Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
Staff			
1		Exhibit List-Stip-1	Comprehensive Stipulated Exhibit List
2		Composite Stip-2	PEF's responses to Staff's First Set of Interrogatories (Nos. 5, 10, 12, 28, 29, 38, 43, and 49)
			PEF's responses to Staff's Second Set of Interrogatories (Nos. 52-57)
			PEF's responses to Staff's Third Set of Interrogatories (Nos. 60 and 61)
			PEF's responses to Staff's Fourth Set of Interrogatories (Nos. 62, 65-67, 68(including Attachment A), 72-75, 78, 81, 82, 85, 86, 88, 93, 94, 100-102, 104, 105, 110-114, 121(including Attachment G), 122-125, 128-131, 138, 139, 142, 145, and 147)
			PEF's responses to Staff's Fifth Set of Interrogatories (Nos. 148, 151-153, 159-161, and 163)
			PEF's response to Staff's Third Request for Production of Documents (No. 7)
3		Composite Confidential Stip-3	Transcript and exhibits of April 19, 2005, panel deposition of PEF witnesses Pamela Murphy, Robert Caldwell, Bruce Hughes, and Sam Waters
			PEF's responses to Staff's First Set of Interrogatories (Nos. 3, 11, 17-27, 30-35, 37, 42, 46, and 47)
			PEF's responses to Staff's Third Set of Interrogatories (No. 59)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 041414-EI EXHIBIT NO. 1
COMPANY/ FPSC Staff
WITNESS: Exhibit List Stip-1
DATE: 04-29-05

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
			PEF's responses to Staff's Fourth Set of Interrogatories (Nos. 64, 71(including Attachment B), 76, 77, 79, 83(including Attachments C, D, and E), 84, 87(including Attachment F), 95, 96, 99, 106, 107, 115-120, 132, 134, 136, 140, 141, 144, and 146)
			PEF's responses to Staff's Fifth Set of Interrogatories (Nos. 149-151, 154, and 162)
			PEF's responses to Staff's First Request for Production of Documents (Nos. 3 and 4)
			PEF's responses to Staff's Fourth Request for Production of Documents (Nos. 16, 17(only bates stamp 1015-1022), 23(only bates stamp 1063-1109 and 1277-1291), 28, 30, 31, 32, 35-37, and 41)
Testimony Exhibit List			
PEF			
4	Robert F. Caldwell	RFC-1	Visual Aid Map
5	Pamela R. Murphy	PRM-1	A Firm Gas Supply Contract with BG LNG Services, LLC for Hines Unit 4
6	Pamela R. Murphy	PRM-2	A Precedent Agreement for Firm Transportation with Southern Natural Gas Company
7	Pamela R. Murphy	PRM-3	Firm Gas Transportation Contracts with Florida Gas Transmission Company
8	Pamela R. Murphy	PRM-4	A Visual Aid Map
9	Pamela R. Murphy	PRM-5	Analysis of Gas Supply Alternatives on Comparable Volume Basis

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
10	Pamela R. Murphy	PRM-6	Analysis of Contracts Versus Current Market Option
11	Bruce H. Hughes	BHH-1	Map of Interstate Pipelines
12	Bruce H. Hughes	BHH-2	Southern Natural's Pipeline Project Timeline
13	Bruce H. Hughes	BHH-3	Aerial Photo of LNG Facilities
14	Samuel S. Waters	SSW-1	Graph of Historical and Projected Energy by Fuel Type for Peninsular Florida

EXHIBIT NO. ___________

DOCKET NO: 041414-EI

WITNESS: VARIOUS

PARTY: PROGRESS ENERGY FLORIDA

DESCRIPTION: COMPOSITE STIP 2:
1) PEF's responses to Staff's First Set of Interrogatories (Nos. 5, 10, 12, 28, 29, 38, 43, and 49);
2) PEF's responses to Staff's Second Set of Interrogatories (Nos. 52-57);
3) PEF's responses to Staff's Third Set of Interrogatories (Nos. 60 and 61);
4) PEF's responses to Staff's Fourth Set of Interrogatories (Nos. 62, 65-67, 68 (including attachment A), 72- 75, 78, 81, 82, 85, 86, 88, 93, 94, 100-102, 104, 105, 110-114, 121 (with Attachment G), 122-125, 128-131, 138, 139, 142, 145, and 147);
5) PEF's responses to Staff's Fifth Set of Interrogatories (Nos. 148, 151-153, 159-161, and 163); and
6) PEF's response to Staff's Third Request for Production of Documents (No. 7).

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 2
COMPANY/ FPSC Staff
WITNESS: Composite Stip-2
DATE 04-29-05

5. Please elaborate further on the circumstances that would implement Sections 3.6(1) and (2).

Answer:

A circumstance such as a force majeure event (e.g., hurricane or pipeline outage) that might limit the amount of gas the Seller can deliver to Buyer would cause the pricing structure, as outlined in Section 3.6 (1) or (2), to be invoked.

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Please refer to Exhibit PRM-2 (*i.e.*, Precedent Agreement By and Between Southern Natural Gas Company and Florida Power Corporation d/b/a Progress Energy Florida, dated December 2, 2004) to Pamela R. Murphy's December 20, 2004 pre-filed testimony for Interrogatory Nos. 10-13.

10. Please list and describe the types of FERC-approved generally applicable charges or surcharges contemplated by Part 1(e).

Answer:

A. 1/ Surcharges applicable to service under Rate Schedule FT.

Storage Cost Reconciliation Mechanism Volumetric Surcharge:	$ .003 applicable to each Dth transported
GRI Surcharge:	$ .000 applicable to Reservation Quantities of high load factor shippers and
	$ .000 is applicable to reservation quantities of low load factor shippers.
	$ .0000 applicable to each Dth transported.
ACA Surcharge:	$ .0019 applicable to each Dth transported.

12. Please describe PEF's actions to date and future planned actions to satisfy the conditions set forth in Part 5(b)(vi).

Answer:

Southern Natural has informed PEF in writing that PEF currently meets the credit requirements set forth in the Precedent Agreement and that no additional action is required at this time to meet the conditions set forth in Part 5(b)(vi).

28. For each alternative, please indicate the rate at which PEF discounted cash flows back to the present.

Answer:

Discount Rate used was 8.16%.

29. Please provide the reasons for the date selected in footnote (d).

Answer:

The analysis that is summarized in Exhibit PRM-5 to Pamela R. Murphy's December 20, 2004, pre-filed testimony is the same analysis relied upon by Progress Energy Florida management when it approved execution of agreements with BG LNG Services, LLC, Southern Natural Gas Company and Florida Gas Transmission System during the 3rd Quarter of 2004. The forward curve for HH as of 8/5/04 was the latest available at the time the analysis was prepared.

38. Please refer to page 6, lines 2 and 3 of Pamela R. Murphy's December 20, 2004, pre-filed testimony. Please indicate the degree of volatility that PEF has experienced in the "basis" adder for gas supplied from the Mobile Bay-Destin production zones.

Answer:

Over the past 5 years (2000 – 2004), volatilities of Transco Zone 4 Gas Daily prices have trended upward reaching a peak of 96.4% in 2003. During this 5 year period, volatilities at Transco Zone 4 have exceeded the volatilities at Henry Hub 3 out of the 5 years, implying an increase in the volatility of the basis. Probably more pertinent is the trending upward of the Mobile Bay-Destin production area basis (Transco Zone 4 minus Henry Hub) over this same time period.

43. Did PEF include the expected value of using its existing resources to "bridge the gap" when evaluating the cost effectiveness of the six proposals received in response to PEF's RFP for natural gas supply for Hines Unit 4?

Answer:

No, we do not expect a delay in the in-service date of the Cypress pipeline. Additionally, if a delay in the in-service date of the Cypress pipeline does occur, it is expected to be not more than a few months, the impacts of which would not materially alter the economics of the Cypress alternative relative to the other alternatives.

49. On page 11, lines 22-23, of the prefiled direct testimony of Pamela Murphy, filed December 20, 2004, short term alternatives for natural gas are referenced. What are these alternatives and how is short term defined?

Answer:

Short term is defined as the duration between May 1, 2007 and when the Cypress Pipeline service commences. Any delay in the in-service date of the Cypress pipeline, if it were to occur, is expected to be not more than a few months. Please see the response to Question #42 for the short-term alternatives referred to in the referenced testimony.

INTERROGATORIES

52. Are you aware of any state Commissions that have granted an investor-owned electric utility pre-approval of a long-term supply contract?

Answer:

In PSC Docket No. 970096-EQ, Order No. PSC-97-0652-S-EQ, the Florida Public Service Commission approved PEF's long-term gas supply contract with BP Energy (formerly Vastar Gas Marketing) associated with the Tiger Bay facility. This approval was part of the Commission's overall approval of PEF's purchase of the Tiger Bay facility, but in conjunction with that purchase, the Commission reviewed and approved the reasonableness and prudency of PEF's long-term gas supply contract with BP Energy. Additionally, Public Service Commissions from other states have, on numerous occasions, pre-approved long-term purchase power contracts that are similar, in principle, to long-term fuel supply contracts.

53. In the past ten years, has PEF entered into any long-term supply contracts? If so, please identify each contract arrangement including the length of the contract term. Have these contracts been approved by any regulatory body?

Answer:

PEF has entered into 2 long-term supply contracts within the past ten years, one with BP Energy (formerly Vastar Gas Marketing) and one with Virginia Power Energy Marketing (formerly Citrus Trading Corp.) for terms of 15-years and 20-years respectively. The Virginia Power Energy Marketing agreement also provides for long-term firm transportation. The BP Energy gas supply contract was approved by the Florida Public Service Commission in association with PEF's purchase of the Tiger Bay facility as noted in response to Interrogatory 52 above.

54. What, if any, safeguards are in place to protect the rate payer if an international LNG price develops in the coming years that is lower than the contract price that PEF is required to pay?

Answer:

No such "safeguards" specific to an international LNG price were needed in the operative contracts for the following reasons. The LNG price in the contract in this matter are tied to a Henry Hub price index and were negotiated between the parties based on the bids provided in the responses to PEF's request for proposals. Naturally, LNG suppliers desire to tie their prices to an index such as the Henry Hub to ensure that their gas receives market pricing, and PEF also desires such an index to ensure that the gas it purchases is reflective of the market delivery location for the gas in the United States. Tying gas prices to the Henry Hub index also affords PEF the ability to hedge future gas supplies in order to reduce price volatility and provide rate stability for its ratepayers. Accordingly, the prices in the supply contracts at issue are highly competitive and beneficial to PEF's ratepayers on a long term basis, irrespective of the possibility that there could conceivably be short-term future pricing fluctuations in the international LNG market, because, as noted above, those prices are reflective of the market in the United States location where PEF will actually take delivery of its gas.

To further explain, even if international LNG prices were facially lower than the contract prices, those international prices may be tied to the production source of the gas versus the delivery side of the sale to the customer. Under that type of pricing, additional costs, such as transportation costs from the international supply location to the domestic delivery point, would have to be considered, and there is no way to reasonably have "safeguard" provisions in contracts such as the one at issue to effectively deal with such unknown contingencies. That is why PEF and its suppliers agreed to a pricing mechanism that is reflective of the market delivery location for the gas in the United States.

55. If the Commission does not approve PEF's 20-year contract for LNG, will PEF be precluded from filing for cost recovery of the costs?

Answer:

PEF would not be precluded from filing for cost recovery of the costs should the Commission decline to approve in advance PEF's 20-year contract for LNG. However, PEF's LNG contract is conditioned upon the Commission's pre-approval of that contract, and PEF would exercise its contractual right not to move forward with any of the agreements if the Commission denied approval of the 20-year LNG gas supply contract.

56. Why should the Commission approve PEF's 20-year contract for LNG?

Response:

Answer:

The Cypress project at issue in this matter involves bringing a new source of fuel, specifically liquefied natural gas, into Florida. Unlike a "standard" natural gas pipeline from a nearby source of natural gas, an LNG project such as this one requires significant additional upfront capital investment from the supplier to build the natural gas pipeline LNG infrastructure (such as gas reserves and the associated production, a liquefaction plant, and LNG ships, which totals more than $1 billion).

