-specific offers; or

- proposals that are not in conformance with the requirements and instructions contained herein.

4. Those who submit proposals do so without recourse against FPC or Florida Progress Corporation or any of Florida Progress Corporation's subsidiary companies for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Attachment A

Notice of Intent to Bid Form

Project Bidder

Respondent Contact Name: _____
Title: _____
Company Name: _____
Address: _____
_____
Telephone: _____
Facsimile: _____
Project Name: _____
Project Location: _____

General Description of the Proposed Project:

_____
_____
_____

(Attach additional sheets as needed)

Proposed Capacity Delivered to FPC: _____
Contract Term: _____
Power Generation Technology: _____
Primary Fuel: _____
Back-up Fuel: _____
Specific Entity to Contract with FPC:

_____

Respondent Classification:
(e.g., Utility, Power Marketer, EWG, QF, etc.):

_____

Other Parties Involved in the Proposal:

_____

Respondent Qualifications:
Describe similar projects developed by Respondent, identifying project capacity, location, contract commencement date and term, and any other information the Respondent considers appropriate. *(Attach additional sheets as needed)*

_____
_____
_____

Respondent's Signature: _____
(Title/Position)

Attachment B

Proposal Summary Form

Company/Respondent: _____
Respondent Contact Name: _____
Mailing Address: _____
_____
Telephone: _____
Facsimile: _____
General Description of the Proposed Project: _____
_____
_____
(Attach additional sheets as needed)
Power Generation Technology: _____
Unit(s) Name: _____
Project Location: _____
Contract Term: _____
Unit(s) Summer MW Rating: _____
Unit(s) Winter MW Rating: _____
Unit(s) Fuel Type(s): _____
Proposed Capacity (MW) Delivered to FPC: _____
Proposed delivery point to FPC: _____
Other Parties with an Interest in the Proposal: _____
_____

Certification: Respondent hereby certifies that all of the statements and representations made in this proposal, including all attachments, are true to the best of Respondent's knowledge and belief. Respondent agrees to be bound by its representations and the terms and conditions of the Request for Proposals. This proposal shall remain in effect until at least October 1, 2000.

Signed: _____
Name: _____
(Typed)
Title: _____
Date: _____

Attachment C

Respondents are requested to respond to the following data requests. All of this information is important to assist FPC in better understanding, among other things, the price and non-price attributes addressed in each alternative generating proposal, including their technical and financial viability, pricing structure, dispatchability, deliverability, water supply, environmental compliance, and performance criteria.

Certain data requirements in this RFP reference "Seasons," which will, for consistency, be defined as:

Winter	[December *through* February]
Summer	[June *through* September]
Shoulder	[Balance of the Months]

Section 1: General Proposal Information

Respondents are requested to provide brief but concise answers to the Data Requests below. If annual escalation is expected or if contract price will vary, include any such rates or indices.

1. Provide documentation of Respondent's previous experience providing the proposed product.

2. Provide the following information for your company:

   a. Annual reports and Form 10-K for the past three years. If these documents are not readily available, then audited financial statements for the past three years will be accepted.

   b. Dunn and Bradstreet identification number credit rating of the Respondent's senior debt securities. Any additional documentation needed to allow FPC to determine the Respondent's financial strength.

   c. Ten year summary of litigation activity related to (1) provision of energy products and services (fuel, power, ancillary services, engineering, on-site services), (2) lease option arrangements for assets, (3) purchases of energy products and services (as above), or (4) industrial construction projects (power plants, industrial plants, cogeneration facilities, etc.).

3. Provide copies of notices to be published, per Section III.D.2 of the RFP.

4. Provide a complete schedule of the proposed contract terms and conditions.

5. Provide a detailed list and summary of contract flexibility attributes included in the proposal as well as discrete cost or fee structures for each of the proposed attributes.

6. Present a detailed description of any security or credit instruments proposed by the Respondent to back its performance obligation.

7. Provide a detailed summary of any liquidated damages provisions included in the proposal and a description of the particular circumstance(s) they are intended to mitigate.

8. Describe whether or not this capacity has been offered in another RFP or is in any other way obligated or may be obligated to others, and under what conditions it would be released to serve this proposed sale.

9. Describe the firmness of the capacity in your offer.

10. Explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the energy after it has been scheduled.)

Section 2: Specific Supply Resource Information

1. For a proposal involving a specific unit(s), provide the following information using the data tables included where appropriate:

    a. (Proposed) Unit name and location.

    b. For new units, provide the schedule for licensing, permitting and construction, including the projected date of commercial operation.

    c. Descriptions (including models and manufacturers) of all of the major components.

    d. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation or other fixed price components. Clearly delineate whether each price component and/or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

    e. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

    f. Seasonal Unit ratings (MW, MVAR, MVA) based on the ambient condition

assumptions of Winter (40°F), Summer (90°F), and Shoulder (59°F). If capacity being offered is less than the full capability of the generating unit(s), provide the full capability information for these same ambient conditions. Explain if and how unit performance degradation is accounted for over time. (See Table 3)

g. Generator capability curve.

h. Guaranteed availability. (See Table 4)

i. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation). (See Table 5)

j. For planned maintenance requirements, discuss the means by which FPC will be entitled to schedule the planned maintenance periods. (See Table 6)

k. Detailed Fuel Supply Plan (primary and secondary).

i. Fuel type, on-site storage capability and inventory management plan, applicable fuel specifications, metering requirements. (See Table 9)

- Natural Gas: Include interstate pipeline supplier, connection point, lateral length, type and quantity of firm, recallable, and interruptible transportation.
- Oil: Include type, special specifications, storage tank description, number of hours of full load operation supported by the tank.
- Other Fuels.

ii. Any proposed tolling or other fuel procurement arrangements that would involve FPC in the fuel management process.

iii. Operating limits on either the primary or secondary fuels, if any.

l. Describe any dispatch notice or scheduling requirements for this offer, including, but not limited to:

i. Minimum run time per dispatch call, if any.

ii. Minimum down time, if any.

iii. Start up energy requirements.

iv. Ramp Rate(s).

iv. Start up time from cold start and from hot start.

v. Start up costs from cold start and from hot start.

vi. Quick start capability (less than 10 minutes). (See Table 7)

m. Maximum and minimum operating levels, capacity breakpoints and corresponding net heat rates (in Btu/kWh, on a higher heating value basis). Provide on a seasonal basis, as outlined in the tables. (See Table 8a and 8b)

n. Maximum or minimum energy take per month, season, year, or contract period, if any.

o. A detailed water supply plan, including data requirements. (See Table 10).

p. A thorough description of anticipated environmental impact, environmental permitting requirements, and actions for compliance.

q. A complete description of any cogeneration aspects of the facility(s) including, but not limited to, fuel, steam, water, or power sales and any details related to qualifying facility status, if any.

r. A complete description of any actual or proposed energy or capacity sales, or sales of any other energy-related products (ancillary services, steam, tankage, etc.) to any other parties from this facility(s).

s. Any other limit on use or availability of resource's output, if any.

Section 3: System Supply Resource Information

1. For a system sale or other sales, please provide the following information. It is difficult to anticipate all possible system supply scenarios, but please use the existing tables to the extent that it is practical and provide any additional information needed in separate schedules, tables and/or forms.

   a. Seasonal Capacity (MW, MVAR, MVA) available for use on the FPC System. (See Table 3)

   b. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation, or other fixed price components. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

c. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

d. A description of the system from which the power will be provided, including the name, location, the installed capacity, capacity mix, fuel mix, technology mix, peak hour load, and reserve projections (with and without the proposed capacity sale) during the proposal period. In addition, provide all data requested in the tables. (See Table 11).

e. A detailed history of the system operations for the past five years including, but not limited to fuel mix, power sales and purchases (energy and demand) to native load and to non-native load, emergency power purchase requirements, historical reserve levels, and incidences of firm transmission interruptions. In addition, provide all data requested in the tables. (See Table 11)

f. In conjunction with the information and data provided in b. and c., please provide copies of the 1999 and 2000 EIA-411 filings and the 1999 Ten Year Site Plan for all systems from which power is to be sold under this proposal offering.

g. An explanation of the priority of this proposed transaction relative to all other supply commitments (existing and future) and any criteria under which the supply of system power by the Respondent might be curtailed or interrupted.

h. A description of any dispatch notice or scheduling requirements for this offer.

i. Guaranteed availability. (See Table 4)

j. Maximum or minimum energy take per month, year, contract period, if any.

k. A thorough description of anticipated environmental impact and compliance resulting from these power sales.

l. Any other limit on use or availability of resource, if any.

Section 4: Supplemental Transmission Information

1. Provide all information required in Section IV.B, Transmission Information Requirements,

of this RFP for each Internal or External Resource included in the Respondent's proposal. This data must be included with the Respondent's proposal when it is submitted.

2. If this data has already been supplied to FPC Transmission Planning associated with a current generation interconnection request on the FPC Transmission System, please clearly identify the request, the date of the request and the project(s) associated with the request.

3. Provide a schedule of the costs that the bidder will be responsible for paying for transmission service to deliver power to FPC's Control Area.

4. Describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the FPC Control Area. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.

5. Describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.

Section 5: Data Tables

Respondents are requested to complete the tables in the attached excel file labeled "Data Tables", as represented herein. Once the tables are completed electronically, the respondent is required to print the resulting data tables and include these printed tables in their proposal document. Add rows as necessary for additional years. If annual escalation is expected, include such escalation rates or indices. Please note any additions or modifications made to the tables. Do not leave blanks: write in "N/A" if topic is not applicable, or "0" if the value is zero. Respondents may provide additional tables, as required to better clarify their proposals. Such additional tables should follow the Water Requirements table, and be labeled "Additional Table - (Description)," and include appropriate units.

Table 1. Fixed Capacity Price Structure- ($/kW-month)

Season	Year: 2003	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2004	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2005	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2006	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2007	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2008	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2009	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2010	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2011	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2012	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
	Price					

Season	Year: 2016	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2017	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2018	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2019	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2020	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2021	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2022	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2023	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2024	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2025	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
	Price					

Table 2a. Variable Price Structure, Primary Fuel- (units below)

Season	Year: 2003 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2004 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2005 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2006 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2007 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2008 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2009 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2010 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						

Season	Year: 2016 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2017 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2018 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2019 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2020 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2021 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2022 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2023 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					

Table 3. Resource Capacity Rating- (units below)

		40°F		59°F		90°F	
Guaranteed Contract Rating	MW						
	MVAR						
	MVA						
Maximum Unit Rating	MW						
	MVAR						
	MVA						

Table 4. Guaranteed Availability- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 5. Equivalent Forced Outage Rate- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 6. Planned Maintenance Requirements- (Number of Outages/Year, Total Hours/Year)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number/year													
Maint Hrs/yr													
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number/year													
Maint Hrs/yr													

Table 7. Operational Parameters- (units below)

Minimum run time per dispatch call		Hours
Minimum down time between calls		Hours
Startup Energy		MMBtu
Ramp Rate		MW / minute
Ramp Rate		minutes to full load
Number of Hot Starts per year		Maximum
Number of Hot Starts per year		Included in bid proce
Cost of Each Hot Start Beyond Those Included		Dollars
Number of Cold Starts per year		Maximum
Number of Cold Starts per year		Included in bid proce
Cost of Each Cold Start Beyond Those Included		Dollars
Quick Start Capability- Minutes to 1st MW		Minutes
Quick Start Capability- MW in ten minutes		MW
Start up time from cold start		Minutes
Start up cost from cold start		$
Start up time from hot start		Minutes
Start up costs from hot start		$

Table 8a. Capacity States on Primary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 8b. Capacity States on Secondary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

NOTE: Net Heat Rates are to be based on Higher Heating Value (HHV)

Table 9. Fuel Supply Requirements		Units
Primary Fuel Maximum Flow rate		
Primary Fuel Pressure Requirement		
Primary Fuel Metering Requirement		
Primary Fuel Storage Capacity		
Secondary Fuel Maximum Flow rate		
Secondary Fuel Pressure Requirement		
Secondary Fuel Metering Requirement		
Secondary Fuel Storage Capacity		

Table 10. Water Requirements		Units
Cooling		
Consumptive Use		
Other		

Table 11. System Reliability Parameters

	Actual					Forecast				
	1995	1996	1997	1998	1999	2003	2004	2005	2006	2007
Installed Capacity										
Contracted System Firm Capacity Purchases										
Contracted System Firm Capacity Sales										
Load Control Capability										
Seasonal Peak Requirements before Direct Load Control										
Firm Peak Requirements after Direct Load Control										
Capacity Margin before Direct Load Control										
Firm Reserve Margin after Direct Load Control										

Attachment D - Planned Unit Data

The following data represent the planned unit data estimates, which FPC utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on FPC's existing Hines Energy Complex site in Polk County, Florida.

2. Planned Size 530 MW (nominal).

3. Commercial Operation of the facility is proposed to be November 30, 2003.

4. The primary fuel is natural gas. Oil will be used as a backup fuel source.

5. The estimated total direct cost is $197.6 million.

6. The estimated annual levelized revenue requirement is $35.6 million over 25 years.

7. The estimated annual value of deferral of this unit is $48.95/kW-yr (03$).

8. The estimated annual fixed O&M is $2.2 million (03$). The estimated variable O&M is $1.11/MWH (03$).

9. The estimated delivered fuel cost is $2.66/MMBtu (03$), plus fixed transportation at the prevailing rate.

10. The following are estimates for:

Planned outage rate	7, 7, 14, 7, 7, 22 days/year (or 2.92%)
Forced outage rate	3.5 %
Heat rate at maximum capacity	6,975 Btu/kWh
Minimum load	250 MW
Ramp Rate	1 Hr.

11. The estimated transmission and interconnection costs for this unit are $5.6 million.

12. Supplemental site certification as well as amendment to related environmental permits will be required for this unit. It is FPC's plan to comply with all environmental standards of Local, Regional, State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.5 % per year
General escalation:	3.1 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.3 %
	55 % equity @ 12.0 %

Attachment E

Florida Power Corporation
Generation Interconnection Study
Data Request Form

INSTRUCTIONS

(*) denotes items that are required for both a Generation Interconnection Feasibility Study and a Generation Interconnection Study and must be completed and included in Respondent's proposal. All items on this form are required prior to the start of engineering design.

If a data item is unavailable, please provide an estimate and indicate it as an estimate. Please note that a restudy could be required if data assumptions change while the study is in progress.

Please fill out and attach a copy of Section II for each generator on the site.

Please use this form to supply the requested data. Submittal of manufacturer data sheets, other than generator characteristic curves, is not an acceptable alternative to completing this form.

SECTION I – Generation Site Data

A) **Contact Person** - Provide name and address of person completing this form

(*)1. Name: _____

(*)2. Address: _____

(*)3. City/State/Zip: _____

(*)4. Telephone: _____

(*)5. Date: _____

B) **Site Location**

(*)1. County: _____

(*)2. Section / Township / Range: _____

(*)3. Site Drawing: Include a site drawing indicating county, section, township, and range. In addition, for a Generation Interconnection Study, a preliminary equipment layout on the site, suitable for site plan permitting, is required.

C) **Proposed Load Requirements for Site**

(*)1. Required Date: _____

(*)2. Nature of Load (Station Service, Start-up Power, Etc.) _____

(*)3. Connected kVA Load: _____

(*)4. Peak Demand kVA Load: _____

(*)5. Expected Power Factor: _____

(*)6. Service Voltage: _____

(*)7. Anticipated Future Load Requirements (please describe): _____

_____

_____

_____

D) **Other Site Information**

(*)1. Net Generation Output (MVA) for Site @ 59°F Outdoor Ambient: _____

(*)2. Net Generation Output (MVA) for Site @ 90°F Outdoor Ambient: _____

(*)3. Proposed Interconnections with Other Systems (please describe):

_____

_____

E) In-Service Dates

(*)1. Required connection to grid for generator testing: _____

(*)2. Commercial in-service date: _____

SECTION II – Individual Generator Data

A) Unit Identification

(*) 1. Plant Name and Unit Number _____

2. Manufacturer _____

3. Generator Serial Number _____

4. Turbine Serial Number _____

B) Ratings and Capabilities

1. Nameplate kV Rating (nominal design voltage) _____

2. MVA Rating

	MVA Rating	@ Hydrogen Pressure
a.	_____	_____
b.	_____	_____
c.	_____	_____
d.	_____	_____

(*) 3. Gross MW Rating @ 59°F Outdoor Ambient _____

(*) 4. Net MW Rating @ 59°F Outdoor Ambient _____

(*) 5. Gross MW Rating @ 90°F Outdoor Ambient _____

(*) 6. Net MW Rating @ 90°F Outdoor Ambient _____

7. Rated Power Factor _____

8. Rated Speed _____

9. Rated Turbine Capability _____

10. Field Voltage at Rated Load _____

11. Field Current at Rated Load _____

12. No-load Field Voltage at Generator Rated Voltage _____

13. Air Gap Field Voltage at Generator Rated Voltage _____

14. Field Resistance ____ohms @ _____ °C

C) Inertia

(*) 1. WR^2 for Generator and Exciter _____ $lb\text{-}ft^2$

(*) 2. WR^2 for Turbine _____ $lb\text{-}ft^2$

(*) 3. Calculated H Constant _____sec. @ _____ MVA

D) Losses and Efficiency

1. Open circuit core loss _____ kW

2. Windage loss _____ kW

3. H_2 seal and exciter friction loss _____ kW

4. Stator I^2R Loss at rated power and voltage _____ °C _____ kW

5. Rotor I^2R Loss at rated power and voltage _____ °C _____ kW

6. Stray Load loss _____ kW

7. Excitation losses _____ kW

E) Generator Time Constants

1. T'_{do} (Direct axis open circuit transient time constant) _____ sec
2. T''_{do} (Direct axis open circuit subtransient time constant) _____ sec
3. T'_{qo} (Quadature axis open circuit transient time constant) _____ sec
4. T''_{qo} (Quadature axis open circuit subtransient time constant) _____ sec
5. T_{a3} (Short circuit time constant) _____ sec

F) Generator Impedances

(*) 1. MVA base for all impedance data _____ MVA

(*) 2. kV base for all impedance data _____ kV

Parameter		Description	p.u. value
(*) 3.	X_d	Direct axis synchronous reactance (unsaturated)	
4.	X_q	Quadrature axis synchronous reactance (unsaturated)	
(*) 5.	X'_d	Direct axis transient reactance (unsaturated)	
6.	X'_{ds}	Direct axis transient reactance (saturated)	
7.	X'_q	Quadrature axis transient reactance (unsaturated)	
8.	X'_{qs}	Quadrature axis transient reactance (saturated)	
(*) 9.	X''_d	Direct axis subtransient reactance (unsaturated)	
10.	X''_q	Quadrature axis subtransient reactance (unsaturated)	
11.	X_L	Armature leakage reactance	
12.	R_1	Positive sequence armature resistance at 75° C	
13.	R_2	Negative sequence armature resistance at 75° C	
14.	X_2	Negative sequence armature reactance at rated voltage	

15. X_0 Positive sequence armature resistance at 75° C _____

16. R_{dc} Direct current armature resistance at 75° C _____

17. Generator neutral grounding resistance _____ ohms

(*)18. Generator neutral grounding reactance _____ ohms

G) Required Characteristic Curves and Diagrams

(*) 1. Real and reactive power capability curves **(Maximum var capability, lagging and leading, is sufficient for Feasibility Study)**

2. Saturation curve, full load and no-load

3. "V" curves

4. Governor overspeed response curve

5. One-Line diagram showing generator and substation equipment connections

H) Excitation System Data

1. Excitation system type _____

2. Voltage regulator model name _____

3. Excitation system model, supply block diagram and model parameters in IEEE[1] or PSS/E format

4. Voltage compensation, supply block diagram and settings if used

5. Voltage regulator overexcitation limiters, supply block diagram and model parameters in IEEE[2] format.

6. Power System Stabilizer (if used), supply Power System Stabilizer block diagram and model parameters in IEEE or PSS/E format

I) Turbine Governor Data

1. Speed/Load governor model name _____

[1] IEEE Standard 421.5-1992 "IEEE Recommended Practice for Excitation System Models for Power System Stability Studies"

[2] IEEE Committee Report, "Recommended Models for Overexcitation Limiting Devices," IEEE Transactions on Energy Conversion, Vol. 10, No. 4, December 1995

2. Governor model, supply block diagram and model parameters in IEEE[3,4] or PSS/E format

J) Generator Step-up Transformer Data

1. Manufacturer _____

2. Model Type _____

3. Serial Number _____

(*) 4. Rating _____ MVA

(*) 5. High voltage winding, nominal voltage _____ kV

(*) 6. High voltage winding connection (wye/delta) _____

(*) 7. Low voltage winding, nominal voltage _____ kV

(*) 8. Low voltage winding connection (wye/delta) _____

9. Transformer resistance _____ p.u.

(*)10. Transformer reactance _____ p.u.

(*)11. Transformer impedance base values _____ MVA _____ kV

12. Available tap settings

HV taps _____ kV

LV taps _____ kV

13. Expected tap settings

HV taps _____ kV

LV taps _____ kV

---

[3] IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbine Control Models for System Dynamic Studies," IEEE transactions on Power Apparatus and Systems, Vol. PAS-92, November, 1973

[4] W.I. Rowen, "simplified Mathematical Representations of Heavy Duty Gas Turbines," Transactions of ASME, Vol.105(1), 1983

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

Exhibit JBC-2

DIRECT TESTIMONY OF JOHN B. CRISP

ON BEHALF OF FLORIDA POWER CORPORATION

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Director, Regulatory Counsel Group
FLORIDA POWER CORPORATION
P.O. Box 14042
St. Petersburg, Florida 33733
Telephone: (727) 820-5184
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GARY L. SASSO
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 5 (Part 2 of 3)
COMPANY/ WITNESS: Crisp
DATE: 10-26-27-00

CARLTON FIELDS

ATTORNEYS AT LAW

ONE PROGRESS PLAZA
200 CENTRAL AVENUE, SUITE 2300
ST. PETERSBURG, FLORIDA 33701-4352

MAILING ADDRESS:
P.O. BOX 2861, ST. PETERSBURG, FL 33731-2861
TEL (727) 821-7000 FAX (727) 822-3768

January 27, 2000

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

VIA FEDERAL EXPRESS

Re: Florida Power Corporation's Request for Proposals

Dear Ms. Bayo:

Pursuant to Rule 25-22.082, Florida Administrative Code, Florida Power Corporation is filing herewith an original and fifteen (15) copies of Florida Power Corporation's Request for Proposals.

We request you acknowledge receipt and filing of the above by stamping the additional copy of this letter and returning it to me in the self-addressed, stamped envelope provided.

If you or your Staff have any questions regarding this filing, please contact me at (727) 821-7000.

Very truly yours,

Gary L. Sasso

Enclosure

RECEIVED & FILED
FPSC-BUREAU OF RECORDS

JBC-2

DOCUMENT NUMBER-DATE
01253 JAN 28 00
FPSC-RECORDS/REPORTING

REQUEST FOR PROPOSALS

January 26, 2000

I. Purpose And Scope

In accordance with Rule 25-22.082, F.A.C., Florida Power Corporation (FPC) issues this request for proposals (RFP) to solicit and screen, for subsequent contract negotiations, competitive proposals for supply-side alternatives to its next planned generating unit. FPC invites proposals that will offer exceptional value to FPC and its customers. Proposals submitted pursuant to this RFP will be considered and evaluated against each other and against FPC's self-build options. FPC's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW (net) to be located at the Hines Energy Complex in Polk County, Florida and available November 30, 2003. For a more detailed description of this planned unit, refer to Attachment D.

Respondents are asked to provide capacity offered in their proposal at a level of firmness that is dedicated solely to FPC's use and subject to dispatch by FPC. For purposes of this solicitation, FPC is interested in long-term proposals with flexible contract options.

II. Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	1/26/2000	
Notice of Intent to Bid (NOI) Due	2/10/2000	NOIs should be received by FPC's RFP Contact by 3:00 P.M. EST
Pre-Bid Meeting	2/18/2000	Tampa Airport Marriott 10:00 A.M. - 12:30 P.M. EST Room To Be Determined
Proposals Due	3/27/2000	Proposals must be received by the RFP Contact by 3:00 P.M. EST

Short-list Determination	5/19/2000	If applicable
Complete Negotiations	8/1/2000	If applicable
File contract(s) with state Public Service Commission for approval	8/15/2000-9/29/2000	If applicable

FPC reserves the right to revise, suspend, or terminate this schedule at its sole discretion. Any changes to the schedule will be provided, as appropriate, to Respondents that have submitted a timely NOI.

III. Proposal Guidelines

A. Instructions for Completing Forms

1. All Respondents are encouraged to submit a written Notice of Intent to Bid (NOI), using the form provided in Attachment A. Please submit the NOIs to the FPC RFP Contact by facsimile, Registered or Certified Mail, Return Receipt Requested, or overnight courier, by 3:00 P.M. EST, February 10, 2000. Voice telephone notices will not be acknowledged.

2. Respondents are also encouraged to attend the February 18, 2000 pre-bid meeting. This meeting is tentatively set to be held from 10:00 A.M. to 12:30 P.M. at the Tampa Airport Marriott (Room TBD). If this time or location change, FPC will notify Respondents who have submitted a NOI.

3. All Respondents must submit with their proposal a Proposal Summary using the form provided in Attachment B.

4. All proposals must be submitted in the format shown in the RFP response forms Attachment C and E. Respondents should, at the time of proposal submittal, supply any additional information not included in the forms if such information may be needed for a thorough understanding or evaluation of the proposal. All responses will be considered commitments to be used in defining any agreement between FPC and the Respondent that may arise from this RFP.

5. Proposals must be signed by a duly authorized officer of the Respondent.

6. A signed original and ten (10) copies of the proposal, including all attachments.

must be submitted along with the electronic forms provided on a 3.5" floppy diskette. The electronic forms may be obtained from FPC on floppy disk or downloaded from the Company website (www.fpc.com). In the event of a discrepancy between the electronic forms and the hard copy, the hard copy will be considered to be correct.

7. All proposals, including all attachments, must be properly completed and returned by overnight courier or Registered or Certified Mail, Return Receipt Requested, in both hard copy and electronic versions, to FPC's RFP Contact:

Michael D. Rib
Director, Resource Planning
Florida Power Corporation
263 13th Avenue South
St. Petersburg, FL 33701
Phone: (727)826-4387
Fax: (727)826-4333
E-mail: rfpresponse@fpc.com

All proposals shall be received by FPC's RFP contact no later than 3:00 P.M. EST on March 27, 2000. Late or incomplete offers may be rejected by FPC. Offers must remain open until at least October 1, 2000. All inquiries and other communications relating in any manner to this RFP must be directed in writing or by facsimile or E-mail to FPC's RFP Contact. FPC may distribute Respondents' questions and FPC's answers to such questions to all other Respondents if FPC deems the question to be of general interest. Unsolicited contact about this process with other FPC personnel or attorneys or consultants retained by FPC may result in disqualification.

8. Complete information is needed to facilitate a timely evaluation. FPC may request clarifying or additional information at any time during the evaluation process, and Respondents will be expected to provide timely responses to facilitate the evaluation and decisionmaking process within the time constraints. Respondents must provide all data requested in the RFP and the applicable attachments. FPC may reject non-specific offers from further consideration.

9. Proposals must reflect any and all of the costs that FPC would be expected to pay for power delivered to FPC's System. If any portion of the total delivered cost of power is not intended to be clearly defined in the pricing outlined in the proposal, then a detailed description of the proposed approach regarding that portion of cost must be clearly delineated in the proposal. Prices and dollar figures quoted must be clearly stated in $US as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.

B. Confidentiality

FPC will take reasonable precautions and use reasonable efforts to protect any proprietary and confidential information contained in a proposal provided that such information is clearly identified by the Respondent as "Proprietary and Confidential" on the page on which proprietary and confidential information appears. Such information may, however, be made available under applicable state or federal law to regulatory commission(s), their staff(s), or other governmental agencies having an interest in these matters. FPC reserves the right to release such information to agents, contractors, or to its parent company or to subsidiaries thereof, for the purpose of evaluating the Respondent's proposal but such companies, agents, or contractors will be required to observe the same care with respect to disclosure as FPC. Under no circumstances will FPC or Florida Progress Corporation or their subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure during or after the solicitation process.

C. Proposal Evaluation Costs

1. To help defray the cost of performing the proposal evaluations, Respondents are required to submit, with the proposal, a non-refundable check payable to Florida Power Corporation for $10,000 for each proposal. Changes in the physical attributes, such as site, output, fuel, or technology changes will require the submission of a separate proposal and payment of another fee.

2. Neither FPC nor its representatives, affiliate companies, or parent company shall be liable for any expenses incurred in connection with preparation of a response to this RFP or for any costs, fees, or lost or foregone profits of unsuccessful Respondents. Respondents should prepare their proposals simply and economically, providing a straightforward and concise description of the Respondent's ability to meet the requirements of the RFP. Any Respondent that submits in its proposal to FPC any information that is determined by FPC to be substantially inaccurate, misleading, exaggerated, or incorrect shall be disqualified from consideration.

D. Regulatory Provisions

1. Any negotiated contract for the purchase of power between FPC and the Respondent will be conditioned upon approval or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation, including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission.

2. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:

Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

Respondents are required to forward copies of these actual published notices to FPC when they are available.

IV. General Specifications

A. Minimum Requirements for Proposals

In addition to the requirements of Section III above, proposals must also meet the minimum requirements set forth below. FPC, in its sole discretion, may reject any proposal that fails to respond adequately or completely to all or any part of this RFP.

1. Capacity offered must be at a level that is dedicated solely to FPC's use and subject to dispatch by FPC. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources will not be evaluated and will be rejected. Proposals must allow FPC the right to use this generating resource, including, but not limited to, electrical transmission services associated with the project, for any purpose that the company deems appropriate in its sole discretion.

2. The capacity must be available no later than November 30, 2003.

3. Proposal prices must reflect any and all costs that FPC will be expected to pay for power delivered to its system, as outlined in this RFP. Further, Respondents shall be responsible for absorbing all charges and costs for firm transmission service (including the cost of all attendant equipment, including but not limited to generator step-up transformers) to deliver each generating resource included in the proposal to the FPC control area, or to interconnect a generating resource to the FPC Transmission System.

4. A Respondent whose proposal is selected shall take all necessary actions to

satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on the Respondent by any federal, state, or local law, or ordinance, rule, or regulation concerning the generation, sale, or delivery of the power. FPC will cooperate with the Respondent to provide information or such other assistance as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise fully support all of FPC's regulatory requirements associated with this potential power supply arrangement.

5. A Respondent whose proposal is selected shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale, or delivery of power for the entire term of the proposed contract, and the Respondent shall include any such costs in its proposal.

6. The proposal must include unit commitment notification and dispatch scheduling provision details for the contract sale. Respondents must describe provisions that can and would be made to allow FPC to dispatch the proposed generating resources directly from FPC's control area energy management control system.

7. The Respondent's proposal must provide a milestone schedule that identifies key dates, including but not limited to dates for regulatory approvals, finalization of transmission and interconnection agreements, finalization of fuel supply arrangements, pre-construction milestones, and construction milestones, along with terms for default.

B. Electrical Transmission Requirements

Respondents are asked to provide the information that is necessary to understand and assess the transmission delivery path(s) and the FPC system impacts of the proposed power supply arrangements. Under the guidelines outlined herein, Attachments C and E provide detailed information requirements for each resource included in the proposal. Respondents who are placed on the "short list" shall provide reasonable assurances that they will be able to provide or secure adequate and reliable firm transmission capability for each generating resource included in the Respondent's proposal for the duration of the term of the power supply to FPC.

1. Definition of Terms

- FPC Transmission System: Transmission facilities owned, controlled, or operated by FPC.

- FPC Control Area: The FPC Transmission System bounded by FPC tie-line metering and telemetry which controls generation directly to maintain

interchange schedules and frequency.

- Resource: Each specific generating resource or system power resource included in the Respondent's proposal.

---

2. External Resource Information Requirements

   a. For each Resource included in the proposal not directly connected to the FPC Transmission System (External Resource), the Respondent shall describe the location of the External Resource and specify in detail all transmission path(s) that will be utilized, the transmission service that will be purchased, and the name of each transmission provider required to deliver the External Resource to the FPC Control Area. The description of the location of each External Resource should include:

      - For specific generation, the specific delivery point on the transmission system where the generation is located.

      - For a system power offer, the transmission system(s) on which the power resources are located.

   b. Respondents are responsible for paying for and clearly delineating in their price quotes all charges and costs for firm transmission service to deliver power to the FPC Control Area.

   c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current Florida Reliability Coordinating Council (FRCC) load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

   d. For proposals included in the "short list" that include External Resources, the Respondents must demonstrate during the "short list" evaluation phase of this RFP that firm transmission service can be secured on all transmission paths required to deliver the External Resource to the FPC Control Area.

3. Internal Resource Information Requirements

   a. For each Resource included in the proposal that is directly connected to the FPC Transmission System (Internal Resource), the Respondent must

describe the specific delivery point on the FPC Transmission System where the Resource is or is proposed to be located.

b. The Respondent shall include in the proposal the costs of all generation equipment up to and including the generator step-up transformer(s).

c. The Respondent must supply detailed information with the proposal for new generation that is not modeled in the current FRCC load flow cases (i.e., FY99) by completing the asterisked items on the "Florida Power Corporation Generation Interconnection Study Data Request Form," a copy of which is provided in Attachment E.

4. Transmission System Impact Study

During the "short list" evaluation phase of this RFP, FPC will perform a transmission system impact study to evaluate all proposals on the "short list" at the same time. All required information to conduct this study must have already been provided to FPC in accordance with the schedule provisions of this RFP. The cost of this study shall be pro-rated among all Respondents whose proposals are included on the "short list." Coincident with the determination by FPC of the "short list," FPC will issue System Impact Study Agreements to each Respondent included on the "short list."

C. Non-Price Attributes

1. At this time, FPC would view more favorably proposals that:

- Offer a greater degree of firmness and reliability;
- Offer shorter unit commitment notification and greater dispatch flexibility;
- Offer greater contract flexibility through creative proposal options potentially including, but not limited to:
  - The right for FPC to terminate early,
  - Supplemental capacity call options
  - Options to buy the generating asset at pre-determined prices.

  (Respondents must provide discrete cost or fee structures for proposed contract flexibility attributes.)

- Offer greater supplier performance assurances through parent guarantees, securities, deposits, or other means;

- Promote FPC transmission system reliability and integrity;
- Utilize commercially proven technologies;
- Minimize potential adverse environmental impacts; and
- Offer larger megawatt block sizes.

2. FPC will consider the following additional non-price attributes in its evaluation of proposals:

- Respondent's qualifications and experience;
- Technical and financial viability of the proposal;
- Project location (for example: grid location, zoning, community acceptance);
- Resource scheduling and dispatchability;
- Deliverability (interconnection and transmission), including system reliability and transmission related issues;
- Fuel supply, including, but not limited to:
    - Firmness of fuel supply,
    - Backup fuel supply,
    - Dual fuel capability,
    - Transportation flexibility,
    - Fuel management or tolling requirements;
- Water supply;
- Environmental compliance;
- Operational and maintenance plans;
- Performance criteria;
- Pricing structure;

- Potential for increases or decreases in FPC's cost of capital;
- The effect of Respondent's financing arrangements on FPC's system reliability;
- Any competitive advantage the financing arrangement may give the Respondent; and
- All factors that must be considered or discussed by FPC pursuant to F.A.C. Rule 25-22.081, .082.

3. This list of attributes is not intended to be all inclusive. Other innovative and cost effective offerings, which provide value to FPC and its customers, will be viewed favorably.

D. Performance Assurances

FPC will rely on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement and should be included in the Respondent's proposal. Performance guarantees and financial credit assurances will also be required of the Respondents, subject to negotiation, at FPC's discretion, and also should be included in Respondent's proposal.

V. Proposal Evaluation

A. Proposal Evaluation Procedure

1. FPC and/or independent consultants will evaluate proposals and recommend proposals, if any, which provide the most value to FPC and its customers. FPC reserves the right to evaluate the proposals in a manner that ultimately produces the most competitive responses from which to begin negotiations. Proposals that offer less than 530 MW may be combined with other proposals as supply-side alternatives to FPC's next planned generating unit. FPC shall determine in its sole discretion the value of any proposals and of any resulting agreement to FPC and its customers.

2. Information provided from each Respondent by the proposal due date will be used to develop a short list of proposals from which selection(s) could be made for direct negotiations. No additional information will be accepted after the proposal due date, except for clarifications requested by FPC and possible

transmission study results. FPC will evaluate the proposals in terms of price and non-price attributes.

3. FPC will perform an initial screening evaluation to identify and eliminate any proposals that are not responsive to the RFP, do not meet the minimum requirements set forth in the RFP, are clearly not economically competitive with other proposals, or are submitted by Respondents that lack appropriate creditworthiness or sufficient financial resources or qualifications to provide dependable and reliable service.

4. The proposals that pass the initial evaluation screen will be further evaluated based on qualitative and non-price attributes, as discussed at Section IV. C above, and using production costing methods and other models so that all reasonable cost impacts can be quantified. A selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will compete with each other and with any self-build options before FPC makes any final selection.

B. Reservation of Rights

1. FPC reserves the right, without qualification and in its sole discretion, to accept or reject any or all proposals for any reason or to make the award to that Respondent, who, in the opinion of FPC, will provide the most value to FPC and its customers. FPC also reserves the right to make an award to other than the lowest price offer or to the proposal evidencing the greatest technical ability if FPC determines that to do so would result in the greatest value to FPC and its customers. FPC may make an award of contract without further discussion.

2. FPC reserves the right to reject any, all, or portions of the proposals received for failure to meet any criteria set forth in this RFP. FPC also may decline to enter into a power purchase arrangement with any Respondent, or to abandon the project in its entirety. FPC reserves the right to revise the capacity needs forecast at any point during the RFP process or during negotiations and any such change may reduce, eliminate, or increase the amount of power sought.

3. Respondents should be aware that the following, without limitation, will be classified as non-responsive and will not be considered or evaluated if submitted:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- incomplete, inaccurate, conditional, deceptive, misleading, ambiguous,

exaggerated, or non-specific offers; or

- proposals that are not in conformance with the requirements and instructions contained herein.

4. Those who submit proposals do so without recourse against FPC or Florida Progress Corporation or any of Florida Progress Corporation's subsidiary companies for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Attachment A

Notice of Intent to Bid Form

Project Bidder

Respondent Contact Name: _____
Title: _____
Company Name: _____
Address: _____
_____
Telephone: _____
Facsimile: _____
Project Name: _____
Project Location: _____

General Description of the Proposed Project:

_____
_____
_____

(Attach additional sheets as needed)

Proposed Capacity Delivered to FPC: _____
Contract Term: _____
Power Generation Technology: _____
Primary Fuel: _____
Back-up Fuel: _____
Specific Entity to Contract with FPC:

_____

Respondent Classification:
(e.g., Utility, Power Marketer, EWG, QF, etc.):

_____

Other Parties Involved in the Proposal:

_____

Respondent Qualifications:
Describe similar projects developed by Respondent, identifying project capacity, location, contract commencement date and term, and any other information the Respondent considers appropriate. *(Attach additional sheets as needed)*

_____
_____
_____

Respondent's Signature: _____
(Title/Position)

Attachment B

Proposal Summary Form

Company/Respondent: _____
Respondent Contact Name: _____
Mailing Address: _____
_____
Telephone: _____
Facsimile: _____
General Description of the Proposed Project: _____
_____
_____
(Attach additional sheets as needed)
Power Generation Technology: _____
Unit(s) Name: _____
Project Location: _____
Contract Term: _____
Unit(s) Summer MW Rating: _____
Unit(s) Winter MW Rating: _____
Unit(s) Fuel Type(s): _____
Proposed Capacity (MW) Delivered to FPC: _____
Proposed delivery point to FPC: _____
Other Parties with an Interest in the Proposal: _____
_____

Certification: Respondent hereby certifies that all of the statements and representations made in this proposal, including all attachments, are true to the best of Respondent's knowledge and belief. Respondent agrees to be bound by its representations and the terms and conditions of the Request for Proposals. This proposal shall remain in effect until at least October 1, 2000.

Signed: _____
Name: _____
(Typed)
Title: _____
Date: _____

Attachment C

Respondents are requested to respond to the following data requests. All of this information is important to assist FPC in better understanding, among other things, the price and non-price attributes addressed in each alternative generating proposal, including their technical and financial viability, pricing structure, dispatchability, deliverability, water supply, environmental compliance, and performance criteria.

Certain data requirements in this RFP reference "Seasons," which will, for consistency, be defined as:

Winter	[December *through* February]
Summer	[June *through* September]
Shoulder	[Balance of the Months]

Section 1: General Proposal Information

Respondents are requested to provide brief but concise answers to the Data Requests below. If annual escalation is expected or if contract price will vary, include any such rates or indices.

1. Provide documentation of Respondent's previous experience providing the proposed product.

2. Provide the following information for your company:

   a. Annual reports and Form 10-K for the past three years. If these documents are not readily available, then audited financial statements for the past three years will be accepted.

   b. Dunn and Bradstreet identification number credit rating of the Respondent's senior debt securities. Any additional documentation needed to allow FPC to determine the Respondent's financial strength.

   c. Ten year summary of litigation activity related to (1) provision of energy products and services (fuel, power, ancillary services, engineering, on-site services), (2) lease option arrangements for assets, (3) purchases of energy products and services (as above), or (4) industrial construction projects (power plants, industrial plants, cogeneration facilities, etc.).

3. Provide copies of notices to be published, per Section III.D.2 of the RFP.

4. Provide a complete schedule of the proposed contract terms and conditions.

5. Provide a detailed list and summary of contract flexibility attributes included in the proposal as well as discrete cost or fee structures for each of the proposed attributes.

6. Present a detailed description of any security or credit instruments proposed by the Respondent to back its performance obligation.

7. Provide a detailed summary of any liquidated damages provisions included in the proposal and a description of the particular circumstance(s) they are intended to mitigate.