As discussed in detail in PEF's pre-filed testimony, responses to the Staff's requests for production of documents, and responses to Staff's 1st set of interrogatories, PEF contracted with Southern Natural for firm transportation of the gas supply through an expansion of Southern's existing pipeline system to be built from Elba Island to a point of interconnection with the FGT pipeline in Clay County, Florida, and with FGT for transportation from the point of interconnection with Southern to the Hines Energy Complex. PEF's commitment to the Cypress LNG expansion project on the Southern Natural Gas Pipeline is approximately 40% of the overall Cypress project. Understandably, suppliers and transportation companies such as BG, Southern Natural, and FGT would not want to go forward with a "green field", capital-intensive project of this magnitude without some "front end" assurance that they will have long-term customers to make the project worthwhile and financially feasible. Similarly, companies such as PEF would not want to commit to any such project on a long-term basis without pre-approval from the Commission on the issues of reasonableness and prudency. In fact, our understanding is that Florida Power & Light is requiring respondents to its August, 2004 Request for Proposals for LNG supply and transportation to include conditions precedent in their respective bids for Commission pre-approval of any contract. Unlike smaller, shorter term or less complicated fuel supply and transportation arrangements that by their nature do not lend themselves to advance approval from the Commission, a long term capital-intensive project such as this one will not ever reasonably happen unless all parties in the project have advance assurances regarding their respective financial concerns, and that is why the Commission should approve PEF's 20-year contract for LNG.

Without the Commission's pre-approval of PEF's long term natural gas supply purchase and firm transportation agreements, the State of Florida will be denied a new long-term supply of natural gas from an LNG source as well as a new pipeline alternative to the existing pipelines - Florida Gas Transmission and Gulfstream Natural Gas System. This new pipeline extension, which will receive natural gas that has been regasified at the Elba Island LNG Terminal and then transported to consumers throughout Florida, not only benefits PEF's consumers and ratepayers, but all natural gas users in the State of Florida. If approved, Florida will no longer be solely dependent on natural gas supplied from the Gulf of Mexico and will no longer be dependent on natural gas supply subject to significant hurricane disruptions. Rather, Florida would have access to a liquefied natural gas supply from the Elba Island LNG Terminal. This will increase security and diversity of natural gas supply, which again benefits all consumers within the State.

Through its pre-filed testimony, responses to the Staff's requests for production of documents, and responses to Staff's 1st set of interrogatories, PEF believes it has demonstrated that these contracts, taken collectively, represent a reasonable, prudent, and cost-effective choice that provide PEF's customers the best overall gas supply and transportation option for Hines 4 and other system needs. The contracts at issue also enhance diversity of fuel supply for PEF while maintaining system reliability and performance. Therefore, PEF believes it is prudent for the Commission to pre-approve the LNG contract at issue.

57. If the Commission did not approve PEF's 20-year LNG contract, would PEF honor the contract?

Answer:

As stated in response to Interrogatory 55 above, PEF's LNG contract is conditioned upon the Commission's pre-approval of that contract, and PEF would exercise its contractual right not to move forward with any of the agreements if the Commission denied pre-approval of the 20-year LNG gas supply contract.

60. How was the 8.16% discount rate developed?

Response: The 8.16% cost of capital utilized in the Cypress analysis represents Progress Energy Florida's (PEF) weighted average cost of capital (WACC). This WACC is predicated on a utility capital structure of 48% debt and 52% equity funding.

The cost of debt estimate utilized was based on a combination of the 10-year Treasury rate, a market-based measure of the PEF utility's spread over the 10 year Treasury (risk free rate), and an estimate of the premium that would be charged by the market in order to lock in these borrowing costs for a point in the future. Our last comprehensive update of the utility's borrowing costs was performed during the early summer 2004, utilizing market data available as of April 30, 2004. At that time, the 10-year Treasury was yielding 4.51%, the current PEF spread over a 10-year period was 0.99%, and we estimated that to lock in rates for any period greater than 30 months into the future, the market would require about a 100 basis point premium (or 1%). Therefore, the PEF cost of debt appropriate for analyzing this project was estimated as follows:

Cost of debt = 10-year Treasury + PEF 10-year spread + forward premium for period greater than 30 months in the future.
or
= 4.51% + .99% + 1.00%
= 6.5%.

The PEF cost of equity utilized in the analysis is the regulated allowed return for the utility, or 12.0%.

We have relied upon an estimated marginal tax rate of 38.575% for PEF. This is composed of a marginal federal tax rate of 35.0% and the company's marginal corporate state income tax rate of 3.575%.

The basic calculation for deriving the WACC is: Combine the cost of equity and the after-tax cost of debt, according to the mix indicated by the capital structure. Formulaically, the calculation is:

WACC = (Cost of Equity * Equity %) + ((Pre-tax Cost of Debt) * (1-tax rate) * (Debt %))
WACC = (12.0% * 52%) + ((6.5%)*(1-38.575%)*(48%))
WACC = (.0624) + (.0192)
WACC = 8.16%

61. Has Progress Energy Florida discussed these supply and transportation contracts with bond rating agencies such as Standard and Poor's or Moody's? If yes, please explain or describe the discussion.

Response: Progress Energy Florida contacted its analysts at Standard and Poor's in advance of the press release announcing the supply and transportation contracts to provide preliminary notice of the transaction. Progress Energy Florida, however, had no substantive conversations with Standard and Poor's regarding the transaction.

INTERROGATORIES

62. Please refer to PEF's response to Staff's First Set of Interrogatories (Nos. 1-4) for the following interrogatories:

A. If the Gas Sale and Purchase Contract between BG LNG Services and PEF (contract) is amended to provide an alternate pricing mechanism as provided by Sections 3.3 and 3.6, will PEF seek Commission approval of this alternate pricing mechanism prior to its effective date?

B. If BG LNG Services and PEF do amend the contract pursuant to Section 3.3 or 3.6, will PEF seek an additional amendment to protect ratepayers in the event that the amended contract becomes uneconomic in a future time period?

C. Does the contract limit the number of instances in which the parties may exercise Sections 3.3 and 3.6?

D. Does the contract limit when the parties may exercise Sections 3.3 and 3.6?

E. Does the contract limit how frequently the parties may exercise Sections 3.3 and 3.6?

F. What other options are available to PEF to achieve the same result of an alternate price mechanism?

Answer:

A. If PEF converts to an alternate pricing mechanism, the gas costs are subject to the Florida Public Service Commission's review and approval during the annual fuel clause review hearing, but not before the effective date. The alternate pricing mechanism in the BG LNG contract gives PEF the option to convert the floating index price to a fixed price or alternate pricing mechanism for hedging purposes. This is a common practice to build in flexibility on price mechanisms with the supplier as we do with other term gas supply contracts. For example, PEF may request BG LNG to convert the floating index price to a fixed price for a certain time period in the contract in order that PEF may execute its hedging strategy.

B. As stated in A above, the purpose of building in the price flexibility is to allow PEF to execute its hedging strategy. All prices contracted by PEF are subject to the Florida Public Service Commission's review and approval during the annual fuel clause review hearing.

C. Sections 3.3 and 3.6 do not specify a limited number of instances.

D. According to section 3.5, "the Party seeking such change must make such request of the other Party prior to 2:30 P.M. Eastern Prevailing Time on the last trading day of the NYMEX gas futures contract (Henry Hub) of the Month immediately preceding the relevant Month or Months for which the change would be effective."

E. Sections 3.3 and 3.6 do not specify a limited number of frequencies.

F. Another option for PEF to achieve the same result of an alternate price mechanism is to financially contract the price change with third parties using over the counter or the New York Merchantile Exchange (NYMEX) financial gas futures.

65. Did PEF consider the impact of the proposed Duke Energy Gas Transmission's Southeast Supply Hub, and any other similar proposed supply storage and transport infrastructure developments, in determining its basis adder for the Mobile Bay-Destin production areas cited on Line 3 of Page 6 in Pamela Murphy's Direct Testimony in this docket? Please explain.

Answer:

PEF did not consider these developments to determine the basis adder for the Mobile Bay-Destin production areas. PEF did review the historical basis for the Mobile Bay-Destin production areas and saw an upward trend in the basis adder from the 2000 to 2004 time frame. Please see response to Interrogatory 64B for the basis. In addition, PEF determined the proposed BG basis adder for re-gasified LNG at Elba Island Terminal to be competitive with Mobile Bay-Destin production area gas supply based on the results of the RFP responses from other suppliers of regasified LNG at Elba Island as well as the June 2004 RFP responses from suppliers.

66. Does the offer made by BG LNG Services, LLC, as appears on Bates stamp pages 76 through 81 in PEF's response to Staff's First Request for Production of Documents No. 4, constitute the basis of the selected alternative as referenced on Page 15, Lines 3 and 4 of Pamela Murphy's Direct Testimony in this docket?

Answer:

The offer from BG LNG Services represents part of the best overall choice for the gas supply portion only for our next planned generating unit, Hines 4. Please note that the price stated in the aforementioned offer was lowered to reflect the actual price cited in the BG LNG Services Gas Sale and Purchase Contract with PEF.

67. Please identify each natural gas production zone from which PEF can economically and reliably purchase natural gas supply and the average market price of natural gas for each such production zone from 2000 to 2004.

Answer:

Platts Inside FERC's Gas Market Report				
	FGT Z1	FGT Z2	FGT Z3	Transco Z4
2000	$3.84	$3.88	$3.84	$3.90
2001	$4.16	$4.25	$4.18	$4.31
2002	$3.19	$3.24	$3.21	$3.25
2003	$4.87	$5.39	$5.41	$5.08
2004	$6.09	$6.15	$6.17	$6.21

Platts Gas Daily					
	FGT Z1	FGT Z2	FGT Z3	FGT City Gate	Transco Z4
2000	$4.24	$4.28	$4.25	$4.68	$4.31
2001	$3.94	$3.97	$3.95	$4.37	$4.01
2002	$3.32	$3.36	$3.38	$3.92	$3.41
2003	$5.36	$5.42	$5.42	$5.69	$5.47
2004	$5.78	$5.87	$5.92	$6.14	$5.93

67.

Platts Inside FERC's Gas Market Report				
	FGT Z1	FGT Z2	FGT Z3	Transco Z4
2000	$3.841	$3.883	$3.834	$3.899
2001	$4.188	$4.258	$4.195	$4.300
2002	$3.185	$3.240	$3.206	$3.263
2003	$5.307	$5.393	$5.409	$5.452
2004	$6.088	$6.153	$6.171	$6.213

Platts Gas Daily					
	FGT Z1	FGT Z2	FGT Z3	FGT City Gate	Transco Z4
2000	$4.243	$4.292	$4.266	$4.614	$4.319
2001	$3.944	$3.981	$3.964	$4.379	$4.016
2002	$3.320	$3.360	$3.379	$3.917	$3.410
2003	$5.356	$5.422	$5.420	$5.690	$5.467
2004	$5.779	$5.875	$5.920	$6.143	$5.926

The Inside FERC (IFERC) first of the month posted prices were used to calculate the prices in the table labeled "Platts Inside FERC's Gas Market Report" above. The IFERC data is supplied monthly and these monthly values were averaged to calculate the annual prices. However, for November '03, IFERC did not post a price for Transco Z4. To fill this missing price, the average basis was calculated between Henry Hub prices and the Transco Z4 prices in October '03 and December '03. The resulting basis of $0.06 was then added to the November '03 Henry Hub price to calculate the Transco Z4 price for November '03.

68. Please refer to Page 14 of PRM-2 of Pamela Murphy's Direct Testimony in this docket.

A. Has Southern Natural Gas Company achieved the precedent agreement shown in Section 5(a)ii on this page?

B. Does it appear at this time that Southern Natural Gas Company will achieve the precedent agreement shown in Section 5(a)iii on this page?

Answer:

A. Yes, please see Attachment A, copy of letter from Bruce Hughes of Southern Natural to Rob Caldwell dated January 25, 2005.

B. Southern Natural Gas Company expects to confirm sufficient commitments to proceed with the project. If all conditions are met by parties that have signed precedent agreements, Southern Natural will waive the condition set forth in Section 5 (a) iii.

Bruce H. Hughes
Director
Business Development

Southern Natural Gas
an El Paso company

January 25, 2005

Mr. Robert F. Caldwell
Vice President, Regulated Commercial Operations
Progress Energy Carolinas, Inc.
P.O. Box 1551
Raleigh, NC 27602

Dear Rob:

This is to advise you that on December 3, 2004, the El Paso Corporation Board of Directors ("El Paso") approved the construction of the Cypress Project by Southern Natural Gas Company ("Southern") to provide firm transportation service to Florida Power Corp., d/b/a Progress Energy Florida, Inc. ("FPC") as set forth in the Precedent Agreement dated December 2, 2004, between Southern and FPC ("Agreement").

Accordingly, Southern is hereby informing you that it has fulfilled the condition precedent set forth in Section 5(a)(ii) of the Precedent Agreement and that such condition has been satisfied as of January 31, 2005.

Please confirm to us in writing when FPC meets any of its conditions precedent set forth in Section 5(b) of the Precedent Agreement. Based on the financial information obtained by our credit department, FPC has met the condition precedent set forth in Section 5(b)(vi) by demonstrating to Southern that FPC is creditworthy to perform its financial obligations under the terms of the Precedent Agreement. We would note, however, that this obligation to sustain a showing of creditworthiness extends for the term of the Service Agreement notwithstanding the fact that FPC has met the condition precedent at this time.

Sincerely,

Bruce H. Hughes

cc: Mr. Norman Holmes
Ms. Patricia Francis

Southern Natural Gas
1900 Fifth Avenue North Birmingham, Alabama 35203
PO Box 2563 Birmingham, Alabama 35202.2563
tel 205.325.7146 fax 205.326.3787

ATTACHMENT
A

72. How did PEF determine that the supply disruption associated with hurricanes is sufficiently important to make geographic supply diversity one of four criteria for selecting a natural gas supplier for Hines Unit 4 and other units?

Answer:

Based on many factors such as 1) PEF's continuing dependence on natural gas in the Gulf of Mexico; 2) uncertainty of the severity of storms affecting natural gas production in the Gulf of Mexico; 3) the incremental costs associated with supply disruptions from storms in the Gulf of Mexico; and 4) the importance of maintaining reliability to our customers, PEF determined that geographic supply diversity should be a criteria. Please see below a table which summarizes incremental costs as a result of storms/hurricanes since 2002.

Name	Date	Incremental Cost
Tropical Storm Isidore	9/24/2002 - 9/27/2002	$132,816
Hurricane Lili	10/1/2002 - 10/4/2002	$218,807
Tropical Storm Claudette	7/14/2003-7/16/2003	$9,884
Tropical Storm Bonnie	8/10/2004-8/13/2004	$140,778
Hurricane Ivan	9/13/2004-10/6/2004	$6,631,796

73. Can natural gas line-packing, natural gas underground storage, or other gas unavailability mitigating measures offset some or all of PEF's incremental costs associated with the unavailability of natural gas fuel supply in the event of hurricanes and tropical storms in the Gulf of Mexico?

Answer:

Depending on the amount of contracted capacity, underground natural gas storage could offset some of the incremental costs associated with unavailability of natural gas supply in the event of hurricanes or tropical storms in the Gulf of Mexico. It is difficult to determine whether underground natural gas storage could mitigate all of PEF's incremental costs since there would be a specific contracted amount of storage available to PEF and the storm/hurricane's severity would not be known. Natural gas line-packing with pipelines can assist PEF on a limited basis depending on the pipelines line pack availability and pressures, but it is only used to supply plants on a short-term basis. It would not be considered a long-term solution.

74. Please explain how line packing, natural gas underground storage, or other gas unavailability mitigating measures offset some of the incremental costs that would otherwise have been experienced by PEF from 2000 to 2004.

Answer:

Since PEF does not own and/or lease natural gas underground storage, PEF is not able to offset the incremental costs that have been previously experienced by the unavailability of gas. PEF does have an Operational Balancing Account with Gulfstream Natural Gas where it is able to swing its daily burns over or under depending on Gulfstream's excess gas in the pipeline. In addition, when Florida Gas Transmission does not have an "Alert Day" in effect, PEF is allowed to swing its daily burns over or under for that particular gas day. To the extent that PEF owned and/or leased natural gas underground storage, the offset of the incremental costs would depend on the length of the gas interruption and how much storage capacity was contracted by PEF as stated in the response to Interrogatory No. 73.

75. Please refer to Section 1.1 of the Gas Sale and Purchase Contract between BG LNG Services and PEF for the following questions:

A. Does the "Contract Quantity for Hines" represent PEF's maximum throughput needs for natural gas at Hines Unit 4? If not, please explain.

B. What options can PEF choose from if PEF's throughput needs for Hines Unit 4 on a given day are less than the "Contract Quantity for Hines"? Please rank from greatest to least value for PEF, and provide the assumptions used in that ranking.

C. What options can PEF choose from if PEF's system throughput needs on a given day are less than the "Contract Quantity for System"? Please rank from greatest to least value for PEF, and provide the assumptions used in that ranking.

Answer:

A. Based on the monthly data provided under Interrogatory 122, the daily highest daily volume appears in August 2014 at 72,001 MMBtu. The "Contract Quantity for Hines" is identified as 60,000 MMBtu/day, however, please remember that the Contract Quantity for the System can also be delivered to Hines Complex as well during the summer period.

B. PEF would attempt to economically optimize any excess transportation capacity and/or supply. The proposed contracts would be optimized along with PEF's other gas supply and transportation contracts. When excess transportation capacity and/or supply exist, the market conditions and the pipeline's flexibility to go long would dictate which option PEF would use. Potential options to balance PEF's system throughput:

- Deliver excess supply to other PEF facilities if needed. (Assumption: natural gas can be used at other PEF facilities.)
- Go long on the interstate pipelines as imbalance gas. (Assumption: the pipelines have imposed no restrictions that day.)
- Sell natural gas delivered supplies (supply and transport) to other counterparties. (Assumption: The pipelines have imposed restrictions on daily balance and PEF must sell gas to avoid daily penalties or the price a counterparty is willing to pay is more than the supply and variable transport costs are to PEF, thereby resulting is a margin profit to be flowed through the fuel adjustment clause.)
- Sell excess natural gas at the Elba LNG facility receipt point. (Assumption: See third bullet above except that variable transport costs are not included.)
- Sell excess natural gas at various Gulf of Mexico receipt points (Assumption: See third bullet above.)

C. Please see response to Interrogatory 75 (B) above.

78. Because PEF had a stated criterion to reduce reliance on gas from the Gulf of Mexico, could a Gulf of Mexico gas supplier have won this bidding process?

Answer:

Yes, because this was only one out of the four criteria upon which PEF based its decision. However, the Gulf of Mexico suppliers were not willing to provide a twenty year proposal to PEF, and their price was also higher than BG LNG Services' ultimate price to PEF. As a result, it was difficult to equally compare the supply alternatives.

81. Did PEF provide public notice of its bid solicitations for long term supply of LNG for Hines Unit 4 and other gas units? Why or why not?

Answer:

No. Please see the three attachments in response to Interrogatory No. 83 which reflect the lists of counterparties that received PEF's RFP's. PEF maintains this list of credit worthy counterparties for each RFP distribution.

82. What was the sequence of events and associated dates PEF used in its solicitation process for gas supply to Hines Unit 4 and other units, beginning with the development of the first RFP through the selection of BG/Cypress/FGT (events may include such items as development of the RFP, RFP distribution, bid due dates, bid evaluation, determinations to rebid, contract negotiations, and ultimate selection)?

Answer:

NON-BINDING LNG GAS RFP DISTRIBUTED AUGUST 22, 2003

- Development of RFP early August 2003.
- Distributed non-binding RFP on August 22, 2003.
- Bid responses due September 3, 2003.
- Bid evaluation in September 2003.

BINDING LNG RFP DISTRIBUTED APRIL 5, 2004

- Development of RFP during March 2004.
- Distributed binding RFP on April 5, 2004.
- Bid responses due April 26, 2004.
- Bid evaluation, negotiation and rebids from May to mid-August 2004.

FROM BINDING DOMESTIC GAS RFP DISTRIBUTED JUNE 14, 2004

- Development of RFP in early June 2004.
- Distributed binding RFP on June 14, 2004.
- Bid responses due June 24, 2004.
- Bid evaluation, negotiation and rebids from June to August 2004.

FINAL SELECTION OF GAS AND TRANSPORTATION OPTION FOR HINES 4 LATE AUGUST 2004

85. Have FGT and PEF successfully met the requirements set forth in paragraph 2 of FGT's first December 2, 2004 letter to Ms. Murphy?

Answer:

Yes, by execution of a letter agreement dated January 31, 2005, between FGT and PEF, the stipulations contained in paragraph 2 of FGT's first December 2, 2004 letter to Ms. Murphy were satisfied.

86. What is/are those natural gas production areas from which PEF purchases gas other than the Mobile Bay-Destin production area, as alluded to at Lines 3-4 of Page 12 of Pamela Murphy's Direct Testimony in this docket? Are these production areas capable of providing a cost-effective alternative for natural gas for Hines Unit 4 during the 2007-2027 period? Did PEF consider those production area(s) in preparing its determination to solicit a long term supply of natural gas for Hines Unit 4, or in its associated RFP process? Please explain.

Answer:

Other PEF's production area natural gas sources include receipt points and pools located in Florida Gas Transmission Zone 1, Zone 2, Zone 3, and all other Gulfstream Natural Gas Systems receipt points. Florida Gas Transmission personnel indicated that FGT Zones 1 and 2 could not be expanded at their current maximum rate under schedule FTS-2 and therefore PEF dismissed this option as a viable alternative. The remaining production areas sourced from FGT Zone 3 and Gulfstream are considered part of the Mobile Bay-Destin production area, which was evaluated during the Hines 4 RFP.

88. Please describe any conclusions made by PEF regarding the adequacy of Gulf Coast sources in the provision of the long term supply of natural gas to Hines Unit 4 as a result of responses to its August 2003 RFP.

Answer:

The main conclusion made by PEF regarding the adequacy of Gulf Coast sources in the provision of the long term supply of natural gas to Hines Unit 4 as a result of responses to its August 2003 RFP was that the Gulf Coast LNG projects in the Mobile Bay Area were not far enough along to bid on the RFP. PEF also concluded that suppliers desired a NYMEX or Henry Hub index for the gas pricing. Finally, the willingness to assume foreign/import related risks varied among suppliers.

93. What process did PEF use to ensure that potential natural gas suppliers were not excluded in its solicitation process?

Answer:

PEF maintains a list of viable and credit worthy counterparties who have the ability to supply natural gas to Progress Energy. Indeed, most viable and credit worthy gas suppliers already have existing natural gas contracts with PEF. PEF distributed the RFP's to the most updated (at the time of the RFP distribution) list of those counterparties consisting of both domestic and foreign LNG suppliers capable of serving PEF.

94. How did PEF select specific suppliers to solicit a bid for LNG either from Elba Island LNG terminal or a Bahamian LNG terminal?

Answer:

PEF distributed LNG RFP's to all natural gas suppliers that had contractual rights to deliver LNG to Elba Island LNG Terminal and/or the project owners of the Bahamas-based LNG terminal projects with the exception of El Paso, because they had made the announcement that they were trying to sell their Bahamas-based LNG terminal project.

100. Regarding Elba Island LNG, is the greatest natural gas reliability risk associated with the commodity (production, liquefaction, shipping, regasification) or its domestic pipeline transportation to the Hines Complex? Why?

Answer:

[redacted] the natural gas reliability risk includes the events which could negatively impact the regasification at the Elba Island Terminal or the transportation associated with the pipeline transportation on Southern Natural and Florida Gas Transmission to the Hines Complex.

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TPA#2003672.1

101. If Gulf of Mexico natural gas resources would provide PEF a different level of operational flexibility in serving Hines 4 and other units compared to that which would be provided by Elba Island LNG, please identify those differences.

Answer:

As previously indicated in PEF response to Interrogatory No. 46 of the Staff's First Set of Interrogatories, Elba Island LNG presents a different level of operational flexibility as compared to Gulf of Mexico natural gas sources as it provides:

- Accessibility (via associated development of a new major pipeline into the State of Florida) to an additional and geographically separate source of natural gas that will mitigate the risks of supply disruptions and pipeline operational constraints;
- Long-term certainty and security of supply with a higher degree of price stability (that is not available from Gulf of Mexico based suppliers); and
- The opportunity to release transportation capacity and/or sell a bundled (gas and transportation) product on Southern Natural's pipeline system in the event it is not needed for PEF generation requirements.