8. Describe whether or not this capacity has been offered in another RFP or is in any other way obligated or may be obligated to others, and under what conditions it would be released to serve this proposed sale.

9. Describe the firmness of the capacity in your offer.

10. Explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the energy after it has been scheduled.)

Section 2: Specific Supply Resource Information

1. For a proposal involving a specific unit(s), provide the following information using the data tables included where appropriate:

   a. (Proposed) Unit name and location.

   b. For new units, provide the schedule for licensing, permitting and construction, including the projected date of commercial operation.

   c. Descriptions (including models and manufacturers) of all of the major components.

   d. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation or other fixed price components. Clearly delineate whether each price component and/or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

   e. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

   f. Seasonal Unit ratings (MW, MVAR, MVA) based on the ambient condition

assumptions of Winter (40°F), Summer (90°F), and Shoulder (59°F). If capacity being offered is less than the full capability of the generating unit(s), provide the full capability information for these same ambient conditions. Explain if and how unit performance degradation is accounted for over time. (See Table 3)

g. Generator capability curve.

h. Guaranteed availability. (See Table 4)

i. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation). (See Table 5)

j. For planned maintenance requirements, discuss the means by which FPC will be entitled to schedule the planned maintenance periods. (See Table 6)

k. Detailed Fuel Supply Plan (primary and secondary).

i. Fuel type, on-site storage capability and inventory management plan, applicable fuel specifications, metering requirements. (See Table 9)

- Natural Gas: Include interstate pipeline supplier, connection point, lateral length, type and quantity of firm, recallable, and interruptible transportation.
- Oil: Include type, special specifications, storage tank description, number of hours of full load operation supported by the tank.
- Other Fuels.

ii. Any proposed tolling or other fuel procurement arrangements that would involve FPC in the fuel management process.

iii. Operating limits on either the primary or secondary fuels, if any.

l. Describe any dispatch notice or scheduling requirements for this offer, including, but not limited to:

i. Minimum run time per dispatch call, if any.

ii. Minimum down time, if any.

iii. Start up energy requirements.

iv. Ramp Rate(s).

iv. Start up time from cold start and from hot start.

v. Start up costs from cold start and from hot start.

vi. Quick start capability (less than 10 minutes). (See Table 7)

m. Maximum and minimum operating levels, capacity breakpoints and corresponding net heat rates (in Btu/kWh, on a higher heating value basis). Provide on a seasonal basis, as outlined in the tables. (See Table 8a and 8b)

n. Maximum or minimum energy take per month, season, year, or contract period, if any.

o. A detailed water supply plan, including data requirements. (See Table 10).

p. A thorough description of anticipated environmental impact, environmental permitting requirements, and actions for compliance.

q. A complete description of any cogeneration aspects of the facility(s) including, but not limited to, fuel, steam, water, or power sales and any details related to qualifying facility status, if any.

r. A complete description of any actual or proposed energy or capacity sales, or sales of any other energy-related products (ancillary services, steam, tankage, etc.) to any other parties from this facility(s).

s. Any other limit on use or availability of resource's output, if any.

Section 3: System Supply Resource Information

1. For a system sale or other sales, please provide the following information. It is difficult to anticipate all possible system supply scenarios, but please use the existing tables to the extent that it is practical and provide any additional information needed in separate schedules, tables and/or forms.

   a. Seasonal Capacity (MW, MVAR, MVA) available for use on the FPC System. (See Table 3)

   b. Provide a detailed schedule of the fixed price components of the proposal and complete the attached data tables. Respondents may choose to separate pricing for fixed O&M, fixed fuel transportation, or other fixed price components. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 1)

c. Provide a detailed schedule of the variable price components of the proposal and complete the attached data tables. Respondents are encouraged to provide as much discrete information as possible to assist in the proper evaluation of the proposal. Additional tables may be used, if needed. If pricing is to be based on a standard index, make the formula basis for pricing and the exact reference index explicitly clear. Clearly delineate whether each price component or the all-in price offering are guaranteed prices or forecast prices. (See Table 2)

d. A description of the system from which the power will be provided, including the name, location, the installed capacity, capacity mix, fuel mix, technology mix, peak hour load, and reserve projections (with and without the proposed capacity sale) during the proposal period. In addition, provide all data requested in the tables. (See Table 11).

e. A detailed history of the system operations for the past five years including, but not limited to fuel mix, power sales and purchases (energy and demand) to native load and to non-native load, emergency power purchase requirements, historical reserve levels, and incidences of firm transmission interruptions. In addition, provide all data requested in the tables. (See Table 11)

f. In conjunction with the information and data provided in b. and c., please provide copies of the 1999 and 2000 EIA-411 filings and the 1999 Ten Year Site Plan for all systems from which power is to be sold under this proposal offering.

g. An explanation of the priority of this proposed transaction relative to all other supply commitments (existing and future) and any criteria under which the supply of system power by the Respondent might be curtailed or interrupted.

h. A description of any dispatch notice or scheduling requirements for this offer.

i. Guaranteed availability. (See Table 4)

j. Maximum or minimum energy take per month, year, contract period, if any.

k. A thorough description of anticipated environmental impact and compliance resulting from these power sales.

l. Any other limit on use or availability of resource, if any.

Section 4: Supplemental Transmission Information

1. Provide all information required in Section IV.B, Transmission Information Requirements,

of this RFP for each Internal or External Resource included in the Respondent's proposal. This data must be included with the Respondent's proposal when it is submitted.

2. If this data has already been supplied to FPC Transmission Planning associated with a current generation interconnection request on the FPC Transmission System, please clearly identify the request, the date of the request and the project(s) associated with the request.

3. Provide a schedule of the costs that the bidder will be responsible for paying for transmission service to deliver power to FPC's Control Area.

4. Describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the FPC Control Area. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.

5. Describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.

Section 5: Data Tables

Respondents are requested to complete the tables in the attached excel file labeled "Data Tables", as represented herein. Once the tables are completed electronically, the respondent is required to print the resulting data tables and include these printed tables in their proposal document. Add rows as necessary for additional years. If annual escalation is expected, include such escalation rates or indices. Please note any additions or modifications made to the tables. Do not leave blanks: write in "N/A" if topic is not applicable, or "0" if the value is zero. Respondents may provide additional tables, as required to better clarify their proposals. Such additional tables should follow the Water Requirements table, and be labeled "Additional Table - (Description)," and include appropriate units.

Table 1. Fixed Capacity Price Structure- ($/kW-month)

Season	Year: 2003	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2004	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2005	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2006	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2007	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2008	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2009	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2010	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2011	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2012	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					

Season	Year: 2016	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2017	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2018	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2019	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2020	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2021	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2022	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2023	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2024	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year: 2025	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					

Table 2a Variable Price Structure, Primary Fuel- (units below)

Season	Year: 2003 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2004 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2005 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units:)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2006 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2007 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2008 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2009 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Escal / Index						
Shoulder	Price						
	Escal / Index						
Summer	Price						
	Escal / Index						

Season	Year: 2010 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2017 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2018 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2019 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2020 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2021 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2022 Fuel:	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					
Shoulder	Price					
	Escal / Index					
Summer	Price					
	Escal / Index					

Season	Year: 2023 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)
Winter	Price					
	Escal / Index					

Table 3. Resource Capacity Rating- (units below)

		40°F		59°F		90°F	
Guaranteed Contract Rating	MW						
	MVAR						
	MVA						
Maximum Unit Rating	MW						
	MVAR						
	MVA						

Table 4. Guaranteed Availability- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 5. Equivalent Forced Outage Rate- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 6. Planned Maintenance Requirements- (Number of Outages/Year, Total Hours/Year)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number year													
Maint Hrs/yr													
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number year													
Maint Hrs/yr													

Table 7. Operational Parameters- (units below)

Minimum run time per dispatch call		Hours
Minimum down time between calls		Hours
Startup Energy		MMBtu
Ramp Rate		MW / minute
Ramp Rate		minutes to full load
Number of Hot Starts per year		Maximum
Number of Hot Starts per year		Included in bid proce
Cost of Each Hot Start Beyond Those Included		Dollars
Number of Cold Starts per year		Maximum
Number of Cold Starts per year		Included in bid proce
Cost of Each Cold Start Beyond Those Included		Dollars
Quick Start Capability- Minutes to 1st MW		Minutes
Quick Start Capability- MW in ten minutes		MW
Start up time from cold start		Minutes
Start up cost from cold start		$
Start up time from hot start		Minutes
Start up costs from hot start		$

Table 8a. Capacity States on Primary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 8b. Capacity States on Secondary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

NOTE: Net Heat Rates are to be based on Higher Heating Value (HHV)

Table 9. Fuel Supply Requirements		Units
Primary Fuel Maximum Flow rate		
Primary Fuel Pressure Requirement		
Primary Fuel Metering Requirement		
Primary Fuel Storage Capacity		
Secondary Fuel Maximum Flow rate		
Secondary Fuel Pressure Requirement		
Secondary Fuel Metering Requirement		
Secondary Fuel Storage Capacity		

Table 10. Water Requirements		Units
Cooling		
Consumptive Use		
Other		

Table 11. System Reliability Parameters

	Actual					Forecast				
	1995	1996	1997	1998	1999	2003	2004	2005	2006	2007
Installed Capacity										
Contracted System Firm Capacity Purchases										
Contracted System Firm Capacity Sales										
Load Control Capability										
Seasonal Peak Requirements before Direct Load Control										
Firm Peak Requirements after Direct Load Control										
Capacity Margin before Direct Load Control										
Firm Reserve Margin after Direct Load Control										

Attachment D - Planned Unit Data

The following data represent the planned unit data estimates, which FPC utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on FPC's existing Hines Energy Complex site in Polk County, Florida.

2. Planned Size 530 MW (nominal).

3. Commercial Operation of the facility is proposed to be November 30, 2003.

4. The primary fuel is natural gas. Oil will be used as a backup fuel source.

5. The estimated total direct cost is $197.6 million.

6. The estimated annual levelized revenue requirement is $35.6 million over 25 years.

7. The estimated annual value of deferral of this unit is $48.95/kW-yr (03$).

8. The estimated annual fixed O&M is $2.2 million (03$). The estimated variable O&M is $1.11/MWH (03$).

9. The estimated delivered fuel cost is $2.66/MMBtu (03$), plus fixed transportation at the prevailing rate.

10. The following are estimates for:

Planned outage rate	7, 7, 14, 7, 7, 22 days/year (or 2.92%)
Forced outage rate	3.5 %
Heat rate at maximum capacity	6,975 Btu/kWh
Minimum load	250 MW
Ramp Rate	1 Hr.

11. The estimated transmission and interconnection costs for this unit are $5.6 million.

12. Supplemental site certification as well as amendment to related environmental permits will be required for this unit. It is FPC's plan to comply with all environmental standards of Local, Regional, State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.5 % per year
General escalation:	3.1 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.3 %
	55 % equity @ 12.0 %

Attachment E

Florida Power Corporation
Generation Interconnection Study
Data Request Form

INSTRUCTIONS

(*) denotes items that are required for both a Generation Interconnection Feasibility Study and a Generation Interconnection Study and must be completed and included in Respondent's proposal. All items on this form are required prior to the start of engineering design.

If a data item is unavailable, please provide an estimate and indicate it as an estimate. Please note that a restudy could be required if data assumptions change while the study is in progress.

Please fill out and attach a copy of Section II for each generator on the site.

Please use this form to supply the requested data. Submittal of manufacturer data sheets, other than generator characteristic curves, is not an acceptable alternative to completing this form.

SECTION I - Generation Site Data

A) **Contact Person** - Provide name and address of person completing this form

(*)1. Name: _____

(*)2. Address: _____

(*)3. City/State/Zip: _____

(*)4. Telephone: _____

(*)5. Date: _____

B) Site Location

(*)1. County: _____

(*)2. Section / Township / Range: _____

(*)3. Site Drawing: Include a site drawing indicating county, section, township, and range. In addition, for a Generation Interconnection Study, a preliminary equipment layout on the site, suitable for site plan permitting, is required.

C) **Proposed Load Requirements for Site**

(*)1. Required Date: _____

(*)2. Nature of Load (Station Service, Start-up Power, Etc.) _____

(*)3. Connected kVA Load: _____

(*)4. Peak Demand kVA Load: _____

(*)5. Expected Power Factor: _____

(*)6. Service Voltage: _____

(*)7. Anticipated Future Load Requirements (please describe): _____

_____

_____

_____

D) **Other Site Information**

(*)1. Net Generation Output (MVA) for Site @ 59°F Outdoor Ambient: _____

(*)2. Net Generation Output (MVA) for Site @ 90°F Outdoor Ambient: _____

(*)3. Proposed Interconnections with Other Systems (please describe):

_____

_____

E) **In-Service Dates**

(*)1. Required connection to grid for generator testing: _____

(*)2. Commercial in-service date: _____

SECTION II - Individual Generator Data

A) **Unit Identification**

(*) 1. Plant Name and Unit Number _____

2. Manufacturer _____

3. Generator Serial Number _____

4. Turbine Serial Number _____

B) **Ratings and Capabilities**

1. Nameplate kV Rating (nominal design voltage) _____

2. MVA Rating

	MVA Rating	@ Hydrogen Pressure
a.	_____	_____
b.	_____	_____
c.	_____	_____
d.	_____	_____

(*) 3. Gross MW Rating @ 59°F Outdoor Ambient _____

(*) 4. Net MW Rating @ 59°F Outdoor Ambient _____

(*) 5. Gross MW Rating @ 90°F Outdoor Ambient _____

(*) 6. Net MW Rating @ 90°F Outdoor Ambient _____

7. Rated Power Factor _____

8. Rated Speed _____

9. Rated Turbine Capability _____

10. Field Voltage at Rated Load _____

11. Field Current at Rated Load _____

12. No-load Field Voltage at Generator Rated Voltage _____

13. Air Gap Field Voltage at Generator Rated Voltage _____

14. Field Resistance ____ohms @ _____ °C

C) Inertia

(*) 1. WR^2 for Generator and Exciter _____ $lb\text{-}ft^2$

(*) 2. WR^2 for Turbine _____ $lb\text{-}ft^2$

(*) 3. Calculated H Constant _____ sec. @ _____ MVA

D) Losses and Efficiency

1. Open circuit core loss _____ kW

2. Windage loss _____ kW

3. H_2 seal and exciter friction loss _____ kW

4. Stator I^2R Loss at rated power and voltage _____ °C _____ kW

5. Rotor I^2R Loss at rated power and voltage _____ °C _____ kW

6. Stray Load loss _____ kW

7. Excitation losses _____ kW

E) Generator Time Constants

1. T'_{do} (Direct axis open circuit transient time constant) _____ sec
2. T''_{do} (Direct axis open circuit subtransient time constant) _____ sec
3. T'_{qo} (Quadature axis open circuit transient time constant) _____ sec
4. T''_{qo} (Quadature axis open circuit subtransient time constant) _____ sec
5. T_{a3} (Short circuit time constant) _____ sec

F) Generator Impedances

(*) 1. MVA base for all impedance data _____ MVA

(*) 2. kV base for all impedance data _____ kV

Parameter		Description	p.u. value
(*) 3.	X_d	Direct axis synchronous reactance (unsaturated)	
4.	X_q	Quadrature axis synchronous reactance (unsaturated)	
(*) 5.	X'_d	Direct axis transient reactance (unsaturated)	
6.	X'_{ds}	Direct axis transient reactance (saturated)	
7.	X'_q	Quadrature axis transient reactance (unsaturated)	
8.	X'_{qs}	Quadrature axis transient reactance (saturated)	
(*) 9.	X''_d	Direct axis subtransient reactance (unsaturated)	
10.	X''_q	Quadrature axis subtransient reactance (unsaturated)	
11.	X_L	Armature leakage reactance	
12.	R_1	Positive sequence armature resistance at 75° C	
13.	R_2	Negative sequence armature resistance at 75° C	
14.	X_2	Negative sequence armature reactance at rated voltage	

15. X_0 Positive sequence armature resistance at 75° C _____

16. R_{dc} Direct current armature resistance at 75° C _____

17. Generator neutral grounding resistance _____ ohms

(*)18. Generator neutral grounding reactance _____ ohms

G) Required Characteristic Curves and Diagrams

(*) 1. Real and reactive power capability curves **(Maximum var capability, lagging and leading, is sufficient for Feasibility Study)**

2. Saturation curve, full load and no-load

3. "V" curves

4. Governor overspeed response curve

5. One-Line diagram showing generator and substation equipment connections

H) Excitation System Data

1. Excitation system type _____

2. Voltage regulator model name _____

3. Excitation system model, supply block diagram and model parameters in IEEE[1] or PSS/E format

4. Voltage compensation, supply block diagram and settings if used

5. Voltage regulator overexcitation limiters, supply block diagram and model parameters in IEEE[2] format.

6. Power System Stabilizer (if used), supply Power System Stabilizer block diagram and model parameters in IEEE or PSS/E format

I) Turbine Governor Data

1. Speed/Load governor model name _____

[1] IEEE Standard 421.5-1992 "IEEE Recommended Practice for Excitation System Models for Power System Stability Studies"

[2] IEEE Committee Report, "Recommended Models for Overexcitation Limiting Devices," IEEE Transactions on Energy Conversion, Vol. 10, No. 4, December 1995

2. Governor model, supply block diagram and model parameters in IEEE[3,4] or PSS/E format

J) Generator Step-up Transformer Data

1. Manufacturer _____

2. Model Type _____

3. Serial Number _____

(*) 4. Rating _____ MVA

(*) 5. High voltage winding, nominal voltage _____ kV

(*) 6. High voltage winding connection (wye/delta) _____

(*) 7. Low voltage winding, nominal voltage _____ kV

(*) 8. Low voltage winding connection (wye/delta) _____

9. Transformer resistance _____ p.u.

(*)10. Transformer reactance _____ p.u.

(*)11. Transformer impedance base values _____ MVA _____ kV

12. Available tap settings

HV taps _____ kV

LV taps _____ kV

13. Expected tap settings

HV taps _____ kV

LV taps _____ kV

[3] IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbine Control Models for System Dynamic Studies." IEEE transactions on Power Apparatus and Systems, Vol. PAS-92, November, 1973

[4] W.I. Rowen, "simplified Mathematical Representations of Heavy Duty Gas Turbines." Transactions of ASME, Vol.105(1), 1983

Table 1 Fixed Capacity Price Structure- ($/kW-month)

Season	Year 2004	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2005	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2006	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. / Index					

Season	Year 2007	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. Index					

Season	Year 2008	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2009	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2010	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2011	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2012	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2013	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2014	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2015	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2016	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2017	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2018	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. / Index					

Season	Year 2019	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year 2020	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. / Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. / Index					

Season	Year 2021	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. / Index					

Season	Year 2022	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. / Index					
Summer	Price					
	Escal. Index					

Season	Year 2023	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2024	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2025	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2026	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2027	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Season	Year 2028	Capacity	O & M	Other	All-In	Fuel Transportation
Winter	Price					
	Escal. Index					
Shoulder	Price					
	Escal. Index					
Summer	Price					
	Escal. Index					

Table 2a. Example Price Stacking Template Fuels Tables Below

Season	Year 2013 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2014 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2015 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2016 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2017 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2018 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2019 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2020 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2021 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2022 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2023 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2024 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2025 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2026 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2027 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Season	Year 2028 Fuel	O&M ($/MWh)	Commodity (¢/MMBtu)	Emissions SO2 ($/ton)	Emissions Other ($/MWh)	All-In Price ($/MWh)	Fuel Transportation (units)
Winter	Price						
	Fiscal Index						
Shoulde	Price						
	Fiscal Index						
Summe	Price						
	Fiscal Index						

Table 3. Resource Capacity Rating- (units below)

		40°F		59°F		90°F	
Guaranteed Contract Rating	MW						
	MVAR						
	MVA						
Maximum Unit Rating	MW						
	MVAR						
	MVA						

Table 4. Guaranteed Availability- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 5. Equivalent Forced Outage Rate- (%)

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Winter	On-Peak													
	Off-Peak													
Shoulder	On-Peak													
	Off-Peak													
Summer	On-Peak													
	Off-Peak													

Table 6. Planned Maintenance Requirements- (Number of Outages/Year, Total Hours/Year)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number/year													
Maint Hrs/yr													
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number/year													
Maint Hrs/yr													

Table 7. Operational Parameters- (units below)

Minimum run time per dispatch call		Hours
Minimum down time between calls		Hours
Startup Energy		MMBtu
Ramp Rate		MW / minute
Ramp Rate		minutes to full load
Number of Hot Starts per year		Maximum
Number of Hot Starts per year		Included in bid proce
Cost of Each Hot Start Beyond Those Included		Dollars
Number of Cold Starts per year		Maximum
Number of Cold Starts per year		Included in bid proce
Cost of Each Cold Start Beyond Those Included		Dollars
Quick Start Capability- Minutes to 1st MW		Minutes
Quick Start Capability- MW in ten minutes		MW
Start up time from cold start		Minutes
Start up cost from cold start		$
Start up time from hot start		Minutes
Start up costs from hot start		$

Table 8a. Capacity States on Primary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 8b. Capacity States on Secondary Fuel (units below)

Fuel:	40°F	59°F	90°F
Min Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
1st Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
2nd Breakpt Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Expected Max Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			
Overcapacity Plant Output (Net MW)			
Associated Net Heat Rate (Btu/kWh)			

Table 9. Fuel Supply Requirements		Units
Primary Fuel Maximum Flow rate		
Primary Fuel Pressure Requirement		
Primary Fuel Metering Requirement		
Primary Fuel Storage Capacity		
Secondary Fuel Maximum Flow rate		
Secondary Fuel Pressure Requirement		
Secondary Fuel Metering Requirement		
Secondary Fuel Storage Capacity		

Table 10. Water Requirements		Units
Cooling		
Consumptive Use		
Other		

Table 11. System Reliability Parameters

	Actual					Forecast				
	1995	1996	1997	1998	1999	2003	2004	2005	2006	2007
Installed Capacity										
Contracted System Firm Capacity Purchases										
Contracted System Firm Capacity Sales										
Load Control Capability										
Seasonal Peak Requirements before Direct Load Control										
Firm Peak Requirements after Direct Load Control										
Capacity Margin before Direct Load Control										
Firm Reserve Margin after Direct Load Control										

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JBC-3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 5 Pg 3 of 3
COMPANY/ WITNESS: Crisp
DATE: 10-26-27-00

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REDACTED

EXHIBIT NO. 6

Docket No: 001064-EI

Party: Florida Power Corporation

Description: COMPOSITE EXHIBIT

(1) FPC's **CONFIDENTIAL** Response to Staff Interrogatory Nos. 4-5, 21-23

(2) FPC's **CONFIDENTIAL** Response to Staff Request for Production of Documents No. 8

Proffered By: Commission Staff

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 6
COMPANY/ WITNESS: Florida Power Corporation
DATE: 10-26 & 27-00

STAFF COMPOSITE EXHIBIT
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4. What is FPC's estimate of the off balance sheet obligation that would have resulted if Bidder A had been selected? Please include a schedule showing the calculation and state all assumptions.

Answer:

FPC's estimate of the initial off-balance sheet obligation that would have resulted if Bidder A had been selected is [redacted]. This value represents the present value of the annual capacity payments over the life of the contract multiplied by the risk factor and would be added to the off-balance sheet obligations from existing contracts each year. The calculation is based on the following assumptions:

Length of contract:	[redacted]
Annual capacity payments:	[redacted]
Discount rate:	10%
Risk factor:	40%

The off-balance sheet obligation is reduced each year as the remaining length of the contract decreases.

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5. What is FPC's estimate of the off balance sheet obligation that would have resulted if Bidder B had been selected? Please include a schedule showing the calculation and state all assumptions.

Answer:

FPC's estimate of the initial off-balance sheet obligation that would have resulted if Bidder B had been selected is [redacted] This value represents the present value of the annual capacity payments over the life of the contract multiplied by the risk factor and would be added to the off-balance sheet obligations from existing contracts each year. The calculation is based on the following assumptions:

Length of contract:	[redacted]
Annual capacity payments:	[redacted]
Discount rate:	10%
Risk factor:	40%

The off-balance sheet obligation changes each year as payment increase and the remaining term of the contract decreases.

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21. Refer to confidential exhibit JBC-3, Appendix 6 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

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22. Refer to confidential exhibit JBC-3, Appendix 6 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. This analysis should exclude the impact of the cost of imputed debt as described on pages 12-15 of John B. Crisp's confidential direct testimony. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

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23. Refer to John B. Crisp's confidential direct testimony, page 15. Provide a PWRR analysis for each of the expansion plans evaluated under the high-fuel price forecast case, the low-fuel price forecast case, and the "Gulfstream" sensitivity. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

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CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATIONS
REQUEST FOR
CONFIDENTIAL
CLASSIFICATION FILED
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REQUEST FOR
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AUGUST 7, 2000.

19. **Refer to confidential exhibit JBC-3, Appendix 5 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.**

Answer:

The tables attached provide the results of the analyses performed in a format as close as possible to the format requested.

include imputed debt

8,204,588 H
- 8,231,958 P
27,370

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EP EXHIBIT NO. 7
COMPANY/ WITNESS: Florida Power Corporation
DATE: 10-26-27-00

Hines 2 Case (Interrogatory 19)

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW RESOURCE CAPITAL (FINANCIAL) REVENUE REQUIREMENT	NEW RESOURCE FUEL AND O&M REVENUE REQUIREMENT	NEW RESOURCE TOTAL REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT.
2000	605,100	460,139	33,940	-	33,940	1,099,179	1,099,179	1,099,179
2001	650,428	466,474	33,777	-	33,777	1,150,679	1,060,240	2,159,419
2002	618,939	473,069	36,167	-	36,167	1,128,175	957,804	3,117,224
2003	680,026	479,873	33,022	-	33,022	1,192,921	933,173	4,050,397
2004	609,674	472,343	65,875	71,065	136,940	1,218,957	878,596	4,928,993
2005	660,767	491,439	63,460	75,668	139,128	1,291,334	857,610	5,786,603
2006	604,807	498,128	102,370	145,159	247,529	1,350,464	826,388	6,612,991
2007	652,178	530,937	98,441	161,053	259,494	1,442,609	813,392	7,426,383
2008	613,050	526,694	138,003	220,186	358,189	1,497,933	778,205	8,204,588
2009	668,429	495,271	132,692	258,086	390,778	1,554,478	744,109	8,948,697
2010	676,173	375,693	173,004	353,885	526,889	1,578,755	696,333	9,645,029
2011	732,664	347,903	165,151	387,421	552,572	1,633,139	663,705	10,308,735
2012	728,120	360,732	159,248	373,616	532,864	1,621,716	607,263	10,915,998
2013	754,097	374,159	153,514	395,011	548,525	1,676,781	578,534	11,494,532
2014	745,352	389,269	147,903	393,470	541,373	1,675,994	532,813	12,027,346
2015	770,045	405,180	142,399	404,714	547,113	1,722,338	504,512	12,531,858
2016	760,877	423,099	136,959	401,777	538,736	1,722,712	464,960	12,996,818
2017	785,611	439,499	131,571	414,718	546,289	1,771,399	440,524	13,437,342
2018	775,950	457,998	126,194	413,162	539,356	1,773,304	406,337	13,843,679
2019	801,314	477,484	120,819	425,039	545,858	1,824,656	385,243	14,228,922
2020	791,695	499,380	115,448	422,016	537,464	1,828,539	355,720	14,584,642
2021	817,417	519,554	110,079	435,684	545,763	1,882,734	337,476	14,922,118
2022	806,929	542,252	104,714	434,111	538,825	1,888,006	311,823	15,233,941
2023	833,579	566,168	99,352	446,667	546,019	1,945,766	296,105	15,530,046
2024	823,459	592,987	94,223	443,556	537,779	1,954,225	274,018	15,804,064
2025	850,501	617,839	89,328	458,006	547,334	2,015,674	260,421	16,064,484
2026	839,841	645,739	84,708	456,425	541,133	2,026,713	241,267	16,305,751
2027	869,862	675,145	80,362	469,711	550,073	2,095,080	229,803	16,535,554
2028	859,231	708,064	76,306	466,511	542,817	2,110,112	213,261	16,748,815

same

2008 8,204,588 8,236,491 31,903

Panda 530 Case (Interrogatory 19)

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW RESOURCE CAPITAL (FINANCIAL) REVENUE REQUIREMENT	NEW RESOURCE FUEL AND O&M REVENUE REQUIREMENT	NEW RESOURCE TOTAL REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT.
2000	605,100	460,139	33,940	-	33,940	1,099,179	1,099,179	1,099,179
2001	650,428	466,474	33,777	-	33,777	1,150,679	1,060,240	2,159,419
2002	618,939	473,069	36,167	-	36,167	1,128,175	957,804	3,117,224
2003	680,026	480,166	35,521	-	35,521	1,195,714	935,358	4,052,582
2004	623,448	472,399	33,492	100,156	133,648	1,229,495	886,192	4,938,773
2005	673,754	493,479	31,211	103,731	134,942	1,302,175	864,810	5,803,583
2006	604,807	498,128	111,516	145,159	256,675	1,359,610	831,985	6,635,568
2007	652,178	530,937	107,218	161,053	268,271	1,451,386	818,341	7,453,909
2008	613,050	526,694	146,429	220,186	366,615	1,506,359	782,582	8,236,491
2009	668,429	495,271	140,785	258,086	398,871	1,562,571	747,983	8,984,474
2010	676,173	375,693	180,779	353,885	534,664	1,586,530	699,762	9,684,236
2011	732,664	347,903	172,621	387,421	560,042	1,640,609	666,741	10,350,977
2012	728,120	360,732	166,457	373,616	540,073	1,628,925	609,963	10,960,940
2013	754,097	374,159	160,506	395,011	555,517	1,683,773	580,946	11,541,887
2014	745,352	389,269	154,685	393,470	548,155	1,682,776	534,970	12,076,856
2015	770,045	405,180	148,972	404,714	553,686	1,728,911	506,437	12,583,293
2016	760,877	423,099	143,322	401,777	545,099	1,729,075	466,678	13,049,971
2017	785,611	439,499	137,724	414,718	552,442	1,777,552	442,054	13,492,025
2018	775,950	457,998	132,136	413,162	545,298	1,779,246	407,699	13,899,724
2019	801,314	477,484	126,552	425,039	551,591	1,830,389	386,453	14,286,178
2020	791,695	499,380	120,971	422,016	542,987	1,834,062	356,794	14,642,972
2021	817,417	519,554	115,393	435,684	551,077	1,888,048	338,429	14,981,401
2022	806,929	542,252	109,818	434,111	543,929	1,893,110	312,666	15,294,066
2023	833,579	566,168	104,246	446,667	550,913	1,950,660	296,849	15,590,916
2024	823,459	592,987	98,677	443,556	542,233	1,958,679	274,643	15,865,558
2025	850,501	617,839	93,112	458,006	551,118	2,019,458	260,909	16,126,468
2026	839,841	645,739	88,094	456,425	544,519	2,030,099	241,670	16,368,137
2027	869,862	675,145	83,622	+ 469,711	553,333	2,098,340	230,161	16,598,298
2028	859,231	708,064	79,439	466,511	= 545,950	2,113,245	213,577	16,811,876

Same Same Difference Same Difference

imputed debt } = 4,533

16,811,876
- 16,748,815
63,061 great

20. Refer to confidential exhibit JBC-3, Appendix 5 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. This analysis should exclude the impact of the cost of imputed debt as described on pages 12-15 of John B. Crisp's confidential direct testimony. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

The tables attached provide the results of the analyses performed in a format as close as possible to the format requested.

Hines 2 Case (Interrogatory 20)

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW RESOURCE CAPITAL (FINANCIAL) REVENUE REQUIREMENT	NEW RESOURCE FUEL AND O&M REVENUE REQUIREMENT	NEW RESOURCE TOTAL REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT.
2000	605,100	460,139	33,940	-	33,940	1,099,179	1,099,179	1,099,179
2001	650,428	466,474	33,777	-	33,777	1,150,679	1,060,240	2,159,419
2002	618,939	473,069	36,167	-	36,167	1,128,175	957,804	3,117,224
2003	680,026	479,873	33,022	-	33,022	1,192,921	933,173	4,050,397
2004	609,674	472,343	65,875	71,065	136,940	1,218,957	878,596	4,928,993
2005	660,767	491,439	63,460	75,668	139,128	1,291,334	857,610	5,786,603
2006	604,807	498,128	102,370	145,159	247,529	1,350,464	826,388	6,612,991
2007	652,178	530,937	98,441	161,053	259,494	1,442,609	813,392	7,426,383
2008	613,050	526,694	138,003	220,186	358,189	1,497,933	778,205	8,204,588
2009	668,429	495,271	132,692	258,086	390,778	1,554,478	744,109	8,948,697
2010	676,173	375,693	173,004	353,885	526,889	1,578,755	696,333	9,645,029
2011	732,664	347,903	165,151	387,421	552,572	1,633,139	663,705	10,308,735
2012	728,120	360,732	159,248	373,616	532,864	1,621,716	607,263	10,915,998
2013	754,097	374,159	153,514	395,011	548,525	1,676,781	578,534	11,494,532
2014	745,352	389,269	147,903	393,470	541,373	1,675,994	532,813	12,027,346
2015	770,045	405,180	142,399	404,714	547,113	1,722,338	504,512	12,531,858
2016	760,877	423,099	136,959	401,777	538,736	1,722,712	464,960	12,996,818
2017	785,611	439,499	131,571	414,718	546,289	1,771,399	440,524	13,437,342
2018	775,950	457,998	126,194	413,162	539,356	1,773,304	406,337	13,843,679
2019	801,314	477,484	120,819	425,039	545,858	1,824,656	385,243	14,228,922
2020	791,695	499,380	115,448	422,016	537,464	1,828,539	355,720	14,584,642
2021	817,417	519,554	110,079	435,684	545,763	1,882,734	337,476	14,922,118
2022	806,929	542,252	104,714	434,111	538,825	1,888,006	311,823	15,233,941
2023	833,579	566,168	99,352	446,667	546,019	1,945,766	296,105	15,530,046
2024	823,459	592,987	94,223	443,556	537,779	1,954,225	274,018	15,804,064
2025	850,501	617,839	89,328	458,006	547,334	2,015,674	260,421	16,064,484
2026	839,841	645,739	84,708	456,425	541,133	2,026,713	241,267	16,305,751
2027	869,862	675,145	80,362	469,711	550,073	2,095,080	229,803	16,535,554
2028	859,231	708,064	76,306	466,511	542,817	2,110,112	213,261	16,748,815

Panda 530 Case (Interrogatory 20)

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW RESOURCE CAPITAL (FINANCIAL) REVENUE REQUIREMENT	NEW RESOURCE FUEL AND O&M REVENUE REQUIREMENT	NEW RESOURCE TOTAL REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT.
2000	605,100	460,139	33,940	-	33,940	1,099,179	1,099,179	1,099,179
2001	650,428	466,474	33,777	-	33,777	1,150,679	1,060,240	2,159,419
2002	618,939	473,069	36,167	-	36,167	1,128,175	957,804	3,117,224
2003	680,026	480,166	33,022	-	33,022	1,193,214	933,403	4,050,627
2004	623,448	472,399	31,003	100,156	131,159	1,227,006	884,397	4,935,024
2005	673,754	493,479	30,031	103,731	133,762	1,300,995	864,026	5,799,050
2006	604,807	498,128	111,516	145,159	256,675	1,359,610	831,985	6,631,035
2007	652,178	530,937	107,218	161,053	268,271	1,451,386	818,341	7,449,376
2008	613,050	526,694	146,429	220,186	366,615	1,506,359	782,582	8,231,958
2009	668,429	495,271	140,785	258,086	398,871	1,562,571	747,983	8,979,941
2010	676,173	375,693	180,779	353,885	534,664	1,586,530	699,762	9,679,703
2011	732,664	347,903	172,621	387,421	560,042	1,640,609	666,741	10,346,444
2012	728,120	360,732	166,457	373,616	540,073	1,628,925	609,963	10,956,407
2013	754,097	374,159	160,506	395,011	555,517	1,683,773	580,946	11,537,353
2014	745,352	389,269	154,685	393,470	548,155	1,682,776	534,970	12,072,323
2015	770,045	405,180	148,972	404,714	553,686	1,728,911	506,437	12,578,760
2016	760,877	423,099	143,322	401,777	545,099	1,729,075	466,678	13,045,438
2017	785,611	439,499	137,724	414,718	552,442	1,777,552	442,054	13,487,492
2018	775,950	457,998	132,136	413,162	545,298	1,779,246	407,699	13,895,191
2019	801,314	477,484	126,552	425,039	551,591	1,830,389	386,453	14,281,645
2020	791,695	499,380	120,971	422,016	542,987	1,834,062	356,794	14,638,439
2021	817,417	519,554	115,393	435,684	551,077	1,888,048	338,429	14,976,868
2022	806,929	542,252	109,818	434,111	543,929	1,893,110	312,666	15,289,533
2023	833,579	566,168	104,246	446,667	550,913	1,950,660	296,849	15,586,383
2024	823,459	592,987	98,677	443,556	542,233	1,958,679	274,643	15,861,025
2025	850,501	617,839	93,112	458,006	551,118	2,019,458	260,909	16,121,935
2026	839,841	645,739	88,094	456,425	544,519	2,030,099	241,670	16,363,604
2027	869,862	675,145	83,622	469,711	553,333	2,098,340	230,161	16,593,765
2028	859,231	708,064	79,439	466,511	545,950	2,113,245	213,577	16,807,343

$$\frac{16,807,343 - 16,748,815}{58,528} = \text{I.D.} = \frac{4,533}{60,061}$$

21. Refer to confidential exhibit JBC-3, Appendix 6 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

Annual and Cumulative Revenue Requirement
Hines 2

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	787,329	459,222	1,253,420
2004	38,569	1,003	3,136	769,534	447,197	1,259,440
2005	45,021	1,796	3,244	844,751	469,460	1,364,272
2006	82,555	5,133	10,087	826,159	473,397	1,397,331
2007	88,170	6,113	6,607	919,728	508,009	1,528,628
2008	126,127	9,845	13,880	914,938	503,667	1,568,456
2009	131,057	11,035	15,729	1,022,392	472,779	1,652,992
2010	170,083	15,197	17,662	1,098,027	341,519	1,642,487
2011	165,006	15,641	19,945	1,120,341	358,825	1,679,758
2012	161,266	16,106	21,856	1,143,109	366,117	1,708,454
2013	156,495	16,579	21,201	1,166,340	373,558	1,734,172
2014	152,117	17,070	18,048	1,190,043	381,149	1,758,427
2015	149,246	17,579	26,712	1,214,227	388,895	1,796,660
2016	146,172	18,103	18,733	1,238,903	396,798	1,818,709
2017	142,672	18,641	21,472	1,264,081	404,862	1,851,729
2018	139,996	19,200	24,416	1,289,770	413,090	1,886,472
2019	136,548	19,773	22,824	1,315,981	421,485	1,916,612
2020	132,907	20,364	21,145	1,342,725	430,051	1,947,191
2021	132,336	20,980	29,277	1,370,013	438,790	1,991,396
2022	130,054	21,608	22,499	1,397,855	447,708	2,019,723
2023	126,416	22,254	25,789	1,426,263	456,806	2,057,527
2024	124,298	22,922	29,325	1,455,248	466,089	2,097,881
2025	120,780	23,608	27,413	1,484,822	475,561	2,132,184
2026	118,337	24,315	25,395	1,514,997	485,226	2,168,270
2027	114,502	25,043	29,139	1,545,785	495,087	2,209,556
2028	110,213	25,596	23,573	1,577,200	505,148	2,241,730
Cumulative	1,093,411	118,506	149,466	10,868,062	4,492,510	16,721,956

Annual and Cumulative Revenue Requirement
Panda

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	-	-	-	787,369	470,216	1,257,585
2004	-	-	-	775,388	500,233	1,275,621
2005	15,343	1,020	382	836,386	509,830	1,362,961
2006	91,361	5,229	6,523	823,319	473,656	1,400,088
2007	96,449	6,210	6,533	922,503	508,032	1,539,727
2008	134,932	9,946	17,752	919,092	503,495	1,585,217
2009	139,447	11,136	10,228	1,011,893	472,875	1,645,580
2010	177,716	15,299	17,956	1,098,523	340,995	1,650,490
2011	172,864	15,747	25,624	1,120,848	358,290	1,693,373
2012	168,580	16,212	18,020	1,143,626	365,572	1,712,009
2013	163,352	16,687	21,112	1,166,867	373,001	1,741,019
2014	159,625	17,183	21,960	1,190,581	380,581	1,769,930
2015	154,665	17,688	22,441	1,214,777	388,316	1,797,887
2016	150,037	18,214	18,616	1,239,464	396,207	1,822,538
2017	148,694	18,761	25,811	1,264,653	404,259	1,862,178
2018	146,450	19,321	19,808	1,290,354	412,475	1,888,409
2019	142,689	19,897	22,717	1,316,577	420,857	1,922,737
2020	139,521	20,492	25,843	1,343,333	429,410	1,958,600
2021	135,489	21,105	24,147	1,370,633	438,137	1,989,510
2022	131,963	21,737	22,358	1,398,488	447,041	2,021,586
2023	132,175	22,393	30,999	1,426,908	456,126	2,068,602
2024	129,137	23,062	23,790	1,455,907	465,395	2,097,292
2025	124,625	23,751	27,284	1,485,494	474,853	2,136,008
2026	123,800	24,465	31,038	1,515,683	484,504	2,179,489
2027	120,335	25,196	29,001	1,546,486	494,350	2,215,368
2028	117,669	25,949	26,853	1,577,914	504,396	2,252,781
Cumulative	1,085,179	117,741	143,265	10,865,912	4,576,138	16,788,235

22. Refer to confidential exhibit JBC-3, Appendix 6 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. This analysis should exclude the impact of the cost of imputed debt as described on pages 12-15 of John B. Crisp's confidential direct testimony. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