102. Does Elba Island LNG contain single point of delivery failure risk? If not, please explain how optional gas would be available in the event LNG shipping is disrupted.

Answer:

Should Elba Island LNG Terminal experience a delivery failure and LNG deliveries could not be made, please see PEF's options outlined in Interrogatories Nos. 129 and 130. Also, please see response to Interrogatory No. 42 which reflects other PEF options.

104. PEF'S April 2004 RFP specified a certain duration for the contract period. What present or forecasted market supply, bid information, or other conditions caused PEF to not consider a shorter duration contract?

Answer:

Since the first RFP conducted in August 2003 was non-binding, PEF conducted a second LNG RFP to solicit bids for a binding proposal. In order to compare the supply bids for LNG, PEF provided for a certain duration so that we could compare the costs associated with the Cypress expansion project and the Bahamas projects. In addition, Southern Natural required a term of twenty years from PEF to build the new pipeline to Florida Gas Transmission. Correspondingly, PEF's supply RFP was for twenty years to ensure gas supply was available to fill the pipeline capacity for the entire term. This was especially important since there are fewer suppliers delivering to Elba Island Terminal than the Gulf Coast.

105. PEF is seeking approval of three 20-year contracts. Was it PEF's goal to match these contracts at 20 years or was the term of the contracts dictated by the 20 year term being the minimum term available for one of these contracts?

Answer:

Both. PEF wanted to secure and match all three twenty-year contracts as a package. In addition, Southern Natural and BG LNG Services required a twenty year commitment from PEF.

110. What is the probability that the Southeast US regional average LNG price will at some point during the 20 year period between 2007 and 2027 be significantly lower than the Gulf of Mexico market proxy referenced on Line 10 of Page 14 of Witness Murphy's Direct Testimony filed in this docket?

Answer:

The Gulf of Mexico market proxy reflects gas commodity prices based on Henry Hub. PEF expects North American LNG prices to be tied to a Henry Hub price index. In fact, all of the LNG respondents to PEF's RFP's reflected LNG prices tied to a Henry Hub index. PEF does not know whether a Southeast US regional average LNG price will be contemplated in the future for Gulf of Mexico supply or the probability associated with it.

111. Which utilities in the U.S., if any, currently receive regasified LNG under long term contract from Elba Island or any other LNG terminal in the U.S.?

Answer:

PEF does not have this information.

112. Which utilities in the U.S., if any, currently recover the costs of regasified LNG purchased under long term contract via an up-front approval of the contract rates from the utility regulator?

Answer:

PEF does not have this information.

113. Which gas consuming entities in the U.S. other than utilities currently receive regasified LNG under long term contract from Elba Island or any other LNG terminal in the U.S?

Answer:

PEF does not have this information.

114. Please explain the commodity price difference between what appears in BG LNG Services LLC's response to PEF's April 2004 RFP for the supply of regasified LNG to Hines Unit 4 and the actual contract between PEF and BG LNG Services LLC, which is an exhibit to Pamela Murphy's Direct Testimony in this docket?

Answer:

The commodity price decreased from BG LNG Services LLC's response to PEF's April 2004 RFP for the supply of regasified LNG to Hines Unit 4 to the actual contract between PEF and BG LNG Services LLC. This decrease in commodity price was due to the fact that PEF negotiated a more favorable commodity price for the ratepayers.

121. Please provide PEF's current generation, peak demands (summer and winter) and resulting reserve margins for the next ten years. What is the current in-service date and capacity of Hines 4?

Answer:

Please refer to Attachment G, PEF's 2004 Ten Year Site Plan (TYSP) for PEF's generation, peak demands (summer and winter) and reserve margins for the next ten years. The current in-service date for Hines 4 is December 2007.

Progress Energy Florida
Ten-Year Site Plan

April 2004

2004-2013

Submitted to:
Florida Public Service Commission

Progress Energy

ATTACHMENT
G

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CHAPTER 3 FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 4 ENVIRONMENTAL AND LAND USE INFORMATION

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REQUIRED SCHEDULES

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LIST OF
TABLES AND FIGURES

CODE IDENTIFICATION SHEET

Generating Unit Type

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

Fuel Type

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

Fuel Transportation

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

Future Generating Unit Status

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

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INTRODUCTION

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

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

The TYSP document contains four chapters as described below:

CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

CHAPTER 2

FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

Progress Energy

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

Progress Energy Florida (PEF) is a wholly owned subsidiary of Progress Energy, Inc. (Progress Energy), a registered holding company under the Public Utility Holding Company Act (PUHCA) of 1935. Progress Energy and its subsidiaries, including PEF, are subject to the regulatory provisions of the PUHCA. Progress Energy is the parent company of PEF and certain other subsidiaries.

AREA OF SERVICE

PEF provided electric service during 2003 to an average of 1.5 million customers in Florida. Its service area covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 21 municipal and 9 rural electric cooperative systems. Major wholesale power sales customers include Seminole Electric Cooperative, Inc., Florida Municipal Power Agency, and Florida Power & Light Company. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (FPSC). PEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

As of December 31, 2003, PEF had approximately 5,000 circuit miles of transmission lines including about 200 miles of 500 kV lines and about 1,500 miles of 230 kV lines. PEF had distribution lines of approximately 25,000 circuit miles of overhead conductor and about 15,000 circuit miles of underground cable. Distribution and transmission substations in service had a transformer capacity of approximately 45,000,000 kVA in 614 transformers. Distribution line transformers numbered 356,930 with an aggregate capacity of about 18,000,000 kVA. A map of the Electric System can be found in Figure 1.2.

ENERGY MANAGEMENT

PEF customers participating in the company's residential Energy Management program are managing future growth and costs. Approximately 380,000 customers participated in the Energy Management program at the end of the year, contributing about 735,000 kW of winter peak-shaving capacity for use during high load periods.

TOTAL CAPACITY RESOURCE

As of December 31, 2003, PEF had total summer capacity resources of approximately 9,782 MW consisting of installed capacity of 8,475 MW (excluding Crystal River 3 joint ownership) and 1,307 MW of firm purchased power. Hines Unit 2, a 516 MW combined-cycle unit, was placed into service in December 2003. Additional information on PEF's existing generating resources is shown on Schedule 1 and Table 3.1.

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map

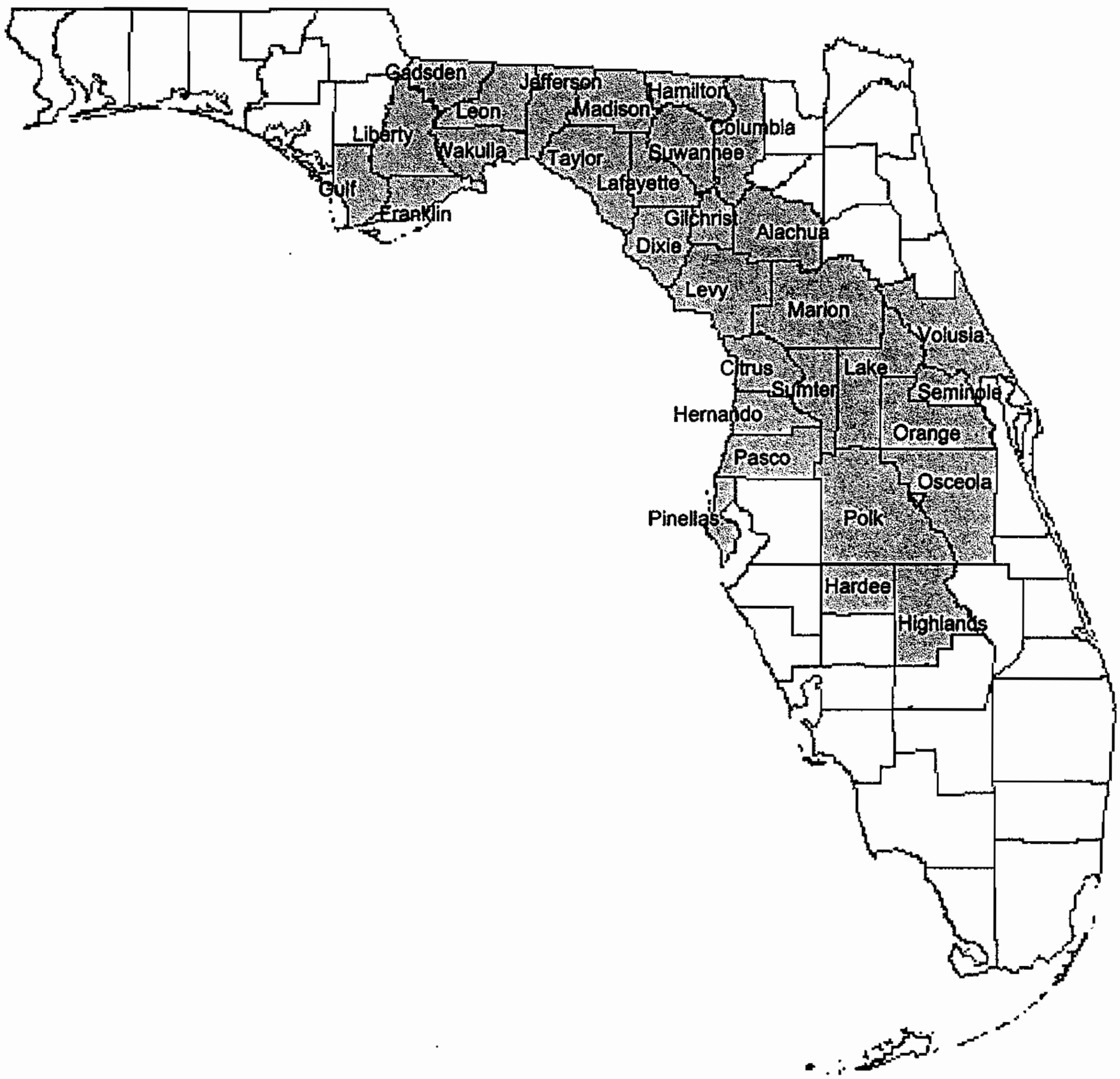

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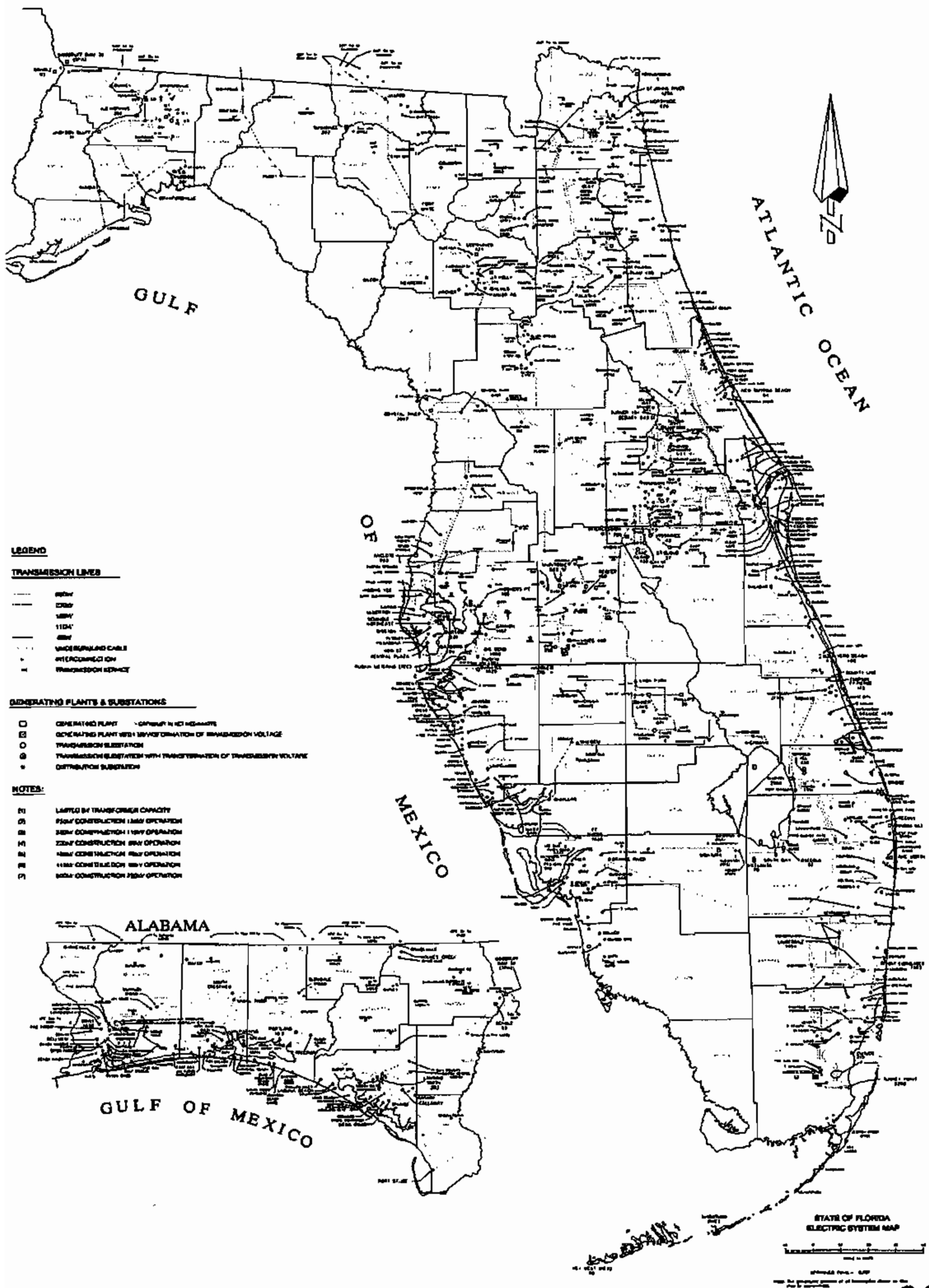
FIGURE 1.2

PROGRESS ENERGY FLORIDA

Electric System Map



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PROGRESS ENERGY FLORIDA

SCHEDULE 1

EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2003

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

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT

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

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

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

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

PEF's customer growth is expected to average 1.7 percent between 2004 and 2013, less than the ten-year historical average of 2.2 percent. The ten-year historical growth rate falls to 2.0 percent when accounting for the creation of PEF's Seasonal Service Rate tariff, which artificially inflates customer growth figures. Slower population growth -- based on the latest projection from the University of Florida's Bureau of Economic and Business Research -- results in a lower base case customer projection when compared to the higher historical growth rate. This translates into lower projected energy and demand growth rates from historic rate levels.

Net energy for load, which had grown at an average of 3.9 percent between 1994 and 2003, is expected to increase by 2.1 percent per year from 2004-2013 in the base case, 2.4 percent in the high case and 1.8 percent in the low case. Projected weakness from the wholesale jurisdiction has contributed to lower projected PEF system growth rates compared to prior forecasts.

Summer net firm demand is expected to grow an average of 2.3 percent per year during the next ten years. This compares to the 3.3 percent average annual growth rate experienced throughout the last ten years. High and low summer growth rates for net firm demand are 2.6 percent and 2.0 percent per year, respectively. Winter net firm demand is projected to grow at 2.3 percent per year after having increased by 5.9 percent per year from 1994 to 2003. The high historical growth figure is driven by an extreme weather peak day in 2003 and a fairly mild winter peak weather condition in 1994. High and low winter net firm demand growth rates are 2.6 percent and 2.0 percent, respectively.

Summer net firm retail demand is expected to grow an average of 2.4 percent per year during the next ten years; this compares to the 3.7 percent average annual growth rate experienced throughout the last ten years. High and low summer growth rates for net firm retail demand are 2.8 percent and 2.1 percent per year, respectively. Winter net firm retail demand is projected to grow at approximately 2.0 percent per year after having increased by 6.0 percent per year from 1994 to 2003. High and low winter net firm retail demand growth rates are 2.4 percent and 1.6 percent, respectively.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

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

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PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1994	2,734,821	2.485	13,863	1,100,537	12,597	8,252	122,987	67,097
1995	2,801,105	2.491	14,938	1,124,679	13,282	8,612	126,189	68,247
1996	2,847,802	2.494	15,481	1,141,671	13,560	8,848	129,440	68,356
1997	2,895,266	2.495	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,959,509	2.502	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,047,293	2.511	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,044,449	2.467	17,116	1,234,286	13,867	10,813	143,475	75,368
2001	3,141,867	2.465	17,604	1,274,672	13,810	11,061	146,983	75,251
2002	3,207,661	2.465	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,286,782	2.468	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,352,412	2.468	19,704	1,358,414	14,505	12,105	156,903	77,150
2005	3,410,218	2.466	20,212	1,382,699	14,618	12,535	159,634	78,523
2006	3,468,155	2.465	20,706	1,406,712	14,719	12,955	162,422	79,761
2007	3,526,276	2.464	21,206	1,431,102	14,818	13,392	165,425	80,955
2008	3,588,935	2.465	21,713	1,455,971	14,913	13,833	168,552	82,070
2009	3,653,234	2.467	22,222	1,481,124	15,003	14,270	171,715	83,103
2010	3,714,098	2.466	22,705	1,505,866	15,078	14,698	174,825	84,073
2011	3,772,892	2.466	23,180	1,529,665	15,154	15,118	177,814	85,021
2012	3,827,099	2.465	23,668	1,552,660	15,244	15,533	180,703	85,959
2013	3,879,660	2.463	24,159	1,575,153	15,338	15,950	183,527	86,908

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
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	4,224	2,927	1,443,116	0	26	2,205	30,784
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,957
2004	4,144	2,625	1,578,667	0	29	3,066	39,048
2005	4,197	2,625	1,598,857	0	29	3,191	40,164
2006	4,281	2,625	1,630,857	0	29	3,310	41,281
2007	4,328	2,625	1,648,762	0	30	3,428	42,384
2008	4,372	2,625	1,665,524	0	30	3,546	43,494
2009	4,416	2,625	1,682,286	0	30	3,666	44,604
2010	4,453	2,625	1,696,381	0	30	3,789	45,675
2011	4,482	2,625	1,707,429	0	31	3,911	46,722
2012	4,511	2,625	1,718,476	0	31	4,024	47,767
2013	4,538	2,625	1,728,762	0	31	4,136	48,814

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PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
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	1,842	34,715	18,035	1,292,073
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,004	1,400,299
2001	3,839	1,830	40,933	20,752	1,444,958
2002	3,173	2,534	42,567	21,156	1,475,783
2003	3,359	2,595	43,911	21,665	1,510,516
2004	3,349	2,764	45,161	22,159	1,540,101
2005	2,927	2,654	45,745	22,735	1,567,693
2006	3,011	2,828	47,120	23,310	1,595,069
2007	2,890	2,770	48,044	23,885	1,623,037
2008	2,672	2,881	49,047	24,463	1,651,611
2009	2,593	2,950	50,147	25,039	1,680,503
2010	2,580	3,008	51,263	25,616	1,708,932
2011	2,549	3,085	52,356	26,191	1,736,295
2012	2,563	3,148	53,478	26,769	1,762,757
2013	2,581	3,213	54,608	27,345	1,788,650

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
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	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,742
2004	9,143	774	8,369	369	304	187	47	165	75	7,997
2005	9,255	689	8,565	374	272	201	49	167	75	8,117
2006	9,651	889	8,762	377	246	216	51	168	75	8,519
2007	9,888	928	8,960	378	225	230	53	169	75	8,758
2008	10,066	904	9,162	360	208	244	55	170	75	8,953
2009	10,215	848	9,367	349	194	258	58	171	75	9,110
2010	10,418	852	9,567	330	180	272	60	172	75	9,329
2011	10,582	823	9,759	331	168	286	62	173	75	9,486
2012	10,737	792	9,945	332	156	301	65	174	75	9,635
2013	10,921	795	10,127	333	146	315	67	176	75	9,810

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(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
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	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,742
2004	9,291	774	8,517	369	304	187	47	165	75	8,145
2005	9,418	689	8,728	374	272	201	49	167	75	8,281
2006	9,844	889	8,955	377	246	216	51	168	75	8,712
2007	10,099	928	9,171	378	225	230	53	169	75	8,969
2008	10,310	904	9,406	360	208	244	55	170	75	9,198
2009	10,475	848	9,627	349	194	258	58	171	75	9,371
2010	10,733	852	9,882	330	180	272	60	172	75	9,644
2011	10,949	823	10,126	331	168	286	62	173	75	9,853
2012	11,138	792	10,346	332	156	301	65	174	75	10,036
2013	11,391	795	10,597	333	146	315	67	176	75	10,280

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
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	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,742
2004	8,988	774	8,214	369	304	187	47	165	75	7,842
2005	9,088	689	8,398	374	272	201	49	167	75	7,951
2006	9,461	889	8,572	377	246	216	51	168	75	8,329
2007	9,672	928	8,744	378	225	230	53	169	75	8,542
2008	9,816	904	8,912	360	208	244	55	170	75	8,704
2009	9,925	848	9,077	349	194	258	58	171	75	8,821
2010	10,083	852	9,232	330	180	272	60	172	75	8,994
2011	10,226	823	9,403	331	168	286	62	173	75	9,130
2012	10,332	792	9,540	332	156	301	65	174	75	9,230
2013	10,465	795	9,671	333	146	315	67	176	75	9,354

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

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PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
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	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	10,626	1,408	9,218	520	735	343	30	125	248	8,625
2004/05	10,922	1,508	9,414	523	715	372	33	126	251	8,903
2005/06	11,049	1,437	9,612	379	698	401	36	127	255	9,153
2006/07	11,519	1,714	9,805	380	687	431	39	128	258	9,596
2007/08	11,672	1,672	10,001	361	681	461	43	129	261	9,737
2008/09	11,850	1,649	10,202	351	678	491	46	130	265	9,891
2009/10	12,099	1,697	10,402	341	676	519	49	131	268	10,114
2010/11	12,287	1,692	10,595	332	675	549	52	132	271	10,276
2011/12	12,475	1,694	10,781	333	675	578	55	133	274	10,426
2012/13	12,692	1,730	10,962	334	676	607	58	134	277	10,605

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

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PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
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	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	10,788	1,408	9,381	520	735	343	30	125	248	8,788
2004/05	11,100	1,508	9,592	523	715	372	33	126	251	9,081
2005/06	11,258	1,437	9,821	379	698	401	36	127	255	9,362
2006/07	11,747	1,714	10,033	380	687	431	39	128	258	9,824
2007/08	11,936	1,672	10,264	361	681	461	43	129	261	10,001
2008/09	12,130	1,649	10,482	351	678	491	46	130	265	10,171
2009/10	12,435	1,697	10,738	341	676	519	49	131	268	10,451
2010/11	12,679	1,692	10,987	332	675	549	52	132	271	10,668
2011/12	12,902	1,694	11,208	333	675	578	55	133	274	10,854
2012/13	13,190	1,730	11,460	334	676	607	58	134	277	11,104

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

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PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
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	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	10,457	1,408	9,050	520	735	343	30	125	248	8,457
2004/05	10,742	1,508	9,234	523	715	372	33	126	251	8,723
2005/06	10,843	1,437	9,406	379	698	401	36	127	255	8,947
2006/07	11,285	1,714	9,571	380	687	431	39	128	258	9,362
2007/08	11,404	1,672	9,732	361	681	461	43	129	261	9,469
2008/09	11,540	1,649	9,892	351	678	491	46	130	265	9,581
2009/10	11,740	1,697	10,043	341	676	519	49	131	268	9,756
2010/11	11,907	1,692	10,215	332	675	549	52	132	271	9,896
2011/12	12,044	1,694	10,350	333	675	578	55	133	274	9,996
2012/13	12,207	1,730	10,477	334	676	607	58	134	277	10,121

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1994	32,150	219	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,505	420	359	565	37,957	3,354	3,850	45,161	59.7
2005	47,110	441	360	564	39,048	3,349	3,348	45,745	58.7
2006	48,508	462	362	564	40,163	2,927	4,030	47,120	58.8
2007	49,453	482	363	564	41,281	3,011	3,752	48,044	57.2
2008	50,479	502	365	565	42,383	2,890	3,774	49,047	57.5
2009	51,599	522	366	564	43,495	2,672	3,980	50,147	57.9
2010	52,737	542	368	564	44,606	2,593	4,064	51,263	57.9
2011	53,851	562	369	564	45,676	2,580	4,100	52,356	58.2
2012	54,996	582	371	565	46,723	2,549	4,206	53,478	58.5
2013	56,147	602	373	564	47,766	2,563	4,279	54,608	58.8