Annual and Cumulative Revenue Requirement
Hines 2

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	787,329	459,222	1,253,420
2004	38,569	1,003	3,136	769,534	447,197	1,259,440
2005	45,021	1,796	3,244	844,751	469,460	1,364,272
2006	82,555	5,133	10,087	826,159	473,397	1,397,331
2007	88,170	6,113	6,607	919,728	508,009	1,528,628
2008	126,127	9,845	13,880	914,938	503,667	1,568,456
2009	131,057	11,035	15,729	1,022,392	472,779	1,652,992
2010	170,083	15,197	17,662	1,098,027	341,519	1,642,487
2011	165,006	15,641	19,945	1,120,341	358,825	1,679,758
2012	161,266	16,106	21,856	1,143,109	366,117	1,708,454
2013	156,495	16,579	21,201	1,166,340	373,558	1,734,172
2014	152,117	17,070	18,048	1,190,043	381,149	1,758,427
2015	149,246	17,579	26,712	1,214,227	388,895	1,796,660
2016	146,172	18,103	18,733	1,238,903	396,798	1,818,709
2017	142,672	18,641	21,472	1,264,081	404,862	1,851,729
2018	139,996	19,200	24,416	1,289,770	413,090	1,886,472
2019	136,548	19,773	22,824	1,315,981	421,485	1,916,612
2020	132,907	20,364	21,145	1,342,725	430,051	1,947,191
2021	132,336	20,980	29,277	1,370,013	438,790	1,991,396
2022	130,054	21,608	22,499	1,397,855	447,708	2,019,723
2023	126,416	22,254	25,789	1,426,263	456,806	2,057,527
2024	124,298	22,922	29,325	1,455,248	466,089	2,097,881
2025	120,780	23,608	27,413	1,484,822	475,561	2,132,184
2026	118,337	24,315	25,395	1,514,997	485,226	2,168,270
2027	114,502	25,043	29,139	1,545,785	495,087	2,209,556
2028	110,213	25,596	23,573	1,577,200	505,148	2,241,730
Cumulative	1,093,411	118,506	149,466	10,868,062	4,492,510	16,721,956

Annual and Cumulative Revenue Requirement
Panda without Imputed Debt

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	-	-	-	787,369	468,048	1,255,417
2004	-	-	-	775,388	499,205	1,274,593
2005	15,343	1,020	382	836,386	509,830	1,362,961
2006	91,361	5,229	6,523	823,319	473,656	1,400,088
2007	96,449	6,210	6,533	922,503	508,032	1,539,727
2008	134,932	9,946	17,752	919,092	503,495	1,585,217
2009	139,447	11,136	10,228	1,011,893	472,875	1,645,580
2010	177,716	15,299	17,956	1,098,523	340,995	1,650,490
2011	172,864	15,747	25,624	1,120,848	358,290	1,693,373
2012	168,580	16,212	18,020	1,143,626	365,572	1,712,009
2013	163,352	16,687	21,112	1,166,867	373,001	1,741,019
2014	159,625	17,183	21,960	1,190,581	380,581	1,769,930
2015	154,665	17,688	22,441	1,214,777	388,316	1,797,887
2016	150,037	18,214	18,616	1,239,464	396,207	1,822,538
2017	148,694	18,761	25,811	1,264,653	404,259	1,862,178
2018	146,450	19,321	19,808	1,290,354	412,475	1,888,409
2019	142,689	19,897	22,717	1,316,577	420,857	1,922,737
2020	139,521	20,492	25,843	1,343,333	429,410	1,958,600
2021	135,489	21,105	24,147	1,370,633	438,137	1,989,510
2022	131,963	21,737	22,358	1,398,488	447,041	2,021,586
2023	132,175	22,393	30,999	1,426,908	456,126	2,068,602
2024	129,137	23,062	23,790	1,455,907	465,395	2,097,292
2025	124,625	23,751	27,284	1,485,494	474,853	2,136,008
2026	123,800	24,465	31,038	1,515,683	484,504	2,179,489
2027	120,335	25,196	29,001	1,546,486	494,350	2,215,368
2028	117,669	25,949	26,853	1,577,914	504,396	2,252,781
Cumulative	1,085,179	117,741	143,265	10,865,912	4,573,271	16,785,368

23. Refer to John B. Crisp's confidential direct testimony, page 15. Provide a PWRR analysis for each of the expansion plans evaluated under the high-fuel price forecast case, the low-fuel price forecast case, and the "Gulfstream" sensitivity. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

Annual and Cumulative Revenue Requirement
Hines 2 - High Fuel Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	822,631	460,585	1,290,086
2004	38,569	1,003	3,136	810,685	448,801	1,302,195
2005	45,021	1,796	3,244	892,491	470,601	1,413,153
2006	82,555	5,133	10,087	876,855	476,823	1,451,454
2007	88,170	6,113	6,607	972,225	511,150	1,584,265
2008	126,127	9,845	13,880	957,366	507,427	1,614,644
2009	131,057	11,035	15,729	1,068,919	477,222	1,703,962
2010	170,083	15,197	17,662	1,150,014	345,647	1,698,603
2011	165,006	15,641	19,945	1,173,386	363,037	1,737,014
2012	161,266	16,106	21,856	1,197,232	370,415	1,766,874
2013	156,495	16,579	21,201	1,221,562	377,942	1,793,779
2014	152,117	17,070	18,048	1,246,387	385,623	1,819,245
2015	149,246	17,579	26,712	1,271,717	393,460	1,858,714
2016	146,172	18,103	18,733	1,297,561	401,456	1,882,025
2017	142,672	18,641	21,472	1,323,931	409,614	1,916,331
2018	139,996	19,200	24,416	1,350,836	417,939	1,952,387
2019	136,548	19,773	22,824	1,378,289	426,432	1,983,866
2020	132,907	20,364	21,145	1,406,299	435,099	2,015,813
2021	132,336	20,980	29,277	1,434,878	443,941	2,061,412
2022	130,054	21,608	22,499	1,464,038	452,963	2,091,162
2023	126,416	22,254	25,789	1,493,791	462,168	2,130,418
2024	124,298	22,922	29,325	1,524,149	471,560	2,172,253
2025	120,780	23,608	27,413	1,555,123	481,144	2,208,067
2026	118,337	24,315	25,395	1,586,727	490,922	2,245,696
2027	114,502	25,043	29,139	1,618,973	500,898	2,288,555
2028	110,213	25,596	23,573	1,651,875	511,078	2,322,334
Cumulative	1,093,411	118,506	149,466	11,403,495	4,529,769	17,294,647

Annual and Cumulative Revenue Requirement
Hines 2 - Low Fuel Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	749,648	452,627	1,209,145
2004	38,569	1,003	3,136	721,764	441,457	1,205,930
2005	45,021	1,796	3,244	779,988	464,327	1,294,376
2006	82,555	5,133	10,087	734,331	486,169	1,318,276
2007	88,170	6,113	6,607	826,801	502,970	1,430,662
2008	126,127	9,845	13,880	807,537	499,932	1,457,320
2009	131,057	11,035	15,729	890,891	467,958	1,516,670
2010	170,083	15,197	17,662	942,920	336,870	1,482,732
2011	165,006	15,641	19,945	962,083	354,081	1,516,756
2012	161,266	16,106	21,856	981,635	361,277	1,542,140
2013	156,495	16,579	21,201	1,001,584	368,619	1,564,477
2014	152,117	17,070	18,048	1,021,938	376,111	1,585,284
2015	149,246	17,579	26,712	1,042,707	383,754	1,619,998
2016	146,172	18,103	18,733	1,063,897	391,553	1,638,457
2017	142,672	18,641	21,472	1,085,518	399,510	1,667,814
2018	139,996	19,200	24,416	1,107,578	407,629	1,698,820
2019	136,548	19,773	22,824	1,130,087	415,913	1,725,146
2020	132,907	20,364	21,145	1,153,053	424,366	1,751,834
2021	132,336	20,980	29,277	1,176,486	432,990	1,792,069
2022	130,054	21,608	22,499	1,200,395	441,789	1,816,345
2023	126,416	22,254	25,789	1,224,790	450,767	1,850,016
2024	124,298	22,922	29,325	1,249,681	459,928	1,886,153
2025	120,780	23,608	27,413	1,275,077	469,275	1,916,152
2026	118,337	24,315	25,395	1,300,990	478,812	1,947,849
2027	114,502	25,043	29,139	1,327,429	488,542	1,984,655
2028	110,213	25,596	23,573	1,354,406	498,471	2,012,258
Cumulative	1,093,411	118,506	149,466	9,557,667	4,450,915	15,369,965

Annual and Cumulative Revenue Requirement
Hines 2 - Gulfstream Sensitivity

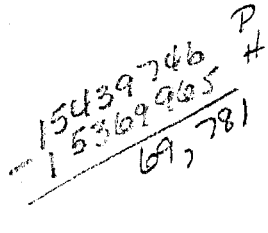
Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	768,251	454,744	1,229,865
2004	38,569	1,003	3,136	756,816	445,063	1,244,588
2005	45,021	1,796	3,244	827,405	467,200	1,344,666
2006	82,555	5,133	10,087	818,809	472,108	1,388,693
2007	88,170	6,113	6,607	907,323	505,849	1,514,062
2008	126,127	9,845	13,880	908,444	502,648	1,560,943
2009	131,057	11,035	15,729	1,013,279	471,136	1,642,236
2010	170,083	15,197	17,662	1,088,811	339,430	1,631,182
2011	165,006	15,641	19,945	1,110,938	356,693	1,668,223
2012	161,266	16,106	21,856	1,133,515	363,942	1,696,685
2013	156,495	16,579	21,201	1,156,551	371,339	1,722,164
2014	152,117	17,070	18,048	1,180,055	378,885	1,746,175
2015	149,246	17,579	26,712	1,204,036	386,585	1,784,159
2016	146,172	18,103	18,733	1,228,505	394,441	1,805,954
2017	142,672	18,641	21,472	1,253,471	402,457	1,838,715
2018	139,996	19,200	24,416	1,278,945	410,636	1,873,193
2019	136,548	19,773	22,824	1,304,936	418,981	1,903,063
2020	132,907	20,364	21,145	1,331,456	427,496	1,933,367
2021	132,336	20,980	29,277	1,358,514	436,184	1,977,291
2022	130,054	21,608	22,499	1,386,122	445,048	2,005,331
2023	126,416	22,254	25,789	1,414,292	454,093	2,042,843
2024	124,298	22,922	29,325	1,443,034	463,321	2,082,899
2025	120,780	23,608	27,413	1,472,359	472,737	2,116,896
2026	118,337	24,315	25,395	1,502,281	482,344	2,152,672
2027	114,502	25,043	29,139	1,532,811	492,146	2,193,641
2028	110,213	25,596	23,573	1,563,962	502,148	2,225,491
Cumulative	1,093,411	118,506	149,466	10,749,081	4,468,553	16,579,018

Annual and Cumulative Revenue Requirement
Panda - High Fuel Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	-	-	-	822,822	471,562	1,294,384
2004	-	-	-	817,151	501,716	1,318,867
2005	15,343	1,020	382	889,795	513,271	1,419,811
2006	91,361	5,229	6,523	873,629	477,197	1,453,939
2007	96,449	6,210	6,533	975,199	511,250	1,595,641
2008	134,932	9,946	17,752	961,895	507,176	1,631,701
2009	139,447	11,136	10,228	1,057,455	477,556	1,695,822
2010	177,716	15,299	17,956	1,150,505	345,084	1,706,560
2011	172,864	15,747	25,624	1,173,886	362,462	1,750,584
2012	168,580	16,212	18,020	1,197,742	369,829	1,770,382
2013	163,352	16,687	21,112	1,222,083	377,344	1,800,579
2014	159,625	17,183	21,960	1,246,919	385,013	1,830,699
2015	154,665	17,688	22,441	1,272,260	392,837	1,859,891
2016	150,037	18,214	18,616	1,298,115	400,821	1,885,803
2017	148,694	18,761	25,811	1,324,496	408,967	1,926,728
2018	146,450	19,321	19,808	1,351,413	417,278	1,954,271
2019	142,689	19,897	22,717	1,378,877	425,758	1,989,938
2020	139,521	20,492	25,843	1,406,899	434,410	2,027,166
2021	135,489	21,105	24,147	1,435,491	443,239	2,059,470
2022	131,963	21,737	22,358	1,464,664	452,246	2,092,968
2023	132,175	22,393	30,999	1,494,429	461,437	2,141,434
2024	129,137	23,062	23,790	1,524,800	470,815	2,171,604
2025	124,625	23,751	27,284	1,555,788	480,383	2,211,830
2026	123,800	24,465	31,038	1,587,405	490,145	2,256,853
2027	120,335	25,196	29,001	1,619,665	500,106	2,294,304
2028	117,669	25,949	26,853	1,652,581	510,270	2,333,321
Cumulative	1,085,179	117,741	143,265	11,405,931	4,615,062	17,367,178

Annual and Cumulative Revenue Requirement
Panda - Low Fuel Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	-	-	-	749,160	463,814	1,212,974
2004	-	-	-	727,467	492,867	1,220,334
2005	15,343	1,020	382	775,687	505,977	1,298,409
2006	91,361	5,229	6,523	748,235	469,364	1,320,712
2007	96,449	6,210	6,533	829,390	503,032	1,441,614
2008	134,932	9,946	17,752	811,091	499,982	1,473,703
2009	139,447	11,136	10,228	882,261	467,809	1,510,882
2010	177,716	15,299	17,956	943,275	336,622	1,490,868
2011	172,864	15,747	25,624	962,444	353,828	1,530,508
2012	168,580	16,212	18,020	982,003	361,019	1,545,834
2013	163,352	16,687	21,112	1,001,960	368,356	1,571,467
2014	159,625	17,183	21,960	1,022,323	375,842	1,596,932
2015	154,665	17,688	22,441	1,043,099	383,480	1,621,373
2016	150,037	18,214	18,616	1,064,297	391,273	1,642,437
2017	148,694	18,761	25,811	1,085,926	399,225	1,678,417
2018	146,450	19,321	19,808	1,107,995	407,338	1,700,913
2019	142,689	19,897	22,717	1,130,512	415,616	1,731,431
2020	139,521	20,492	25,843	1,153,487	424,063	1,763,406
2021	135,489	21,105	24,147	1,176,929	432,681	1,790,350
2022	131,963	21,737	22,358	1,200,847	441,474	1,818,378
2023	132,175	22,393	30,999	1,225,251	450,446	1,861,264
2024	129,137	23,062	23,790	1,250,151	459,600	1,885,741
2025	124,625	23,751	27,284	1,275,557	468,940	1,920,157
2026	123,800	24,465	31,038	1,301,480	478,470	1,959,252
2027	120,335	25,196	29,001	1,327,929	488,194	1,990,656
2028	117,669	25,949	26,853	1,354,916	498,115	2,023,502
Cumulative	1,085,179	117,741	143,265	9,569,822	4,523,739	15,439,746



Annual and Cumulative Revenue Requirement
Panda - Gulfstream Fuel Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	-	-	-	771,157	466,992	1,238,149
2004	-	-	-	766,104	496,721	1,262,825
2005	15,343	1,020	382	827,789	509,055	1,353,590
2006	91,361	5,229	6,523	815,438	472,079	1,390,630
2007	96,449	6,210	6,533	909,788	505,913	1,524,893
2008	134,932	9,946	17,752	913,324	502,763	1,578,717
2009	139,447	11,136	10,228	1,002,771	470,722	1,634,305
2010	177,716	15,299	17,956	1,089,695	339,273	1,639,940
2011	172,864	15,747	25,624	1,111,840	356,533	1,682,609
2012	168,580	16,212	18,020	1,134,436	363,779	1,701,026
2013	163,352	16,687	21,112	1,157,490	371,172	1,729,813
2014	159,625	17,183	21,960	1,181,013	378,715	1,758,496
2015	154,665	17,688	22,441	1,205,014	386,411	1,786,220
2016	150,037	18,214	18,616	1,229,503	394,264	1,810,635
2017	148,694	18,761	25,811	1,254,490	402,277	1,850,032
2018	146,450	19,321	19,808	1,279,984	410,452	1,876,016
2019	142,689	19,897	22,717	1,305,997	418,793	1,910,093
2020	139,521	20,492	25,843	1,332,538	427,304	1,945,699
2021	135,489	21,105	24,147	1,359,618	435,988	1,976,347
2022	131,963	21,737	22,358	1,387,249	444,849	2,008,155
2023	132,175	22,393	30,999	1,415,442	453,889	2,054,898
2024	129,137	23,062	23,790	1,444,207	463,113	2,083,310
2025	124,625	23,751	27,284	1,473,557	472,525	2,121,741
2026	123,800	24,465	31,038	1,503,503	482,128	2,164,933
2027	120,335	25,196	29,001	1,534,058	491,926	2,200,516
2028	117,669	25,949	26,853	1,565,234	501,923	2,237,627
Cumulative	1,085,179	117,741	143,265	10,761,455	4,555,208	16,662,848

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines Unit 2 Power Plant.	)	Docket No.: 001064-EI
	)	Submitted for Filing: October 10, 2000

FLORIDA POWER CORPORATION'S
RESPONSE TO STAFF'S FIRST REQUEST
FOR PRODUCTION OF DOCUMENTS (NOS. 1 – 10)

Florida Power Corporation, through its undersigned attorneys responds to Staff's First Request for Production of Documents to Florida Power Corporation (Nos. 1 – 10), subject to its general and specific objections filed with the Commission on September 18, 2000, as set forth below.

PRODUCTION REQUESTS

1. **Referring to page 12 of the testimony of John Crisp, please provide the work papers and documentation used**

(The answer continues to

FPC will produce the non-

2. **Referring to page 21 of t**

documentation used to d

FPC will produce the non-

3. **Please provide copies**

Florida Progress Corporatio

by or for investment bankin

Florida Power or Florida F
banking firms that refer to

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 8
COMPANY/ WITNESS: Florida Power Corporation
DATE: 11-26-07

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines Unit 2 Power Plant.	)	Docket No.: 001064-EI
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PRODUCTION REQUESTS

1. **Referring to page 12 of the testimony of John Crisp, please provide the work papers and documentation used as a basis for the answer to the question in lines 18 and 19. (The answer continues to page 15.)**

   FPC will produce the non-privileged documents responsive to this request.

2. **Referring to page 21 of the Need Study, please provide all workpapers and documentation used to develop the financial assumptions.**

   FPC will produce the non-privileged documents responsive to this request.

3. **Please provide copies of all reports or reviews for Florida Power Corporation or Florida Progress Corporation that refer to the Hines 2 Power Plant and that were prepared by or for investment banking firms.**

   Florida Power or Florida Progress did not prepare any reports or reviews for investment banking firms that refer to the Hines 2 power plant.

DOCUMENT NUMBER-DATE
12902 OCT 10 8
FPSC-RECORDS/REPORTING

4. Please provide the most recent credit report for Florida Power Corporation prepared by Standard and Poor's.

The most recent credit report for Florida Power prepared by Standard and Poor's is attached.

5. Please provide the most recent credit report for Florida Power Corporation prepared by Moody's Investor Services.

The most recent credit report for Florida Power prepared by Moody's Investor Services is attached.

6. For the 12 months ending August 31, 2000, please provide all reports, analyses, reviews, and information prepared by or for Florida Power Corporation and provided or sent to Standard and Poor's.

Florida Power did not prepare or have prepared any reports, analyses, reviews, or information for Standard and Poor's during the 12 months ending August 31, 2000.

7. For the 12 months ending August 31, 2000, please provide all reports, analyses, reviews, and information prepared by or for Florida Power Corporation and provided or sent to Moody's Investor Services.

Florida Power did not prepare or have prepared any reports, analyses, reviews, or information for Moody's Investor Services during the 12 months ending August 31, 2000.

8. Refer to page 40 of Exhibit JBC-1, the Need Study. Provide all documents supporting the statement "These conclusions were initially tested using specific targeted financial assessments. . .".

FPC will produce the non-privileged documents responsive to this request.

9. Refer to page 47 of Exhibit JBC-1, the Need Study. Provide all documents supporting the statement "These contract benefits represent somewhere between a $20 to

$40 million advantage to FPC's ratepayers over current market prices for the exact same combined cycle technology."

Without waiving its objections filed separately on September 18, 2000, FPC states that the $20 to $40 million advantage to FPC's ratepayers over current combined cycle market prices were based on a 1998/99 Black & Veatch (B&V) Technology Review Report. The attached section 6.4 and Tables 28, 29, and 41 from this B&V report include Hines #2 "overnight" cost estimates as well as "overnight" market price estimates for similar combined cycle generation. (West. 501FC 2x1 CC).

10. Refer to the direct testimony of John Crisp, page 9, lines 14-19. Provide all documents supporting the statement that FPC "will achieve fuel savings in the range of $40 million per year from the Hines 2 plant."

FPC will produce the non-privileged documents responsive to this request.

RESPECTFULLY SUBMITTED

Gary L. Sasso
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and

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P.O. Box 2861
St. Petersburg, FL 33731
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT a true and correct copy of the foregoing has been furnished by Federal Express to Deborah Hart, as counsel for Florida Public Service Commission, and via U. S. Mail to all other interested parties of record as listed below on this 10th day of October, 2000.

Attorney

PARTIES OF RECORD:

Deborah D. Hart
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Myron Rollins
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Paul Darst
Strategic Planning
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-2100

FGT Results

FGT

Year	FGTBase	Panda @ 530 FGT201
2000	1,193,786	1,193,786
2001	1,243,373	1,243,373
2002	1,169,888	1,169,888
2003	1,255,996	1,255,169
2004	1,251,359	1,255,062
2005	1,341,522	1,325,762
2006	1,335,270	1,333,112
2007	1,449,290	1,451,784
2008	1,455,653	1,459,234
2009	1,518,642	1,510,138
2010	1,481,792	1,479,264

REDACTED

Year	FGTBase	Panda @ 530 FGT201
2000	-	-
2001	-	-
2002	-	-
2003	-	(827)
2004	-	3,703
2005	-	(15,760)
2006	-	(2,158)
2007	-	2,494
2008	-	3,581
2009	-	(8,504)
2010	-	(2,528)

Year	FGTBase	Panda @ 530 FGT201
2000	1,189,336	1,189,336
2001	1,240,870	1,240,870
2002	1,194,525	1,194,525
2003	1,287,490	1,287,000
2004	1,290,728	1,293,712
2005	1,386,125	1,380,005
2006	1,387,828	1,385,222
2007	1,502,236	1,505,037
2008	1,501,219	1,505,172
2009	1,567,857	1,557,408
2010	1,531,596	1,531,420

NOT

Florida Power
CORPORATION

May 31, 2000

Mr. Sam Doaks
Panda Energy International, Inc.
4100 Spring Valley Road, Suite 1001
Dallas, TX 75244

Re: Proposal Response to Florida Power RFP

Dear Mr. Doaks:

This is to confirm that we have not selected your proposed project to fulfill our need for additional generating capacity. We appreciate your responding to our Request for Proposals and for your courtesy and cooperation during our evaluation process.

Sincerely,

Michael D. Rib
Director Resource Planning

MDR/bhl

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 9
COMPANY/ WITNESS: Panda
DATE: 10-26-00

#9

EXHIBIT NO. 10

~~**Docket No:** 001064-EI~~

Party: Florida Power Corporation

Description: COMPOSITE EXHIBIT

(1) FPC's Response to Staff Interrogatory Nos. 1-3, 6, 11-14, 16-18, 21-23, 30, 36-38

(2) FPC's Response to Staff Request for Production of Documents Nos. 4-5

(3) Late-filed Exhibit from Deposition of John B. Crisp

Proffered By: Commission Staff

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 10
COMPANY/ WITNESS: FPSC Com. Staff
DATE: 10-26 & 27-00

STAFF COMPOSITE EXHIBIT
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Late-filed Deposition Exhibits

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines 2 Power Plant	)	DOCKET NO. 001064-EI
	)	Submitted for filing: October 10, 2000

FLORIDA POWER CORPORATION'S RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER CORPORATION (NOS. 1 - 38)

Florida Power Corporation ("FPC" or the "Company"), pursuant to Florida Rule of Civil Procedure 1.340 and the Commission's Order Establishing Procedure issued August 30, 2000, respectfully files with the Florida Public Service Commission ("PSC" or the "Commission"), its response to Staff's First Set of Interrogatories subject to both its general and specific objections filed with the Commission on September 18, 2000.

INTERROGATORIES

1. **Refer to page 13 of the testimony of John Crisp. What is the amount of imputed debt used by Standard and Poor's in its evaluation of FPC's financial condition and credit rating? Please include the period for this imputed debt.**

Answer:

Without waiving its objections filed separately on September 18, 2000, FPC states that Standard and Poor's estimate of Florida Power Corporation's off-balance sheet (imputed) debt is $781.2 million as of 12/31/1999. Florida Power believes Standard and Poor's has calculated this value using some erroneous assumptions and has adjusted the off-balance sheet obligation downward to $462.4 million. Discussions with the rating agency indicate that they will revise their estimate downward in future credit reports.

Florida Power maintains that the above information is not relevant to its analysis of the need for Hines 2 or to the comparison of Hines 2 with the bids received during its Request for Proposal. Imputed debt for existing contracts were not used in the analysis, therefore the results of the

analysis would be the same regardless of the existing level of imputed debt. The calculation of imputed debt for purchase power alternatives was made in order to maintain the existing capital structure for all alternatives so as to allow a fair and unbiased comparison.

2. Refer to page 13 of the testimony of John Crisp. What is the amount of imputed debt used by Moody's in its evaluation of FPC's financial condition and credit rating?

Please include the period for this imputed debt.

Answer:

Without waiving its objections filed separately on September 18, 2000, Moody's Investors Service considers off-balance sheet obligations in its credit analysis but does not publish its estimate of this obligation.

3. What is FPC's estimate of its Standard & Poor's total off balance sheet obligation? Please include a schedule showing the calculation of this estimate as of June 30, 2000 and include any schedule similar in format to Attachment 1.

Answer:

Without waiving its objections separately filed on September 18, 2000, Florida Power states that it has no off-balance sheet obligations other than imputed debt related to its purchase power contracts, therefore its total off-balance sheet obligations are the same as its imputed debt. Please refer to FPC's response to Interrogatory 1 for a discussion of imputed debt. Florida Power is unable to prepare an attachment similar to Staff's Attachment 1 because information on this schedule, in particular the risk factors for specific contracts, is proprietary information belonging to Standard and Poor's which Florida Power is not at liberty to release.

6. What is FPC's common equity ratio adjusted for Standard & Poor's off balance sheet obligations as of June 30, 2000? As part of the answer to this interrogatory please show the capital structure and calculation.

Answer:

Without waiving its objections filed separately on September 18, 2000, FPC's common equity ratio adjusted for Standard and Poor's off balance sheet obligation as of June, 2000 is 42.91%. Details of the calculation are shown in the attachment hereto. This information has previously been submitted to the FPSC in FPC's surveillance report for the month of June, 2000. (Schedule 4, page 3 of 4).

FLORIDA POWER CORPORATION
AVERAGE CAPITAL STRUCTURE
FPSC ADJUSTED BASIS
JUNE 2000

	SYSTEM PER BOOKS	SPECIFIC ADJUSTMENTS	ADJUSTED SYSTEM PER BOOKS	PRO RATA 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
COMMON EQUITY	$ 1,914,227,648	$87,444,135	$2,001,671,783	182,543,215	$1,819,128,568	52.01% ***	11.00%	5.72%	12.00%	6.24%	13.00%	6.76%
PREFERRED STOCK	33,496,700	0	33,496,700	3,055,181	30,441,519	0.87%	4.51%	0.04%	4.51%	0.04%	4.51%	0.04%
LONG TERM DEBT												
FIXED RATE	1,357,679,325	(320,606,945)	1,037,072,380	94,589,723	942,482,657	26.94%	7.27%	1.96%	7.27%	1.96%	7.27%	1.96%
VARIABLE RATE *	177,653,846	(109,193,839)	68,460,007	6,244,128	62,215,879	1.78%	5.92%	0.11%	5.92%	0.11%	5.92%	0.11%
SHORT TERM DEBT *	71,262,385	(5,732,834)	65,529,551	5,976,846	59,552,705	1.70%	6.21%	0.11%	6.21%	0.11%	6.21%	0.11%
REVENUE DECOUPLING	286,021		286,021	26,088	259,933	0.01%	5.83%	0.00%	5.83%	0.00%	5.83%	0.00%
CUSTOMER DEPOSITS												
ACTIVE	102,678,206		102,678,206	0	102,678,206	2.93%	6.20%	0.18%	6.20%	0.18%	6.20%	0.18%
INACTIVE	442,891		442,891	0	442,891	0.01%	0	0	0.00%	0	0	0
INVESTMENT TAX CREDIT												
POST '70 TOTAL	69,442,123		69,442,123	6,333,706								
-EQUITY **					40,894,255	1.17%	10.89%	0.13%	11.87%	0.14%	12.86%	0.15%
-DEBT **					22,214,162	0.63%	7.19%	0.05%	7.19%	0.05%	7.19%	0.05%
DEFERRED INCOME TAXES	451,815,692	9,824,412	461,640,104	42,105,460	419,534,644	11.99%	0	0	0.00%	0	0	0
FAS 109 LIABILITY-NET	(22,710,077)	(5,223,846)	(27,933,923)	(2,547,809)	(25,386,114)	-0.73%		0	0.00%	0	0	0
DEFERRED EARNINGS	24,260,029	0	24,260,029	0	24,260,029	0.69%	5.77%	0.04%	5.77%	0.04%	5.77%	0.04%
TOTAL	$4,180,534,789	($343,488,917)	$3,837,045,872	$338,326,538	$3,498,719,334	100.00%		8.34%		8.87%		9.40%

* DAILY WEIGHTED AVERAGE
** COST RATES CALCULATED PER IRS RULING
*** EQUITY RATIO INCLUDING DEBT ASSOCIATED WITH QUALIFYING FACILITIES CONTRACTS (Based on FPSC Capital Structure) 42.91%

900000

Interrogatory No. 6

Florida Power Corporation
Average Capital Structure
FPSC Adjusted Basis
June-00

		FPSC Adjusted Retail with Off-Balance Sheet Debt	Ratio
Common Equity	$	1,819,128,568	42.90%
Preferred Stock		30,441,519	0.72%
Long-term Debt		1,746,467,587	41.19%
Short-term Debt		59,552,705	1.40%
Revenue Decoupling		259,933	0.01%
Customer Deposits		103,121,097	2.43%
Investment Tax Credit		63,108,417	1.49%
Deferred Income Taxes		419,534,644	9.89%
FAS 109 Liability-Net		(25,386,114)	-0.60%
Deferred Earnings		24,260,029	0.57%
Total	$	4,240,488,385	100.00%

Purchased Power Debt:

Tiger Bay Regulatory Asset - Retail	$	297,822,811
Off-Balance Sheet Debt per FPC Calculation (Retail Portion)	$	443,946,240
Total Purchased Power Debt	$	741,769,051

11. Refer to exhibit RDN-1 to Robert D. Niekum's direct testimony. In tabular form, provide the high, base, and low case delivered price forecasts for coal, residual oil, distillate oil, and natural gas for years 2001 to 2020.

Answer:

Attached.

11. Refer to exhibit RDN-1 to Robert D. Niekum's direct testimony. In tabular form, provide the high, base, and low case delivered price forecasts for coal, residual oil, distillate oil, and natural gas for years 2001 through 2020.

Base Fuel Price Forecast

Year	Wellhead - Natural Gas	Citygate - Natural Gas	Coal	Residual Oil	Distillate Oil
2001	2.59	3.04	1.83	2.76	5.07
2002	2.63	3.13	1.83	2.78	5.12
2003	2.71	3.21	1.85	2.81	5.17
2004	2.80	3.30	1.87	2.84	5.22
2005	2.88	3.38	1.85	2.87	5.28
2006	2.94	3.45	1.87	2.90	5.33
2007	3.01	3.52	1.89	2.93	5.38
2008	3.07	3.58	1.93	2.96	5.44
2009	3.14	3.65	1.96	2.99	5.49
2010	3.17	3.69	1.98	3.02	5.55
2011	3.20	3.72	2.00	3.05	5.60
2012	3.24	3.76	2.02	3.08	5.66
2013	3.27	3.80	2.04	3.11	5.71
2014	3.30	3.84	2.06	3.14	5.77
2015	3.33	3.87	2.08	3.17	5.83
2016	3.37	3.91	2.10	3.20	5.89
2017	3.40	3.95	2.12	3.23	5.95
2018	3.43	3.99	2.14	3.27	6.00
2019	3.47	4.03	2.17	3.30	6.06
2020	3.50	4.07	2.19	3.33	6.13

High Fuel Price Forecast

Year	Wellhead - Natural Gas	Citygate - Natural Gas	Coal	Residual Oil	Distillate Oil
2001	3.00	3.45	1.85	2.80	4.85
2002	3.00	3.50	1.86	2.80	4.85
2003	3.10	3.60	1.88	2.80	4.95
2004	3.20	3.70	1.90	2.85	5.00
2005	3.30	3.80	1.87	2.90	5.15
2006	3.30	3.81	1.89	3.10	5.40
2007	3.30	3.81	1.92	3.15	5.50
2008	3.30	3.81	1.95	3.25	5.60
2009	3.30	3.81	1.97	3.35	5.85
2010	3.33	3.85	1.99	3.42	5.97
2011	3.37	3.89	2.01	3.49	6.09
2012	3.40	3.93	2.03	3.56	6.21
2013	3.43	3.96	2.05	3.63	6.33
2014	3.47	4.00	2.07	3.70	6.46
2015	3.50	4.04	2.09	3.77	6.59
2016	3.54	4.08	2.11	3.85	6.72
2017	3.57	4.13	2.13	3.93	6.85
2018	3.61	4.17	2.15	4.00	6.99
2019	3.65	4.21	2.18	4.08	7.13
2020	3.68	4.25	2.20	4.17	7.27

Low Fuel Price Forecast

Year	Wellhead - Natural Gas	Citygate - Natural Gas	Coal	Residual Oil	Distillate Oil
2001	2.20	2.65	1.80	2.15	4.00
2002	2.20	2.70	1.80	2.35	4.40
2003	2.20	2.70	1.82	2.35	4.40
2004	2.20	2.70	1.84	2.35	4.40
2005	2.20	2.70	1.80	2.35	4.40
2006	2.20	2.71	1.83	2.35	4.40
2007	2.20	2.71	1.86	2.35	4.40
2008	2.20	2.71	1.89	2.35	4.40
2009	2.20	2.71	1.92	2.35	4.40
2010	2.21	2.72	1.93	2.36	4.42
2011	2.22	2.74	1.94	2.37	4.44
2012	2.23	2.75	1.95	2.39	4.47
2013	2.24	2.76	1.96	2.40	4.49
2014	2.26	2.78	1.97	2.41	4.51
2015	2.27	2.79	1.98	2.42	4.53
2016	2.28	2.81	1.99	2.43	4.56
2017	2.29	2.82	2.00	2.45	4.58
2018	2.30	2.83	2.01	2.46	4.60
2019	2.31	2.85	2.02	2.47	4.63
2020	2.32	2.86	2.03	2.48	4.65

12. Refer to pages 34-35 of exhibit JBC-1, the Need Study. Provide the delivered price for each fuel associated with the screening evaluation of generation alternatives for each year in the evaluation period.

Answer:

Attached.

12. Refer to pages 34-35 of exhibit JBC-1, the Need Study. Provide the delivered price for each fuel associated with the screening evaluation of generation alternatives for each year in the evaluation period.

FLORIDA POWER CORPORATION

NOMINAL, DELIVERED COAL PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	LOW SULFUR COAL (<1.0%)				MEDIUM SULFUR COAL (1.0 - 2.0%)				HIGH SULFUR COAL (>2.0%)			
YEAR	$/TON	¢/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	¢/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	¢/MBTU	ESCALATION %	% SPOT PURCHASE
					1/	1/		4/				
1997		DATA			47.25	189.00		0.00		DATA		
1998		NOT			47.00	188.00	-0.53	0.00		NOT		
1999		AVAILABLE			46.25	185.00	-1.60	0.00		AVAILABLE		
	2/	2/		4/	3/	3/		4/				
2000	48.75	195.00		0.00	40.75	163.00		0.00				
2001	48.25	193.00	-1.03	0.00	41.25	165.00	1.23	0.00				
2002	48.00	192.00	-0.52	0.00	41.75	167.00	1.21	0.00				
2003	48.50	194.00	1.04	0.00	42.25	169.00	1.20	0.00				
2004	49.00	196.00	1.03	0.00	42.75	171.00	1.18	0.00		NOT		
2005	47.75	191.00	-2.55	0.00	43.25	173.00	1.17	0.00		APPLICABLE		
2006	48.25	193.00	1.05	0.00	44.25	177.00	2.31	0.00				
2007	48.75	195.00	1.04	0.00	44.75	179.00	1.13	0.00				
2008	49.75	199.00	2.05	0.00	45.50	182.00	1.68	0.00				
2009	50.50	202.00	1.51	0.00	46.00	184.00	1.10	0.00				

HEAT CONTENT <1.0% LOW SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT 1.0 - 2.0% MED. SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT >2.0% HIGH SULFUR COAL = N/A MBTU/TON

ASH CONTENT <1.0% LOW SULFUR COAL = 8.36 PERCENT
ASH CONTENT 1.0 - 2.0% MED. SULFUR COAL = 8.89 PERCENT
ASH CONTENT >2.0% HIGH SULFUR COAL = N/A PERCENT

NOTES: 1/ TOTAL COAL - $/TON ARE APPROXIMATE - AS BURNED DATA
2/ LIMITED TO 1.2 lb SO2/MBTU
3/ LIMITED TO 2.1 lb SO2/MBTU
4/ 100% CONTRACT

FLORIDA POWER CORPORATION

NOMINAL, DELIVERED DISTILLATE OIL and NATURAL GAS PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	DISTILLATE OIL			NATURAL GAS		
			ESCALATION			ESCALATION
YEAR	$/BBL	c/MBTU	%	c/MBTU	c/THERM	%
	1 /	1 /				
1997	27.55	475.00		287.00	28.70	
1998	21.52	371.00	-21.89	291.00	29.10	1.39
1999	22.04	380.00	2.43	299.00	29.90	2.75
	2 /	2 /		3 /	3 /	
2000	29.12	502.00		261.00	26.10	
2001	27.61	476.00	-5.18	259.00	25.90	-0.77
2002	27.49	474.00	-0.42	263.00	26.30	1.54
2003	27.67	477.00	0.63	271.00	27.10	3.04
2004	27.90	481.00	0.84	280.00	28.00	3.32
2005	28.36	489.00	1.66	288.00	28.80	2.86
2006	28.94	499.00	2.04	294.00	29.40	2.08
2007	29.58	510.00	2.20	301.00	30.10	2.38
2008	30.22	521.00	2.16	307.00	30.70	1.99
2009	30.80	531.00	1.92	314.00	31.40	2.28

HEAT CONTENT DISTILLATE OIL = 5.80 MBTU/BBL

ASH CONTENT DISTILLATE OIL = 0.00 PERCENT

NOTES: 1 / AS BURNED DATA - APPROXIMATE
2 / WITHOUT INLAND FREIGHT - 0.5% SULFUR
3 / SUPPLY COST ONLY

13. Refer to pages 33-35 of exhibit JBC-1, the Need Study. Provide a present worth revenue requirements (PWRR) analysis for each of the expansion plans in which the following alternatives were included: 1) Combined Cycle - HEC #2; 2) Integrated Gasification Combined Cycle; 3) Pulverized Coal Plant; and 4) Fluidized Bed Coal Plant. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed operations and maintenance (O&M), non-fuel variable O&M, fuel, purchased power, and total costs.

The present worth revenue requirements ("PWRR") for the 1) Combined Cycle – HEC #2 ; 2) Integrated Gasification Combined Cycle (IGCC) ; 3) Pulverized Coal (PC) Plant; and 4) Fluidized Bed (FB) Coal Plant are attached. The components of the "PWRR" are typical report runs available from the "PROSCREEN" model and provide a general breakdown of the annual and cumulative totals. The IGCC (output run #PS12P634), PC Plant (output run #PS12P286), and FB Plant (output run #PS12P334) totals that are attached were based on the most attractive (highest ranking) run for that technology alternative.

PS000012P634 • IGCC

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	605100.	460139.	33940.	0.	1099178.	33940.	1099178.	1099178.
2001	650428.	466474.	33777.	0.	1150679.	31123.	1060241.	2159419.
2002	618939.	473069.	36167.	0.	1128175.	30705.	957804.	3117223.
2003	680026.	483351.	33022.	0.	1196399.	25832.	935894.	4053117.
2004	609674.	498668.	65875.	71065.	1245282.	98703.	897570.	4950688.
2005	660767.	508753.	63460.	75668.	1308648.	92399.	869108.	5819796.
2006	604807.	521791.	102370.	145159.	1374128.	151471.	840869.	6660665.
2007	652178.	537799.	98441.	161053.	1449470.	146311.	817261.	7477926.
2008	613050.	546596.	138003.	220186.	1517834.	186086.	788544.	8266470.
2009	668429.	498690.	132692.	258086.	1557897.	187060.	745745.	9012215.
2010	665363.	386090.	301790.	343005.	1696248.	284396.	748155.	9760370.
2011	724607.	348092.	288977.	372063.	1733739.	268646.	704589.	10464959.
2012	719222.	360899.	278328.	360555.	1719003.	239234.	643693.	11108652.
2013	745605.	374357.	268044.	380148.	1768154.	223643.	610060.	11718712.
2014	736816.	389465.	258066.	379303.	1763649.	202625.	560680.	12279392.
2015	761364.	405379.	248363.	390035.	1805140.	187001.	528766.	12808158.
2016	751670.	423294.	238879.	388228.	1802071.	169256.	486379.	13294537.
2017	776727.	439701.	229591.	400246.	1846265.	156633.	459142.	13753679.
2018	767040.	458198.	220338.	399438.	1845015.	142017.	422769.	14176448.
2019	792287.	477692.	211088.	410796.	1891864.	131300.	399433.	14575881.
2020	782145.	499583.	201841.	408983.	1892553.	118829.	368173.	14944054.
2021	808232.	519764.	192597.	421702.	1942295.	110112.	348152.	15292206.
2022	797709.	542459.	183356.	420941.	1944466.	99806.	321148.	15613354.
2023	824193.	566383.	174119.	432975.	1997670.	92387.	304003.	15917357.
2024	813554.	593198.	165115.	431145.	2003012.	83607.	280859.	16198216.
2025	840953.	618060.	156344.	444633.	2059990.	77645.	266146.	16464362.
2026	830289.	645956.	147848.	443917.	2068009.	70446.	246183.	16710545.
2027	860177.	675368.	139627.	456695.	2131867.	65409.	233838.	16944384.
2028	848956.	708284.	131695.	454868.	2143802.	59282.	216666.	17161050.
2029	877558.	738952.	116564.	469173.	2202248.	54545.	205079.	17366130.
2030	866291.	773300.	110801.	468524.	2218916.	49708.	190391.	17556522.
2031	895387.	809524.	97374.	482088.	2284372.	45812.	180602.	17737124.
2032	883764.	849663.	93621.	480420.	2307467.	41817.	168090.	17905214.
2033	913759.	887880.	80580.	495460.	2377679.	38664.	159592.	18064806.
2034	901175.	930237.	77702.	494891.	2404006.	35412.	148676.	18213482.
2035	931739.	974913.	74830.	509307.	2490788.	33287.	141936.	18355418.
2036	919497.	1024424.	71962.	507668.	2523552.	30434.	132501.	18487920.
2037	951145.	1071611.	69099.	523455.	2615311.	28667.	126526.	18614446.
2038	938619.	1123911.	66241.	522982.	2651752.	26266.	118206.	18732652.
2039	970776.	1179086.	63388.	538318.	2751567.	24714.	113015.	18845668.
***** TOTALS IN 2000 DOLLARS *****								
	31260020.	24791052.	5695915.	14163179.	75910152.	4175227.	18845668.	

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CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	605100.	460139.	33940.	0.	1099178.	33940.	1099178.	1099178.
2001	650428.	466474.	33777.	0.	1150679.	31123.	1060241.	2159419.
2002	618939.	473069.	36167.	0.	1128175.	30705.	957804.	3117223.
2003	680026.	483351.	33022.	0.	1196399.	25832.	935894.	4053117.
2004	609674.	498668.	65875.	71065.	1245282.	98703.	897570.	4950688.
2005	660767.	508753.	63460.	75668.	1308648.	92399.	869108.	5819796.
2006	604807.	521791.	102370.	145159.	1374128.	151471.	840869.	6660665.
2007	652178.	537799.	98441.	161053.	1449470.	146311.	817261.	7477926.
2008	576289.	545995.	259685.	233538.	1615507.	256239.	839287.	8317213.
2009	628052.	497937.	249700.	267982.	1643670.	247807.	786804.	9104016.
2010	703960.	387458.	250486.	304271.	1646175.	244684.	726069.	9830085.
2011	769405.	348726.	239716.	333104.	1690951.	232793.	687200.	10517285.
2012	761341.	361362.	231025.	322074.	1675802.	207112.	627516.	11144801.
2013	791166.	374900.	222621.	340671.	1729358.	194351.	596675.	11741476.
2014	781652.	389996.	214449.	339352.	1725448.	176058.	548535.	12290011.
2015	808273.	405934.	206482.	349275.	1769964.	162794.	518462.	12808473.
2016	797803.	423840.	198559.	347085.	1767287.	147270.	476991.	13285464.
2017	823280.	440264.	190639.	359927.	1814110.	136919.	451146.	13736610.
2018	812801.	458752.	182721.	358620.	1812895.	124044.	415409.	14152019.
2019	839911.	478267.	174807.	369492.	1862477.	114919.	393228.	14545247.
2020	829346.	500149.	166895.	366852.	1863243.	103834.	362471.	14907718.
2021	857130.	520353.	158987.	379197.	1915667.	96468.	343379.	15251097.
2022	846171.	543037.	151081.	377471.	1917760.	87296.	316737.	15567834.
2023	874057.	566979.	143179.	389475.	1973689.	81059.	300354.	15868188.
2024	863016.	593784.	135510.	386731.	1979041.	73228.	277498.	16145686.
2025	892312.	618668.	128167.	399743.	2038890.	68205.	263420.	16409106.
2026	883066.	646554.	121193.	396246.	2047059.	61598.	243689.	16652795.
2027	914125.	675990.	114493.	409583.	2114191.	57484.	231899.	16884694.
2028	902663.	708893.	108906.	406691.	2127153.	52109.	214983.	17099678.
2029	932882.	739584.	96945.	420745.	2190156.	48209.	203953.	17303632.
2030	921377.	773919.	93174.	418955.	2207425.	43943.	189405.	17493038.
2031	951998.	810165.	80563.	432420.	2275145.	40556.	179873.	17672910.
2032	939985.	850292.	77625.	429756.	2297659.	36961.	167375.	17840286.
2033	971634.	888534.	74692.	444610.	2379471.	34856.	159712.	17999998.
2034	958594.	930877.	71764.	442842.	2404078.	31826.	148681.	18148678.
2035	990805.	975578.	66612.	457144.	2490139.	29846.	141899.	18290578.
2036	978050.	1025078.	63901.	454458.	2521487.	27217.	132393.	18422970.
2037	1012630.	1072294.	61195.	468883.	2615002.	25645.	126511.	18549482.
2038	999692.	1124579.	27672.	467194.	2619138.	22060.	116752.	18666234.
2039	1033817.	1179780.	27853.	482221.	2723670.	20950.	111870.	18778104.
				***** TOTALS IN 2000 DOLLARS *****				
	32729200.	24808564.	5058351.	12809553.	75405656.	3898819.	18778104.	

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	605100.	460139.	33940.	0.	1099179.	33940.	1099178.	1099178.
2001	650428.	466474.	33777.	0.	1150679.	31123.	1060241.	2159419.
2002	618939.	473069.	36167.	0.	1128175.	30705.	957804.	3117223.
2003	680026.	483351.	33022.	0.	1196399.	25832.	935894.	4053117.
2004	609674.	498668.	65875.	71065.	1245282.	98703.	897570.	4950688.
2005	660767.	508753.	63460.	75668.	1308648.	92399.	869108.	5819796.
2006	604807.	521791.	102370.	145159.	1374128.	151471.	840869.	6660665.
2007	652178.	537799.	98441.	161053.	1449470.	146311.	817261.	7477926.
2008	613050.	546596.	138003.	220186.	1517834.	186086.	788544.	8266470.
2009	668429.	498690.	132692.	258086.	1557897.	187060.	745745.	9012215.
2010	681894.	386158.	244853.	343425.	1656330.	259468.	730548.	9742763.
2011	741028.	348081.	234265.	375999.	1699373.	248010.	690623.	10433386.
2012	734898.	360860.	225748.	363303.	1684809.	220574.	630889.	11064275.
2013	762118.	374312.	217511.	384178.	1738119.	207599.	599697.	11663972.
2014	753138.	389421.	209501.	383173.	1735233.	188417.	551646.	12215618.
2015	780229.	405337.	201694.	394050.	1781310.	174507.	521786.	12737404.
2016	770309.	423252.	194038.	391670.	1779270.	158083.	480225.	13217629.
2017	796021.	439657.	186516.	404546.	1826740.	146990.	454287.	13671916.
2018	785702.	458156.	179018.	403504.	1826381.	133480.	418499.	14090415.
2019	811948.	477646.	171523.	415402.	1876520.	123919.	396193.	14486608.
2020	801557.	499539.	164032.	412954.	1878081.	112245.	365358.	14851966.
2021	828268.	519716.	156543.	426634.	1931162.	104533.	346157.	15198123.
2022	817096.	542412.	149057.	425605.	1934170.	94911.	319447.	15517570.
2023	844688.	566334.	141575.	438258.	1990855.	88238.	302966.	15820536.
2024	833762.	593150.	134326.	435752.	1996990.	79935.	280015.	16100551.
2025	861880.	618010.	127311.	450294.	2057493.	74625.	265824.	16366375.
2026	850498.	645907.	120570.	449286.	2066262.	67838.	245975.	16612350.
2027	881573.	675319.	114104.	462762.	2133759.	63275.	234046.	16846396.
2028	870067.	708236.	107928.	460199.	2146430.	57418.	216931.	17063328.
2029	899410.	738925.	94553.	475682.	2208570.	53102.	205668.	17268996.
2030	887416.	773274.	90165.	474704.	2225559.	48468.	190961.	17459958.
2031	917730.	809496.	77734.	489072.	2294032.	44812.	181366.	17641324.
2032	905771.	849612.	74977.	486648.	2317008.	40912.	168785.	17810110.
2033	936607.	887828.	62932.	502953.	2390320.	37983.	160440.	17970550.
2034	923313.	930183.	61051.	502014.	2416561.	34823.	149453.	18120002.
2035	970571.	974858.	59174.	502647.	2507251.	32015.	142875.	18262876.
2036	960741.	1024370.	57302.	497344.	2539758.	29122.	133352.	18396228.
2037	993657.	1071555.	55435.	514036.	2634683.	27550.	127463.	18523692.
2038	980291.	1123882.	53574.	513008.	2670755.	25256.	119053.	18642746.
2039	1014178.	1179056.	51717.	528908.	2773858.	23848.	113931.	18756678.
				***** TOTALS IN 2000 DOLLARS *****				
	31959762.	24789872.	4756473.	14239233.	75745320.	3985587.	18756678.	

14. Refer to pages 33-35 of exhibit JBC-1, the Need Study. Provide a PWRR analysis for the following using FPC's high natural gas price forecast: 1) Combined Cycle - HEC #2; 2) Integrated Gasification Combined Cycle; 3) Pulverized Coal Plant; and 4) Fluidized Bed Coal Plant. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

The present worth revenue requirements ("PWRR") for the 1) Combined Cycle – HEC #2 ; 2) Integrated Gasification Combined Cycle (IGCC) ; 3) Pulverized Coal (PC) Plant; and 4) Fluidized Bed (FB) Coal Plant for the high natural gas price forecast are attached. The components of the "PWRR" are typical report runs available from the "PROSCREEN" model and provide a general breakdown of the annual and cumulative totals. The IGCC (output run #PS15P473), PC Plant (output run #15P157), and FB Plant (output run #15P227) totals that are attached were based on the most attractive (highest ranking) run for that technology alternative.

PS000015P157 • PVC

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	620715.	462985.	33940.	0.	1117640.	33940.	1117640.	1117640.
2001	678562.	470801.	33777.	0.	1183140.	31123.	1090150.	2207791.
2002	641490.	477412.	36167.	0.	1155069.	30705.	980637.	3188428.
2003	706615.	488104.	33022.	0.	1227741.	25832.	960412.	4148840.
2004	634974.	500326.	65875.	77612.	1278787.	103422.	921720.	5070560.
2005	691046.	510448.	63460.	82942.	1347897.	97230.	895175.	5965735.
2006	632391.	522748.	102370.	156685.	1414194.	158523.	865387.	6831121.
2007	681690.	537814.	98441.	171473.	1489417.	152186.	839784.	7670905.
2008	598107.	545997.	259685.	236203.	1639992.	257624.	852007.	8522912.
2009	657803.	497951.	249700.	265569.	1671023.	246652.	799897.	9322809.
2010	748246.	387566.	250486.	303256.	1689554.	244236.	745202.	10068011.
2011	815655.	348907.	239716.	345130.	1749407.	237680.	710956.	10778967.
2012	806487.	361532.	231025.	334687.	1733731.	211835.	649208.	11428175.
2013	846225.	375115.	222621.	355946.	1799908.	199621.	621016.	12049191.
2014	837767.	390237.	214449.	355845.	1798298.	181301.	571695.	12620886.
2015	871711.	406193.	206482.	368403.	1852789.	168397.	542724.	13163610.
2016	862233.	424111.	198559.	367323.	1852227.	152732.	499916.	13663526.
2017	898165.	440570.	190639.	381365.	1910739.	142250.	475176.	14138702.
2018	889245.	459073.	182721.	380847.	1911886.	129137.	438092.	14576794.
2019	926093.	478634.	174807.	394432.	1973967.	120185.	416767.	14993561.
2020	915974.	500552.	166895.	392847.	1976268.	108891.	384459.	15378020.
2021	952205.	520792.	158987.	410693.	2042677.	102114.	366146.	15744166.
2022	941846.	543493.	151081.	410601.	2047021.	92767.	338086.	16082252.
2023	982115.	567465.	143179.	425348.	2118107.	86518.	322331.	16404583.
2024	970331.	594286.	135510.	424110.	2124237.	78469.	297857.	16702440.
2025	1013635.	619202.	128167.	440368.	2201373.	73453.	284412.	16986852.
2026	1002313.	647127.	121193.	439981.	2210614.	66804.	263159.	17250010.
2027	1044897.	676631.	114493.	456546.	2292567.	62636.	251465.	17501474.
2028	1032301.	709556.	108906.	454459.	2305222.	56937.	232980.	17734454.
2029	1077759.	740311.	96945.	472817.	2387832.	53058.	222361.	17956816.
2030	1065331.	774725.	93174.	472191.	2405421.	48510.	206394.	18163210.
2031	1111433.	811030.	80563.	490007.	2493033.	45109.	197099.	18360308.
2032	1097381.	851203.	77625.	488186.	2514395.	41217.	183164.	18543472.
2033	1146599.	889494.	74692.	507474.	2618260.	39075.	175739.	18719212.
2034	1132829.	931870.	71764.	506699.	2643162.	35775.	163467.	18882680.
2035	1183373.	976622.	66612.	525315.	2751922.	33731.	156817.	19039496.
2036	1169735.	1026170.	63901.	521375.	2781182.	30730.	146028.	19185524.
2037	1222826.	1073484.	61195.	543231.	2900736.	29242.	140335.	19325858.
2038	1210565.	1125822.	27672.	542961.	2907021.	25437.	129585.	19455444.
2039	1263947.	1181118.	27853.	564134.	3037051.	24315.	124741.	19580186.
			***** TOTALS IN 2000 DOLLARS *****					
	36582616.	24847476.	5058351.	14067061.	80555504.	4059399.	19580186.	

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PS000015P473 * IGCC

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	620715.	462985.	33940.	0.	1117640.	33940.	1117640.	1117640.
2001	678562.	470801.	33777.	0.	1183140.	31123.	1090150.	2207791.
2002	641490.	477412.	36167.	0.	1155069.	30705.	980637.	3188428.
2003	706615.	488104.	33022.	0.	1227741.	25832.	960412.	4148840.
2004	634974.	500326.	65875.	77612.	1278787.	103422.	921720.	5070560.
2005	691046.	510448.	63460.	82942.	1347897.	97230.	895175.	5965735.
2006	632391.	522748.	102370.	156685.	1414194.	158523.	865387.	6831121.
2007	681690.	537814.	98441.	171473.	1489417.	152186.	839784.	7670905.
2008	642064.	546602.	138003.	223574.	1550242.	187846.	805381.	8476286.
2009	706009.	498711.	132692.	255199.	1592612.	185678.	762363.	9238649.
2010	709930.	386164.	301790.	340034.	1737918.	283086.	766534.	10005183.
2011	765481.	348202.	288977.	387546.	1790206.	274938.	727537.	10732720.
2012	759422.	361017.	278328.	376984.	1775751.	245386.	664943.	11397663.
2013	794544.	374515.	268044.	399996.	1837099.	230492.	633848.	12031511.
2014	786712.	389633.	258066.	400928.	1835339.	209500.	583471.	12614982.
2015	818118.	405577.	248363.	414607.	1886664.	194199.	552647.	13167629.
2016	809498.	423499.	238879.	414454.	1886329.	176335.	509121.	13676750.
2017	842575.	439916.	229591.	429816.	1941899.	163986.	482925.	14159675.
2018	833862.	450421.	220338.	430802.	1943423.	149203.	445319.	14604994.
2019	867967.	477938.	211088.	445649.	2002642.	138658.	422822.	15027816.
2020	858355.	499857.	201841.	445445.	2005498.	125922.	390145.	15417961.
2021	894338.	520059.	192597.	462134.	2069127.	117359.	370887.	15788848.
2022	884641.	542784.	183356.	463184.	2073965.	106783.	342536.	16131384.
2023	921950.	566724.	174119.	479300.	2142093.	99437.	325981.	16457365.
2024	911219.	593554.	165115.	479030.	2148917.	90321.	301318.	16758683.
2025	950852.	618434.	156344.	497179.	2222809.	84434.	287182.	17045864.
2026	939986.	646352.	147848.	498281.	2232467.	76917.	265760.	17311624.
2027	980023.	675784.	139627.	515797.	2311230.	71891.	253512.	17565136.
2028	967782.	708710.	131695.	515472.	2323659.	65407.	234843.	17799980.
2029	1010124.	739407.	116564.	535193.	2401288.	60693.	223615.	18023594.
2030	997969.	773779.	110801.	536375.	2418924.	55530.	207553.	18231146.
2031	1041247.	810051.	97374.	555400.	2504072.	51608.	197972.	18429118.
2032	1027801.	850229.	93621.	555207.	2526858.	47265.	184072.	18613190.
2033	1073306.	888496.	80580.	576448.	2618829.	44100.	175778.	18788968.
2034	1059697.	930883.	77702.	577711.	2645993.	40534.	163642.	18952610.
2035	1106575.	975629.	74830.	598383.	2755416.	38363.	157016.	19109626.
2036	1091722.	1025155.	71962.	598133.	2786971.	35184.	146332.	19255958.
2037	1141892.	1072370.	69099.	621032.	2904393.	33388.	140512.	19396470.
2038	1129840.	1124704.	66241.	622375.	2943159.	30696.	131196.	19527666.
2039	1180312.	1179912.	63388.	644847.	3068458.	29089.	126031.	19653698.
***** TOTALS IN 2000 DOLLARS *****								
	34793292.	24823706.	5695915.	15785223.	81098120.	4377189.	19653698.	

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	620715.	462985.	33940.	0.	1117640.	33940.	1117640.	1117640.
2001	678562.	470801.	33777.	0.	1183140.	31123.	1090150.	2207791.
2002	641490.	477412.	36167.	0.	1155069.	30705.	980637.	3188428.
2003	706615.	488104.	33022.	0.	1227741.	25832.	960412.	4148840.
2004	634974.	500326.	65875.	77612.	1278787.	103422.	921720.	5070560.
2005	691046.	510448.	63460.	82942.	1347897.	97230.	895175.	5965735.
2006	632391.	522748.	102370.	156685.	1414194.	158523.	865387.	6831121.
2007	681690.	537814.	98441.	171473.	1489417.	152186.	839784.	7670905.
2008	642064.	546602.	138003.	223574.	1550242.	187846.	805381.	8476286.
2009	706009.	498711.	132692.	255199.	1592612.	185678.	762363.	9238649.
2010	727551.	386212.	244853.	341363.	1699979.	258559.	749800.	9988449.
2011	780181.	348185.	234265.	393714.	1756344.	255210.	713776.	10702225.
2012	775955.	360977.	225748.	380963.	1743642.	227187.	652920.	11355145.
2013	809781.	374466.	217511.	406472.	1808231.	215291.	623888.	11979033.
2014	802998.	389585.	209501.	406779.	1808864.	195921.	575054.	12554087.
2015	833843.	405516.	201694.	421618.	1862670.	182582.	545618.	13099705.
2016	826688.	423449.	194038.	420477.	1864652.	165858.	503270.	13602975.
2017	856785.	439867.	186516.	439109.	1922276.	155585.	478045.	14081020.
2018	844071.	458371.	179018.	444347.	1925808.	142039.	441282.	14522302.
2019	878340.	477879.	171523.	459822.	1987564.	133297.	419638.	14941940.
2020	869012.	499789.	164032.	459661.	1992494.	121332.	387615.	15329555.
2021	904973.	520002.	156543.	477160.	2058678.	113590.	369014.	15698569.
2022	895371.	542726.	149057.	478431.	2065585.	103636.	341152.	16039721.
2023	932869.	566664.	141575.	495235.	2136344.	96909.	325107.	16364828.
2024	922414.	593494.	134326.	495061.	2145295.	88252.	300810.	16665638.
2025	962094.	618371.	127311.	514075.	2221850.	82866.	287058.	16952696.
2026	951303.	646289.	120570.	515458.	2233620.	75715.	265898.	17218594.
2027	991563.	675718.	114104.	533720.	2315106.	71058.	253937.	17472532.
2028	979595.	708645.	107928.	533539.	2329707.	64831.	235454.	17707986.
2029	1022006.	739335.	94553.	554203.	2410097.	60414.	224435.	17932420.
2030	1009934.	773702.	90165.	555716.	2429517.	55419.	208462.	18140882.
2031	1053488.	809974.	77734.	575557.	2516753.	51649.	198974.	18339856.
2032	1040248.	850148.	74977.	575619.	2540992.	47393.	185101.	18524958.
2033	1085890.	888410.	62932.	597842.	2635074.	44352.	176868.	18701826.
2034	1072350.	930814.	61051.	599508.	2663723.	40852.	164739.	18866564.
2035	1119556.	975530.	59174.	621081.	2775341.	38764.	158152.	19024716.
2036	1104917.	1025081.	57302.	621155.	2808455.	35623.	147460.	19172176.
2037	1155019.	1072297.	55435.	645325.	2928076.	33902.	141658.	19313834.
2038	1142975.	1124605.	53574.	647152.	2968306.	31236.	132317.	19446152.
2039	1193872.	1179822.	51717.	670622.	3096034.	29669.	127164.	19573316.
	35181196.	24821876.	4756474.	16248274.	81007816.	4226273.	19573316.	

***** TOTALS IN 2000 DOLLARS *****

16. **Refer to John B. Crisp's direct testimony, page 14. Provide a PWRR analysis for the "Base Expansion Plan". For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.**

Answer:

The present worth revenue requirements ("PWRR") for the "Base Expansion Plan" are attached (output run #PS12). The components of the "PWRR" are typical report runs available from the "PROSCREEN" model and provide a general breakdown of the annual and cumulative totals.

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	605100.	460139.	33940.	0.	1099178.	33940.	1099178.	1099178.
2001	650428.	466474.	33777.	0.	1150679.	31123.	1060241.	2159419.
2002	618939.	473069.	36167.	0.	1128175.	30705.	957804.	3117223.
2003	680026.	483351.	33022.	0.	1196399.	25832.	935894.	4053117.
2004	609674.	498668.	65875.	71065.	1245282.	98703.	897570.	4950688.
2005	660767.	508753.	63460.	75668.	1308648.	92399.	869108.	5819796.
2006	604807.	521791.	102370.	145159.	1374128.	151471.	840869.	6660665.
2007	652178.	537799.	98441.	161053.	1449470.	146311.	817261.	7477926.
2008	613050.	546596.	138003.	220186.	1517834.	186086.	788544.	8266470.
2009	668429.	498690.	132692.	258086.	1557897.	187060.	745745.	9012215.
2010	676173.	385852.	173004.	353885.	1588915.	232392.	700814.	9713029.
2011	732664.	347903.	165151.	387421.	1633139.	224564.	663705.	10376734.
2012	728120.	360732.	159248.	373616.	1621716.	199535.	607264.	10983998.
2013	754097.	374159.	153514.	395011.	1676781.	189256.	578534.	11562532.
2014	745352.	389269.	147903.	393470.	1675994.	172107.	532814.	12095346.
2015	770045.	405180.	142399.	404714.	1722338.	160262.	504512.	12599858.
2016	760877.	423099.	136959.	401777.	1722711.	145405.	464960.	13064818.
2017	785611.	439499.	131571.	414718.	1771398.	135855.	440524.	13505342.
2018	775950.	457998.	126194.	413162.	1773304.	123589.	406337.	13911679.
2019	801314.	477484.	120819.	425039.	1824656.	115248.	385243.	14296922.
2020	791695.	499380.	115448.	422016.	1828539.	104557.	355720.	14652642.
2021	817417.	519554.	110079.	435684.	1882734.	97827.	337476.	14990118.
2022	806929.	542252.	104714.	434111.	1888006.	88992.	311823.	15301941.
2023	833579.	566168.	99352.	446667.	1945767.	83093.	296105.	15598046.
2024	823459.	592987.	94223.	443556.	1954225.	75407.	274018.	15872064.
2025	850501.	617839.	89328.	458006.	2015675.	70714.	260421.	16132485.
2026	839841.	645739.	84708.	456425.	2026713.	64418.	241267.	16373752.
2027	869862.	675145.	80362.	469711.	2095081.	60336.	229803.	16603555.
2028	859231.	708064.	76306.	466511.	2110113.	54860.	213261.	16816816.
2029	887455.	738724.	65051.	481799.	2173030.	50924.	202358.	17019174.
2030	876240.	773076.	62286.	480214.	2191816.	46549.	188066.	17207240.
2031	905493.	809291.	50982.	494288.	2260054.	43109.	178680.	17385920.
2032	894419.	849434.	49350.	491202.	2284406.	39377.	166410.	17552330.
2033	924066.	887643.	38431.	507196.	2357337.	36623.	158226.	17710556.
2034	911583.	930001.	37676.	505618.	2384878.	33600.	147494.	17858050.
2035	942328.	974671.	27163.	520539.	2464702.	31211.	140450.	17998500.
2036	930586.	1024187.	27328.	517379.	2499480.	28600.	131237.	18129738.
2037	961676.	1071365.	27497.	534340.	2594879.	27181.	125538.	18255276.
2038	949153.	1123666.	27672.	532774.	2633266.	24983.	117382.	18372658.
2039	981539.	1178834.	27853.	548615.	2736841.	23677.	112411.	18485068.
***** TOTALS IN 2000 DOLLARS *****								
	31550656.	24784524.	3490318.	14540683.	74366168.	3767880.	18485068.	

17. **Refer to John B. Crisp's direct testimony, page 15. Provide a PWRR analysis for the high fuel price forecast sensitivity to the "Base Expansion Plan". For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.**

Answer:

The present worth revenue requirements ("PWRR") for the "Base Expansion Plan" for the high fuel price forecast are attached (output run #PS15). The components of the "PWRR" are typical report runs available from the "PROSCREEN" model and provide a general breakdown of the annual and cumulative totals.

PS000015

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	620715.	462985.	33940.	0.	1117640.	33940.	1117640.	1117640.
2001	678562.	470801.	33777.	0.	1183140.	31123.	1090150.	2207791.
2002	641490.	477412.	36167.	0.	1155069.	30705.	980637.	3188428.
2003	706615.	488104.	33022.	0.	1227741.	25832.	960412.	4148840.
2004	634974.	500326.	65875.	77612.	1278787.	103422.	921720.	5070560.
2005	691046.	510448.	63460.	82942.	1347897.	97230.	895175.	5965735.
2006	632391.	522748.	102370.	156685.	1414194.	158523.	865387.	6831121.
2007	681690.	537814.	98441.	171473.	1489417.	152186.	839784.	7670905.
2008	642064.	546602.	138003.	223574.	1550242.	187846.	805381.	8476286.
2009	706009.	498711.	132692.	255199.	1592612.	185678.	762363.	9238649.
2010	725063.	385904.	173004.	351147.	1635119.	231185.	721193.	9959842.
2011	773999.	347994.	165151.	408246.	1695389.	233028.	689004.	10648846.
2012	768581.	360827.	159248.	396135.	1684791.	207967.	630882.	11279728.
2013	803604.	374279.	153514.	422010.	1753407.	198571.	604972.	11884700.
2014	795740.	389409.	147903.	423141.	1756193.	181540.	558309.	12443009.
2015	827409.	405332.	142400.	438376.	1813516.	170122.	531220.	12974229.
2016	819271.	423270.	136959.	438001.	1817502.	155182.	490544.	13464773.
2017	852118.	439678.	131571.	455421.	1878788.	145977.	467230.	13932003.
2018	843349.	458181.	126194.	456637.	1884361.	133551.	431785.	14363788.
2019	877762.	477681.	120819.	473182.	1949444.	125413.	411590.	14775378.
2020	868637.	499590.	115448.	472761.	1956436.	114429.	380601.	15155979.
2021	904394.	519793.	110079.	491684.	2025951.	107865.	363147.	15519126.
2022	894662.	542502.	104714.	492991.	2034869.	98717.	336079.	15855205.
2023	932275.	566450.	99352.	510970.	2109047.	92878.	320953.	16176158.
2024	922011.	593278.	94223.	510502.	2120015.	84794.	297265.	16473423.
2025	961472.	618149.	89328.	531066.	2200015.	80153.	284237.	16757660.
2026	950494.	646058.	84708.	532480.	2213740.	73472.	263531.	17021190.
2027	990909.	675483.	80362.	552015.	2298770.	69364.	252145.	17273336.
2028	979159.	708415.	76306.	551496.	2315376.	63449.	234006.	17507342.
2029	1021315.	739092.	65051.	573847.	2399304.	59496.	223430.	17730772.
2030	1009029.	773452.	62287.	575373.	2420140.	54714.	207657.	17938428.
2031	1052741.	809690.	50982.	596613.	2510025.	51199.	198442.	18136870.
2032	1039755.	849851.	49350.	596296.	2535252.	47033.	184683.	18321554.
2033	1085148.	888100.	38431.	620337.	2632017.	44217.	176663.	18498216.
2034	1071402.	930500.	37676.	621978.	2661556.	40796.	164605.	18662820.
2035	1118777.	975209.	27163.	645064.	2766214.	38307.	157631.	18820452.
2036	1104384.	1024757.	27328.	644712.	2801181.	35286.	147078.	18967530.
2037	1154184.	1071997.	27497.	670859.	2924537.	33786.	141486.	19109016.
2038	1141964.	1124313.	27672.	672625.	2966573.	31217.	132240.	19241256.
2039	1192956.	1179524.	27853.	697734.	3098067.	29802.	127247.	19368504.
			***** TOTALS IN 2000 DOLLARS *****					
	35118120.	24814708.	3490318.	16791184.	80214336.	4039995.	19368504.	

18. Refer to John B. Crisp's direct testimony, page 15. Provide a PWRR analysis for the sensitivity to the "Base Expansion Plan" in which the current differential price of oil and gas to coal was held constant over time. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

The present worth revenue requirements ("PWRR") for the "Base Expansion Plan" for which the current differential price of oil and gas to coal was held constant over time are attached (output run # PS17). The components of the "PWRR" are typical report runs available from the "PROSCREEN" model and provide a general breakdown of the annual and cumulative total.

PS000017

CAPITAL EXPENDITURE AND RECOVERY MODULE
SYSTEM REVENUE REQUIREMENTS

YEAR	EXISTING UNIT OPERATING EXPENSES	PURCHASED POWER AND OTHER PRODUCTION COSTS	NEW UNIT CAPITAL REVENUE REQUIREMENT	NEW UNIT FUEL AND O&M REVENUE REQUIREMENT	SYSTEM REVENUE REQUIREMENT	PRESENT WORTH OF NEW UNIT REVENUE REQUIREMENT	PRESENT WORTH OF SYSTEM REVENUE REQUIREMENT	ACCUMULATED PRESENT WORTH OF SYSTEM REV. REQ.
2000	605100.	460139.	33940.	0.	1099178.	33940.	1099178.	1099178.
2001	655549.	468655.	33777.	0.	1157980.	31123.	1066968.	2166146.
2002	621157.	475762.	36167.	0.	1133085.	30705.	961973.	3128120.
2003	680870.	486867.	33022.	0.	1200759.	25832.	939305.	4067424.
2004	605936.	498803.	65875.	68189.	1238802.	96630.	892900.	4960324.
2005	648272.	508764.	63460.	70371.	1290867.	88881.	857299.	5817623.
2006	588381.	521314.	102370.	134095.	1346160.	144700.	823755.	6641378.
2007	631841.	536293.	98441.	146845.	1413419.	138300.	796934.	7438312.
2008	597867.	545480.	138003.	194805.	1476155.	172900.	766891.	8205203.
2009	652754.	497408.	132692.	222603.	1505457.	170075.	720643.	8925845.
2010	666859.	384986.	173004.	303706.	1528555.	210260.	674191.	9600036.
2011	716505.	347829.	165151.	334036.	1563521.	202869.	635413.	10235449.
2012	713824.	360655.	159248.	319961.	1553688.	179443.	581790.	10817239.
2013	734305.	374072.	153514.	339710.	1601602.	170176.	552595.	11369834.
2014	725632.	389179.	147903.	337123.	1599837.	154194.	508603.	11878437.
2015	746071.	405084.	142399.	347197.	1640751.	143414.	480613.	12359050.
2016	737718.	422998.	136959.	343320.	1640996.	129628.	442905.	12801955.
2017	758067.	439391.	131571.	354919.	1683949.	120984.	418776.	13220731.
2018	749207.	457888.	126194.	352291.	1685579.	109641.	386236.	13606967.
2019	770302.	477367.	120819.	362886.	1731375.	102126.	365548.	13972515.
2020	761784.	499259.	115448.	358912.	1735402.	92281.	337601.	14310116.
2021	782795.	519426.	110079.	371110.	1783409.	86252.	319672.	14629788.
2022	773747.	542119.	104714.	368443.	1789023.	78147.	295475.	14925263.
2023	795536.	566028.	99352.	379601.	1840517.	72887.	280088.	15205351.
2024	786830.	592842.	94223.	375527.	1849422.	65868.	259323.	15464674.
2025	808506.	617687.	89328.	388368.	1903889.	61717.	245978.	15710652.
2026	800039.	645581.	84708.	385626.	1915953.	55990.	228081.	15938733.
2027	822609.	674979.	80362.	397427.	1975377.	52407.	216673.	16155406.
2028	813705.	707894.	76306.	393215.	1991119.	47453.	201235.	16356641.
2029	836106.	738546.	65051.	406796.	2046498.	43940.	190575.	16547216.
2030	826828.	772892.	62287.	404020.	2066027.	40011.	177273.	16724489.
2031	849882.	809100.	50982.	416485.	2126448.	36958.	168117.	16892606.
2032	840983.	849239.	49350.	412333.	2151905.	33632.	156758.	17049364.
2033	863929.	887439.	38431.	426513.	2216313.	31207.	148760.	17198124.
2034	854478.	929795.	37676.	423710.	2245659.	28535.	138883.	17337008.
2035	878386.	974413.	27163.	436893.	2316856.	26444.	132025.	17469032.
2036	869314.	1023924.	27328.	432662.	2353228.	24152.	123558.	17592590.
2037	893011.	1071092.	27497.	447642.	2439243.	22987.	118008.	17710598.
2038	883323.	1123389.	27672.	444831.	2479215.	21063.	110515.	17821114.
2039	908029.	1178546.	27853.	458777.	2573204.	19987.	105690.	17926804.
				***** TOTALS IN 2000 DOLLARS *****				
	30256036.	24783122.	3490319.	12360948.	70890424.	3397736.	17926804.	

0000028

21. Refer to confidential exhibit JBC-3, Appendix 6 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

Annual and Cumulative Revenue Requirement
Hines 2

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	787,329	459,222	1,253,420
2004	38,569	1,003	3,136	769,534	447,197	1,259,440
2005	45,021	1,796	3,244	844,751	469,460	1,364,272
2006	82,555	5,133	10,087	826,159	473,397	1,397,331
2007	88,170	6,113	6,607	919,728	508,009	1,528,628
2008	126,127	9,845	13,880	914,938	503,667	1,568,456
2009	131,057	11,035	15,729	1,022,392	472,779	1,652,992
2010	170,083	15,197	17,662	1,098,027	341,519	1,642,487
2011	165,006	15,641	19,945	1,120,341	358,825	1,679,758
2012	161,266	16,106	21,856	1,143,109	366,117	1,708,454
2013	156,495	16,579	21,201	1,166,340	373,558	1,734,172
2014	152,117	17,070	18,048	1,190,043	381,149	1,758,427
2015	149,246	17,579	26,712	1,214,227	388,895	1,796,660
2016	146,172	18,103	18,733	1,238,903	396,798	1,818,709
2017	142,672	18,641	21,472	1,264,081	404,862	1,851,729
2018	139,996	19,200	24,416	1,289,770	413,090	1,886,472
2019	136,548	19,773	22,824	1,315,981	421,485	1,916,612
2020	132,907	20,364	21,145	1,342,725	430,051	1,947,191
2021	132,336	20,980	29,277	1,370,013	438,790	1,991,396
2022	130,054	21,608	22,499	1,397,855	447,708	2,019,723
2023	126,416	22,254	25,789	1,426,263	456,806	2,057,527
2024	124,298	22,922	29,325	1,455,248	466,089	2,097,881
2025	120,780	23,608	27,413	1,484,822	475,561	2,132,184
2026	118,337	24,315	25,395	1,514,997	485,226	2,168,270
2027	114,502	25,043	29,139	1,545,785	495,087	2,209,556
2028	110,213	25,596	23,573	1,577,200	505,148	2,241,730
Cumulative	1,093,411	118,506	149,466	10,868,062	4,492,510	16,721,956

22. Refer to confidential exhibit JBC-3, Appendix 6 to John B. Crisp's confidential direct testimony. Provide a PWRR analysis for each of the expansion plans evaluated. This analysis should exclude the impact of the cost of imputed debt as described on pages 12-15 of John B. Crisp's confidential direct testimony. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

Annual and Cumulative Revenue Requirement
Hines 2

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	787,329	459,222	1,253,420
2004	38,569	1,003	3,136	769,534	447,197	1,259,440
2005	45,021	1,796	3,244	844,751	469,460	1,364,272
2006	82,555	5,133	10,087	826,159	473,397	1,397,331
2007	88,170	6,113	6,607	919,728	508,009	1,528,628
2008	126,127	9,845	13,880	914,938	503,667	1,568,456
2009	131,057	11,035	15,729	1,022,392	472,779	1,652,992
2010	170,083	15,197	17,662	1,098,027	341,519	1,642,487
2011	165,006	15,641	19,945	1,120,341	358,825	1,679,758
2012	161,266	16,106	21,856	1,143,109	366,117	1,708,454
2013	156,495	16,579	21,201	1,166,340	373,558	1,734,172
2014	152,117	17,070	18,048	1,190,043	381,149	1,758,427
2015	149,246	17,579	26,712	1,214,227	388,895	1,796,660
2016	146,172	18,103	18,733	1,238,903	396,798	1,818,709
2017	142,672	18,641	21,472	1,264,081	404,862	1,851,729
2018	139,996	19,200	24,416	1,289,770	413,090	1,886,472
2019	136,548	19,773	22,824	1,315,981	421,485	1,916,612
2020	132,907	20,364	21,145	1,342,725	430,051	1,947,191
2021	132,336	20,980	29,277	1,370,013	438,790	1,991,396
2022	130,054	21,608	22,499	1,397,855	447,708	2,019,723
2023	126,416	22,254	25,789	1,426,263	456,806	2,057,527
2024	124,298	22,922	29,325	1,455,248	466,089	2,097,881
2025	120,780	23,608	27,413	1,484,822	475,561	2,132,184
2026	118,337	24,315	25,395	1,514,997	485,226	2,168,270
2027	114,502	25,043	29,139	1,545,785	495,087	2,209,556
2028	110,213	25,596	23,573	1,577,200	505,148	2,241,730
Cumulative	1,093,411	118,506	149,466	10,868,062	4,492,510	16,721,956

23. Refer to John B. Crisp's confidential direct testimony, page 15. Provide a PWRR analysis for each of the expansion plans evaluated under the high-fuel price forecast case, the low-fuel price forecast case, and the "Gulfstream" sensitivity. For each year in the evaluation period, provide the annual and cumulative PWRR for each of the following components: capital, fixed O&M, non-fuel variable O&M, fuel, purchased power, and total costs.

Answer:

Attached.