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

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

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PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1994	32,150	219	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	47,317	420	359	565	39,777	3,354	2,842	45,973	59.6
2005	47,975	441	360	564	40,973	3,349	2,288	46,610	58.6
2006	49,530	462	362	564	42,241	2,927	2,974	48,142	58.7
2007	50,578	482	363	564	43,436	3,011	2,722	49,169	57.1
2008	51,783	502	365	565	44,721	2,890	2,740	50,351	57.3
2009	52,999	522	366	564	45,913	2,672	2,962	51,547	57.9
2010	54,431	542	368	564	47,260	2,593	3,104	52,957	57.8
2011	55,833	562	369	564	48,583	2,580	3,175	54,338	58.1
2012	57,178	582	371	565	49,808	2,549	3,303	55,660	58.4
2013	58,694	602	373	564	51,210	2,563	3,382	57,155	58.8

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

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 historical load factor which is based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.2)

PROGRESS ENERGY FLORIDA

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

(1)	(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 (%) **
1994	32,150	219	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	45,659	420	359	565	38,288	3,354	2,673	44,315	59.7
2005	46,235	441	360	564	39,344	3,349	2,177	44,870	58.7
2006	47,501	462	362	564	40,338	2,927	2,848	46,113	58.8
2007	48,300	482	363	564	41,304	3,011	2,576	46,891	57.2
2008	49,142	502	365	565	42,244	2,890	2,576	47,710	57.4
2009	50,039	522	366	564	43,145	2,672	2,770	48,587	57.9
2010	50,933	542	368	564	43,980	2,593	2,886	49,459	57.9
2011	51,924	562	369	564	44,917	2,580	2,932	50,429	58.2
2012	52,796	582	371	565	45,705	2,549	3,024	51,278	58.4
2013	53,654	602	373	564	46,480	2,563	3,072	52,115	58.8

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

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 historical load factor which is based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.3)

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PROGRESS ENERGY FLORIDA

SCHEDULE 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2003		FORECAST 2004		FORECAST 2005	
	PEAK DEMAND	NEL	PEAK DEMAND	NEL	PEAK DEMAND	NEL
MONTH	MW	GWh	MW	GWh	MW	GWh
JANUARY	10,507	3,842	8,626	3,662	8,903	3,578
FEBRUARY	6,508	2,814	6,838	3,170	7,040	3,240
MARCH	7,178	3,239	5,729	3,361	5,912	3,451
APRIL	7,209	3,190	6,228	3,250	6,408	3,354
MAY	8,037	4,016	7,185	3,921	7,450	4,025
JUNE	8,287	4,016	7,751	4,183	7,871	4,234
JULY	8,476	4,351	7,993	4,447	8,115	4,491
AUGUST	8,254	4,220	7,996	4,537	8,116	4,594
SEPTEMBER	7,982	3,988	7,534	4,215	7,636	4,278
OCTOBER	7,383	3,631	6,846	3,704	7,027	3,744
NOVEMBER	6,887	3,201	5,712	3,226	5,844	3,239
DECEMBER	8,172	3,403	7,010	3,485	7,224	3,517
TOTAL		43,911		45,161		45,745

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel units) are shown on Schedule 5. PEF's two-year actual and ten-year projected energy sources, in GWh and percent, are shown by fuel type on Schedules 6.1 and 6.2, respectively. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one-fuel source. Natural gas consumption is projected to increase as plants are added to meet future load growth. PEF's coal, nuclear, and purchased power requirements are projected to remain relatively stable over the ten-year planning horizon.

PROGRESS ENERGY FLORIDA

SCHEDULE 5

FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	NUCLEAR		TRILLION BTU	69	62	69	63	68	63	69	52	68	63	69	63
(2)	COAL		1,000 TON	5,557	6,173	6,385	6,664	6,564	6,375	6,445	6,879	6,678	6,812	6,853	6,866
(3)	RESIDUAL	TOTAL	1,000 BBL	9,851	10,701	10,152	9,994	8,204	9,159	7,618	7,570	5,982	6,562	5,732	6,062
(4)		STEAM	1,000 BBL	9,851	10,701	10,152	9,994	8,204	9,159	7,618	7,570	5,982	6,562	5,732	6,062
(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	1,548	1,076	723	844	538	580	368	716	622	912	615	800
(9)		STEAM	1,000 BBL	108	119	35	30	39	34	36	47	145	143	178	154
(10)		CC	1,000 BBL	0	32	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	1,440	925	688	814	499	546	332	669	477	769	437	646
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	55,916	52,180	55,222	59,474	75,156	85,571	95,041	109,803	131,853	148,327	154,830	165,725
(14)		STEAM	1,000 MCF	4,717	832	0	0	0	0	0	0	0	0	0	0
(15)		CC	1,000 MCF	35,526	36,370	41,571	44,642	63,386	70,917	83,107	94,606	119,643	133,758	144,069	153,471
(16)		CT	1,000 MCF	15,673	14,978	13,651	14,832	11,770	14,654	11,934	15,197	12,210	14,569	10,761	12,254
(17)	OTHER (SPECIFY)														
	SEASONAL PURCHASE	CT	1,000 BBL	N/A	N/A	0	12	0	0	0	0	0	0	0	0
	SEASONAL PURCHASE	CT	1,000 MCF	N/A	N/A	19	97	0	0	0	0	0	0	0	0

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PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	27	97	154	146	80	89	74	105	97	8	0	0
(2)	NUCLEAR		GWh	6,700	6,039	6,658	6,131	6,640	6,092	6,658	5,089	6,640	6,146	6,658	6,145
(3)	COAL		GWh	14,406	16,111	16,485	17,198	16,919	16,433	16,614	17,775	17,260	17,626	17,741	17,776
(4)	RESIDUAL	TOTAL	GWh	6,319	6,785	6,258	6,149	4,990	5,553	4,513	4,557	3,603	3,984	3,445	3,664
(5)		STEAM	GWh	6,319	6,785	6,258	6,149	4,990	5,553	4,513	4,557	3,603	3,984	3,445	3,664
(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	607	405	286	336	206	260	160	318	231	363	219	316
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	19	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	607	386	286	336	206	260	160	318	231	363	219	316
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	6,446	6,155	7,020	7,589	10,101	11,558	13,054	15,018	18,362	20,645	21,821	23,314
(15)		STEAM	GWh	462	83	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	4,816	4,938	5,881	6,355	9,101	10,244	11,959	13,671	17,256	19,350	20,832	22,216
(17)		CT	GWh	1,168	1,134	1,139	1,234	1,000	1,314	1,095	1,347	1,106	1,295	989	1,098
(18)	OTHER 2/														
	QF PURCHASES		GWh	5,091	5,022	4,677	4,587	4,589	4,463	4,362	3,673	3,584	3,584	3,594	3,393
	IMPORT FROM OUT OF STATE		GWh	3,317	3,555	3,623	3,609	3,595	3,596	3,612	3,612	1,486	0	0	0
	EXPORT TO OUT OF STATE		GWh	-346	-258	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	42,567	43,911	45,161	45,745	47,120	48,044	49,047	50,147	51,263	52,356	53,478	54,608

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

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

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	ANNUAL FIRM INTERCHANGE 1/		%	0.1%	0.2%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.0%	0.0%	0.0%
(2)	NUCLEAR		%	15.7%	13.8%	14.7%	13.4%	14.1%	12.7%	13.6%	10.1%	13.0%	11.7%	12.4%	11.3%
(3)	COAL		%	33.8%	36.7%	36.5%	37.6%	35.9%	34.2%	33.9%	35.4%	33.7%	33.7%	33.2%	32.6%
(4)	RESIDUAL	TOTAL	%	14.8%	15.5%	13.9%	13.4%	10.6%	11.6%	9.2%	9.1%	7.0%	7.6%	6.4%	6.7%
(5)		STEAM	%	14.8%	15.5%	13.9%	13.4%	10.6%	11.6%	9.2%	9.1%	7.0%	7.6%	6.4%	6.7%
(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	%	1.4%	0.9%	0.6%	0.7%	0.4%	0.5%	0.3%	0.6%	0.5%	0.7%	0.4%	0.6%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	1.4%	0.9%	0.6%	0.7%	0.4%	0.5%	0.3%	0.6%	0.5%	0.7%	0.4%	0.6%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	15.1%	14.0%	15.5%	16.6%	21.4%	24.1%	26.6%	29.9%	35.8%	39.4%	40.8%	42.7%
(15)		STEAM	%	1.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(16)		CC	%	11.3%	11.2%	13.0%	13.9%	19.3%	21.3%	24.4%	27.3%	33.7%	37.0%	39.0%	40.7%
(17)		CT	%	2.7%	2.6%	2.5%	2.7%	2.1%	2.7%	2.2%	2.7%	2.2%	2.5%	1.8%	2.0%
(18)	OTHER 2/														
	QF PURCHASES		%	12.0%	11.4%	10.4%	10.0%	9.7%	9.3%	8.9%	7.3%	7.0%	6.8%	6.7%	6.2%
	IMPORT FROM OUT OF STATE		%	7.8%	8.1%	8.0%	7.9%	7.6%	7.5%	7.4%	7.2%	2.9%	0.0%	0.0%	0.0%
	EXPORT TO OUT OF STATE		%	-0.8%	-0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

1/ NET ENERGY PURCHASED (+) OR SOLD (-) WITHIN THE FRCC REGION.

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

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric energy usage over the planning horizon. PEF's forecasting framework utilizes a set of econometric models to achieve this end. This chapter will describe the underlying methodology of thc customer, energy, and peak demand forecasts including any assumptions incorporated within each. Also included is a description of how Demand-Side Management (DSM) impacts the forecast, the development of high and low forecast scenarios and a review of DSM programs.

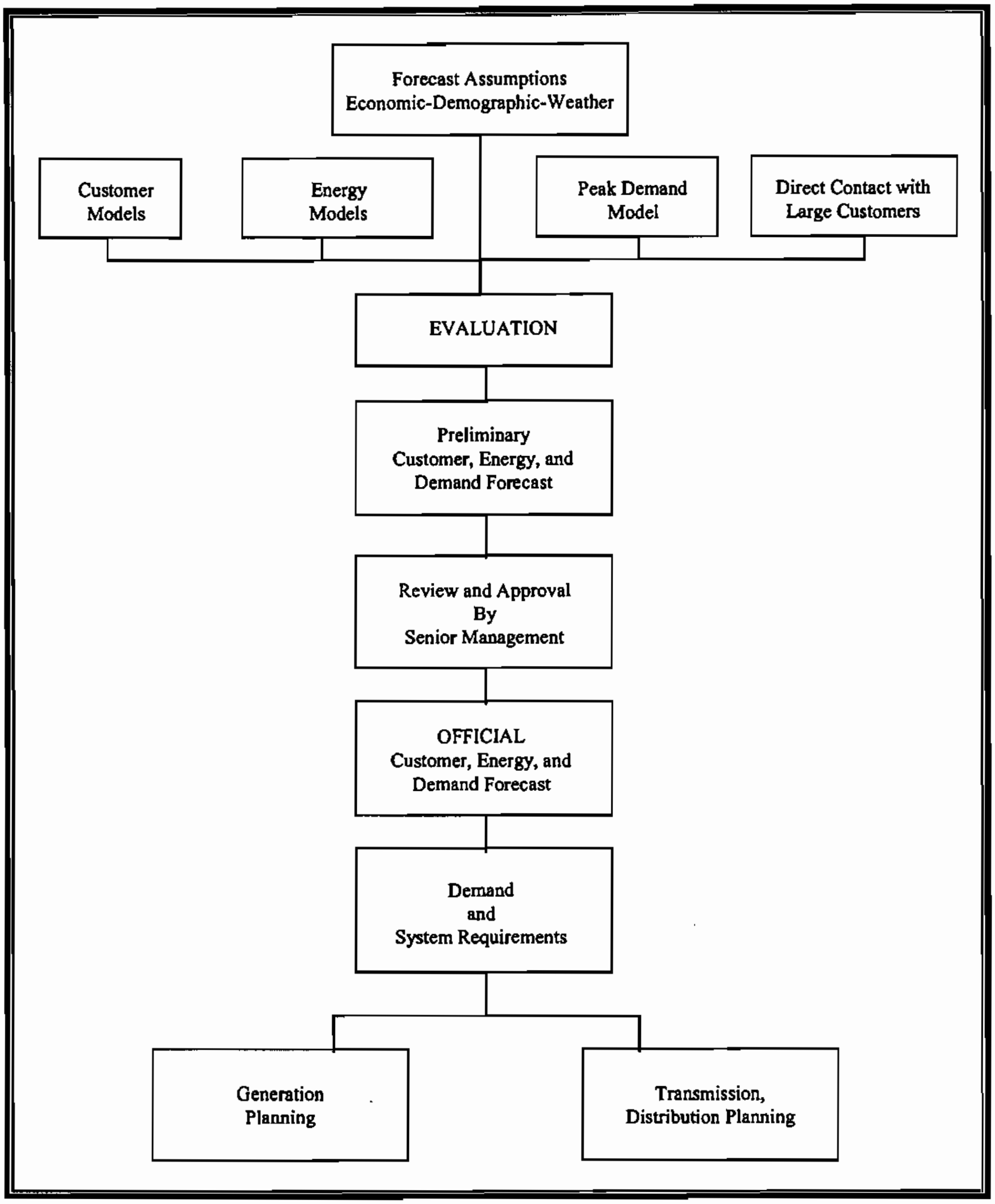
Figure 2.1, entitled "Customer, Energy and Demand Forecast", gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage as well as customer growth based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the forecaster at PEF 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 Financial Planning & Regulatory Services Department develops these assumptions based on discussions with a number of departments within PEF, as well as through the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



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GENERAL ASSUMPTIONS

1. Normal weather conditions are assumed over the forecast horizon using a sales-weighted average of conditions at the St. Petersburg, Orlando and Tallahassee weather stations. For kilowatt-hour sales projections, normal weather is based on a historical thirty-year average of service area weighted billing month degree-days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak.

2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 134 (January 2003) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (Quarter 2, 2003) are also incorporated.

3. Within the Progress Energy Florida (PEF) service area the phosphate mining industry is the dominant sector in the industrial sales class. Five major customers accounted for almost 30% of the industrial class MWh sales in 2003. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts.

   Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations that are heavily influenced by the state of these global conditions as well as local conditions. Until recently there has been excess mining capacity in the industry due to weak farm commodity prices and a strong U.S. exchange rate. Weak farm commodity prices lead to lower crop production, which results in less demand for fertilizer products. A strong U.S. currency results in U.S. fertilizer producers becoming less price-competitive. More recently, industry energy consumption has rebounded somewhat, although not to the levels experienced in the year 2000. The increase is mainly due to the elimination of extended vacation shutdowns that occurred during the lean times. A continued improvement into 2004 is based on a weaker U.S. dollar that will result in improved price competitiveness of the Florida producers worldwide.

4. PEF supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations received by PEF as of May 31, 2003. The forecast of energy and demand to PR customers reflects the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with FMPA, New Smyrna Beach, Tallahassee, Homestead, Reedy Creek Utilities, Florida Power & Light, and Seminole Electric Cooperative, Inc. (SECI). PEF's contractual arrangement with SECI includes a "supplemental" service contract (1983 contract) for service over and above stated levels they commit to supply themselves. The firm PR contract with SECI includes 150 MW of stratified intermediate service (October 1995 contract) which is projected to continue through the forecast horizon. The firm PR contract with SECI also includes amendments to provide an additional 150 MW of stratified intermediate service beginning June 2006, and 150 MW of stratified peaking service beginning December 2006. Agreements to provide interruptible service at two individual SECI metering sites have also been included in this projection.

5. This forecast assumes that PEF will successfully renew all future franchise agreements.

6. This forecast incorporates demand and energy reductions from PEF's dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

7. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. Regarding wholesale customers, the company does not plan for generation resources unless a long-term contract is in place. Current FR customers are assumed to renew their contracts with PEF except those who have given notice to terminate. Current PR contracts are projected to terminate as terms reach their expiration date. Deviation from these assumptions can occur based on information provided by the Progress Energy Ventures term marketing organization.

SHORT-TERM ECONOMIC ASSUMPTIONS

The short-term economic outlook (one year out) is still influenced by the terrorist events of September 11, 2001. While it is believed that the Florida tourist and travel industry is just now reaching pre 9/11 levels, the airline industry continues to struggle. This has kept travel-related tourist activities subdued the past two years. The continued reaction on the part of the Federal Reserve Board to dictate loose monetary policies, which hold down interest rates to 40-year lows, helped stimulate the national economy in 2003, especially the housing and automotive industries. This forecast incorporates a moderate economic upturn realizing that a boost from the housing and automotive industries, typical during the initial stages of economic expansion, will most likely not pack its usual punch. The recent Federal tax cuts and mortgage refinancing will continue to fuel economic expansion in 2004.

Going forward, this forecast assumes that the Federal Reserve Board (FRB) will orchestrate a proper balance of economic growth with low inflation via monetary policy measures. A shift from pursuing inflationary pressures to maintaining economic growth will keep the economy from slipping back into recession. Energy prices are also expected to settle at an equilibrium level between the depressed prices of the 1998-1999 period and recent high levels. Geopolitically, this forecast assumes no additional terrorist event in the U.S. and no "shock" to any supply or demand condition such as oil embargos. This means a return to "trend" level economic growth for the remaining years of the planning horizon is assumed.

On a regional basis, the aftermath of the September 11th attack will have a lingering but fading impact on travel and tourism industries in Florida. Airline industry financial woes will limit volume of passenger service for the foreseeable future. Interest rate levels will continue to influence the pace of economic growth in Florida through its effect on the construction industry. On the other hand, low returns on interest-bearing accounts hurt many senior citizens and reduce their disposable incomes. Personal income is expected to continue growing as population and jobs expand but not at the torrid pace experienced in the 1990s.

LONG-TERM ECONOMIC ASSUMPTIONS

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

Population Growth Trends

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

Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. This will continue to occur, but at less than historic rates for several reasons. First, Americans entering retirement age during the late 1990s and early twenty-first century were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Now that this generation is retiring, there exists a smaller pool of retirees capable of migrating to Florida. As we enter into the second decade of the new century and the baby-boom generation enters retirement age, the reverse effect can be expected.

Second, the enormous growth in population and corresponding development of the 1980s 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.

Another reason for a population growth slowdown deals with a younger age cohort. 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. This being the case, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period but at a less significant level.

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

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

<u>FORECAST METHODOLOGY</u>

The PEF forecast of customers, energy sales and peak demand is developed using customer class-specific econometric models. These models are expressly designed to capture class-specific variation over time. By modeling customer growth and average energy usage individually, the forecaster can better capture subtle changes in existing customer usage as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management and interruptible service.

ENERGY AND CUSTOMER FORECAST

In the retail jurisdiction, customer class models have been specified showing a historical relationship to weather and economic/demographic indicators using monthly data for sales models and annual data for customer models. Sales are regressed against "driver" variables that best explain monthly fluctuations over the historical sample period. Forecasts of these input variables are either derived internally or come from a review of the latest projections made by several independent forecasting concerns. The external sources of data include Economy.Com and the University of Florida's Bureau of Economic and Business Research. Internal company forecasts are used for projections of electricity price, weather conditions and the length of the billing month. Normal weather, which is assumed throughout the forecast horizon, is based on the 30-year average of heating and cooling degree-days by month as measured at the St Petersburg, Orlando and Tallahassee weather stations. Projections of PEF's demand-side management (conservation programs) are also incorporated as reductions to the forecast. Specific sectors are modeled as follows:

Residential Sector

Residential kWh usage per customer is modeled as a function of real Florida personal income, cooling degree-days, heating degree-days, the real price of electricity to the residential class and the average number of billing days in each sales month. This equation captures significant variation in residential usage caused by economic cycles, weather fluctuations, electric price movements and sales month duration. Projections of kWh usage per customer combined with the customer forecast provide the forecast of total residential energy sales. The residential customer forecast is developed by correlating annual customer growth with PEF service area population growth. County level population projections for the 29 counties, in which PEF serves residential customers, are provided by the BEBR.

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Commercial Sector

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

Industrial Sector

Energy sales to this sector are separated into two sub-sectors. A significant portion of industrial energy use is consumed by the phosphate mining industry. Because this one industry comprises nearly a 30% share of the total industrial class, it is separated and modeled apart from the rest of the class. The term "non-phosphate industrial" is used to refer to those customers who comprise the remaining portion of total industrial class sales. Both groups are impacted significantly by changes in economic activity. However, adequately explaining sales levels requires separate explanatory variables. Non-phosphate industrial energy sales are modeled using Florida manufacturing employment and a Florida industrial production index developed by Economy.Com, the real price of electricity to the industrial class, and the average number of sales month billing days.

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

Street Lighting

Electricity sales to the street and highway lighting class are projected to increase due to growth in the service area population base. Because this class comprised less than 0.01% of PEF's 2003 electric sales and just 0.1% of total customers, a simple time trend was used to project energy consumption and customer growth in this class.

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Public Authorities

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

Sales for Resale Sector

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

Seminole Electric Cooperative, Incorporated (SECI) is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average of several years' historical load shape of total load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has an agreement with SECI to serve stratified intermediate and peaking energy. This agreement involves serving 150 MW of stratified intermediate demand that is assumed to remain a requirement on the PEF system throughout the forecast horizon. This contract has been amended to provide an additional 150 MW stratified intermediate product and a 150 MW stratified peaking product beginning in 2006. Energy usage under this contract is projected using typical intermediate and peak load factors, respectively. Agreements to provide non-firm or interruptible service are currently in effect between PEF and SECI at two separate metering points amounting to an estimated 65 MW.

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 PEF. The full requirement customers are modeled individually using local weather station data and population growth trends. Since the ultimate consumers of electricity in this sector are, to a large degree, residential and commercial customers, it is assumed that their use patterns will follow those of the PEF retail-based residential and commercial customer classes. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach (NSB), Homestead and Tallahassee, and other power providers like Florida Municipal Power Agency (FMPA) and Florida Power & Light. In each case, these customers contract with PEF for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of the FMPA and NSB contracts are subject to change each year via a letter of "declared" MW nomination. More specifically, this means that the level and type of demand and energy under contract can increase or decrease for each year a value is nominated. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load. The energy projections for the Florida Municipal Power Agency (FMPA) also include a "losses service contract" for energy PEF supplies to FMPA for transmission losses incurred when "wheeling" power to their ultimate customers in PEF's transmission area. This projection is based on the projected requirements of the aggregated needs of the cities of Ocala, Leesburg and Bushnell.

PEAK DEMAND FORECAST

The forecast of peak demand also employs a disaggregated econometric methodology. For seasonal (winter and summer) peak demands, as well as each month of the year, PEF's coincident system peak is dissected into five major components. These components consist of potential firm retail load, conservation and load management program capability, wholesale demand, company use demand and interruptible demand.

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

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been approved by the Florida Public Service Commission. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm rctail demand resulting in a projected series of retail demand figures one would expect to occur.

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

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

Each of the peak demand components described above is a positive value except for the DSM program MW impacts and IS and CS load. These impacts represent a reduction in peak demand and are assigned a negative value. Total system peak demand is then calculated as the arithmetic sum of the five components.

HIGH AND LOW FORECAST SCENARIOS

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

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

The low retail scenario was chosen from among the ranked scenarios resulting in a bandwidth forecast reflecting an approximate probability of occurrence of 0.10. The high retail scenario similarly represents a bandwidth forecast with an approximate probability of occurrence of 0.90. In both scenarios the high and low peak demand bandwidth forecasts are projected from the energy forecasts using the load factor implicit in the base forecast scenario.