Annual and Cumulative Revenue Requirement
Hines 2 - High Fuel Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	822,631	460,585	1,290,086
2004	38,569	1,003	3,136	810,685	448,801	1,302,195
2005	45,021	1,796	3,244	892,491	470,601	1,413,153
2006	82,555	5,133	10,087	876,855	476,823	1,451,454
2007	88,170	6,113	6,607	972,225	511,150	1,584,265
2008	126,127	9,845	13,880	957,366	507,427	1,614,644
2009	131,057	11,035	15,729	1,068,919	477,222	1,703,962
2010	170,083	15,197	17,662	1,150,014	345,647	1,698,603
2011	165,006	15,641	19,945	1,173,386	363,037	1,737,014
2012	161,266	16,106	21,856	1,197,232	370,415	1,766,874
2013	156,495	16,579	21,201	1,221,562	377,942	1,793,779
2014	152,117	17,070	18,048	1,246,387	385,623	1,819,245
2015	149,246	17,579	26,712	1,271,717	393,460	1,858,714
2016	146,172	18,103	18,733	1,297,561	401,456	1,882,025
2017	142,672	18,641	21,472	1,323,931	409,614	1,916,331
2018	139,996	19,200	24,416	1,350,836	417,939	1,952,387
2019	136,548	19,773	22,824	1,378,289	426,432	1,983,866
2020	132,907	20,364	21,145	1,406,299	435,099	2,015,813
2021	132,336	20,980	29,277	1,434,878	443,941	2,061,412
2022	130,054	21,608	22,499	1,464,038	452,963	2,091,162
2023	126,416	22,254	25,789	1,493,791	462,168	2,130,418
2024	124,298	22,922	29,325	1,524,149	471,560	2,172,253
2025	120,780	23,608	27,413	1,555,123	481,144	2,208,067
2026	118,337	24,315	25,395	1,586,727	490,922	2,245,696
2027	114,502	25,043	29,139	1,618,973	500,898	2,288,555
2028	110,213	25,596	23,573	1,651,875	511,078	2,322,334
Cumulative	1,093,411	118,506	149,466	11,403,495	4,529,769	17,294,647

Annual and Cumulative Revenue Requirement
Hines 2 - Low Fuel Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	749,648	452,627	1,209,145
2004	38,569	1,003	3,136	721,764	441,457	1,205,930
2005	45,021	1,796	3,244	779,988	464,327	1,294,376
2006	82,555	5,133	10,087	734,331	486,169	1,318,276
2007	88,170	6,113	6,607	826,801	502,970	1,430,662
2008	126,127	9,845	13,880	807,537	499,932	1,457,320
2009	131,057	11,035	15,729	890,891	467,958	1,516,670
2010	170,083	15,197	17,662	942,920	336,870	1,482,732
2011	165,006	15,641	19,945	962,083	354,081	1,516,756
2012	161,266	16,106	21,856	981,635	361,277	1,542,140
2013	156,495	16,579	21,201	1,001,584	368,619	1,564,477
2014	152,117	17,070	18,048	1,021,938	376,111	1,585,284
2015	149,246	17,579	26,712	1,042,707	383,754	1,619,998
2016	146,172	18,103	18,733	1,063,897	391,553	1,638,457
2017	142,672	18,641	21,472	1,085,518	399,510	1,667,814
2018	139,996	19,200	24,416	1,107,578	407,629	1,698,820
2019	136,548	19,773	22,824	1,130,087	415,913	1,725,146
2020	132,907	20,364	21,145	1,153,053	424,366	1,751,834
2021	132,336	20,980	29,277	1,176,486	432,990	1,792,069
2022	130,054	21,608	22,499	1,200,395	441,789	1,816,345
2023	126,416	22,254	25,789	1,224,790	450,767	1,850,016
2024	124,298	22,922	29,325	1,249,681	459,928	1,886,153
2025	120,780	23,608	27,413	1,275,077	469,275	1,916,152
2026	118,337	24,315	25,395	1,300,990	478,812	1,947,849
2027	114,502	25,043	29,139	1,327,429	488,542	1,984,655
2028	110,213	25,596	23,573	1,354,406	498,471	2,012,258
Cumulative	1,093,411	118,506	149,466	9,557,667	4,450,915	15,369,965

Annual and Cumulative Revenue Requirement
Hines 2 - Gulfstream Sensitivity

Year	Capital	Fixed O&M	Variable O&M	Fuel	Purchased Power	Total
2003	6,467	212	191	768,251	454,744	1,229,865
2004	38,569	1,003	3,136	756,816	445,063	1,244,588
2005	45,021	1,796	3,244	827,405	467,200	1,344,666
2006	82,555	5,133	10,087	818,809	472,108	1,388,693
2007	88,170	6,113	6,607	907,323	505,849	1,514,062
2008	126,127	9,845	13,880	908,444	502,648	1,560,943
2009	131,057	11,035	15,729	1,013,279	471,136	1,642,236
2010	170,083	15,197	17,662	1,088,811	339,430	1,631,182
2011	165,006	15,641	19,945	1,110,938	356,693	1,668,223
2012	161,266	16,106	21,856	1,133,515	363,942	1,696,685
2013	156,495	16,579	21,201	1,156,551	371,339	1,722,164
2014	152,117	17,070	18,048	1,180,055	378,885	1,746,175
2015	149,246	17,579	26,712	1,204,036	386,585	1,784,159
2016	146,172	18,103	18,733	1,228,505	394,441	1,805,954
2017	142,672	18,641	21,472	1,253,471	402,457	1,838,715
2018	139,996	19,200	24,416	1,278,945	410,636	1,873,193
2019	136,548	19,773	22,824	1,304,936	418,981	1,903,063
2020	132,907	20,364	21,145	1,331,456	427,496	1,933,367
2021	132,336	20,980	29,277	1,358,514	436,184	1,977,291
2022	130,054	21,608	22,499	1,386,122	445,048	2,005,331
2023	126,416	22,254	25,789	1,414,292	454,093	2,042,843
2024	124,298	22,922	29,325	1,443,034	463,321	2,082,899
2025	120,780	23,608	27,413	1,472,359	472,737	2,116,896
2026	118,337	24,315	25,395	1,502,281	482,344	2,152,672
2027	114,502	25,043	29,139	1,532,811	492,146	2,193,641
2028	110,213	25,596	23,573	1,563,962	502,148	2,225,491
Cumulative	1,093,411	118,506	149,466	10,749,081	4,468,553	16,579,018

30. Refer to the direct testimony of Peter M. O'Neill, page 5, lines 12-22. What, if any, cost was assumed for the interconnection upgrade between FPC and Tampa Electric Company which is to be negotiated during 2000? What is the status of the negotiation?

Answer:

Both FPC's and TECO's 2000 Ten Year Site Plans indicate the need to upgrade Barcola-Pebbledale 230kv interconnection by 2003. Moving towards this goal, FPC and TECO began formal negotiations concerning the needed upgrades in August 2000. FPC anticipates that these negotiations will culminate in an executed Transmission and Interconnection and Operating Agreement between FPC and TECO by years end. The cost of these upgrades is accounted for in FPC's $ 5.6 million dollar estimate of increased transmission costs associated with Hines 2.

36. What is the current status of contract negotiations with pipeline suppliers for Hines 2?

Answer:

Without waiving its objections filed separately on September 18, 2000, FPC states that it is currently negotiating with Florida Gas Transmission Company, Buccaneer Pipeline, Gulfstream Natural Gas System and El Paso Merchant Energy for natural gas transportation capacity to the Hines site. Each company has proposed options that would make capacity available to serve Hines 2 prior to the expected in service date of November 2003.

37. Will FPC have a firm natural gas transportation contract in hand by the time this case goes to hearing? If the response is "no", explain fully the reasons such contract is not completed.

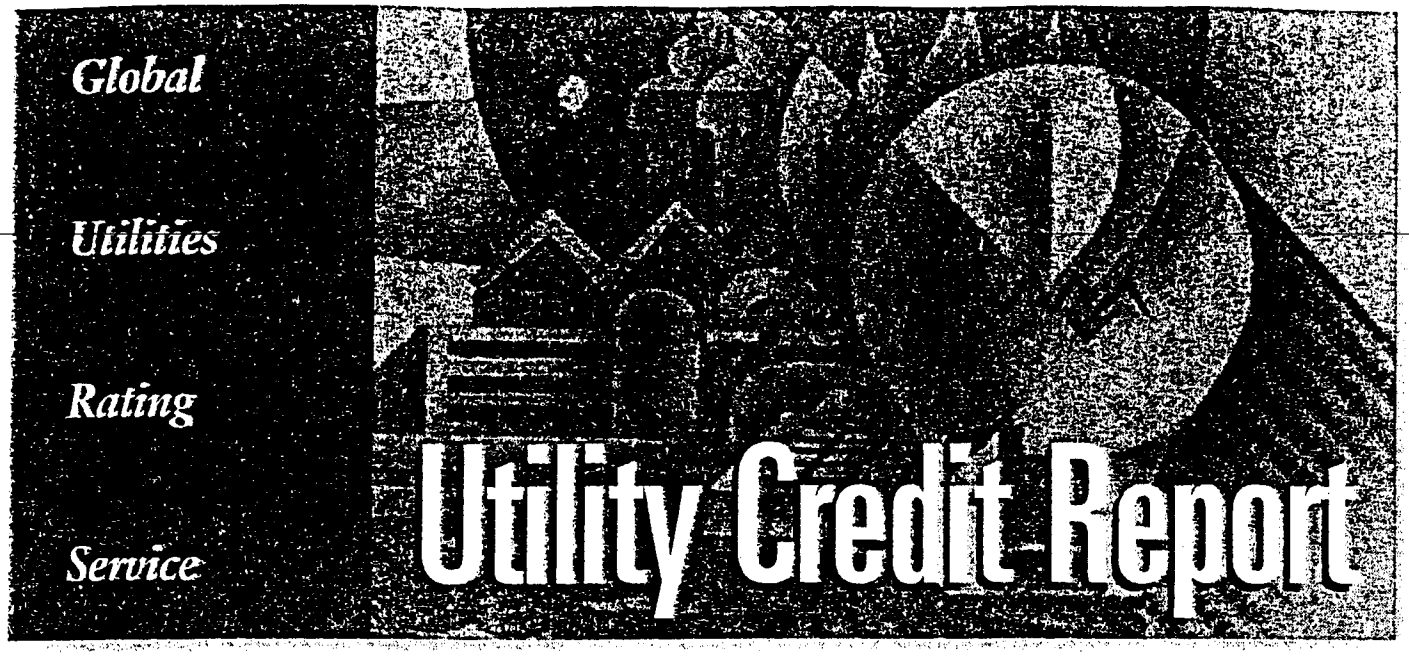
Answer:

Without waiving its objections filed separately on September 18, 2000, FPC states that it is seriously negotiating with each of the providers identified above and is confident that a contract will be executed in time to provide adequate natural gas transportation capacity for Hines 2. However, given the various contingencies impacting each of the pipeline providers (ie. The El-Paso-Coastal merger, FGT's decision on Phase 6 timing, Bucaneer's landowner issues in Pasco County, and the status of the El Paso Cypress Project), FPC is unable to predict at this time whether these negotiations will be completed by the hearing date.

38. Witness Major states in his testimony, at page 8, lines 11 - 13, that the existing lateral is sufficient to supply the Hines 2 unit. Witness Niekum states in his testimony, at page 5, lines 9-20, that FPC does not have firm capacity sufficient to serve Hines 2, but that FPC will be able to serve Hines 2 by the expected in-service date in late 2003. Does FPC have to build any facilities to provide service to Hines 2 because they do not have sufficient capacity, or if the existing lateral is sufficient, will FGT or another provider have to do anything to serve the Hines 2 unit?

Answer:

The existing lateral from the Hines meter and regulatory station is adequately sized to accommodate the additional volumes of natural gas necessary for Hines 2 regardless of the transportation service provider selected. In order to provide the needed transportation service to this point, however, each of the pipeline owners (including FGT) will have to build new (or expand existing) mainline capacity that connects back to the natural gas producing areas.



FLORIDA POWER CORP.

Analyst: John W. Whitlock, New York (1) 212-438-7678

Corporate Credit Rating

AA-/Watch Neg/A-1+

Business Profile

1 2 3 [4] 5 6 7

strong — weak

Outstanding Rating(s)

Florida Power Corp.	
Sr unsecd debt	
Local currency	A+/Watch Neg
Sr secd debt	
Local currency	AA-/Watch Neg
CP	
Local currency	Watch Neg/A-1+
Pfd stk	
Local currency	A/Watch Neg
Florida Progress Corp.	
Corp credit rating	A/Watch Neg/A-1
Sr unsecd debt	
Local currency	A/Watch Neg
CP	
Local currency	Watch Neg/A-1
Pfd stk	
Local currency	BBB+/Watch Neg

Corporate Credit Rating History

Oct. 23, 1986	A+/A-1•
June 26, 1990	AA-/A-1+

Company Contact

Pam Saari (1) 727-820-5871

RATIONALE

The ratings on Florida Power Corp. and affiliates are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s (CP&L) offer to acquire parent Florida Progress Corp. for $5.3 billion plus the assumption of $42.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

Florida Power's ratings reflect an above average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by less supportive regulation and the growing threat of widespread competition in the state. Also, the uncharacteristically high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

The utility's financials have rebounded to previous levels after being held back during the outage at the Crystal River Unit 3 nuclear plant, which returned to service in early 1998. Debt leverage is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220MW facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, the risk profile of these units is greater than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage and improve the consolidated financial profile. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times (x) is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

Financial Summary (Mil. $)

	1998	1997	1996	1995	1994
Gross revenues	2,648.2	2,448.4	2,393.6	2,271.7	2,080.5
Net income from continuing operations	250.1	135.9	238.4	227.0	200.8
Funds from operations (FFO)	659.6	459.5	529.8	524.3	502.0
Net cash flow	503.2	265.6	352.7	333.9	316.2
Capital expenditures	310.2	387.2	217.3	283.4	319.5
Total capital	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Adjusted ratios					
Pretax interest coverage (x)	2.79	2.93	3.56	3.33	3.02
Total debt/total capital (%)	56.9	59.7	48.8	48.2	50.9
FFO interest coverage (x)	4.01	3.30	4.64	4.47	4.28
FFO/avg. total debt (%)	25.8	20.7	30.0	28.8	30.1

STANDARD & POOR'S

Rating Methodology

Florida Power's corporate credit rating is based on the financial and business risk profile analysis of the consolidated enterprise. Florida Power's first mortgage bonds are rated the same as the firm's corporate credit rating. While these bonds are collateralized by utility property, Standard & Poor's ultimate recovery analysis does not project the value of such collateral to exceed substantially the maximum amount of first mortgage bonds that could be outstanding under the terms of the indenture. Therefore, Standard & Poor's does not have the necessary confidence that first mortgage bondholders would receive their principal in a bankruptcy scenario to consider higher secured ratings. Stress cases consider varying percentages of book value for the different utility asset classes based on the quality of each asset class. Nuclear assets are presumed to have no collateral value.

The utility's senior unsecured debt is rated one notch lower than the corporate credit rating because unsecured bondholders are disadvantaged by the presence of first mortgage bonds currently outstanding. In Florida Power's case, less than 35% of total debt outstanding is secured and assets are considered encumbered only up to the amount needed to satisfy the corresponding secured debt actually outstanding.

Business Description

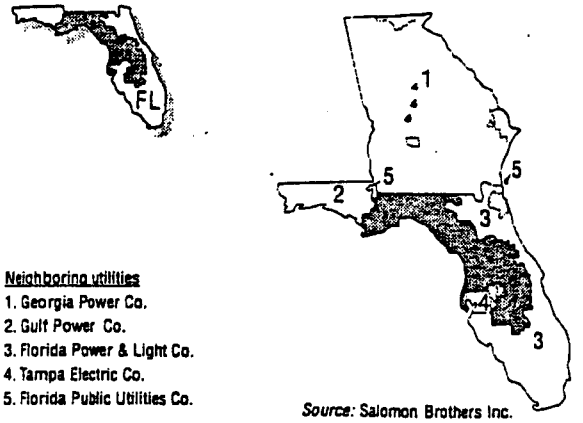
Florida Power, the regulated subsidiary of Florida Progress (*see November 1999 Utility Credit Report*), provides electric service to 1.3 million customers in central and northern Florida. The utility accounted for 80% of assets, 88% of earnings, and 73% of revenues for Florida Progress in 1998. Financing of the nonutility businesses is done at Progress Capital Holdings, which was formed to consolidate Florida Progress' diversified operations into one entity. The principal nonregulated operating subsidiary is Electric Fuels, which engages in coal mining, procurement and transportation, rail car services, and bulk commodities transportation. Progress Capital Holdings' ratings reflect a guarantee by parent Florida Progress.

Business Profile

Regulation. Florida Power's retail rates are regulated by the Florida Public Service Commission (PSC), which allows recovery of fuel-adjustment and purchased-power capacity costs, ratemaking incentives for operational efficiency, and accelerated cost recovery. The PSC has been generally supportive of Florida Power, as evidenced by the substantial recovery allowed for the buyout of the Tiger Bay purchased-power contract and acquisition of the facility. Still, the 1999 ruling allowing Duke Energy Corp. to build a merchant power plant serving the town of New Smyrna Beach (pending appeal and Florida Power Plant Siting Board approval) is a credit concern.

Previously, Florida's peninsular geography and transmission constraints helped to isolate the

FLORIDA POWER CORP.



Neighboring utilities
1. Georgia Power Co.
2. Gulf Power Co.
3. Florida Power & Light Co.
4. Tampa Electric Co.
5. Florida Public Utilities Co.

Source: Salomon Brothers Inc.

Standard & Poor's
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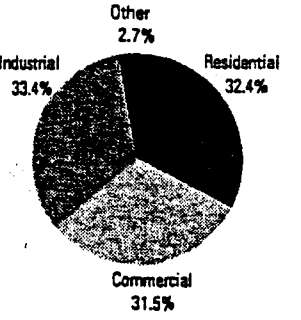
Regulation

Regulatory agency	Florida Public Service Commission
State	Florida
Case period	Eight months.
Interim procedures	Selectively.
Authorized returns (past 12 to 18 months)	
Return on equity (electric)	11.75%
Return on equity (gas)	11.3%
Return on equity (telephone)	13.2%
Rate base	Average original cost.
Test period	Forecast.
CWIP	Some CWIP included in rate base for a partial cash return.
Adjustment mechanisms	Fuel and purchased-power adjustment clauses (semiautomatic), both the capacity and energy components of purchased power are reflected through the fuel ajustment clause; demand-side management related expenses can be recovered without filing a base rate case; an oil backout cost adjustment allows accelerated recovery of investments in projects designed to displace oil-generated capacity.
Incentive ratemaking	Demand-side management; plant performance; rate of return and price cap/index; oil backout cost recovery factor rule.

Commissioners	Party	Term
Julia Johnson, Chair	Democrat	January 2001
Susan F. Clark	Democrat	January 2003
E. Leon Jacobs, Jr.	Democrat	January 2002
Joe Garcia	Independent	January 2002
J. Terry Deason	Democrat	January 2003

Source: Regulatory Research Associates Inc.

Industry Retail Sales (MWh)
1997



Source: Edison Electric Institute.

state's investor-owned utilities from competition. However, several other companies are seeking to build plants similar to the Duke/New Smyrna project, which could be the impetus for widespread competition throughout Florida. Still, there has been no grassroots support for electric restructuring legislation in past legislative sessions, given the small industrial base and temperate residential and commercial rates in the state. However, in Standard & Poor's view, additional merchant plant approvals, as well as new proposals, may be a catalyst for comprehensive legislation in Florida during 2000 to 2001.

Florida Power, which does not plan to seek base rate relief for the foreseeable future, is currently authorized a regulatory return on equity (ROE) of 12%, with an allowed range between 11% and 13%. However, the allowed rate of returns for the Florida investor-owned utilities have been under greater PSC scrutiny recently, which could affect the utility in the future. Still, Florida Power is protected by a rate stipulation that does not expire until 2001.

Markets. Florida Power serves about half of Florida's 67 counties, with a population of almost 5 million residing in the service territory. Service is provided in portions of central and north-central Florida and along the west coast of the state, including St. Petersburg and Clearwater, as well as the areas surrounding Walt Disney World, Orlando, Ocala, and Tallahassee. Some of the municipalities in the franchise area have exerted some pressure on the company when negotiating franchise renewal agreements by threatening to exit the system and team up with an independent power producer (IPP). Yet, the company is protected to some degree by the high cost of the distribution plant that would have to be purchased from Florida Power before a municipality could leave.

Florida Power's industrial customers accounted for about 9% of retail electric revenues and 13% of retail kWh sales, lessening its future exposure to potential electric restructuring in Florida. The company's heavy reliance on residential customers (60% of retail electric revenues and 50% of retail kWh sales) helps to guard against fluctuations in economic activity among the diverse customer base. Continued economic growth will likely fuel customer growth of 2% per year and retail kWh sales increases of 3% per year for 2000 and 2001.

Environmental concerns in Florida have limited Florida Power's transmission network, and no new high-voltage lines are likely in the foreseeable future. Combined with capacity constraints at the transmission interface with Georgia Power Co. outside of Florida, the utility has little transmission flexibility. Standard & Poor's is concerned that the lack of transmission could cause

bottlenecks during high demand periods, which could lead to price spikes.

Operations. To meet its future firm load projected demand, Florida Power could build an additional 1,000MW of gas-fired, combined-cycle generation at its Hines facility (a 500MW unit went into service in 1998). The ability to build and place in service gas-fired, combined-cycle plants in a short time gives the company increased flexibility in planning its long-range capacity needs.

Service Area Economics (% chg.)

	1996	1997	1998	1999-2001*	1999-2009*
Population					
Florida	1.7	1.6	1.5	1.5	1.5
Southeast region	1.3	1.2	1.1	1.0	0.9
National	0.9	0.9	0.9	0.8	0.8
Real per capita income (1992 $)					
Florida	21,894	22,484	23,139	23,526	24,891
Southeast region	19,319	19,848	20,401	20,765	22,008
National	22,183	22,872	23,477	23,791	25,013
Total employment					
Florida	3.2	4.2	3.3	1.7	1.9
Southeast region	2.2	2.7	2.4	1.0	1.2
National	2.2	2.6	2.3	1.0	1.1
Unemployment rate					
Florida	5.0	4.7	4.7	5.4	5.4
Southeast region	5.1	4.8	4.4	5.5	5.6
National	5.3	4.8	4.7	5.4	5.4

*Population and total employment estimates represent average annual growth rates for the period. Real per capita income and unemployment rate estimates represent forecasts for the last year in the period. *Source:* DRI/McGraw-Hill.

Market Segments

	1996	1997	1998	1995	1994
Sales					
Total retail (GWh)	33,387	30,850	30,785	29,499	27,675
Residential (%)	49.5	48.9	50.3	50.6	50.1
Commercial (%)	30.0	30.0	28.7	29.2	29.8
Industrial (%)	13.1	13.6	13.7	13.1	12.9
Other (%)	7.4	7.5	7.2	7.1	7.2
Wholesale (GWh)	3,864	2,440	2,708	2,903	2,339
Total sales (GWh)	37,251	33,290	33,493	32,403	30,015
Revenue					
Total retail (mil. $)	2,390	2,203	2,169	2,074	1,908
Residential (%)	59.6	58.7	59.9	60.4	59.9
Commercial (%)	25.5	25.8	24.8	24.8	25.4
Industrial (%)	9.0	9.4	9.5	9.1	9.1
Other (%)	6.0	6.1	5.8	5.6	5.7
Wholesale (mil. $)	206	151	159	153	125
Total revenue (mil. $)	2,596	2,358	2,328	2,227	2,033
Annual sales growth (%)					
Residential	9.6	(2.6)	3.6	7.8	3.7
Commercial	8.0	4.6	2.7	4.4	4.7
Industrial	4.5	(0.9)	9.3	8.0	5.9
Total retail	8.2	0.2	4.4	6.6	4.3
Standard & Poor's retail avg.	2.0	0.6	3.0	3.1	2.6
Wholesale	58.4	(9.9)	(6.7)	24.1	10.4
Total sales growth	11.9	(0.6)	3.4	8.0	4.8
Retail customer growth	2.0	1.7	1.6	2.2	2.4

Source: Navigant Consulting Inc.

Florida Power's construction needs for 2000 and 2001 will be about $550 million, with the majority of the expense targeted for transmission and distribution activity. Free cash flow is expected to cover amply this level of expenditure.

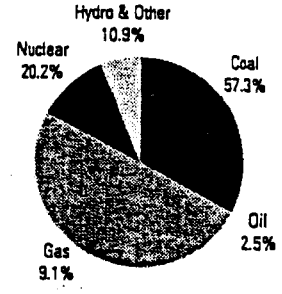
Florida Power's fuel mix is coal 38%, nuclear 15%, gas 7%, oil 20%, and purchased power 20%. The company's coal-fired plants mainly use Appalachian coal delivered by rail and barge and supplied by Florida Progress' subsidiary, Electric Fuels, pursuant to long-term contracts between Florida Power and Electric Fuels. The company's oil needs and gas supply are purchased under contracts and in the spot market from several suppliers with existing contracts sufficient to cover requirements.

A sizable portion of Florida Power's energy needs are provided by purchased-power contracts with other utilities and qualifying facilities (QF), including a large contract with Southern Co. and several QFs totaling 946MW of capacity, 831MW of which is currently available. The PSC allows recovery of QF contract costs in rates, but the company has attempted to buy out several QF contracts to minimize future capacity payments. The elimination of these uneconomical contracts helps to reduce Florida Power's potential exposure to stranded investment.

For credit protection measures, Standard & Poor's adjusts the debt component of utilities with purchased-power contracts to fully realize the financial impact. The net present value of future annual capacity payments for each contract is discounted by 10% (the estimated cost of capital) to identify the potential debt equivalent that a utility incurs when it enters into a long-term purchased-power contract. A risk factor for each contract is then determined on the basis of a qualitative analysis of the contract's terms and conditions, the ability to recover costs through regulatory means, and operating risks. The potential debt equivalent is multiplied by the risk factor to determine the amount of off-balance-sheet obligations added, which was $350 million for Florida Power in 1999.

Florida Power meets environmental standards by burning low-sulfur coal and installing low-nitrogen burners at Crystal River Units 1, 2, 4, and 5. Standard & Poor's believes that more stringent guidelines for nitrogen oxide and mercury emissions are likely to be implemented, which could adversely affect coal-burning

Industry Fuel Mix
1997



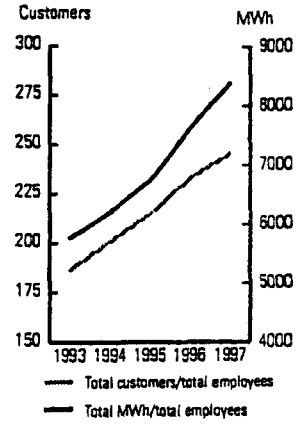
Source: Edison Electric Institute.

Fuel and Power Supply

	1998	1997	1996	1995	1994
Generating capacity					
Owned (MW)	7,727	6,755	7,347	6,526	7,207
Firm purchased (MW)	1,286	1,523	1,495	457	250
Peak demand (MW-summer)	7,444	8,066	8,807	7,128	6,955
Reserve margin (%)	21.1	2.6	0.4	(2.0)	7.2
Peak growth (%)	(7.7)	(8.4)	23.6	2.5	3.4
Annual load factor (%)	N.A.	N.A.	N.A.	49.8	51.2
FRCC regional reserve margin (%-summer)	7.7	N.A.	N.A.	N.A.	N.A.
Generation by fuel source (%)					
Coal	37.9	45.3	60.1	39.2	44.0
Oil	19.6	17.8	22.5	12.2	16.1
Gas	6.5	6.5	4.2	3.9	0.0
Nuclear	14.9	0.0	8.6	18.8	18.0
Purchased	21.0	30.5	4.7	26.0	21.9

FRCC—Florida Reliability Coordinating Council. N.A.—Not available.

Industry Efficiency Measures

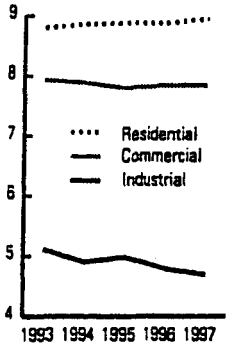


Efficiency Statistics
Operating Efficiency (electric-retail)

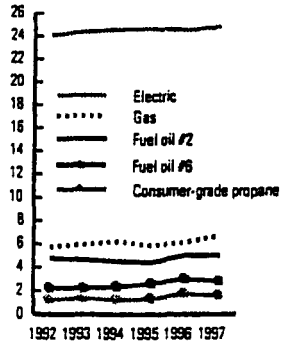
	1998	1997	1996	1995	1994
Total customers/employee	283	239	279	241	225
Industry avg.	259	247	233	215	204
Total MWh/total employee	7,044	5,601	6,650	5,600	5,005
Industry avg.	6,781	6,364	6,061	5,558	5,148
Total revenue/total kWh (cents)	7.16	7.14	7.05	7.03	6.89
Industry avg.	7.00	7.14	7.13	7.16	7.19

Source: Navigant Consulting Inc.

Industry Rates
(cents/kWh)



Average Residential Fuel Cost
($/MMBtu)



Source: American Gas Association.

Nuclear Operating Statistics (1998)

Unit	% owned	Lifetime forced outage rate (%)
Crystal River 3	90.4	21.3

Unit	Book value (mil. $)	Decomm. basis	Est. decomm. cost (mil. $)	Date of estimate	Total amt. funded (mil. $)	Annual amt. funded (mil. $)	Funding sufficiency (%)
Crystal River 3	335.5	Greenfield	420.2	12/98	235.3	21.7	105.4

electric utilities. However, Florida Power's ability to pass along environmental costs to ratepayers in a regulated energy market and its use of natural gas at new plant sites help to mitigate this potential risk.

The Crystal River Unit 3 nuclear plant has performed well since its return to service in early 1998. The plant ran at 100% capacity for 20 consecutive months before beginning a 45-day scheduled refueling outage at the end of September 1999. The turnaround is largely attributable to the new management team that has been running the facility since 1997.

Florida Power's 90.4% share of Crystal River Unit 3 had a net book value of $384 million at year-end 1998. Florida Power is licensed to operate the nuclear plant through December 2016 when decommissioning would likely begin. The PSC has determined future decommissioning costs for Crystal River Unit 3 to be about $2 billion, which is equivalent to $465 million in 1998 dollars. As of June 1999, Florida Power funded about $354 million of its estimated decommissioning expense.

Florida Power and Dynegy Inc. have a power marketing alliance that leverages the utility's physical assets and minimizes its risk exposure through Dynegy's expertise in energy marketing, power trading, and risk management. Florida Power's excess physical capacity is sold on a short-term forward (less than three months) basis and spot basis after its native load requirements are met, and the utility has the right to veto any transaction. Any increase in margins resulting from on-system energy trading is credited back to the utility's ratepayers under the fuel-adjustment clause, which reduces the overall energy costs for its customers. Standard & Poor's views Florida Power's decision to use a successful power marketer (Dynegy) and use only excess capacity backed by physical assets to be a sensible lower-risk strategy, which is favorable to credit quality.

Competitive position. Florida Power's competitive position is enhanced by the small size of its industrial customer class. The primary groups are the phosphate and citrus industries, which reduce the threat of relocation and political opposition. Also, the industrial customers benefit from the current interruptible rate of 4 cents per MWh, which creates a disincentive to seek open competition. Still, the looming presence of planned IPPs could affect the utility's position.

One area that the company has focused on is improving overall system reliability. Residential and commercial customers throughout Florida demand that the service outages be limited in frequency and duration. The company has beefed up its resources dedicated to improving its distribution system, which will position the company favorably when the market transitions from regulation to competition.

Florida Power's biggest investment is the Crystal River Unit 3 nuclear station, with a book value of about $384 million (excluding nuclear fuel). It represents about 20% of common equity and 10% of net electric plant in service and total capitalization. Crystal River Unit 3 is Florida Power's single largest base load facility, and it represented 8% of 1998's total winter capacity (including purchased power).

Energy Costs and Rates (1998) (cents/kWh)

Utility	Fuel	Total variable production	Total fixed production	Purchased power	Production and purchased power	Total energy cost	Residential rate	Commercial rate	Industrial rate
Florida Power Corp.	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**8.62**	**6.09**	**4.90**
Florida Power & Light Co.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	7.87	6.47	4.99
Gulf Power Co.	1.74	2.33	0.37	3.75	2.80	4.01	6.22	5.17	3.81
Tampa Electric Co.	2.23	2.88	1.42	4.10	4.27	5.52	7.99	6.48	4.48
FRCC region average	**1.99**	**2.60**	**0.90**	**3.93**	**3.54**	**4.76**	**7.58**	**6.05**	**4.54**
Standard & Poor's average	**1.50**	**2.39**	**1.79**	**3.95**	**3.96**	**5.57**	**8.67**	**7.35**	**5.10**

FRCC—Florida Reliability Coordinating Council. N.A.—Not available.

Financial Profile

Financial policy: Average

Florida Power's debt leverage is high, but the company continues to make strides to reduce debt to 45% of capitalization. The roll off in 2000 of a portion of the debt associated with the buyout of the Tiger Bay contract and sufficient internal funding for planned capital expenditures provide a platform for the company to achieve its goal. Florida Progress' dividend payout for 1999 is expected to be about 70% of earnings.

Profitability. Through the first three quarters of 1999, retail sales were up slightly from the same period in 1998. Solid customer growth was offset by bad weather in 1999, compared with 1998; a heat wave prevailed in Florida during most of June 1999. Full-year earnings will probably be slightly more than in 1998. Still, the utility's ROE is expected to be about 13% for 1999.

Adjusted pretax interest coverage is expected to be about 4.5x. Robust cash flow, cost-containment initiatives, and strong customer sales growth are the expected catalysts.

Cash flow protection. The utility's modest capital budget of about $300 million per year should be ably funded from internal cash generation. Capital spending will be concentrated in large part on transmission and distribution projects.

Cash flow protection measures are expected to remain healthy during the 2000-2001 period. Standard & Poor's expects a return to prior levels, with funds from operations (adjusted for off-balance-sheet purchased-power obligations) interest coverage of 4.5x and adjusted funds from operations to total average debt of 25% possible.

Capital structure. Debt leverage for the utility is high, but the company is committed to improving this measure. The roll off in 2000 of a portion of the debt associated with the buyout of the Tiger Bay contract will help Florida Power meet its goal as will robust regulated cash flow.

The average remaining life of Florida Power's long-term debt is 12.9 years, with an embedded cost of 6.8%. The PSC's approval of accelerated depreciation has reduced the amount of regulatory assets that could have been stranded in a deregulated energy market.

Financial flexibility. Florida Progress' stock is trading at 230% of its book value, in reaction to CP&L's offer to purchase the company. Florida Power has a $200 million 364-day and a $200 million five-year revolving credit facility, which are used to back up its $400 million commercial paper program.

Florida Power has $585 million in first mortgage bonds outstanding, with maturities through 2023. The utility has registered $370 million in additional first mortgage bonds but has no plans to issue new first mortgage bonds at this time. The company also has a remaining shelf filing of $250 million in medium-term notes.

Financing Flexibility

Common equity characteristics as of June 30, 1999	
Ticker symbol	FPC
Stock price ($)	41.3125
PE ratio (x)	13.7
Dividend yield (%)	5.3
Market to book (%)	209.7
Dividend to book (%)	11.0
Debt characteristics at fiscal year ended 1998	
Secured debt (%)	35
Unsecured debt (%)	65
Subordinated debt (%)	0
Fixed-rate debt (%)	100
Variable-rate debt (%)	0
Avg. life of long-term debt (years)	14
Embedded cost of long-term debt (%)	6.6
Debt maturing in five years (mil. $)	1,284.1

Short-term Financing
As of Dec. 31, 1998

Short-term debt (mil. $)	Arranged	Outstanding	Expiration date	Same-day availability	MAC clause
Commercial paper	400.0	0.0			
Bank lines					
Contracted committed lines	400.0	0.0	11/99	N.A.	N.A.
Avg. cost of short-term debt (%)	N.A.				

MAC—Material adverse change. N.A.—Not available.

Financial Statistics—Florida Power Corp.

	—Year ended Dec. 31—				
	1998	1997	1996	1995	1994
Income statement (mil. $)					
Gross revenues	2,648.2	2,448.4	2,393.6	2,271.7	2,080.5
Operating expenses (excl. DD&A)	1,784.3	1,631.6	1,600.9	1,523.4	1,399.5
Depreciation and amortization	347.1	325.9	324.2	23.7	261.5
Pretax operating income	516.8	490.9	468.5	454.6	419.5
Gross interest expense	136.5	117.3	98.4	104.5	108.4
Pretax income	390.4	205.6	374.2	356.5	315.5
AFUDC and deferrals	16.9	9.7	7.5	9.0	10.9
Income taxes	140.3	69.9	135.8	129.5	114.7
Net income from continuing operations	250.1	135.9	238.4	227.0	200.8
Earnings protection					
Pretax interest coverage (x)	3.77	4.15	4.73	4.33	3.81
Adjusted pretax interest coverage (x)	2.79	2.93	3.56	3.33	3.02
Preferred dividend coverage (x)	3.71	4.07	4.34	3.80	3.34
EBITDA interest coverage (x)	6.32	6.93	8.02	7.14	6.22
AFUDC and deferred income/earnings (%)	6.8	7.1	3.1	4.0	5.4
Return on common equity (nominal) (%)	12.9	6.9	12.6	12.2	10.8
Common dividend payout (%)	62.3	143.2	73.6	83.2	92.1
Annual O&M growth (%)	12.7	2.8	0.7	(7.6)	N.A.
Annual expense growth (excl. DD&A) (%)	9.4	1.9	5.1	8.9	N.A.
O&M/revenues (%)	20.8	20.0	19.9	20.8	24.6
Total operating expenses (excl. DD&A)/revenues (%)	67.4	66.6	66.9	67.1	67.3
Balance sheet (mil. $)					
Cash and equivalents	0.0	0.0	0.0	0.8	0.0
Gross plant	6,732.0	6,869.4	6,522.5	6,403.1	6,201.2
Net plant	3,630.5	3,649.5	3,517.1	3,605.1	3,669.2
Total assets	4,928.1	4,900.8	4,264.0	4,284.9	4,284.5
Short-term debt	138.9	181.3	25.4	30.6	90.7
Long-term debt	1,555.1	1,745.4	1,296.4	1,279.1	1,363.8
Preferred stock	33.5	33.5	33.5	138.5	143.5
Common equity	1,820.1	1,767.5	1,825.5	1,754.0	1,667.4
Total capitalization	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Total off-balance-sheet obligations	748.8	744.4	450.6	448.7	426.0
Balance sheet ratios (%)					
Short-term debt/total capital	3.9	4.9	0.8	1.0	2.8
Long-term debt/total capital	43.8	46.8	40.8	39.9	41.8
Preferred stock/total capital	0.9	0.9	1.1	4.3	4.4
Common equity/total capital	51.3	47.4	57.4	54.8	51.1
Adjusted total debt/total capital	56.9	59.7	48.8	48.2	50.9
Debt/EBITDA (x)	2.0	2.4	1.7	1.8	2.2
Cash flow (mil. $)					
Net income	250.1	135.9	238.4	227.0	200.8
Depreciation	361.0	305.7	313.0	309.2	282.9
Deferred taxes and ITC	36.5	(15.2)	(32.8)	(29.3)	(0.9)
AFUDC and deferrals	(16.9)	(9.7)	(7.5)	(7.3)	(10.9)
Other funds from operations (FFO) adjustments	28.9	42.8	18.7	24.7	30.1
FFO	659.6	459.5	529.8	524.3	502.0
Preferred dividends	(1.5)	(1.5)	(5.8)	(9.7)	(10.1)
Common dividends	(154.9)	(192.4)	(171.3)	(180.7)	(175.7)
Net cash flow (NCF)	503.2	265.6	352.7	333.9	316.2
Working capital changes	89.8	(57.6)	(57.3)	32.8	(10.3)
Capital expenditures (capex)	(310.2)	(387.2)	(217.3)	(283.4)	(319.5)
Discretionary cash flow	282.8	(179.2)	78.1	83.3	(13.6)
Cash flow adequacy					
Capex/avg. total capital (%)	8.5	11.2	6.8	8.8	9.8
NCF/capex (%)	162.2	68.6	162.3	117.8	99.0
FFO/avg. total debt (%)	36.4	28.3	40.3	37.9	34.5
Adjusted FFO/avg. total debt (%)	25.8	20.7	30.0	28.8	30.1
FFO interest coverage (x)	5.66	4.76	6.31	5.95	5.57
Adjusted FFO interest coverage (x)	4.01	3.30	4.64	4.47	4.28

AFUDC—Allowance for funds used during construction. O&M—Operations and maintenance. ITC—Investment tax credits. DD&A—Depreciation, depletion, and amortization. EBITDA—Earnings before interest, taxes, depreciation, and amortization. N.A.—Not available. *Source:* Financial data from EKS™ software by Navigant Consulting Inc.

Florida Power Corp.

John W. Whitlock, New York (1) 212-438-7678

Florida Power Corp.
Corporate Credit Rating
AA-/Watch Neg/A-1+

RATIONALE The ratings of Florida Power Corp. are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s offer to acquire parent Florida Progress Corp. for $5.3 billion plus the assumption of $42.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

Florida Power's ratings reflect an above-average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by less supportive regulation and the growing threat of widespread competition in the state. Also, the high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

The utility's financials have rebounded to previous levels after being held back during the outage at the Crystal River Unit 3 nuclear plant, which returned to service in early 1998. Debt leverage is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220 megawatts facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, these units are riskier than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times (x) is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

Florida Power Corp. Financial Statistics

	—Year ended Dec. 31—				
(Mil. $)	1998	1997	1996	1995	1994
Gross revenues	2,648.2	2,448.4	2,393.6	2,271.7	2,080.5
Net income from cont. operations	250.1	135.9	238.4	227.0	200.8
Funds from operations (FFO)	659.6	459.5	529.8	524.3	502.0
Net cash flow (NCF)	503.2	265.6	352.7	333.9	316.2
Capital expenditures	310.2	387.2	217.3	283.4	319.5
EBIT interest coverage (x)	3.77	4.15	4.73	4.33	3.81
Preferred dividend coverage (x)	3.71	4.07	4.34	3.80	3.34
FFO interest coverage (x)	5.66	4.76	6.31	5.95	5.57
Capital expend./avg. total capital (%)	8.5	11.2	6.8	8.8	9.8
NCF/capital expenditures (%)	162.2	68.6	162.3	117.8	99.0
FFO/avg. total debt (%)	36.4	28.3	40.3	37.9	34.5
Return on common equity (nominal) (%)	13.9	7.5	13.0	12.7	11.4
Total capitalization	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Short-term debt (%)	3.9	4.9	0.8	1.0	2.8
Long-term debt (%)	43.8	46.8	40.8	39.9	41.8
Preferred stock (%)	0.9	0.9	1.1	4.3	4.4
Common equity (%)	51.3	47.4	57.4	54.8	51.1

Florida Power Corp. Operating Statistics

	—Year ended Dec. 31—				
	1998	1997	1996	1995	1994
Total sales (GWh)	37,251	33,290	33,493	32,403	30,015
Residential (%)	44.4	45.3	46.2	46.1	46.2
Commercial (%)	26.8	27.8	26.4	26.6	27.5
Industrial (%)	11.7	12.6	12.6	11.9	11.9
Wholesale (%)	10.4	7.3	8.1	9.0	7.8
Other (%)	6.7	7.0	6.7	6.4	6.6
Avg. retail revenue (cents/kWh)	0.07	0.07	0.07	0.07	0.07
Retail sales growth (%)	8.22	0.21	4.36	6.59	4.32
Capacity at time of peak (MW)	9,013	8,278	8,842	6,983	7,457
Reserve margin (%)	21.1	2.6	0.4	1.4	9.1

GWh—Gigawatt hours. kWh—Kilowatt hours. MW—Megawatts.

BALANCE SHEET STATISTICS FOR ELECTRIC UTILITIES

For 12 months ended Dec. 31, 1999
(Mil. $)

Company Name	Gross plant	Net plant	Current assets	Total assets	Short-term debt	Long-term debt	OBS debt	Pref. stock	Comm. stock	Total cap.
Wisconsin Public Service Corp.	2,053.6	850.8	186.4	1,409.9	50.4	373.1	0.0	51.2	525.1	999.9
Average AA+	2,053.6	850.8	186.4	1,409.9	50.4	373.1	0.0	51.2	525.1	999.9
Madison Gas & Electric Co.	782.2	297.8	71.1	495.5	27.0	148.6	5.7	0.0	185.7	361.2
Northern States Power Wisconsin	1,240.3	752.8	86.7	907.1	80.8	232.0	0.0	0.0	357.0	669.8
Southern Indiana Gas & Electric Co.	1,362.5	738.9	104.0	894.8	76.6	238.3	0.0	19.3	334.6	668.7
Tampa Electric Co.	4,563.7	2,745.0	306.3	3,322.5	356.0	690.3	32.6	0.0	1,043.1	2,089.4
Average AA	1,987.2	1,133.6	142.0	1,405.0	135.1	327.3	9.6	4.8	480.1	947.3
Central Illinois Public Service Co.	2,733.3	1,472.8	249.6	1,781.8	167.9	493.6	0.0	80.0	534.4	1,275.9
Florida Power & Light Co.	18,005.0	7,821.0	893.0	10,608.0	219.0	2,079.0	1,236.6	226.0	4,793.0	7,317.0
Florida Power Corp.	6,993.2	3,651.9	520.7	5,002.5	229.9	1,478.8	781.2	33.5	1,885.0	3,627.2
Indianapolis Power & Light Co.	3,049.5	1,750.4	176.6	2,048.8	49.0	628.0	50.0	59.1	780.5	1,516.6
Northern States Power Co.	9,783.9	4,451.5	1,033.8	9,767.7	1,094.0	3,453.4	198.2	305.3	2,557.5	7,410.2
Otter Tail Power Co.	889.6	503.0	119.9	680.8	5.9	176.4	32.9	33.5	245.7	461.6
San Diego Gas & Electric Co.	4,483.0	2,157.0	843.0	4,366.0	66.0	892.0	260.1	104.0	1,314.0	2,376.0
TECO Energy Inc.	6,064.4	3,627.8	531.8	4,690.1	969.5	1,207.8	32.6	0.0	1,472.5	3,649.8
Union Electric Co.	9,652.7	5,331.8	707.8	7,043.6	11.4	1,816.6	42.7	221.2	2,433.7	4,482.9
Wisconsin Electric Power Co.	6,395.2	3,205.3	645.9	5,052.6	295.5	1,677.6	0.0	30.5	1,880.9	3,884.4
Wisconsin Power & Light Co.	2,508.0	1,241.6	121.5	1,766.1	182.7	414.7	36.5	60.0	599.1	1,256.5
Average AA-	6,414.4	3,201.3	531.3	4,800.7	299.2	1,301.6	242.8	104.8	1,681.5	3,387.1
Alabama Power Co.	12,605.2	7,703.8	848.3	9,648.7	197.8	3,190.4	101.5	664.5	2,988.9	7,041.5
Allegheny Energy Inc.	8,839.7	5,207.2	709.3	6,852.4	830.8	1,499.0	75.8	229.5	1,695.3	4,254.6
Allegheny Generating Co.	828.9	601.7	7.3	620.9	52.5	148.9	0.0	0.0	154.5	355.9
Alliant Energy Corp.	6,205.7	3,128.3	486.0	6,075.7	492.8	1,512.8	211.9	113.6	2,155.6	4,274.8
Ameren Corp.	13,056.5	7,165.2	879.0	9,177.6	209.0	2,382.9	52.5	300.7	3,089.7	5,982.4
Baltimore Gas & Electric Co.	8,976.2	5,510.1	655.0	7,272.6	652.9	1,956.0	248.5	440.0	2,355.4	5,404.3
Consolidated Edison Co. of New York Inc.	14,991.7	10,606.9	1,378.1	13,682.2	770.4	4,243.1	698.5	249.6	4,393.8	9,656.8
Duke Energy Corp.	30,436.0	20,995.0	6,717.0	33,409.0	782.0	8,683.0	233.7	1,450.0	10,198.0	21,113.0
FPL Group Inc.	19,397.0	9,107.0	1,373.0	13,441.0	464.0	3,478.0	1,236.6	226.0	5,370.0	9,538.0
Georgia Power Co.	16,343.3	9,804.7	1,028.6	12,276.9	792.0	2,688.4	473.3	804.2	3,938.2	8,222.8
Gulf Power Co.	1,887.8	1,065.9	158.2	1,308.5	55.0	367.4	12.8	89.2	422.3	934.0

Source: Financial data from EKS™ software by Navigant Consulting Inc.

FPC 284

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Analysis

Publication Date: 26-Apr-2000

Summary: Florida Power Corp.

Analyst: John W Whitlock, New York (1) 212-438-7678

Live Help

Help

Current Ratings

Contents

Rationale

Credit Rating: **AA-/Watch Neg/A-1+**

Rationale

The ratings on Florida Power Corp. are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s offer to acquire parent Florida Progress Corp. for $5.3 billion plus the assumption of $4.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

The ratings on Florida Power reflect an above average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by the changing regulatory and political environment in Florida, which may adversely impact the consolidated business profile of the utility. Also, the uncharacteristically high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

Debt leverage for Florida Power is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220MW facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive. Still, the high amount of debt leverage pressures consolidated credit protection measures.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, the risk profile of these units is greater than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage and improve the consolidated financial profile. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

Moody's Investors Service
Global Credit Research

Florida Power Corporation

September 1999

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Ratings and Contacts

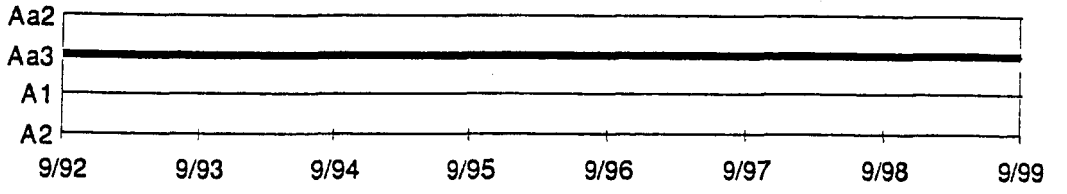
Category	Moody's Rating
Issuer Rating	A1*
First Mortgage Bonds	Aa3*
Senior Unsecured	A1*
Preferred Stock	"a1"*
Commercial Paper	P-1*
Ult Parent: Carolina Power & Light Company	
Issuer Rating	A3

* Placed under review for possible downgrade on August 23, 1999

First Mortgage Bonds	A2
Senior Unsecured Shelf	(P)A3
Subordinate	Baa1
Analyst	**Phone**
A. Tucker Hackett/New York	1.212.553.1653
Scott Solomon/New York	
Susan D. Abbott/New York	

Rating History

Senior Secured



Operating Statistics

Florida Power Corporation (Statistics in bold type)[1]
Peer Group Median (Statistics in light type)

	[2]1999		1998		1997		1996		1995		[3]5-Yr.Avg	
Revenue (US$ bil.)	2.7	1.2	2.6	1.1	2.4	1.1	2.4	1.0	2.3	[4]4.5	[4]6.2	
Assets (US$ bil.)	5.0	2.9	4.9	2.8	4.9	2.7	4.3	2.8	4.3	[4]2.5	[4]3.0	
Com. Equity (US$ bil.)	1.8	0.9	1.8	0.9	1.8	0.9	1.8	0.9	1.8	[4]2.2	[4]3.6	
Op. Margin (%)	14.2	14.8	14.0	15.5	10.1	16.4	13.9	16.1	14.4	15.7	13.4	
ROA(%)	5.3	3.7	5.0	3.6	2.7	3.7	5.5	3.8	5.1	3.7	4.6	
ROE(%)	14.2	12.2	13.7	11.8	7.6	12.0	12.7	12.5	12.4	12.0	11.6	
Div. Payout (%)	133.6	82.8	61.7	85.2	142.0	81.9	71.2	79.0	83.2	82.3	90.0	
Pretax Int. Cov. (X)	4.1	3.5	3.7	3.4	2.7	3.5	4.7	3.4	4.3	3.4	3.9	
Fxd. Chg. Cov. (X)	4.0	3.0	3.7	2.9	2.6	2.9	4.3	2.9	3.8	2.9	3.6	
FFO Int. Cov. (X)	6.5	4.5	6.0	4.5	5.2	4.6	6.6	4.4	6.1	4.4	5.9	
FFO % Total Debt	41.6	25.7	40.7	26.2	25.5	26.4	42.0	25.3	40.9	25.3	36.9	
RCF % Gross CAPEX	97.3	114.0	172.2	124.6	77.0	128.8	176.6	113.5	121.6	113.8	129.7	
Total Cap. (US$ bil.)	3.6	2.0	3.5	2.0	3.7	2.0	3.2	1.8	3.2	[4]1.7	[4]1.8	
TD % Cap.	47.4	49.2	47.8	49.5	51.7	48.8	41.6	49.5	40.9	49.4	45.3	
Pfd. Stk. % Cap.	0.9	5.8	0.9	6.0	0.9	5.8	1.1	4.6	0.8	5.4	0.9	
Common % Cap.	51.7	44.9	51.3	44.9	47.4	45.4	57.4	45.1	54.8	44.9	52.4	

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale	Total
Revenue (US$ mil.)	1,424.6	608.9	214.4	207.9	2,648.2
Kwh(mil.)	16526	9999	4375	3864	37251
¢/Kwh	8.6	6.1	4.9	5.4	7.1
Regional Average	7.9	6.5	4.7	4.3	7.6

Competitive Position	Fuel	Non-Fuel	Investment	Total Cost	Regional Cost
$ per Mwhr.	22.03	3.29	9.15	34.47	34.76

[1] Competivie Position reflects 1997 figures. [2] For the 12 months ended June 30; Balance sheet items are as of June 30. [3] Five year average 1998-1994. [4] Five year compound annual growth rate.

Opinion

Rating Rationale

Florida Power Corporation (FPC) has retained a Aa3 senior secured rating for a number of years by virtue of its capable management, cost-cutting initiatives, supportive regulation, competitive rates, the state's vibrant economy, and limited in-state competition. However, the utility is exposed to nuclear risk through its 90% ownership of the Crystal River nuclear plant and to potential stranded costs from expensive power-purchase contracts and regulatory assets. In addition, ratings pressure originates in acquisition leverage issued by a new holding company created to purchase FPC.

Recent Events

Management announced in August the company will be sold to Carolina Power & Light Company (CP&L, rated A2 sr. sec.) to create the nation's 9th largest utility in terms of generating capacity. The new super regional utility will be headquartered in North Carolina.

New management expects merger-related synergies, driven by cost savings, to exceed $100 million per annum. Savings will result primarily from elimination of duplicate corporate and administrative programs and operating efficiencies. A substantial portion of these savings will be extracted from FPC.

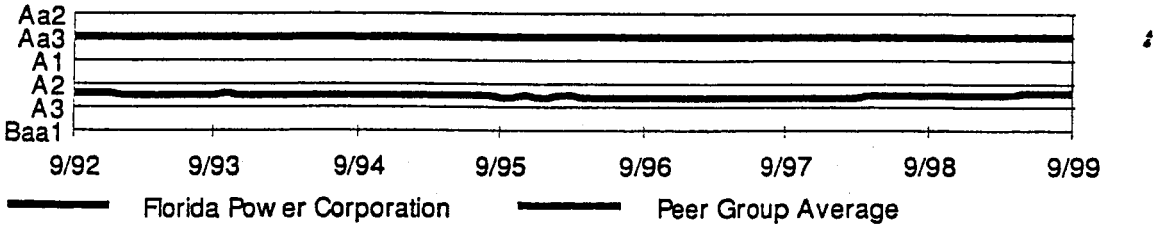
In addition, revenue enhancements are likely from generation expansion and wholesale marketing opportunities. CP&L intends to use the FPC platform to build gas-fired generating plants in Florida.

Rating Outlook

Concern that financial pressure will result from the obligation to service up to $3.5 billion of acquisition leverage to be issued by a new holding company led Moody's to place the securities on review for potential downgrade.

Coupon	Type of Debt	Maturity	Moody's Rating
Florida Power Corporation			
—	Issuer Rating	—	A1
—	MTN Program	—	A1
—	4% Cum. Pfd. Stk.	—	"a1"
—	4.60% Cum. Pfd. Stk.	—	"a1"
—	4.40% Cum. Pfd. Stk.	—	"a1"
—	4.58% Cum. Pfd. Stk.	—	"a1"
—	7.40% Cum. Pfd. Stk.	—	"a1"
—	7.76% Cum. Pfd. Stk.	—	"a1"
—	$7.08 Cum. Pfd. Stk.	—	"a1"
—	4.75% Pfd. Stk.	—	"a1"
7.000%	First Mortgage Bonds	2023	Aa3
8.000%	First Mortgage Bonds	2022	Aa3
8.625%	First Mortgage Bonds	2021	Aa3
6.875%	First Mortgage Bonds	2008	Aa3
6.000%	First Mortgage Bonds	2003	Aa3
6.125%	First Mortgage Bonds	2003	Aa3
7.250%	First Mortgage Bonds	2002	Aa3
7.375%	First Mortgage Bonds	2002	Aa3
6.500%	First Mortgage Bonds	1999	Aa3
6.750%	Medium Term Notes	2028	A1
6.810%	Medium Term Notes	2007	A1
6.770%	Medium Term Notes	2006	A1
6.720%	Medium Term Notes	2005	A1
6.690%	Medium Term Notes	2004	A1
6.620%	Medium Term Notes	2003	A1
6.540%	Medium Term Notes	2002	A1
6.470%	Medium Term Notes	2001	A1
6.330%	Medium Term Notes	2000	A1
—	Commercial Paper	—	P-1
—	415 Shelf Registration	—	(P)Aa3

Rating History Peer Senior Secured



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Risks/Weaknesses

- Financial pressure from acquisition debt issued to finance its acquisition by Carolina Power and Light (CPL).
- Exposure to nuclear risk through Crystal River and CPL's nuclear units.
- Above-market purchased-power contracts constrain the company's ability to reduce production costs.
- Merchant plant sponsors continue attempts at inroads in FPC's service territory.
- Potential stranded costs are high for the rating category, but average for investor owned utilities in Florida.
- Significant risks inherent in expanding unregulated activities of parent.
- Parent guarantee of non-regulated subsidiary debt issued by Progress Capital Holdings, a downstream holding company that finances the parent's non-regulated businesses.

Opportunities/Strengths

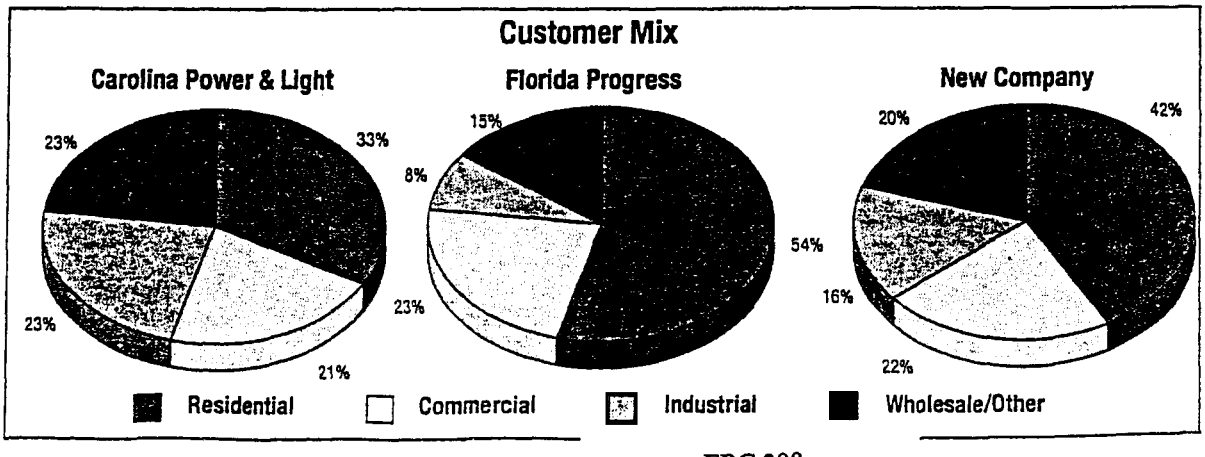
- Acquisition by CPL creates critical mass and cost savings opportunities.
- An economically vibrant service territory.
- The lack of political or regulatory support for deregulation in Florida.
- A growing residential customer base drives steady revenue growth.
- Competitive rates within Florida.

Company Fundamentals

On August 23, 1999, Carolina Power & Light Company announced plans to acquire the parent company of Florida Power Corporation (FPC), Florida Progress, in a cash and stock transaction valued at $8 billion, including the assumption of $2.7 billion in FPC debt and preferred stock. Under terms of the agreement, Florida Progress shareholders will receive $54 per share in a combination of cash and a new CPL holding company's common stock (See Management Strategy and Competitive Position for details). Acquisition debt of $3.5 billion will be issued by a new holding company to finance the acquisition.

Florida Power Corporation is the principal operating subsidiary of Florida Progress Corporation, a diversified energy-related holding company based in St. Petersburg, Florida. As the state's second largest investor-owned utility, FPC provides electric service to more than 1.3 million customers in a 20,000 square-mile service territory encompassing substantial portions of west central and northern Florida, including the fast growing region around Orlando. Electric Fuels Corporation, an energy and transportation company is Florida Progress' other major subsidiary. Progress Capital Holdings, Inc. (PCH), a downstream holding company finances the parent's non-utility businesses. In 1997, the company wrote off its investment in Mid-Continent Life Insurance Company without impacting ratings.

At year-end 1998, FPC comprised approximately 80% of Florida Progress' assets, 73% of its consolidated revenue, and 89% of its net income. Residential and commercial customers contributed 54% and 23% to total electric revenues, respectively, while industrial and wholesale customers each supplied 8%. As demonstrated in the pie chart below, the predominantly residential base of FPC will make a strong complement to CPL's higher mix of commercial and industrial customers. This strategic fit will enhance CPL's plans to expand its electric generation capacity and build a powerful presence in the Southeastern electric and natural gas markets.



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Centered on its growing trade and services industries, while further influenced by tourism and agriculture, Florida's economy continues to be among the fastest growing in the nation. During the 1990s, the state's population has grown by nearly 20% and continues to outperform the region and the nation in employment and income growth. As a result, this vibrant service territory appeals to outside utilities, who are interested in constructing merchant plants to serve it.

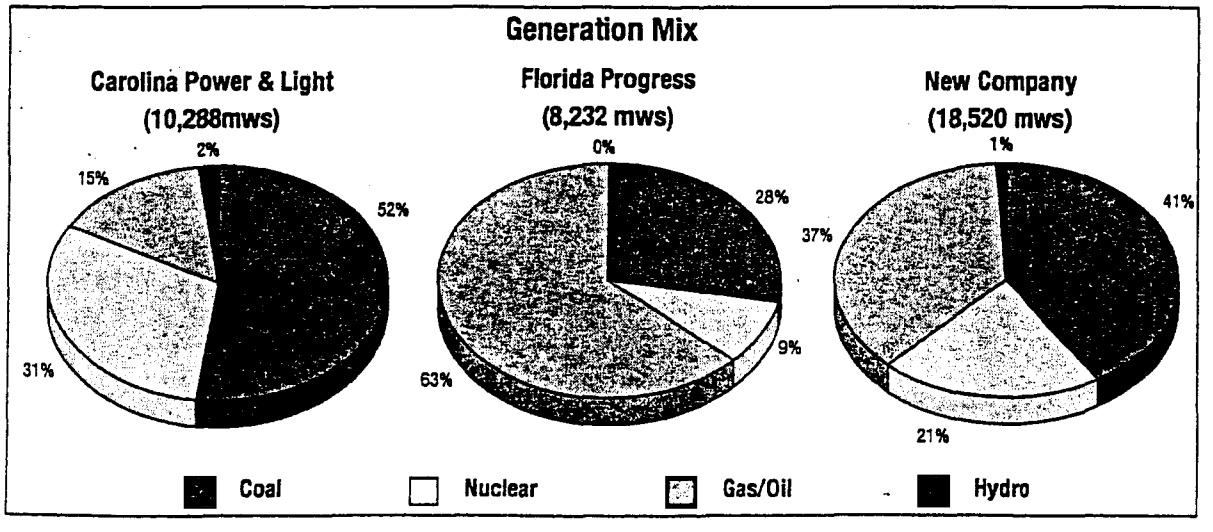
To date, neither the legislature nor the Florida Public Service Commission (FPSC) has been a forceful advocate for deregulation of electricity markets. Despite political disinterest, FPC's management has taken certain steps in anticipation of eventual electric deregulation and created a national retail energy strategy to position itself for a more competitive marketplace. When competition finally arrives, FPC will be relatively well positioned due to its strong customer base and transmission bottlenecks limiting other utilities access to the state. In addition, CPL will construct new plants in the area to serve load growth.

In an attempt to capitalize on increased wholesale demand, several companies, including Duke Energy Power Services (a subsidiary of Duke Energy), are planning to build cogeneration merchant plants to service wholesale customers within Florida, primarily municipalities. However, the plans of these companies have met significant opposition from the three investor-owned utilities in Florida, who have argued that merchant plants are illegal under the state's complex laws governing power projects, specifically the Florida Power Plant Siting (PPSA) Act.

The PPSA governs the building of new generation involving steam capacity of 75 megawatts or more. Other companies, such as Constellation Power (a subsidiary of Baltimore Gas & Electric), have circumvented the PPSA by proposing to build a combustion turbine plant rather than a combined cycle facility.

On March 5, 1999, the Florida Public Service Commission (FPSC) voted 4 to 1 in favor of allowing Duke Energy Power Services to build a 514 megawatt combined cycle merchant plant in New Smyrna Beach, Florida, thereby setting an important precedent for the development of merchant plants, and indirectly increasing the IOU's competition within Florida. Given the decision by the FPSC to allow Duke Energy Power Services to build a merchant plant in New Smyrna Beach, Moody's anticipates other merchant plants will be built, therefore, further increasing in-state competition for wholesale customers. However, Moody's believes the anticipated increase in wholesale competition is partially mitigated by the growth in demand for wholesale energy. All three Florida utilities have appealed the FPSC's decision to the Florida Supreme Court.

At year-end 1998, FPC's resources for serving load consisted of 9,013 mw of electric power, with 7,727 mw generated by owned facilities and 1,286 mw obtained through purchased power contracts. The pie chart below highlights the combined company's post-merger generation mix, which is more balanced, but retains a higher exposure to nuclear assets.



Power purchased under contract from other utilities and non-utility generators comprise a significant portion of total energy sold by the company. These long-term contracts are above market and constrain the company's ability to reduce production costs and become more competitive. FPC is obligated to purchase approximately 871 mw of power (831 mw is currently available) from qualifying facilities with expiration dates ranging from 2002 to 2025. From other utilities, FPC purchases 455 mw of power, primarily from Southern Company with whom it has a contract to purchase approximately 400 mw through 2010.

Over the past few years, management has made progress in renegotiating these contracts, notably the July 1997 buyout of the 220 mw Tiger Bay cogeneration facility, which is now run as a gas-fired combined cycle generating plant. The FPSC recently approved an amended contract between FPC and El Paso Energy to allow two units to operate at times as merchant plants. The utility will retain first call on the power produced by Mulberry and Orange facilities, which will lose their qualifying facility status. El Paso Energy agreed to reduced capacity payments for the facilities in exchange for the ability to operate them by their power marketing subsidiary.

As the majority owner and operator of the Crystal River Nuclear Plant, FPC continues to retain a significant exposure to nuclear assets. Subsequent to restarting in early February 1998, after an extended outage, Crystal River achieved a capacity factor of 90% vs. an industry average of 76.7%. Because the Nuclear Regulatory Commission is currently designing a new system for evaluating safety of nuclear plants, recent scores for Crystal River are not available.

Management Strategy and Competitive Position

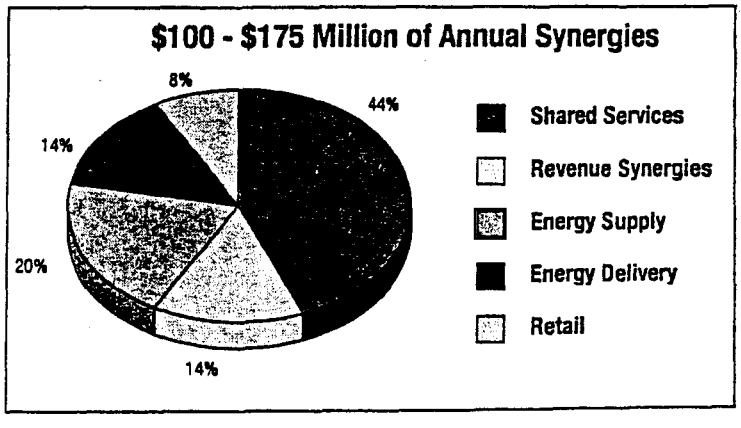
Acquisition by Carolina Power & Light

Because size will be important to achieve economies of scale and expand the customer base in a deregulating market, FPC agreed to be acquired by CPL to create the nation's ninth largest electric utility based on generating capacity. The super regional utility will serve nearly 2.7 million customers in a 50,000 square-mile service territory across three states and will have generating capacity of approximately 18,520 megawatts. Combined assets will total $15.2 billion, while total revenue reaches $6.7 billion. For a discussion of CPL, please refer to the Global Credit Report published in February 1999.

The new company will be operated out of Raleigh, NC, the headquarters of CP&L. A local office will likely remain open in St. Petersburg, Florida. Richard Korpan will retire as chairman, president, and chief executive officer of Florida Progress and will join CP&L's board of directors. The board will consist of 14 members, 10 from CP&L and 4 from FPC.

According to the pie chart below, new management expects merger-related synergies to range from $100 to $175 million on an annual basis, driven primarily by cost savings instead of revenue enhancements. These synergies result primarily from the elimination of duplicate corporate and administrative programs, and from operating efficiencies, including integration of the Crystal River nuclear site with CP&L's three existing nuclear sites. Revenue enhancements are also possible from generation expansion and wholesale marketing opportunities.

After the integration is completed, it is anticipated the company will have a combined workforce of approximately 16,000 employees, reflecting a reduction of about seven percent. The company will use a combination of attrition and moderation in hiring to reduce the need for employee separations. At this early stage in the merger process many of these synergies have not been definitively identified; however, a significant portion of these savings will likely be extracted from FPC.



Strategy Prior to Acquisition May Change

Prior to the acquisition, FPC's strategy was to capitalize on strengths in its core business, pursue growth opportunities through Electric Fuels, and develop a national retail energy business. It remains to be seen how new management will alter FPC's stated strategy.

As part of a national retail strategy, FPC planned to offer commodity-related products and services, as well as their transportation to the retail customer. Through its marketing and service joint venture with Cinergy and New Century Energies, management targets large national companies in diverse locations and offers energy management services. In addition, its power marketing alliance with Houston-based Dynegy, Inc. (formerly NGC Corporation) enables the company to better market its power supply to utilities and large energy users in Florida and other regions. Dynegy's energy marketing, trading, and risk management skills also help FPC optimize the value of its generation portfolio, while reducing energy costs.

Management's focus on cost controls allows FPC to maintain competitive retail prices by limiting O&M increases to less than inflation, and reducing costs associated with expensive purchased-power contracts. In particular, the Tiger Bay buy-out reduced purchased power commitments by 220 mw or 20%, while saving customers approximately $2 billion during the period 2008 through 2025. The Pasco Cogen buy-out is expected to save customers $183 million beginning in 2002. Additional savings come from formation of strategic business units in 1996, and a corporate-wide work process-reengineering program instituted in 1997.

Management continues to grow its non-regulated businesses at Electric Fuels through acquisitions and business expansion. At year-end 1998, Electric Fuels represented approximately 11% of Florida Progress' equity investment and 27% of consolidated revenue. Its business units are energy- related services, inland marine transportation, and rail services. Medium term notes issued by PCH fund business unit operations. Non-regulated businesses include:

- Energy and Related Services – This business unit supplies coal to FPC and other utilities and industrial customers through its network of operations. Abnormal weather in 1998 increased the volume of coal transported to FPC and resulted in higher earnings. Continued growth will be driven largely from the expansion of its river terminal operations and related activities.
- Inland Marine Transportation – This business unit transports coal, agricultural, and other dry bulk commodities through the Ohio and Mississippi rivers. Weak export shipments caused by a strong U.S. dollar and warmer winter weather have negatively impacted 1998 earnings. Growth is expected to be driven by barge fleet expansion.
- Rail Services – This business unit serves the country's major railroads by providing various services. In 1998, the company spent approximately $200 million for acquisitions and will continue to expand its operations into new markets serving other Class 1 and shortline railroads, as well as private fleet owners.

Year 2000—Company Expects to be Ready

Since mid-1997, FPC has been actively preparing for Year 2000 (Y2K) through the replacement and upgrade of computer systems and technologies. Total costs for this program have been estimated between $15 and $20 million, $9.5 million has been incurred and expensed to date. Management plans to complete its Y2K program by the third quarter of 1999 for FPC, and by the fourth quarter of 1999 for Electric Fuels.

Regulation, Rates, and Restructuring

New management will obtain regulatory approvals for the acquisition in two steps. In early 2000, management expects to receive approval for formation of the new holding company from the SEC, FERC, NRC, NCUC, and SCPSC. By next summer, management expects merger approval from CPL and FPC shareholders, the SEC, FERC, the NRC, and the Department of Justice. Approvals from the FPSC and state commissions in North Carolina and South Carolina are not required, but discussions will be held with these state regulators. CPL will register as a holding company under the Public Utilities Holding Company Act of 1935.

Neither legislators nor regulators are moving quickly to implement retail competition in Florida due to the state's competitive electric rates, small number of industrial customers, and relative physical isolation. The 1999 legislative session in Florida adjourned in April without considering restructuring legislation. The Florida legislature has been monitoring restructuring activities in other states via a working group established in 1997. A comprehensive restructuring bill was introduced in the 1998 session, but was not passed.

000057

During 1997, the FPSC approved a settlement agreement allowing FPC to recover a portion of replacement fuel costs incurred during Crystal River's extended outage. While Crystal River was out of service, the company spent $100 million in additional nuclear O&M expenses and approximately $173 million in fuel replacement costs. Under the settlement agreement, FPC agreed not to seek a change in base rates or the authorized range of its equity return for a four year period ending in 2001. The company has not filed for rate relief since 1992 when the FPSC approved a 12% regulatory return on equity with an allowed ranged between 11% and 13%.

Financial Analysis

The acquisition will be treated as a purchase for accounting purposes. This creates goodwill of $3.3 billion to be housed at the new holding company. Despite goodwill amortization of $83 million per year, management expects earnings per share growth of 7-8%. The new entity will continue CPL's dividend policy. The remainder of this report discusses FPC's financial performance and goals as disclosed before the merger.

For the six-month period ended June 30, 1999, Florida Progress' net income increased approximately 12% over the same period in 1998, driven by improved earnings at the utility. FPC earnings increased due to lower amortization of regulatory assets and lower interest expenses for debt refinancings in late 1998. At Electric Fuels, earnings increased due to sales of a coal-based synthetic fuel by the Energy and Related Services group. In addition, the Rail Services and Inland Marine Transportation business units experienced improved operating results during the second quarter of 1999.

Florida Progress' net income increased to $282 million in 1998, up from $54 million in 1997, as the company recovered from the extended outage at Crystal River and rebounded from the $87 million write-off of Mid-Continent. In addition, strong customer growth at the utility and enhanced earnings from diversified operations bolstered results. At the utility, however, accelerated amortization of regulatory assets, expenditures to increase reliability, and a lump-sum pay increase offset increased revenues attributed to hotter-than-normal weather. These accelerations increased utility operation and maintenance expenses beyond the increases already anticipated because of costs related to operating Tiger Bay. Despite higher operating expenses, pre-tax interest coverage strengthened to 3.7 times from 2.6 times. It had been depressed in 1997 due to expenses related to the Crystal River outage.

Funds from operations interest coverage increased from 5.2 times to 6.20 times as income rebounded from depressed levels in 1997, and accelerated amortization increased in amounts sufficient to offset higher interest expense.

On December 31, 1998, FPC's capital structure improved to approximately 48% debt, 1% preferred stock, and 51% common equity, from 52% debt, 1% preferred, and 47% equity at year-end 1997 as debt declined by $233 million. However, these figures do not reflect off-balance sheet obligations from above market power- purchase contracts. Prior to the acquisition by CPL, management intended to repay debt in order to achieve its capital structure target of 55% equity. Whether this goal remains is uncertain. At June 30th, the capital structure remained essentially unchanged.

Construction expenditures (excluding the allowance for funds used during construction) totaled approximately $315 million in 1998, compared to $387 million in 1997. These expenditures covered distribution lines and the construction of the Hines Energy Complex, a 500 mw gas-fired power plant that began operations in April, 1999. Going forward, the company estimates construction expenditures to total approximately $885 million from 1999 to 2001, over half of which relate to transmission and distribution expenditures. Production expenditures total $254 million, including three 100 mw Intercession City peakers scheduled for completion in December 2000. Internally generated funds will finance the capital expenditure program.

Florida Power Corporation

	1998	1997	1996	1995	1994
INCOME STATEMENT ($ millions)					
Revenue	2,648	2,448	2,394	2,272	2,080
Operating Expense	2,136	2,131	1,925	1,815	1,661
Earnings Before Interest, Taxes, Depr. & Amort.	859	644	793	750	681
Depreciation and Amortization	347	326	324	294	262
Earnings Before Interest & Taxes	512	318	468	456	420
Other Income	6	1	1	1	-0
Gross Interest Expense	136	117	98	104	108
Pretax Income	250	136	238	227	201
Income Taxes	140	70	136	130	115
Preferred Dividends	2	2	6	10	10
Net Income Available for Common Stock	249	134	233	217	191
Coverage Analysis					
EBITDA Interest Coverage	6.3	5.5	8.1	7.2	6.3
EBIT Interest Coverage	3.7	2.7	4.8	4.4	3.9
Pretax Interest Coverage	3.7	2.7	4.7	4.3	3.8
FFO Interest Coverage	6.0	5.2	6.6	6.1	5.7
(FFO-Gross Capital Expenditures) Interest Coverage	2.8	0.9	3.4	2.4	1.8
Fixed Charge Coverage	3.7	2.6	4.3	3.8	3.3
Earnings Analysis					
Operating Margin	14.0	10.1	13.9	14.4	14.7
Return on Equity	13.7	7.6	12.7	12.4	11.4
Return on Asset	5.0	2.7	5.5	5.1	4.5
Return on Capital	10.6	6.6	10.3	9.9	9.0
AFUDC % Net Income	6.8	7.2	3.2	3.4	5.7
BALANCE SHEET ($ millions)					
Cash and Equivalents	0	0	0	1	0
Net Plant and Equipment	3,630	3,650	3,517	3,609	3,669
Total Assets	4,928	4,901	4,264	4,285	4,284
Current Portion of LT Debt, Leases & Pref.	92	2	21	31	35
Short-Term Debt	47	180	4	0	55
Long-Term Debt	1,555	1,745	1,296	1,279	1,364
Total Debt	1,694	1,927	1,322	1,310	1,454
Preferred Equity	34	34	34	138	144
Common Equity	1,820	1,768	1,826	1,754	1,667
Total Capitalization	3,548	3,728	3,181	3,202	3,265
Tangible Capitalization (net worth)	3,548	3,728	3,181	3,202	3,265
Capital Structure					
Retained Earnings	816	763	821	761	724
Total Debt - Cash and Equivalents	1,694	1,927	1,322	1,309	1,454
Deferred Charges % Common Equity	45.2	42.6	16.0	6.4	6.0
STD + Curr. Portion of LTD, Leases & Pref. % Capitalization	3.9	4.9	0.8	1.0	2.8
Total Debt % Capitalization	47.8	51.7	41.6	40.9	44.5
Asset Composition					
Net Plant and Equipment % Total Assets	73.7	74.5	82.5	84.2	85.6
Investments % Total Assets	0.2	0.7	0.3	4.3	3.4
Current Assets % Total Assets	9.4	9.5	10.4	8.9	8.6
Deferred Charges % Total Assets	16.7	15.4	6.8	2.6	2.4

Florida Power Corporation

1994		1998	1997	1996	1995	1994
	CASH FLOW STATEMENT ($ millions)					
2,080	Funds From Operations	689	490	555	535	514
1,661	Preferred Dividends	2	2	6	10	10
681	Common Dividends	153	191	166	181	176
	Retained Cash Flow	534	298	384	345	328
262						
420	Gross Capital Expenditures	310	387	217	283	324
	Free Cash Flow	224	-89	166	61	4
-0						
108	Issuance of Long-Term Debt	144	448	0	0	0
201	Retirement of Long-Term Debt	-259	-21	-47	0	0
	Net Change in Long-Term Debt	-115	426	-47	0	0
115						
10	Retirement of Preferred Equity	0	0	-106	0	0
191	Net Change in Preferred Equity	0	0	-106	0	0
	Change in Working Capital	-73	67	64	-34	17
6.3	**Cash Flow Analysis**					
3.9						
3.8	FFO % Gross Capital Expenditures	172.2	77.0	176.6	121.6	101.3
5.7	FFO % Total Debt	40.7	25.5	42.0	40.9	35.3
	Total Debt / FFO	245.8	392.9	238.2	244.8	282.9
1.8	Total Debt / (FFO - Gross Capital Expenditures)	447.0	1,867.0	391.4	520.5	765.9
3.3						
	RCF % Gross Capital Expenditures	172.2	77.0	176.6	121.6	101.3
	RCF % Total Debt	31.5	15.5	29.0	26.3	22.6
14.7						
11.4	**Construction Analysis**					
4.5	Gross Capital Expenditures % Capitalization	8.7	10.4	6.8	8.9	9.9
9.0	CWIP % Common Equity	20.8	15.8	7.7	7.5	13.3
5.7						
	OPERATING STATISTICS					
	Market Analysis					
0						
3,669	Electric % Total Revenue	100.0	100.0	100.0	100.0	100.0
4,284						
	Residential % Electric Revenue	53.8	52.8	54.3	55.1	54.9
35	Commercial % Electric Revenue	23.0	23.2	22.4	22.7	23.3
55	Industrial % Electric Revenue	8.1	8.5	8.6	8.3	8.3
1,364	Wholesale % Electric Revenue	7.9	6.3	6.7	6.8	6.0
1,454						
	Residential % Kwh Sales	44.4	45.3	46.2	46.1	46.2
144	Commercial % Kwh Sales	26.8	27.8	26.4	26.6	27.5
1,667	Industrial % Kwh Sales	11.7	12.6	12.6	11.9	11.9
3,265	Wholesale % Kwh Sales	10.4	7.3	8.1	9.0	7.8
3,265						
	Residential Price per Kwh	8.6	8.6	8.4	8.4	8.2
	Commercial Price per Kwh	6.1	6.1	6.1	6.0	5.9
	Industrial Price per Kwh	4.9	5.0	4.9	4.9	4.8
724	Wholesale Price per Kwh	5.4	6.3	5.9	5.3	5.3
1,454	Total Price per Kwh	7.1	7.4	7.1	7.0	6.9
6.0						
	Competitive Position					
2.8	Fuel Per Mwhr	22.0	22.0	0.0	0.0	0.0
44.5	Non-Fuel Per Mwhr	3.3	3.3	0.0	0.0	0.0
	Investment Per Mwhr	9.2	9.2	0.0	0.0	0.0
	Total Cost Per Mwhr	34.5	34.5	0.0	0.0	0.0
85.6						
3.4						
8.6						
2.4						

Florida Power Corporation

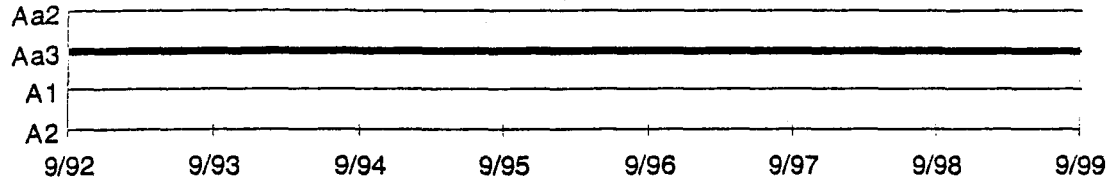
St. Petersburg, Florida, United States October 1, 1999

Ratings and Contacts

Category	Moody's Rating	Analyst	Phone
Issuer Rating	A1*	A. Tucker Hackett/New York	1.212.553.1653
First Mortgage Bonds	Aa3*	Scott Solomon/New York	
Senior Unsecured	A1*	Susan D. Abbott/New York	
Preferred Stock	"a1"*		
Commercial Paper	P-1*		

* Placed under review for possible downgrade on August 23, 1999

Rating History — Senior Secured



Operating Statistics

***Florida Power Corporation* (Statistics in bold type)**[1]
Peer Group Median (Statistics in light type)

	[2]1999		1998		1997		1996		1995		[3]5-Yr.Avg	
Revenue (US$ bil.)	**2.7**	1.2	**2.6**	1.1	**2.4**	1.1	**2.4**	1.0	**2.3**	[4]4.5	[4]6.2
Assets (US$ bil.)	**5.0**	2.9	**4.9**	2.8	**4.9**	2.7	**4.3**	2.8	**4.3**	[4]2.5	[4]3.0
Com. Equity (US$ bil.)	**1.8**	0.9	**1.8**	0.9	**1.8**	0.9	**1.8**	0.9	**1.8**	[4]2.3	[4]3.6
Op. Margin (%)	**14.2**	14.8	**14.0**	15.5	**10.1**	16.4	**13.9**	16.1	**14.4**	15.7	13.4
ROA(%)	**5.3**	3.7	**5.0**	3.6	**2.7**	3.7	**5.5**	3.8	**5.1**	3.7	**4.6**
ROE(%)	**14.2**	12.2	**13.7**	11.7	**7.6**	12.0	**12.7**	12.5	**12.4**	12.0	**11.6**
Div. Payout (%)	**133.6**	82.8	**61.7**	85.2	**142.0**	81.9	**71.2**	79.0	**83.2**	82.3	**90.0**
Pretax Int. Cov. (X)	**4.1**	3.5	**3.7**	3.4	**2.7**	3.5	**4.7**	3.4	**4.3**	3.4	**3.9**
Fxd. Chg. Cov. (X)	**4.0**	3.0	**3.7**	2.9	**2.6**	2.9	**4.3**	2.9	**3.8**	2.9	**3.6**
FFO Int. Cov. (X)	**6.5**	4.5	**6.0**	4.5	**5.2**	4.6	**6.6**	4.4	**6.1**	4.4	**5.9**
FFO % Total Debt	**41.6**	25.7	**40.7**	26.2	**25.5**	26.4	**42.0**	25.3	**40.9**	25.3	**36.9**
RCF % Gross CAPEX	**97.3**	114.0	**172.2**	124.6	**77.0**	128.8	**176.6**	113.5	**121.6**	113.8	**129.7**
Total Cap. (US$ bil.)	**3.6**	2.1	**3.5**	2.0	**3.7**	2.0	**3.2**	1.9	**3.2**	[4]2.3	[4]1.8
TD % Cap.	**47.4**	49.2	**47.8**	49.5	**51.7**	48.8	**41.6**	49.5	**40.9**	49.4	**45.3**
Pfd. Stk. % Cap.	**0.9**	5.5	**0.9**	6.0	**0.9**	5.7	**1.1**	4.6	**0.8**	5.3	**0.9**
Common % Cap.	**51.7**	45.0	**51.3**	44.9	**47.4**	45.4	**57.4**	45.1	**54.8**	45.0	**52.4**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale	Total
Revenue (US$ mil.)	1,424.6	608.9	214.4	207.9	2,648.2
Kwh(mil.)	16526	9999	4375	3864	37251
¢/Kwh	8.6	6.1	4.9	5.4	7.1
Regional Average	7.9	6.5	4.7	4.3	7.6

Competitive Position	Fuel	Non-Fuel	Investment	Total Cost	Regional Cost
$ per Mwhr.	22.03	3.29	9.15	34.47	34.76

[1] Competivie Position reflects 1997 figures. [2] For the 12 months ended June 30; Balance sheet items are as of June 30. [3] Five year average 1998-1994. [4] Five year compound annual growth rate.

Opinion

Rating Rationale

Florida Power Corporation (FPC) has retained a Aa3 senior secured rating for a number of years by virtue of its capable management, cost-cutting initiatives, supportive regulation, competitive rates, the state's vibrant economy, and limited in-state competition. However, the utility is exposed to nuclear risk through its 90% ownership of the Crystal River nuclear plant and to potential stranded costs from expensive power-purchase contracts and regulatory assets. In addition, ratings pressure originates in acquisition leverage issued by a new holding company created to purchase FPC.

Recent Events

Management announced in August the company will be sold to Carolina Power & Light Company (CP&L, rated A2 sr. sec.) to create the nation's 9th largest utility in terms of generating capacity. The new super regional utility will be headquartered in North Carolina.

New management expects merger-related synergies, driven by cost savings, to exceed $100 million per annum. Savings will result primarily from elimination of duplicate corporate and administrative programs and operating efficiencies. A substantial portion of these savings will be extracted from FPC.

In addition, revenue enhancements are likely from generation expansion and wholesale marketing opportunities. CP&L intends to use the FPC platform to build gas-fired generating plants in Florida.

Rating Outlook

Concern that financial pressure will result from the obligation to service up to $3.5 billion of acquisition leverage to be issued by a new holding company led Moody's to place the securities on review for potential downgrade.

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October 20, 2000

VIA FACSIMILE

Deborah D. Hart
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: In Re: Petition for Determination of Need
of Hines Unit 2 Power Plant
Docket No. 001064-EI

Dear DeDe:

I am enclosing FPC's responses to the requests Staff made during Mr. Crisp's deposition. (I previously provided our response to you over the telephone on the imputed debt issue.) As we discussed by phone, we are prepared to agree to treat these responses as a late-filed exhibit to Mr. Crisp's deposition. Again, please understand that we have agreed to do this as a courtesy to Staff without waiving our objection to out-of-time discovery requests.

Sincerely,

Gary L. Sasso

Enclosures

FPC Responses to Supplemental Staff Request

1. What would the Loss of Load Probability values be for Florida Power's system without Hines 2 for the ten year planning period?

Response: The requested values for the "Base Expansion Plan" and the sensitivity case are listed below. Since 2000 and 2001 are the same, the values start in 2002.

	Assisted LOLP With Hines 2 (Days/Year)	Assisted LOLP Without Hines 2 (Days/Year)
2002	0.0175	0.0175
2003	0.0145	0.0145
2004	0.0053	0.0545
2005	0.0123	0.1139
2006	0.0056	0.0564
2007	0.0228	0.1949
2008	0.0058	0.0562
2009	0.0240	0.2012

2. In the Base Expansion Plan resulting from the Integrated Resource Plan Update, Hines 2 was identified as the most cost effective addition to Florida Power's system. What would the revenue requirements be if peakers were chosen first?

Response: The cumulative present worth of revenue requirements for the least cost plan based on peaking capacity in November 2003 (instead of Hines 2) is $18,633 Million which is $148 Million higher than the revenue requirements for the Base Expansion Plan.

Background: As described in the Need Study, FPC's PROSCREEN system optimization assessments performed in support of the Hines 2 Need Determination and the 2000 Ten Year Site Plan compared the economics of a wide range of alternatives over the planning period. From all of the alternatives assessed, the least cost alternative plan that started with a peaker was a case which included an "F" frame peaker in 11/2003 followed with a mix of combined cycle plants and "EA" frame peakers. This plan is summarized below and a copy of the corresponding PROSCREEN Output Report is attached. (Please note that in-service dates for all of the additions listed are actually in November of the preceding year, providing for the winter peaks, in accordance with widely accepted reporting practices.)

Comparison of PROSCREEN Optimization Alternatives

	Base Expansion Plan	Alternative Expansion Plan
2001	IC P12-14	IC P12-14
2002		
2003		
2004	Hines 2	"F" Peaker
2005		Hines 2
2006	Hines 3	
2007		Hines 3
2008	Hines 4	Hines 4
2009		
2010	Hines 5	"EA" Peakers
CPWRR ($000)	$ 18,485,068	$ 18,633,246

3. Please provide a tabulation of system reserve margins in the Base Expansion Plan as well as sensitivities that remove Hines 2 and accommodate the 50 MW capacity divestiture planned as a result of the pending merger with CP&L.

Response: The Reserve Margin tabulation is provided below:

	Base Expansion Plan	Hines 2 Removed from Plan	Base Expansion Plan	Hines 2 Removed from Plan
	(Without Divestiture)		(With Divestiture)	
Winter 00/01	16.0%	16.0%	16.0%	16.0%
Winter 01/02	19.6%	19.6%	19.0%	19.0%
Winter 02/03	21.9%	21.9%	21.2%	21.2%
Winter 03/04	25.3%	18.4%	24.7%	17.8%
Winter 04/05	23.0%	16.3%	22.4%	15.7%
Winter 05/06	24.8%	18.2%	24.2%	17.6%
Winter 06/07	20.6%	14.2%	20.1%	13.6%
Winter 07/08	24.0%	17.7%	24.0%	17.7%
Winter 08/09	20.0%	13.9%	20.0%	13.9%
Winter 09/10	21.9%	15.9%	21.9%	15.9%

	Base Expansion Plan	Hines 2 Removed from Plan	Base Expansion Plan	Hines 2 Removed from Plan
	(Without Divestiture)		(With Divestiture)	
Summer 00	19.0%	19.0%	19.0%	19.0%
Summer 01	18.4%	18.4%	17.7%	17.7%
Summer 02	22.7%	22.7%	22.1%	22.1%
Summer 03	25.7%	25.7%	25.0%	25.0%
Summer 04	28.7%	22.0%	28.0%	21.3%
Summer 05	26.1%	19.5%	25.4%	18.8%
Summer 06	27.2%	20.8%	26.6%	20.2%
Summer 07	22.8%	16.6%	22.8%	16.6%
Summer 08	25.6%	19.5%	25.6%	19.5%
Summer 09	21.3%	15.3%	21.3%	15.3%

990325-EI
Ex 11
Adm

APPENDIX E

The Gulf Power Company Request for Proposals (RFP) follows and appears in its original state as issued.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 11
COMPANY/ WITNESS: Fla. Power Corp.
DATE: 10-26-00

August 21, 1998

Mr. Generic M. Respondent
The Company Name
The Company Address
City, State ZIPCODE

RE: Request for Proposals

Dear Mr. Respondent:

Gulf Power Company has determined that it will need additional firm capacity starting as early as the summer of 2002. The Company is seeking proposals for power supply from eligible Respondents to meet the Company's requirements for electric generation capacity as described in this Request For Proposal (RFP). Location, price, and reliability of the power offered will be major factors in the purchase decision. Creative supply side electric generation alternatives that provide exceptional value and economic benefits to Gulf Power and its customers will be appropriately considered in the proposal evaluations. The attached RFP document details the requirements and specifications that Respondents should meet and also outlines the information that should be provided in a proposal.

Respondents interested in submitting proposals under this solicitation should provide six completed copies and one original of the enclosed forms in both hardcopy and electronic format (3.5" floppy diskette). Any additional information that the Respondent deems necessary to evaluate the offer should be included along with the forms. All proposals must be received no later than 5:00 p.m., on Friday, October 16, 1998 at the following address:

Director, Bulk Power Supply, 15N-8181
Southern Company Services, Inc.
600 N. 18th Street
Birmingham, AL 35203
Phone: (404) 506-7250

Any portions of offers to be treated as confidential must be so identified.

Thank you for your interest in meeting the Company's power supply needs during this period.

Sincerely,

Garey C. Rozier
Director, Bulk Power Supply

REQUEST FOR PROPOSALS
August 21, 1998

Southern Company Services, Inc. (Southern), acting as agent for Gulf Power Company (The Company, or Gulf Power), issues this request for proposals (RFP) to acquire approximately 350-500 megawatts (MW) of supply-side resources beginning in the summer of 2002. The Company invites innovative proposals of various types of electric generation, including those representing base-load, intermediate, and peaking resources. Offers proposing new electric generating facilities located near Panama City, Florida will have a transmission cost advantage.

For purposes of this solicitation, the Company is interested in long term proposals lasting at least five years. In addition to "summer only" and "year round" offers, proposals reflecting various contract periods for the same resource will be considered. The Company is particularly interested in proposals that will offer exceptional value to the Company and its customers. Respondents are encouraged to be creative in crafting offers that will meet the Company's needs.

Proposals submitted pursuant to this solicitation will be considered and evaluated against each other and against any self-build options. Transmission and ancillary service studies will be conducted as appropriate to determine the total cost impacts. A short list will then be developed reflecting those Respondents whose proposals appear to demonstrate the most value (not necessarily the lowest price). Any Respondents so selected will be contacted for negotiations that may lead to a mutually-agreeable power purchase agreement. The Company naturally reserves the right to revise the capacity needs forecast at any point during the process or negotiations; any such change may reduce, eliminate, or increase the amount of power sought.

Respondents are asked to define the firmness of the capacity offered in their proposal in one of the following categories:

Level A: "First Call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
Level B: System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
Level C: Capacity that is backed by the Respondent's purchase(s).
Level D: "Financially firm" (replacement cost with no liquidated damages)
Level E: No specified generation resources

To help defray the cost for performing the evaluation of each proposal, Respondents are required to submit a check for $8,000.00 for each proposal. Changes in the site, output, electrical characteristics (generator ratings), or technology changes (i.e. simple cycle, combined cycle, cogen, primary fuel) will require the submission of a separate proposal and payment of the fee. A change in financial terms is not considered a proposal change.

The Company reserves the right, without qualification and at its sole discretion, to reject any, all, or portions of the proposals received for any creditable reason or for failure to meet any criteria, and further reserves the right without qualification and at its sole discretion to decline to enter into a power purchase arrangement with any Respondent. Respondents should be aware, that the following (if submitted) will be classified as non-responsive and will not be considered or evaluated:

- proposals offering non-firm capacity or energy;
- demand-side proposals;
- proposals offering capacity and/or energy that is generated by facilities owned by the operating companies of the Southern Company;
- proposals involving resources that would result in increasing demand on resources owned by the operating companies of the Southern Company; or
- incomplete, or non-specific offers.

Those who submit proposals do so without recourse against the Southern Company or any of its affiliates or subsidiaries for either rejection of their proposal(s) or for failure to execute a power purchase agreement for any reason.

Tentative Solicitation Schedule

EVENT	DATE	COMMENTS
Solicitation issued	August 21, 1998	
Proposals due	October 16, 1998	Proposals must be received or hand delivered to Southern's RFP Contact by 5:00 PM
Short-list determination	December 11, 1998	If applicable
Complete negotiations	March 1, 1999	If applicable
File contract(s) for certification with state public service commission	March 31, 1999	If applicable

The Company reserves the right to revise, suspend, or terminate this schedule at their sole discretion. Any changes to the schedule will be provided as appropriate.

RFP Contact

Proposals and questions should be submitted to Southern's RFP Contact:

Garey C. Rozier
Director, Bulk Power Supply, 15N-8181
Southern Company Services, Inc.
600 N. 18th Street
Birmingham, AL 35203
Phone: (404) 506-7250

Instructions for Completing Forms

1. All proposals should be submitted in the format shown in the RFP response form Attachment A. Additional information should be supplied (no particular format required) from the appropriate sections of Attachment B. Respondents should supply any additional information not included in these forms if such information may be needed for a thorough understanding and/or evaluation of the proposal.

2. Proposals must be signed by an officer of the Respondent.

3. A signed original and six (6) copies of the proposal forms and Respondent Questionnaire response should be submitted along with the electronic forms on a 3.5" floppy diskette. In the event of a discrepancy between the electronic forms and the hardcopy, the latter will be considered to be correct.

4. Prices and dollar figures quoted must be clearly stated as nominal for the year in which they occur. For non-nominal prices, the appropriate year for the stated dollars must be identified along with applicable escalation rates to be used for subsequent years.

5. Energy prices must be quoted as indicated in the forms as either $/MW-hour or as heat rates to be applied to the designated published fuel index. The fuel index preferred (but not required) is the Henry Hub, as published in *Gas Daily*. Fuel transportation costs and any adjustments for energy pricing must be included in all prices.

Confidentiality

The Company will take reasonable precautions and use reasonable efforts to protect any proprietary and/or confidential information contained in an offer provided that such information is clearly identified by the Respondent as proprietary and confidential on the page on which it appears. Such information may, however, be made available under applicable state and/or federal law to regulatory commission(s), their staff(s) or other governmental agencies having an interest in these matters. The Company reserves the right to release such information to agents or contractors for the purpose of evaluating the Respondent's proposals, but such agents or contractors will be required to observe the same care with respect to disclosure as Gulf Power and Southern. Under no circumstances will the Southern Company, its subsidiaries, agents, or contractors, be liable for any damages resulting from any disclosure before, during, or after the solicitation process.

Transmission Information and Requirements

1. If power is to be provided from resources outside the Southern control area, Respondents must provide a transmission map that shows the expected contract path(s) to be used to deliver power to the Southern Company transmission system. Additionally, the map should show any site-specific electric generation resource, together with a list of control areas to be crossed. For information concerning the

Southern Company transmission systems such as: availability data on specific transmission routes, existing constraints, and interconnection points, Respondents should contact:

John E. Lucas, Manager Transmission Services
Southern Company Services, Inc.
Post Office Box 2625
Birmingham, AL 35202

2. Respondents are responsible for paying all charges and/or costs for delivering power to the Southern Company transmission system. Respondents are to include in their quotes any and all such charges.

3. The costs of any transmission upgrades to the Southern Company transmission system associated with the proposal will be considered in the evaluation. The Company will conduct transmission impact studies, as appropriate, to determine these costs. It should be noted that proposals for new electric generating facilities located near Panama City, Florida will have a significant transmission cost advantage.

4. For new facilities, Respondents are responsible for all costs related to interconnection of the facility to the Southern Company transmission network. Respondents should include all costs associated with a generator step-up transformer and synchronization to the transmission network using a Respondent supplied generator breaker. Interface between the Respondent and the company will be the high side of the Respondent supplied generator step-up transformer.

Regulatory Provisions

1. It shall be the complete and sole responsibility of the Respondent to take all necessary actions to satisfy any regulatory requirements, including but not limited to all licenses and permits that may be imposed on Respondent by any federal, state, or local law concerning the generation, sale and/or delivery of the power. The Company will cooperate with the Respondent to provide information or such other assistance, as may reasonably be necessary for the Respondent to satisfy such regulatory requirements. The Respondent shall likewise provide such information to the Company.

2. The Respondent shall be completely and solely responsible for obtaining and paying for any and all emission allowances or any other regulatory allowances, fees, or taxes that may be required for the generation, sale and/or delivery of power.

3. The proposal is subject to approval and/or acceptance without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matter of this solicitation (including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission).

4. The following regulatory requirement applies to Respondents that propose to construct electric generation facilities in the state of Florida:

   Each participant in this solicitation must publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one quarter of a page and shall be published no later than ten (10) days after the date that the proposals are due. The notice shall state that the participant has submitted a proposal to build an electric power plant, and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

5. The Company's next planned generating unit addition, in the absence of alternate arrangements developed as a result of this solicitation, is a natural gas fired combined cycle installation of approximately 530 MW to be located in the Panama City, Bay County, Florida area. For a more detailed description of this planned unit, refer to Attachment C.

Performance Assurances

The Company will rely, in part, on this contracted power to meet the electric needs of its customers with dependable and reliable electric service. Suitable liquidated damages provisions will be required in any negotiated power purchase agreement. Performance guarantees and financial credit assurances may also be required of the Respondents, subject to negotiation, at the Company's discretion.

Minimum Requirements for Proposals

Proposals that meet these requirements will be considered responsive to this RFP. Non-responsiveness is a basis for rejecting an offer in the Company's sole discretion.

1. All forms, including both hardcopy and electronic versions, must be properly completed and returned to the RFP Contact, Garey C. Rozier, no later than 5:00 p.m. on Friday, October 16, 1998. Late or incomplete offers may be rejected in the sole discretion of the Company. Offers must remain open until at least March 31, 1999.

2. Complete information is needed to facilitate a timely evaluation. Issues that the Respondent prefers to negotiate later may be identified in the response; however, the Respondent must provide all explicit data requested on the forms. The Company may, at is sole discretion and judgment, choose to reject non-specific offers from further consideration.

3. Capacity offered must be firm. Proposals must clearly identify the firmness of the resource by the levels outlined in Attachment B. Proposals with no assurance of firmness or with no indication of the availability of actual firm resources may not be evaluated or considered.

4. Capacity offered will have the most value if fully dispatchable and available for first-call by the Southern Company system 24 hours per day and 7 days per week for the contracted period. Acceptable availability of the power when called for will be negotiated, with higher availability rates being preferred.

5. Proposal prices must include all costs that the Company will be expected to pay for the capacity and energy proposed. Attempts by the Respondent to increase prices will be grounds for rejection of the proposal.

6. No proposal less than 50 MW will be considered acceptable.

Proposal Evaluation

1. Proposals that are considered to be adequately responsive to the requirements of this RFP will be ranked and screened on price to eliminate those that are clearly not competitive before detailed modeling is performed. The majority of the evaluation will focus on price consideration. However, qualitative and non-price attributes will be considered in the overall screening process.

2. Proposals that pass the preliminary responsiveness screens will be further evaluated using appropriate production costing methods and models so that all reasonable cost impacts can be quantified.
   a.) Preference will be given to proposals that offer shorter unit commitment notification and greater dispatch flexibility.
   b.) Preference will be given to proposals that offer more contract flexibility features, such as call/put options, early-out provisions, and variable term pricing. The Respondent must separately identify any additional costs associated with these features.
   c.) It is the Respondent's responsibility to submit additional information related to the proposal if such information will materially improve the quality of its offer or the Company's understanding thereof.

3. An appropriate selection of the best proposals will be chosen as a short-list for negotiations. Short-listed proposals will be evaluated against each other and with any self-build options before the Company makes any commitments regarding the resource(s) to meet its identified needs.

4. The Company reserves the right to contact Respondents to request additional information on any aspect of any proposal.

Attachment A

Respondent's Company Name	
Maximum Capacity (MW)	
Minimum Capacity (MW)	
Proposal Start Month	
Proposal Start Year	20XX
Proposal End Month	
Proposal End Year	
Firmness Level	Enter Level A,B,C,D, or E (see RFP for Level descriptions)

Option Information if Applicable	
Option Premium Price ($/kW-month)	
Option Strike Price ($/kW-month)	
Option Strike Date	

Annual / Monthly	[redacted]	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	[redacted]	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	[redacted]	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Annual / Monthly	[redacted]	January	February	March	April	May	June	July	August	September	October	November	December
Capacity Price ($/kW-month)													
Firm Fuel Delivery Adder ($/kW-month)													
Fixed O&M ($/kW-month)													
Guaranteed Availability (%)													
Guaranteed Dispatch Price ($/MWh)													
OR													
Max. Heat Rate (MBTU/MWh)													
Min. Heat Rate (MBTU/MWh)													
Published Fuel Cost Index (Name)													
Fuel Delivery Adder ($/MWh or $/MBTU)													
Other Adder ($/MWh or ($/MBTU)													
Variable O&M ($/MWh)													

Attachment B

Respondent Questionnaire

All Respondents, as appropriate, must supply the following information:

1) Please provide documentation of your company's previous experience providing the proposed product.

2) Please provide the following financial and credit information for your company and for your parent company (if applicable):
   - Annual reports and Form 10-K for the past three years. If these documents are not available, then audited financial statements for the last three years will be accepted
   - Dunn and Bradstreet identification number
   - Credit rating of the Respondent's senior debt securities
   - Any additional documentation needed to allow the Company to determine the Respondent's financial strength and/or the strength of any corporate parents.

1) Present a detailed description of any security/credit instruments proposed by the Respondent to back its performance obligation.

2) Please describe whether or not this capacity has been offered in another RFP and under what conditions it would be released to serve this proposed sale.

3) Please describe the firmness category that best describes your offer and provide documentation that supports your ranking:
   Level A: "First call" rights on specific generating unit(s) or a system sale that is as firm as service to the Respondent's native load.
   Level B: System sale curtailable before the Respondent's native load and other wholesale obligations. (Respondent must be able to show capacity above other system needs.)
   Level C: Capacity that is backed by the Respondent's purchase(s).
   Level D: "Financially firm" (replacement cost with no liquidated damages)
   Level E: No specified generation resources

4) For a Level A proposal involving a specific unit, please provide the following information:
   A. Unit name, location, and schedule for construction (if applicable)
   B. Monthly Unit ratings
   C. Electrical Data as required in performing load flow and stability studies
   D. Equivalent forced outage rates (for existing units, calculated using the NERC equation for the last five years; for proposed units, as expected in operation.)
   E. Fuel type and source (primary and secondary) and heat rate (applicable if pricing is not quoted as a firm energy price)
   F. Guaranteed availability
   G. Maximum and minimum operating level
   H. Minimum run time per dispatch call
   I. Minimum contract quantity (energy) per year (summer and winter)
   J. Minimum down time
   K. Start up time from cold start and from hot start

L. Will the unit qualify for quick start capability? (less than 10 minutes)
M. Start up costs from cold start and from hot start
N. Descriptions (including models and manufacturers) of all of the major components
O. A detailed description of the fuel and water supplies
P. A thorough description of anticipated environmental impact and compliance.

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1) For a Level A, B, or C system sale and other sales, please provide the following information:
   A. A description of the system from which the power will be provided, including the name, location, peak hour load, the installed capacity, capacity mix and reserve projections (with and without the proposed capacity sale) during the proposal period.
   B. An explanation of any criteria under which the supply of system power might be curtailed or interrupted and the priority of this proposed transaction relative to all other supply commitments (existing and future) of the Respondent.
   C. For a Level A system sale, the proposed supply commitment is assumed to be at least as firm as the Respondent's service to its own native load. Please confirm this assumption. If this is not correct, please explain.
   D. For a Level B system sale, please provide evidence of capacity available above Respondent's existing load commitments. (i.e., Current IRP documentation)
   E. For a Level B or C system sale, please provide methodology by which the Respondent will ensure that sufficient capacity will be available to support the proposed sale.

1) Please describe the transmission arrangements that have been or will be made to provide the firm transmission capacity necessary to deliver the power to the Southern Company transmission network. If transmission agreements are not in place, please describe the status of the negotiations for those arrangements.

2) Please describe whether or to what extent the Respondent would assume the risk of a curtailment or interruption of transmission service.

3) Please explain what will be done to rectify any shortfalls if power is not available when needed. (Describe any penalties that would be associated with failing to deliver the purchase after it has been scheduled.)

4) Please describe any dispatch notice or scheduling requirements for this offer.

5) Please describe any minimum requirement for the numbers of consecutive dispatch hours or a minimum energy take for the contract term?

6) Please describe any other limitations on the use or availability of the power.

Attachment C – Planned Unit Data

These following data represent generic technology assessment estimates which Gulf Power utilizes in its planning and is provided for information purposes only. These planning estimates have not been refined by site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals.

1. A combined cycle generating unit to be located on the Company's existing Lansing T. Smith Electric Generating Plant property in Bay County, Florida.

2. Planned Size 532 MW

3. Commercial Operation of the facility is proposed to be June 1, 2002.

4. The primary fuel is natural gas. No secondary fuel source is anticipated.

5. The estimated total direct cost is $265,768,000 (installed 2002$).

6. The estimated annual levelized revenue requirement is $36,912,000 over 20 years.

7. The estimated annual value of deferral of this unit is $55.25/kW-yr (98$).

8. The estimated annual fixed O & M is $1,458,000(98$). The estimated variable O & M is $1.85/MWH(98$).

9. The estimated delivered fuel cost is $ 2.42/MMBtu (98$).

10. The following are estimates for:

Planned outage rate	5.8 %
Forced outage rate	3.2 %
Heat rate	6,527 Btu/KWH
Minimum load	284 MW
Ramp Rate	1 Hr. (Hot); 4 Hrs. (cold)

11. The estimated transmission interconnection costs associated with this unit are $ 15 million. This unit will also have an estimated $90 million dollars of gas lateral pipeline costs.

12. Air and water discharge permits will be required for this unit. It is the Company's plan to comply with all air and water quality standards of both the State and Federal governments.

13. The major financial assumptions in the development of these numbers were:

Construction escalation:	2.062 % per year
General escalation:	3.062 % per year
Fuel escalation:	Varies by year
Capital structure:	45 % debt @ 7.68 %
	10 % preferred @ 7.73 %
	45 % equity @ 13.5 %

DOCKET NO. 001064-EI
JOHN B. CRISP LATE FILED EXHIBIT NO. 12
CALCULATION OF CPWRR FOR HINES 2 ALTERNATIVE

Calculation of CPWRR for Hines 2 Option
Florida Power Corporation Need Determination

YEAR	Hines 2 Annual Revenue Requirement* ($000's)	Present Worth Hines 2 Annual Revenue Requirement ($000's)	Cumulative Present Worth Hines 2 Annual Revenue Requirement ($000's)
2003	6,870	6,325	6,325
2004	42,709	36,199	42,524
2005	41,417	32,318	74,842
2006	44,678	32,096	106,939
2007	40,157	26,559	133,498
2008	38,962	23,724	157,221
2009	43,769	24,536	181,757
2010	37,296	19,248	201,005
2011	36,629	17,404	218,409
2012	39,648	17,343	235,752
2013	35,494	14,294	250,045
2014	33,886	12,563	262,609
2015	39,588	13,513	276,121
2016	35,124	11,037	287,158
2017	34,385	9,948	297,106
2018	37,980	10,116	307,222
2019	32,851	8,055	315,277
2020	31,223	7,049	322,326
2021	38,910	8,087	330,413
2022	33,271	6,366	336,779
2023	32,032	5,643	342,421
2024	37,525	6,086	348,507
2025	31,632	4,723	353,230
2026	29,913	4,112	357,341
2027	28,956	3,664	361,006
2028	21,790	2,539	363,544
	Additional CPWRR for Panda:		66,279
	Ratepayer Benefit with Hines 2:		18%

* Note: From Line 7 on H2_2004.xls provided in response to PSC Staff Production of Documents Request 1. As noted on H2_2004, "Fuel Pass Thru Revenues" (Line 8) are not included.

Discount Rate: 8.62%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO 12
COMPANY Crisp
DATE 10-26-00

EXHIBIT AST-1: RESUME OF ALAN S. TAYLOR

AREAS OF QUALIFICATION

Competitive bidding resource selection, integrated resource planning, utility restructuring, risk assessment, market analysis and strategic planning

EMPLOYMENT HISTORY

- Vice President, Global Energy Business Sector, PHB Hagler Bailly, Inc., Boulder, CO, 2000-present
- Principal, Economics & Analytics Group, PHB Hagler Bailly, Inc., Boulder, CO, 1997-1999
- Senior Consultant, Law & Economics Group, Hagler Bailly Consulting, Inc., Boulder, CO, 1995-1997
- Senior Associate, Utility Services Group, RCG/Hagler Bailly, Inc., Boulder, CO, 1991-1995
- Summer Intern, Pacific Gas and Electric Company, San Francisco, CA, 1990
- Graduate Student Research Associate (part-time), Lawrence Berkeley Laboratory, Berkeley, CA, 1989-1991
- Senior Consultant, Energy Management Associates, Atlanta, GA, 1983-1988
- Undergraduate Research Associate, MIT Resource Extraction Laboratory, Cambridge, MA, 1982
- Summer Intern, Baltimore Gas and Electric Company, Baltimore, MD, 1980

EDUCATION

- Walter A. Haas School of Business, University of California at Berkeley, MBA, Valedictorian, Corporate Finance, 1991
- Massachusetts Institute of Technology, BS, Energy Engineering, 1983

PROFESSIONAL EXPERIENCE

- Managed the development of market price forecasts under electric utility industry deregulation.
- Conducted competitive bidding project evaluations for conventional generating resources, renewable facilities, and off-system power purchases.
- Assisted in contract negotiations with shortlisted bidders in utility resource solicitations.
- Managed the technical and economic appraisal of cogeneration facilities.
- Performed financial modeling of electric utility bankruptcy workout plans.
- Trained and assisted many of the nation's largest electric and gas utilities in their use of operational and strategic planning computer models.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO 13
COMPANY/ WITNESS: Taylor
DATE 10-26-27-00

SELECTED PROJECTS

1999- **Supply-side Resource Solicitation**
pres. Client: Public Service Company of Colorado

Assisted in the development of PSCo's resource solicitation for new supply-side resources for 2002-2017 and managed the evaluation of proposals. Mr. Taylor and the evaluation team reviewed and modeled over four dozen proposals for supplies from existing and new generation resources in the Rocky Mountain region. The evaluation incorporated not only the contracted costs associated with each proposed resource but also the likely transmission infrastructure investments that specific portfolios of resources might require. The evaluation team supplemented a detailed PROVIEW-based resource optimization analysis with a sophisticated post-processing methodology to incorporate this and other additional factors.

1999- **Solicitation for New Resources**
2000 Client: MidAmerican Energy

Reviewed MidAmerican's solicitation for new power supplies for the 2000-2005 resource-planning period. Mr. Taylor managed a team of individuals who performed a parallel evaluation of MidAmerican's analysis of responses to the utility's request for proposals (RFP). Mr. Taylor studied the challenges that MidAmerican encountered during negotiations and rendered an opinion on the fairness and appropriateness of MidAmerican's actions. He filed testimony before the utility regulatory commissions in Iowa, Illinois, and South Dakota.

1999- **Evaluation of New Resources**
pres. Client: Florida Power Corporation

Helped prepare the FPC's RFP for long-term supply-side resources and assisted in the evaluation of responses. Mr. Taylor oversaw the review of FPC's computer simulations (in PROVIEW and PROSYM) of the proposals that were received. The PHB Hagler Bailly team also evaluated the proposals by using a response surface model to approximate the results that might be produced in the more detailed simulations.

1998- **Evaluation of New Resources**
pres. Client: Public Service Company of Colorado

Assisted the evaluation of proposals for PSCo's near-term 1999 resource additions and managed the complete third party evaluation of proposals for resources in the 2000-2007 time frame. Such resources included third-party facilities and power purchases, as well as company-sponsored interruptible tariffs. Mr. Taylor assisted with the development of the request for proposals and

oversaw the evaluation of all responses. He and his team monitored subsequent negotiations with shortlisted bidders. Mr. Taylor testified before the Colorado Public Utilities Commission on the fairness of the solicitation and the results of the evaluation.

1997- **Evaluation/Negotiation of Transmission Interconnection Solicitation**
1999 Client: New Century Energies

Managed a solicitation for participation in a major transmission project interconnecting Southwestern Public Service (a Texas member of the Southwest Power Pool) and Public Service of Colorado (a member of the Western Systems Coordinating Council). As the first major inter-reliability-council transmission project in the era of open access, FERC required that SPS and PSCo solicit third-party interest in participation. This project required the development of an RFP and evaluation of responses for both equity participation and long-term transmission service for over 21 alternative high-voltage AC/DC/AC transmission projects. The evaluation has focused on the costs and intangible risks of different transmission alternatives relative to the benefits and savings associated with increased economy interchange, avoided future generating capacity, and reductions in single-system spinning reserve and reliability requirements.

1996- **Evaluation/Negotiation of All-Source Solicitation**
1997 Client: Southwestern Public Service

Managed the evaluation of a broad array of responses to an all-source solicitation that was issued by Southwestern Public Service (SPS). Resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads were proposed. The evaluation entailed scoring the proposals for a variety of price and nonprice attributes. Hagler Bailly was retained to assist Southwestern in its negotiations with the bidders and to perform the detailed evaluation of the best and final offers.

1996- **Risk Assessment for 1,000-MW Solicitation**
1997 Client: Seminole Electric Cooperative

Managed the review and assessment of risks associated with responses to a 1,000-MW solicitation that was issued by Seminole Electric Cooperative. The evaluation entailed reviewing selected proposals' financial feasibility, performance guarantees, fuel supply plans, O&M plans, project siting, dispatching flexibility, and bidder qualifications.

1997 **Analysis/Testimony Concerning Louisville Gas & Electric's Fuel Adjustment Clause**
Client: Kentucky Industrial Utility Customers

Performed a detailed examination of Louisville Gas & Electric's (LG&E) fuel adjustment clause and identified misallocated costs in the areas of transmission line losses and purchased power fuel costs. Mr. Taylor also critiqued LG&E's rate adjustment methodology and recommended closer scrutiny of costs associated with jurisdictional and non-jurisdictional sales. Mr. Taylor

testified before the Kentucky Public Service Commission and presented the findings of his analysis.

1997 **Analysis/Testimony Concerning Kentucky Utilities' Fuel Adjustment Clause**
Client: Kentucky Industrial Utility Customers

Performed a detailed examination of Kentucky Utilities' fuel adjustment clause and recommended more appropriate allocations of costs among jurisdictional and non-jurisdictional customers. Particular emphasis was placed on inter-system sales (and the line losses associated with such sales), purchase power fuel costs, the correct determination of jurisdictional sales. Mr. Taylor testified before the Kentucky Public Service Commission and presented the findings of his analysis.

1995 **Development of All-Source Solicitation RFPs**
Client: Southwestern Public Service

Managed the development of five RFPs that solicited resources in the areas of conventional supply-side generation, renewable resources, off-system transactions, DSM, and interruptible loads. The RFPs were issued by SPS as part of an all-source solicitation to identify resources that may be competitive with two generation facilities that SPS intended to develop.

1995 **Environmental Compliance Analysis**
Client: Western utility

Performed a confidential detailed environmental analysis that involved executing hundreds of production simulations of the client utility's system (using PROSCREEN II) to analyze SO_2, NO_x, and particulate reductions associated with different fuel-switching, capital investment, and retirement scenarios.

1994-1996 **Implementation of Continuous Emission Monitoring Regulations**
Clients: Various

Assisted over 80 utilities in ensuring their compliance with the CAAA's continuous emission monitoring (CEM) regulations (40 CFR Part 75). Using *75check*, Hagler Bailly's CEM quality assurance software system, the project team analyzed the electronic data reports that utilities must file with the U.S. EPA on a quarterly basis. These reports contain detailed hourly emissions information for every CAAA-affected plant and serve as the foundation for the SO_2 emission allowance market.

1994 **Evaluation of Big Rivers' Clean Air Act Compliance Plan**
Client: Kentucky Industrial Utility Customers

Performed a detailed analysis of Big Rivers Electric Corporation to determine the appropriate SO_2 emission reduction strategy that the utility should undertake to comply with the 1990 Clean Air Act Amendments (CAAA). The utility's historical operations were studied and dozens of hourly production cost simulations of Big Rivers' utility system were performed to assess the operational and economic impacts of different CAAA compliance strategies. Risk/sensitivity analyses were undertaken to determine the affects of varying assumptions of fuel prices, capital costs, and operating and maintenance costs. Mr. Taylor testified before the Kentucky Public Service Commission, endorsing the implementation of a specific incentive ratemaking methodology that would encourage the utility to minimize its compliance costs.

1994 **Fuel Procurement Audit of Columbia Gas Company**
Client: Public Utilities Commission of Ohio

Assisted in a fuel procurement audit of Columbia Gas Company in Ohio. The utility's gas transportation programs were scrutinized to ensure that full service customers were not subsidizing transportation customers. Cost allocation procedures were studied and marginal costs of service for transportation customers were examined. In addition, the audit included an investigation of how the utility calculated and monitored unaccounted-for-gas.

1994 **Development of Competitive Bidding RFP**
Client: Empire District Electric Company

Based on knowledge gained from the review of dozens of other utility RFPs, developed a combined-cycle resource RFP for Empire District Electric Company. The project team was responsible for the RFP's entire development, including the development of scoring provisions for price and nonprice project attributes.

1993 **Selection of Developer for 25 MW Wind Facility**
Client: Northern States Power

Evaluated ten bids that were received by NSP in a solicitation for the development of a 25 MW wind facility in Minnesota. The proposals were scored and ranked through a point-based evaluation system that was developed prior to the solicitation. The scoring involved an assessment of operational and financial feasibility, power purchase pricing terms, construction schedules, and community acceptance issues.

1993 **Competitive Bidding Design**
Client: Northern States Power

Assisted NSP in the utility's effort to design a generic competitive bidding RFP that could be issued for a variety of generation resources. Two dozen RFPs from other utilities were reviewed to determine the appropriate weights and mechanisms that should be used to score various project attributes.

1993 **Evaluation of 500 MW Supply-Side Solicitation**
Client: San Diego Gas & Electric

Assisted in the evaluation of 15 bids that were received from a 500 MW solicitation for power by SDG&E. The utility wanted to determine whether or not there were less expensive alternatives to the implementation of its plan to repower one of its own units. The 15 projects represented over 4,000 MW. The bids were evaluated using extensive production costing modeling, in which over 1,000 model runs were performed to evaluate each bid under a variety of scenarios.

1992-1993 **Integration of DSM Programs into Utility IRP Filing**
Client: Public Service Company of Colorado

Assisted utility in DSM modeling and IRP optimization using PROSCREEN II/PROVIEW. A data transfer system was designed to translate DSM program information from various utility departments. Simulations were performed to assess the cost-effectiveness of different demand- and supply-side options.

SELECTED PUBLICATIONS AND PRESENTATIONS

"Ancillary Services, A Market Unto Itself" Financial Times Energy Conference: Navigating the New Transmission Roadmap Under FERC Order 2000, June 2000.

"Forecasting Ancillary Service Prices," Infocast Conference: How to Buy, Sell, and Price Ancillary Services in Competitive Markets, October 1999.

"Fundamentals of Electricity Deregulation," American Association of Petroleum Geologists/Electric Power Research Institute Conference, April 1999.

"The Coal/Natural Gas Balance in a Reconfigured Utility Industry," American Bar Association Conference on Electricity Law and Regulation, February 1998.

"Asset Divestitures in the Deregulating Power Markets," Hybrid U.S. Power Market Conference, February 1998.

Modeling Renewable Energy Resources in Integrated Resource Planning, D. Logan, C. Neil, and A. Taylor, National Renewable Energy Laboratory, May 1994.

Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowances, K. Rose, M. Harunuzzaman, and A. Taylor, The National Regulatory Research Institute, December 1993.

"Risk Management Under the 1990 Clean Air Act Amendments: A Study of Emissions Allowance Reserves," Electric Power Research Institute, November 1993.

"Regulatory Accounting for Acid Rain Compliance Planning," 8th Biennial Regulatory Information Conference, September 1992.

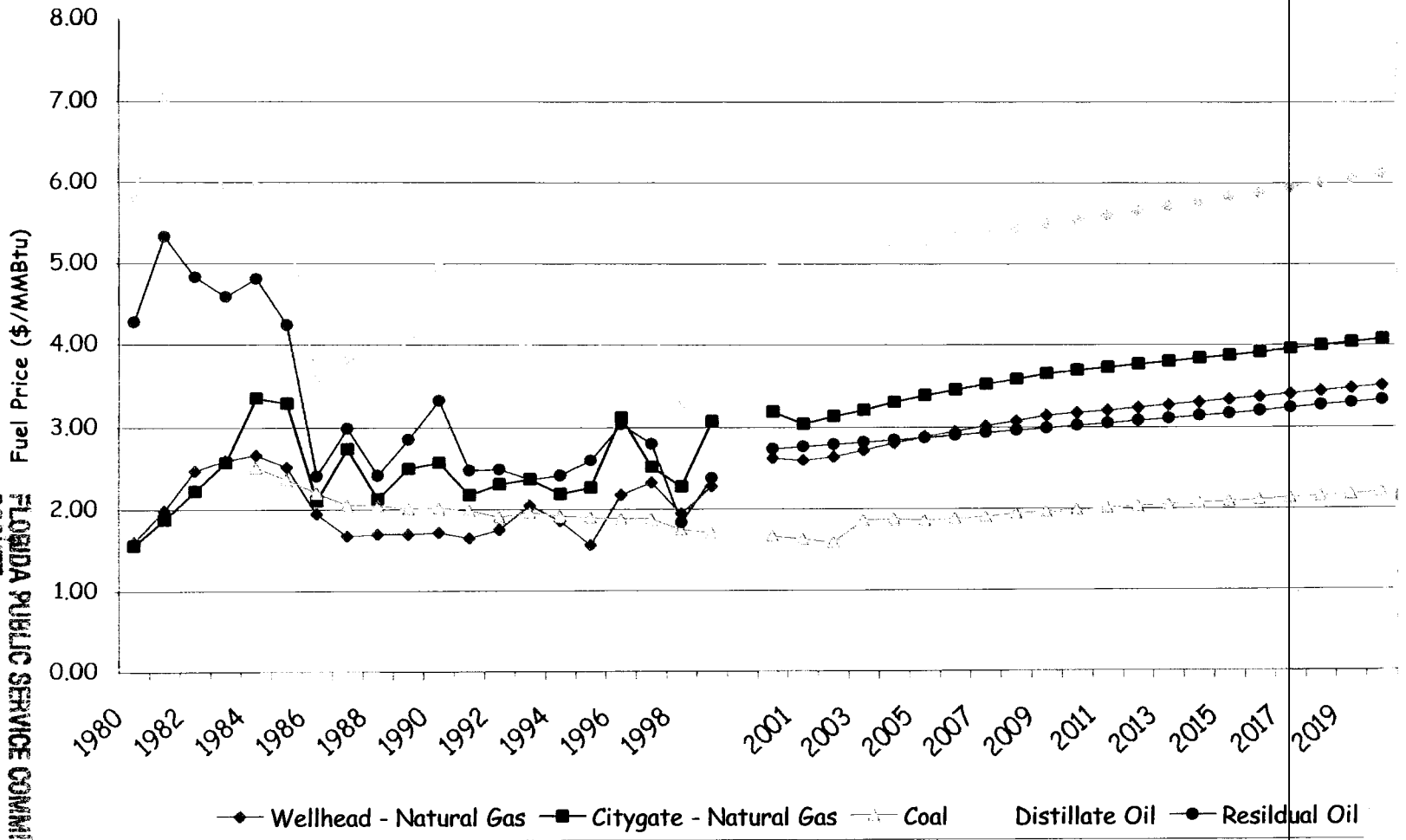
"A Seminar on the Techniques and Approaches to Integrated Resource Planning," Hawaii Public Utilities Commission, September 1992.

"A Comparison of the Uranium and Emissions Allowance Markets," A. Taylor and M. Yokell, Electric Power Research Institute, February 1992.

"State Regulation of Utility Compliance Plans and Its Impact on the Emissions Allowance Marketplace," 103rd National Association of Regulatory Utility Commissioners Annual Convention, November 1991.

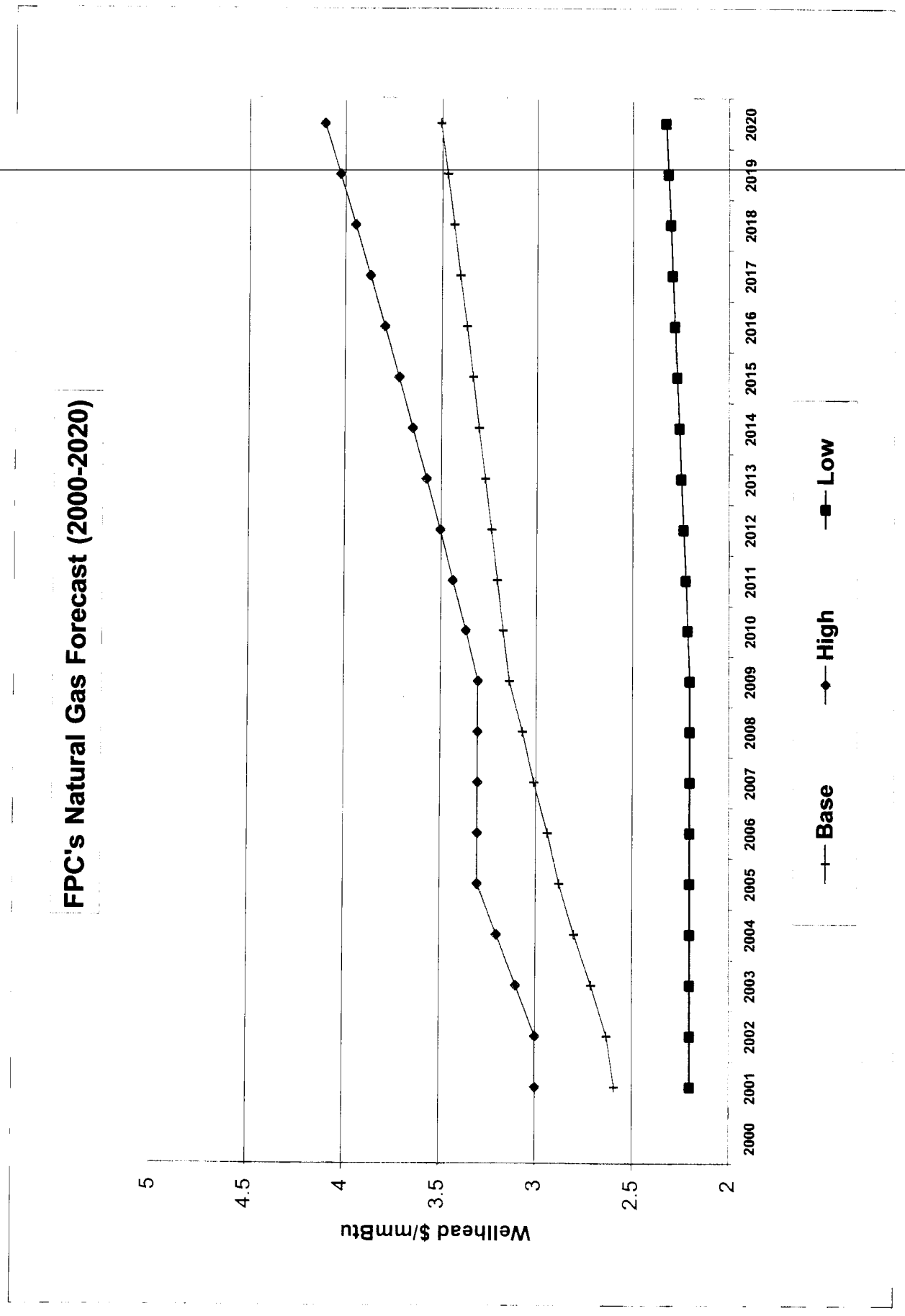
"Repowering and Site Recycling in a Competitive Environment," A. Taylor and E.P. Kahn, Lawrence Berkeley Laboratory, March 1991.

Florida Power Corporation
Fuel Price History and Forecast

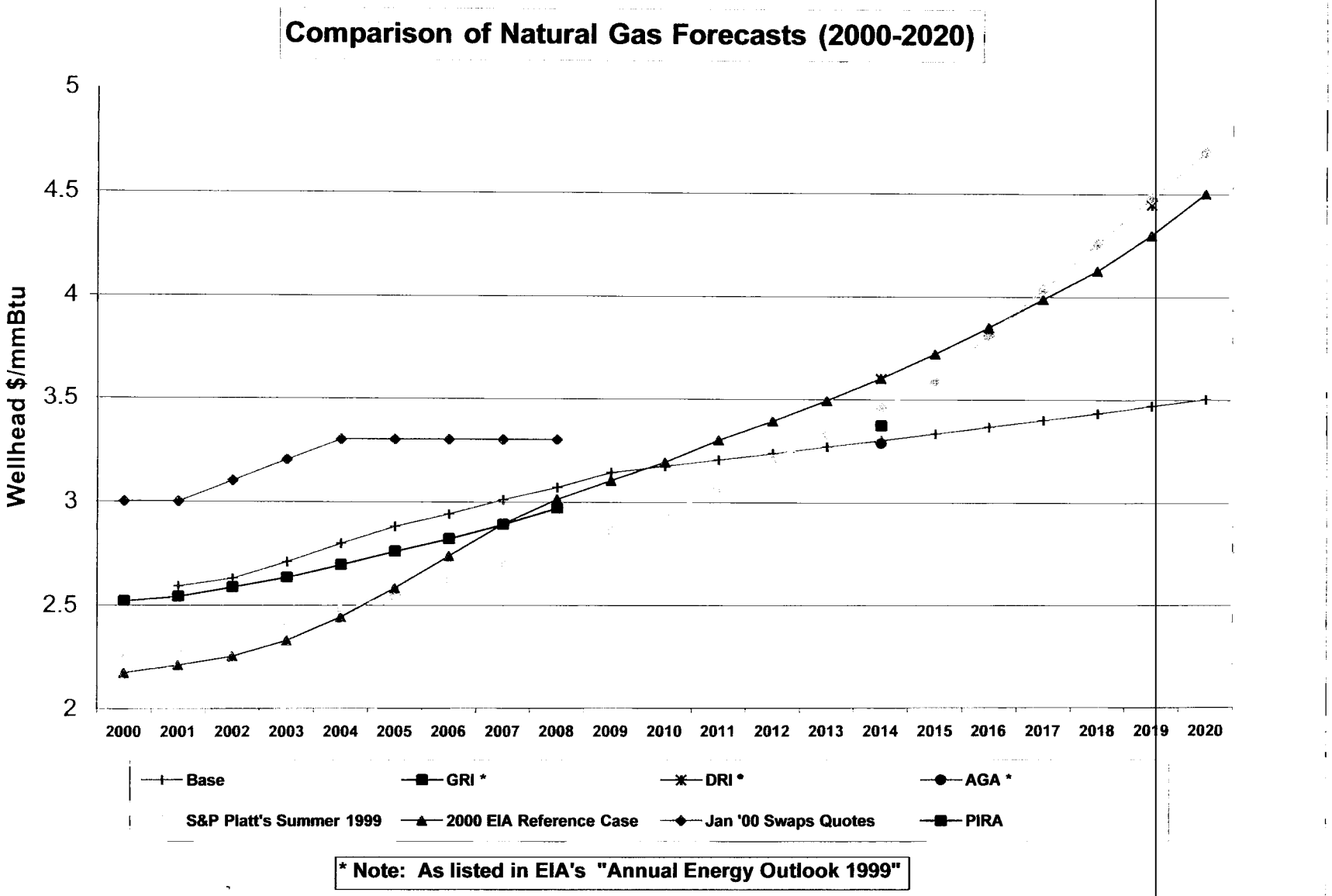


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 20070001-EI EXHIBIT NO. 14
COMPANY/ WITNESS: Nickerson 10-26-07
DATE:

RDN-1


FPC's Natural Gas Forecast (2000-2020)
Wellhead $/mmBtu
5
4.5
4
3.5
3
2.5
2
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Base
High
Low

RDN-2


Comparison of Natural Gas Forecasts (2000-2020)
Wellhead $/mmBtu
5
4.5
4
3.5
3
2.5
2
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020
Base
GRI *
DRI *
AGA *
S&P Platt's Summer 1999
2000 EIA Reference Case
Jan '00 Swaps Quotes
PIRA
* Note: As listed in EIA's "Annual Energy Outlook 1999"

RDN-3

U.S. Gulf Coast Gas Resources

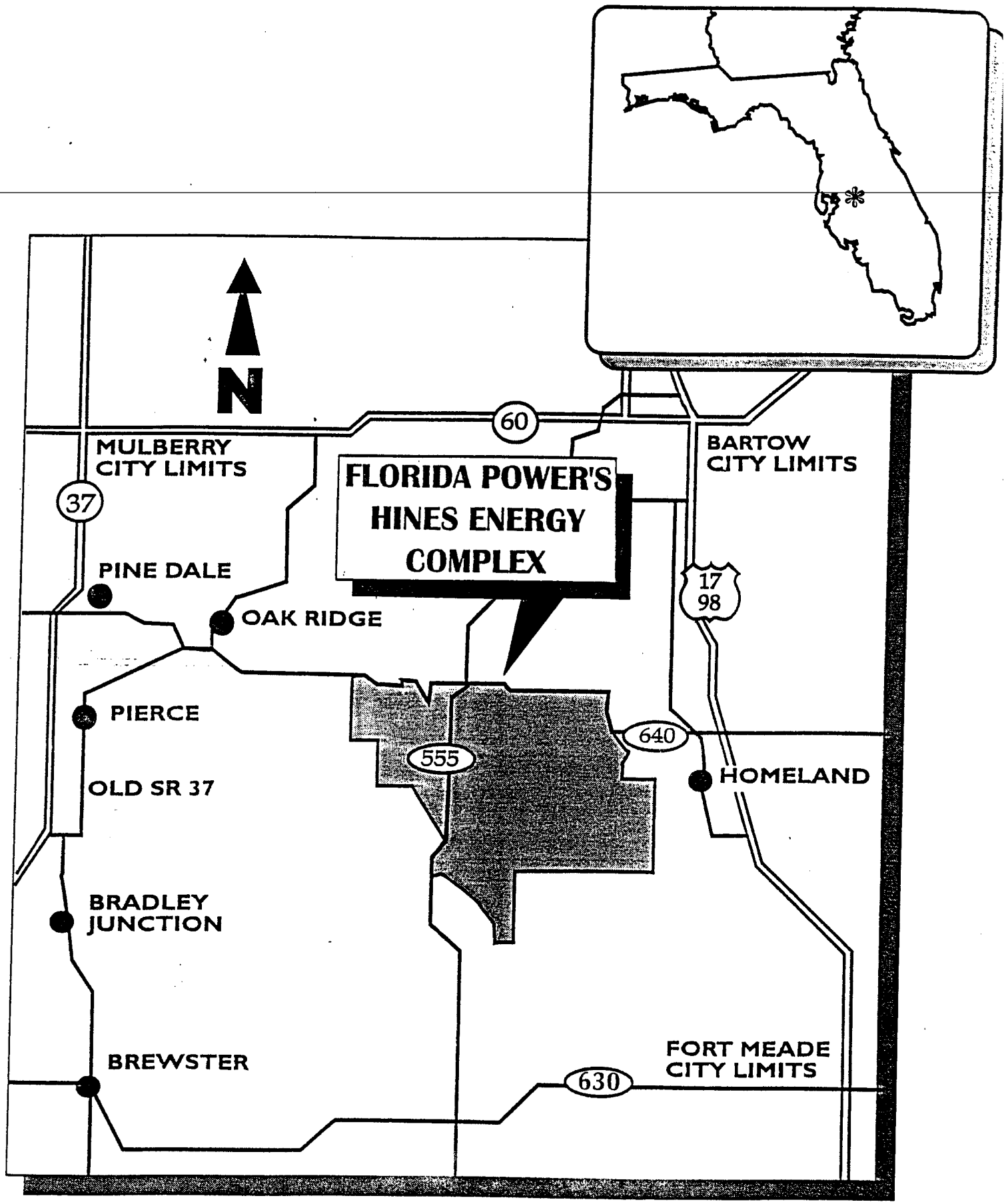
12-31-98 U.S. Gulf Coast Remaining Gas Resources
Proved Reserves + Most Likely Potential (Tcf)

Gulf Coast Onshore	Gulf Coast Offshore	Total
166	166	332

Sources: 12-31-97 EIA proved reserves,
12-31-98 PGC potential resources

RDN-4

	Florida Gas Transmission Company	Gulfstream Natural Gas System L.L.C.	Buccaneer Gas Pipeline Company	Cypress Natural Gas Company
Existing Capacity	1,500,000 MMBtu / Day	0 MMBtu / Day	0 MMBtu / Day	0 MMBtu / Day
Capacity in June 2001 (Planned in service)	1,700,000 MMBtu / Day FGT Phase 4	0 MMBtu / Day	0 MMBtu / Day	0 MMBtu / Day
Capacity in June 2002 (Planned in service)	2,130,000 MMBtu / Day FGT Phase 5	1,100,000 MMBtu /Day	0 MMBtu / Day	450,000 MMBtu / Day
Capacity in June 2003 (Planned in service)	2,130,000 MMBtu / Day + Phase 6	1,100,000 MMBtu / Day	900,000 MMBtu / Day	450,000 MMBtu / Day
Capacity Available for Hines 2 by June 2003	Yes	Yes	Yes	Yes
Connection to Hines	Existing	Planned	Planned	Through FGT Phase 6
Status	Phase 6 open season	Preliminary FERC approval	Preliminary FERC approval	Open Season
Expected In-service date	June 2003	June 2002	Spring 2003	June 2003
Key Issues	Sufficient customer support. Incremental rates.	Viability because of pending El Paso / Coastal merger. Sufficient customer support.	Sufficient customer support. Landowner opposition and environmental concerns.	LNG cost and availability risk. Depends upon FGT Phase 6. Sufficient customer support.
Connections	Anclote Avon Park Bartow DeBary Higgins Hines Intercession City Tiger Bay	Hines Intercession City Tiger Bay	Anclote Hines Intercession City	Anclote Avon Park Bartow DeBary Higgins Hines Intercession City Tiger Bay



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001064-EI EXHIBIT NO. 15
COMPANY/
WITNESS: Mayer
DATE: 10-26-22-08

EGM-1

STATE OF FLORIDA

OFFICE OF COMMISSION CLERK
ANN COLE
COMMISSION CLERK

Public Service Commission

* *

Docket No. : 001064-EI

Docket Title: Petition for Determination of Need for Hines Unit 2 Power Plant by Florida Power Corporation

DN 14238-00: FLORIDA POWER CORPORATION- HINES ENERGY COMPLEX- POWER BLOCK 2- SITE ARRANGEMENT – OVERALL PLAN (EGM-2)

[CLK NOTE: MAP PORTION OF TESTIMONY EXHIBIT CAN BE FOUND IN MAPS MICROFILM.]

STATE OF FLORIDA

OFFICE OF COMMISSION CLERK
ANN COLE
COMMISSION CLERK

Public Service Commission

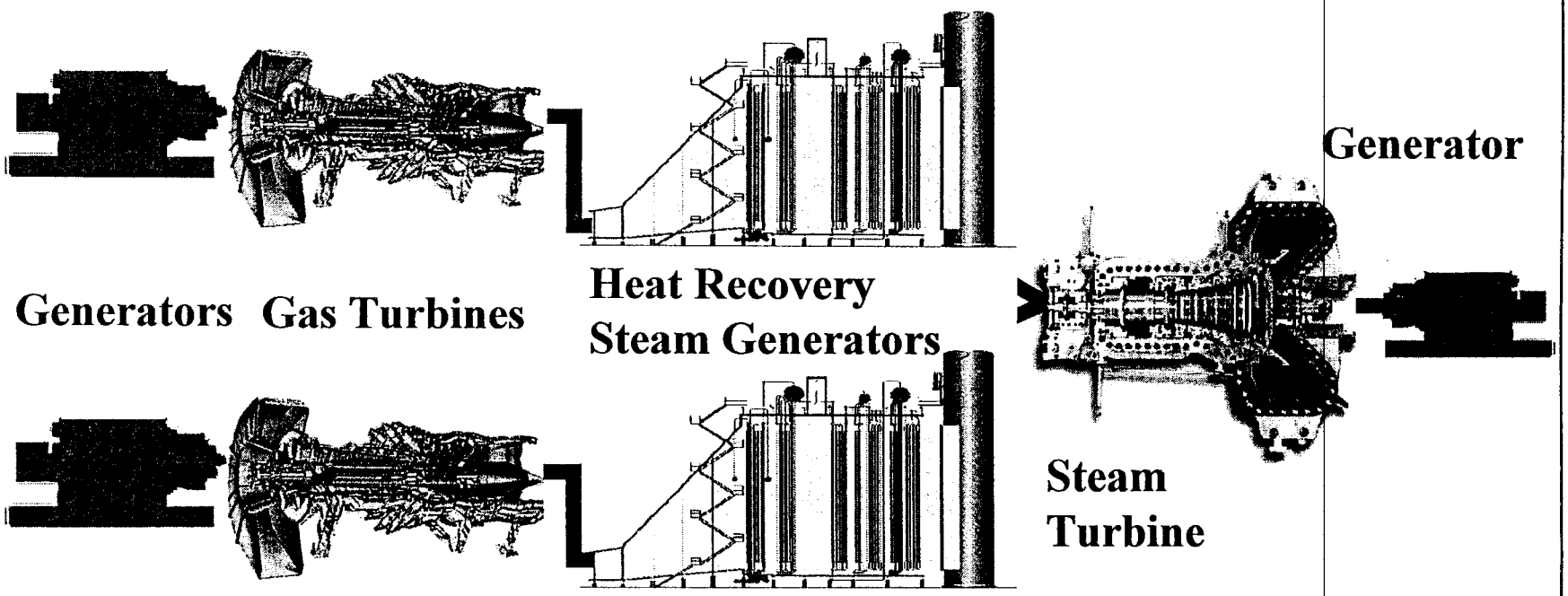
* *

Docket No. : 001064-EI

Docket Title: Petition for Determination of Need for Hines Unit 2 Power Plant by Florida Power Corporation

DN 14238-00: FLORIDA POWER CORPORATION- HINES ENERGY COMPLEX- POWER BLOCK 2- SITE ARRANGEMENT – POWER BLOCK AREA (EGM-3)

[CLK NOTE: MAP PORTION OF TESTIMONY EXHIBIT CAN BE FOUND IN MAPS MICROFILM.]



Florida Power
CORPORATION
HINES ENERGY COMPLEX

FIGURE 3.2.1-3
TYPICAL COMBINED CYCLE SCHEMATIC
(Two on One)

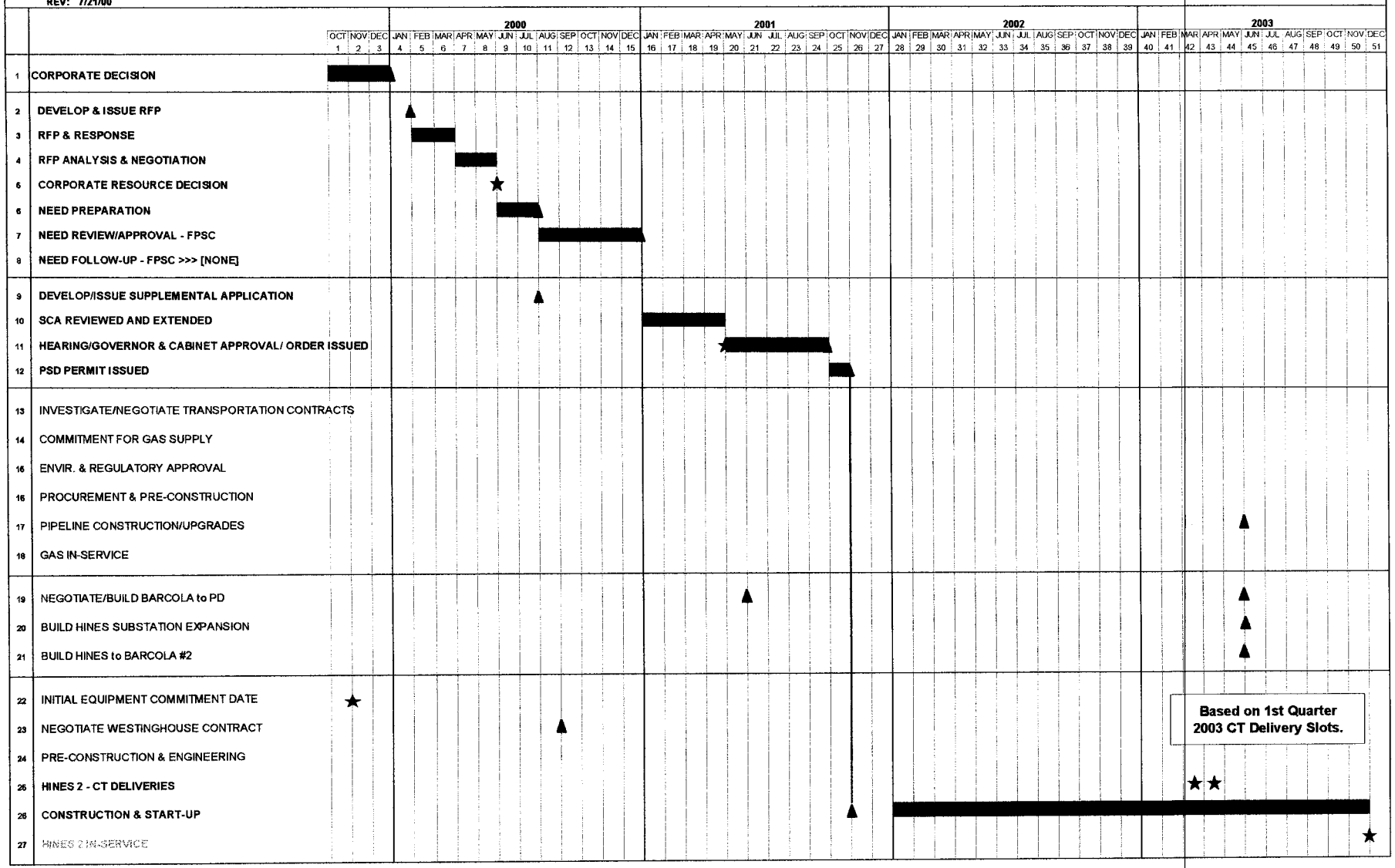
Cost Estimate Summary
Hines Unit 2

Equipment and Construction Contracts	$	157,262,000
Contingency		3,000,000
FPC Internal Costs		10,482,000
Need Hearing and Site Certification		2,415,000
Engineering Contracts		7,413,000
Interest During Construction (AFUDC)		17,028,000
Total Project Cost - Excluding Transmission		**197,600,000**
Transmission		3,201,000
Transmission Substation		2,405,000
Total Transmission Cost		**5,606,000**
Total Project Cost	**$**	**203,206,000**

Hines 2 Self-Build Option Schedule

REGULATORY / ENVIRONMENTAL / PIPELINE / TRANSMISSION / CONSTRUCTION
HINES 2 IN-SERVICE 11/03

REV: 7/21/00



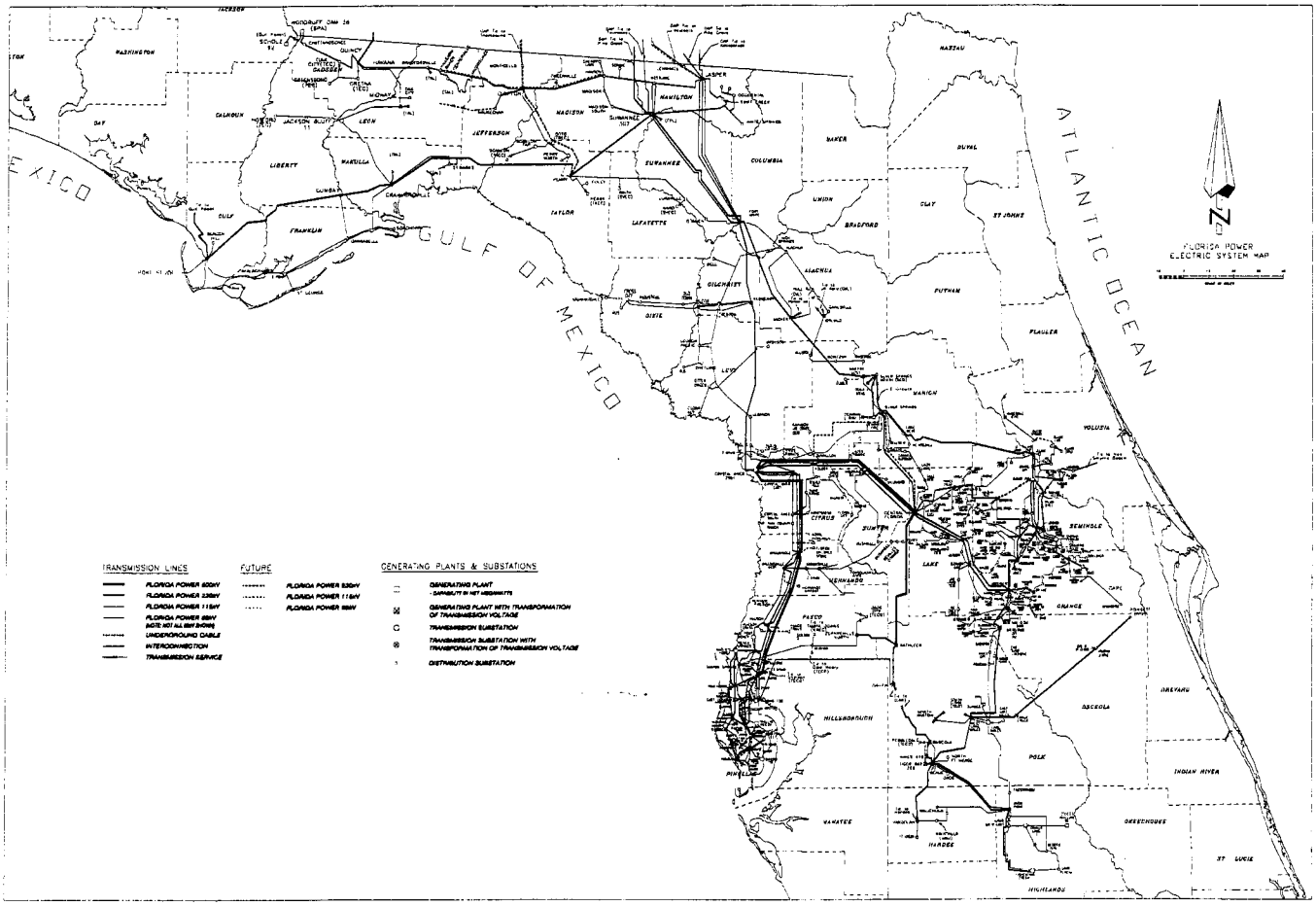
EGM-6

Work In Progress
Printed: 7/21/00

CONFIDENTIAL
Need Report: Sched_jul21.xls

CONFIDENTIAL

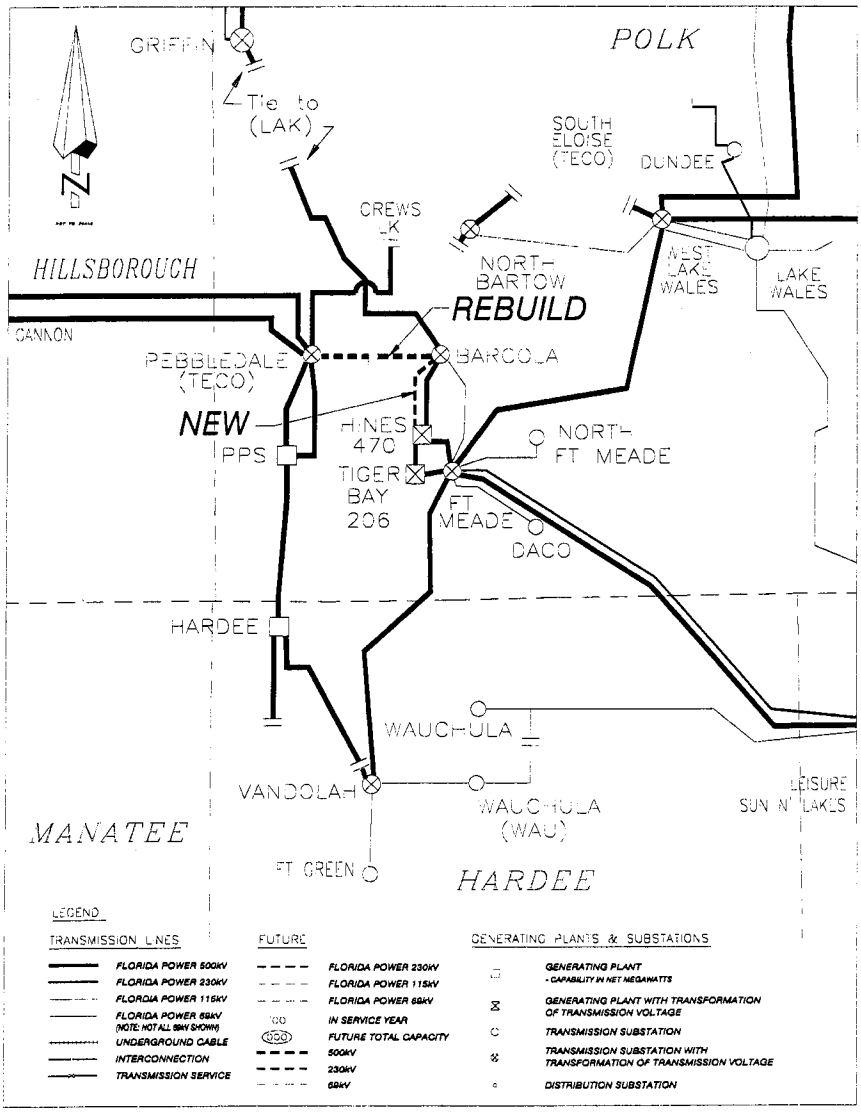
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001064-EI EXHIBIT NO. 16
COMPANY/
WITNESS: FPSC Staff
DATE: 10-26-07-08



FPCs Existing Generation Plants, Substations and Transmission Lines

Exhibit PMO-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 001064-EI EXHIBIT NO. 17
COMPANY/
WITNESS: O'Neill
DATE: 10-26 & 27-00



Transmission Network in the Vicinity of Hines Energy Complex
Exhibit PMO-2

a peninsular Florida perspective.

MR. HAFF: Well, from a peninsular perspective, most if not all the additions are going to be -- that are in the plan are gas-fired, combined cycled and combustion turbine, and even with the units that are shown in this plan, we're still looking at an eight percent winter reserve margin, and I guess we're just trying to figure out what happens if all of a sudden every utility wants to put these CTs in with 24 months of lead time and there's no gas to serve them. I mean, that's a critical concern we have about the, you know, out years of this plan.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 001064-EI EXHIBIT NO. 18
COMPANY/ WITNESS: Duke (Haff)
DATE: 10-26-01

a peninsular Florida perspective.

MR. HAFF: Well, from a peninsular perspective, most if not all the additions are going to be -- that are in the plan are gas-fired, combined cycled and combustion turbine, and even with the units that are shown in this plan, we're still looking at an eight percent winter reserve margin, and I guess we're just trying to figure out what happens if all of a sudden every utility wants to put these CTs in with 24 months of lead time and there's no gas to serve them. I mean, that's a critical concern we have about the, you know, out years of this plan.

MR. HERNANDEZ: Again, I believe it's more of an economic issue, a cost-effectiveness issue that needs to be addressed by different utilities.

Different utilities are going to have different options in terms of how they secure their gas contracts in order to run these units, but you've got to look at usage of the plant. If someone's looking at a very high load factor for a combustion turbine and combined cycle because that type of capacity is becoming much more efficient, they may be more inclined to firm up gas. If a system is looking at a relatively low utilization of that capacity, then for economic reasons it does not -- it makes less sense to go ahead and firm up the gas because you've got the option to run the unit on an alternative fuel, and to

the extent that you do not impact the capacity or the heat rate and it's basically a tradeoff on the cents per million on the fuel choice, it is an economic situation, not a reliability issue.

So to the extent that you've got short construction lead times and relatively shorter permitting times for the 9,000 megawatts or so of existing site that I've mentioned before and the fact that it really gets down to a utility-by-utility analysis, I'm not concerned about showing lower reserve margins in the out years.

Looking at the first five years in both the winter and summer, I believe we are -- we do have adequate supply resources, planned and proposed, for both winter and the summer, and we have the flexibility for each utility to address those issues down the road.

COMMISSIONER DEASON: What I hear you saying is that we don't need a ten-year site plan, we need a five-year site plan?

MR. HERNANDEZ: I'm not suggesting that.

COMMISSIONER DEASON: Well, what you're saying is we've got these projections for ten years, and it's unacceptable in the later years, but you're telling us, don't worry about it because we have enough sited area, locations, and we have short lead times, short construction times, so there's no need to worry about the later years.

As long as we've got things covered for five years, we're okay. That's what I hear you say. Now, if that's not what you're saying, correct me.

MR. HERNANDEZ: Generally that's correct, and the reason I think we're okay in saying that is, looking in years past where other generating plant that had longer lead times -- for example, a fossil fueled, base load coal unit has a much longer, eight to nine year, construction lead time, let alone nuclear. So I think, relative to individual utility planning, you've got to have a much longer look. You've got to look at different options and different alternatives under different scenarios, load growth assumptions, capital cost assumptions.

I guess what I'm saying is, given the fact that looking at the next five years and the expandability that this state has to drop new generating plant that's very efficient, absent of the gas availability issue, which I think is, again, utility specific, that we're okay to show in the long term smaller reserve margins than we have in the past.

To the extent that folks -- the economics turn around and folks are looking at technologies that have much longer lead times, that's why you want to look at a ten-year plan.

COMMISSIONER DEASON: Well, let's look at the

fifth year, and I'm looking at the winter reserve margin year 2001 and 2002, that winter. It indicates 11 percent with a minuscule amount of actual generation capacity above the projected winter peak demand. Is that acceptable?

MR. HERNANDEZ: Again, this is an aggregate, and it's difficult to assess what the impact would be on any individual utility, but --

COMMISSIONER DEASON: No. What you need to -- I'm going to be very polite, but what you need to realize -- you're sitting there saying, "Well, this is an aggregate and each individual utility needs to make economic decisions" and all that. That's fine and dandy, but this commission has the responsibility to make sure that there is adequate capacity for the entire state, not each individual utility, and it's not going to do a lot of good if one utility has adequate capacity and another doesn't and there's no way for there to be sharing of that capacity, and when there are brownouts and blackouts and things of that nature, that's where the rubber meets the road and that's where we have failed in our responsibility. Do you agree with that?

MR. HERNANDEZ: I agree that that is your responsibility.

COMMISSIONER DEASON: All right. Now, perhaps I interrupted, and I apologize. Is what is shown there at 11

percent acceptable in the year -- in the winter for 2001 and 2002?

MR. HERNANDEZ: I would say yes, and the reason why I would say yes are two-fold. Again, it reflects back that we have the potential -- in looking at what's happening with the market in Florida -- and, again, we're focusing on the winter peak. If you go back over the past -- let my divert just a second. If you go back over the past five years, we've had relatively mild winters. Except for the '95-'96 winter, we were pretty much 1,000 megawatts or so below forecasted peak, and again, just to reiterate what I've said before, this does not account for load diversity. This is a compilation, just a simple adding up of all the loads in the state. So you've got load diversity across the state that could account for a further reduction of four percent -- four to five percent, if you look at time of use and time of system peak. So that's another piece that --

COMMISSIONER DEASON: Now, let's talk about the load diversity. You're saying this is a compilation and that this is each individual's forecasted winter peak, and then when all added to -- actually when the winter peak occurs, it's probably not going to be as high as each individual utility's forecasted peak because there's going to be some diversity in that?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: Now, it seems to me that when we have a really severe crunch on energy demands in Florida is when a cold front comes through Florida and goes all the way down to Miami, and that's just about the entire state, and it's not going to be a situation where it's going to be warm in Fort Myers and cold in Miami. It's going to be cold in Fort Myers and cold in Miami, at least in the winter situation.

Now, I can understand in summer peaks, when you have a really hot spell, you're probably going to have some areas of the state that are going to have some thunder showers. They're going to be cooler and there's going to be less demand, but you don't have that in winter, unless there's something I'm missing. So please educate me.

MR. HERNANDEZ: Again, it's directly attributed to the weather, and if we have a cold snap that comes across the whole state, then I agree with you, but often that's not the case. It has happened in the past. Christmas '89, you know, that did happen. We had a cold snap over several days, and what happens is you do exactly what we're showing: You implement load control. You go to your non-firm load resources, and that's what we're showing, again, in that fifth year, that you're at that point where you're down to just -- well, it's less than one percent of

Exhibit CJC-1

December 1999

CHARLES J. CICCHETTI

PROFESSIONAL EXPERIENCE

1998-present	Jeffrey J. Miller Professor in Government, Business, and the Economy, University of Southern California;
1996-present	Co-Founder, Pacific Economics Group;
1990-1997	Adjunct Professor of Economics, University of Southern California;
1992-1996	Managing Director, Arthur Andersen Economic Consulting;
1991-1992	Co-Chairman, Putnam, Hayes & Bartlett, Inc.;
1988-1991	Managing Director, Putnam, Hayes & Bartlett, Inc.;
1987-1990	Deputy Director, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University;
1984-1987	Senior Vice President, National Economic Research Associates;
1980-1984	Co-Founder and Partner, Madison Consulting Group;
1979-1986	Professor of Economics and Environmental Studies, University of Wisconsin-Madison;
1977-1979	Chairman, Public Service Commission of Wisconsin, Appointed by Governor Patrick J. Lucey (member until 1980);
1975-1976	Director, Wisconsin Energy Office and Special Energy Counselor for Governor Patrick J. Lucey, State of Wisconsin;
1974-1979	Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972-1974	Visiting Associate Professor, Economics and Environmental Studies, University of Wisconsin-Madison;
1972	Associate Lecturer, School of Natural Resources of the University of Michigan;
1969-1972	Resources for the Future, Washington, D.C.;
1969	Ph.D., Economics, Rutgers University;
1968-1969	Instructor, Rutgers University;
1965	B.A., Economics, Colorado College;
1961-1964	Attended United States Air Force Academy.

EDITORIAL BOARDS

Journal of Environmental Economics and Management;
Energy Systems and Policy, Former Member;
Land Economics, Former Editor.

FLORIDA PUBLIC SERVICE COMMISSION
EXHIBIT
DOCKET NO. 001064-EI EXHIBIT NO. 19
COMPANY: Cicchetti
WITNESS:
DATE: 10-26-27-00

ADVISORY BOARDS

Alliance for Energy Security;
Association of Environmental and Resource Economics, Executive Committee, Former Member;
Association of Environmental and Resource Economics, Contributing Members Program Committee;
Center for Public Policy Advisory Committee, Former Member;
Department of Energy, Fuel Oil Marketing Advisory Committee, Former Member;
Graduate School of Public Policy at the University of California, Berkeley;
Institute for the Study of Regulation;
National Association of Regulatory Utility Commissioners, Executive Committee and Chairman of the Ad Hoc Committee on the National Energy Act, Former Member;
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