CONSERVATION GOALS

In October 1999, the FPSC established new conservation goals for PEF that span the ten-year period from 2000 through 2009 (in Docket 971005-EG, Order No. PSC-99-1942-FOF-EG). As required by Rule 25-17.0021(4), Florida Administrative Code, PEF then submitted for Commission approval a new DSM Plan that was specifically designed to meet the new conservation goals. PEF's DSM Plan was subsequently approved by the Commission on April 17, 2000 (in Docket 991789-EG, Order No. PSC-00-750-PAA-EG). The following tables present PEF's historical DSM performance by showing the Commission-approved conservation goals as well as the conservation savings actually achieved through PEF's DSM programs for the reporting years of 2000-2003.

Historical Residential Conservation Savings Goals and Achievements

	Cumulative Summer MW		Cumulative Winter MW		Cumulative Energy GWh	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2000	10	17	30	35	15	21
2001	20	29	64	72	32	42
2002	32	43	102	111	50	65
2003	45	59	142	152	69	90

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Historical Commercial/Industrial Conservation Savings Goals and Achievements

	Cumulative Summer MW		Cumulative Winter MW		Cumulative Energy GWh	
Year	Goal	Achieved	Goal	Achieved	Goal	Achieved
2000	4	12	4	12	2	6
2001	8	18	7	17	4	10
2002	11	28	11	24	6	14
2003	15	35	15	29	8	18

The forecasts contained in this Ten-Year Site Plan document are based on PEF's DSM Plan and, therefore, appropriately reflect the level of DSM savings required to meet the Commission-established conservation goals. PEF's DSM Plan consists of five residential programs, 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 bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option) - a customer-completed audit; Type 4: Phone Assisted Audit - a customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III). The Home Energy Check Program serves as the foundation of the Home Energy Improvement Program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement Program

This is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, 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 dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps, heat recovery units, and dedicated 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.

Low Income Weatherization Assistance Program

This umbrella program seeks to improve energy efficiency for low-income customers in existing residential dwellings. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, reduced air infiltration, water heater wrap, HVAC maintenance, high efficiency heat pumps, heat recovery units, and dedicated heat pump water heaters.

Residential Energy Management Program

This is a voluntary customer program that allows PEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio-controlled switches installed on the customer's premises. These interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills. Due to the cost of new installations, this program was modified in the 1999 filing to allow for participation in a winter-only program that provides for direct load control of water heating and central heating appliances during the months of November through March.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check Program

This energy audit program provides commercial and industrial customers with an assessment of the current energy usage at their facilities, recommendations on how they can improve the environmental conditions of their facilities while saving on their electricity bills, and information on low-cost energy efficiency measures. The Business Energy Check consists of the following types of audits: A free walk-through audit, and a paid walk-through audit. Small business customers also have the option to complete a Business Energy Check online at Progress Energy's website. In most cases, this program is a prerequisite for participation in the other C/I programs.

Better Business Program

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to PEF and its customers. The Better Business Program promotes energy efficient heating, ventilation, air conditioning (HVAC), motors, and some building retrofit measures (in particular, ceiling 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, and heat recovery units.

Innovation Incentive Program

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

Commercial Energy Management Program (Rate Schedule GSLM-1)

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

Standby Generation Program

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

Interruptible Service Program

This direct load control program reduces PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to have their power interrupted. PEF will have remote control of the circuit breaker or disconnect switch supplying the customer's equipment. In return for this ability to interrupt load, customers participating in the Interruptible Service program receive a monthly interruptible demand credit applied to their electric bills. In response to customer requests, PEF has implemented 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 PEF's demand at times of capacity shortage during peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit applied to their electric bills.

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development Program

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

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

Progress Energy

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 9,782 MW, as shown in Table 3.1. This capacity resource includes utility purchased power (474 MW), non-utility purchased power (833 MW), combustion turbine (2,619 MW, 143 MW of which is owned by Georgia Power for the months June through September), nuclear (769 MW), fossil steam (3,882 MW) and combined-cycle plants (1,205 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QFs).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2004 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 971005-EG.

Capacity and Demand Forecast

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

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes 2,885 MW (summer rating) of proposed new capacity additions through the summer of 2013. As identified in Schedule 8, PEF's next planned need is the Hines 3 Unit, a 516 MW (summer) power block with a December 2005 in-service date. PEF's self-build option for Hines Unit 3 was determined to be the most cost-effective alternative (FPSC Docket No. 020953-EI, Order No. PSC-03-0175-FOF-EI, issued February 4, 2003). In accordance with Rule 25-22.082 (F.A.C.), PEF issued a request for proposals (RFP) on October 7, 2003 to solicit competitive proposals for supply-side alternatives to its next planned combined-cycle unit, a fourth gas-fired combined-cycle unit at the Hines Energy Complex. Proposals have been received and are currently being evaluated.

PEF's Base Expansion Plan projects requirements for additional combined-cycle units with proposed in-service dates of 2007, 2009, 2010, 2012 and 2013. These high efficiency gas-fired combined-cycle units, together with three CT units planned for December 2006 help the PEF system meet the growing energy requirements of its customer base and also contribute to meeting the requirements of the 1990 Clean Air Act Amendments. Fuel switching, SO_2 emission allowance purchases, re-dispatching of system generation and technology improvements are additional options available to PEF to ensure compliance with these important environmental requirements. Status reports and specifications for new generation facilities are included in Schedule 9. As shown in Schedule 10, there are no new transmission lines associated with the Hines 3 combined-cycle addition.

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

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2003

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

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

Purchased Power			
Qualifying Facility Contracts	19	833	
Investor Owned Utilities	2	474	
TOTAL CAPACITY RESOURCES		**9,782**	

TABLE 3.2

PROGRESS ENERGY FLORIDA

QUALIFYING FACILITY GENERATION CONTRACTS

AS OF DECEMBER 31, 2003

Facility Name	Firm Capacity (MW)
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Jefferson Power	2.0
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery	54.8
Ridge Generating Station	39.6
Royster	30.8
Timber Energy	12.5
US Agrichem	5.6
TOTAL	**832.7**

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PROGRESS ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL	FIRM		FIRM		TOTAL	SYSTEM FIRM					
	INSTALLED	CAPACITY		CAPACITY		CAPACITY	SUMMER PEAK	RESERVE MARGIN		SCHEDULED	RESERVE MARGIN	
	CAPACITY	IMPORT		EXPORT	QF	AVAILABLE	DEMAND	BEFORE MAINTENANCE		MAINTENANCE	AFTER MAINTENANCE	
YEAR	MW	MW		MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2004	8,332	474		0	833	9,639	7,997	1,642	21%	0	1,642	21%
2005	8,332	642	*	0	820	9,794	8,117	1,677	21%	0	1,677	21%
2006	8,848	642	*	0	820	10,310	8,519	1,791	21%	0	1,791	21%
2007	9,322	484		0	802	10,608	8,758	1,850	21%	0	1,850	21%
2008	9,783	484		0	787	11,054	8,954	2,100	23%	0	2,100	23%
2009	9,783	484		0	647	10,914	9,110	1,804	20%	0	1,804	20%
2010 **	10,739	70		0	647	11,456	9,330	2,126	23%	0	2,126	23%
2011	10,739	0		0	647	11,386	9,486	1,900	20%	0	1,900	20%
2012	11,217	0		0	647	11,864	9,634	2,230	23%	0	2,230	23%
2013	11,217	0		0	537	11,754	9,811	1,943	20%	0	1,943	20%

* Progress Energy is currently negotiating a firm purchase of approximately 158 MW which is expected to run from the summer of 2005 through the winter of 2006/2007. The deal is not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

** Progress Energy currently has a contract with the Southern Companies to purchase approximately 400 MW of firm capacity through May, 2010. The expansion plan currently shows the addition of a combined-cycle unit, to be placed in service in May, 2010, as a placeholder for extension of the contract. Discussions are currently underway to extend the contract, and it is expected that agreement will be reached either with the Southern Companies, or another supplier, which will continue the import of this firm capacity and energy across the Florida-Georgia interface well beyond the planning period presented. While the exact terms of the contract extension/replacement are not known at this time, the combined-cycle unit placed in service in 2010 is a reasonable match to the capacity and energy expected to be obtained in either a contract extension or agreement with another supplier.

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PROGRESS ENERGY FLORIDA

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QP	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
2003 / 04	9,174	494 *		833	10,501	8,626	1,875	22%	0	1,875	22%
2004 / 05	9,174	672 *	0	820	10,666	8,903	1,763	20%	0	1,763	20%
2005 / 06	9,756	642 **	0	820	11,218	9,153	2,065	23%	0	2,065	23%
2006 / 07	10,320	642 **	0	802	11,764	9,595	2,169	23%	0	2,169	23%
2007 / 08	10,837	484	0	787	12,108	9,737	2,371	24%	0	2,371	24%
2008 / 09	10,837	484	0	678	11,999	9,891	2,108	21%	0	2,108	21%
2009 / 10	11,373	484	0	647	12,504	10,114	2,390	24%	0	2,390	24%
2010 / 11 ***	11,909	70	0	647	12,626	10,275	2,351	23%	0	2,351	23%
2011 / 12	11,909	0	0	647	12,556	10,427	2,129	20%	0	2,129	20%
2012 / 13	12,445	0	0	647	13,092	10,606	2,486	23%	0	2,486	23%

* Includes Seasonal Purchase of 20 MW in 2003/04 and 188 MW in 2004/05.

** Progress Energy is currently negotiating a firm purchase of approximately 158 MW which is expected to run from the summer of 2005 through the winter of 2006/2007. The deal is not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

*** Progress Energy currently has a contract with the Southern Companies to purchase approximately 400 MW of firm capacity through May, 2010. The expansion plan currently shows the addition of a combined-cycle unit, to be placed in service in May, 2010, as a placeholder for extension of the contract. Discussions are currently underway to extend the contract, and it is expected that agreement will be reached either with the Southern Companies, or another supplier, which will continue the import of this firm capacity and energy across the Florida-Georgia interface well beyond the planning period presented. While the exact terms of the contract extension/replacement are not known at this time, the combined-cycle unit placed in service in 2010 is a reasonable match to the capacity and energy expected to be obtained in either a contract extension or agreement with another supplier.

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PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2004 THROUGH DECEMBER 31, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK	9/2003	12/2005			516	582	U	
PEAKER	1	UNKNOWN	GT	NG	DFO	PL	UN	12/2005	12/2006			158	188	P	
PEAKER	2	UNKNOWN	GT	NG	DFO	PL	UN	12/2005	12/2006			158	188	P	
PEAKER	3	UNKNOWN	GT	NG	DFO	PL	UN	12/2005	12/2006			158	188	P	
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	9/2005	12/2007			461	517	P	
HINES ENERGY COMPLEX	5	POLK	CC	NG	DFO	PL	TK	9/2007	12/2009			478	536	P	
HINES ENERGY COMPLEX	6	POLK	CC	NG	DFO	PL	TK	2/2008	5/2010			478	536	P	
COMBINED-CYCLE	1	UNKNOWN	CC	NG	DFO	PL	UN	2/2010	5/2012			478	536	P	
COMBINED-CYCLE	2	UNKNOWN	CC	NG	DFO	PL	UN	9/2011	12/2013			478	536	P	

000118

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #3
(2)	Capacity	
	a. Summer:	516
	b. Winter:	582
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	9/2003
	b. Commercial in-service date:	12/2005 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	UNDER CONSTRUCTION, LESS THAN 50% COMPLETE
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	5.8 %
	b. Forced Outage Factor (FOF):	3.0 %
	c. Equivalent Availability Factor (EAF):	91.4 %
	d. Resulting Capacity Factor (%):	69.0 %
	e. Average Net Operating Heat Rate (ANOHR):	6,962 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	435.57
	c. Direct Construction Cost ($/kW):	389.18
	d. AFUDC Amount ($/kW):	46.39
	e. Escalation ($/kW):	0.00
	f. Fixed O&M ($/kW-yr):	1.32
	g. Variable O&M ($/mWh):	2.10
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	PEAKER 1
(2)	Capacity	
	a. Summer:	158
	b. Winter:	188
(3)	Technology Type:	COMBUSTION TURBINE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	12/2005
	b. Commercial in-service date:	12/2006 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION (NATURAL GAS) WATER INJECTION (DISTILLATE FUEL OIL)
(7)	Cooling Method:	AIR
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.7 %
	c. Equivalent Availability Factor (EAF):	88.7 %
	d. Resulting Capacity Factor (%):	12.0 %
	e. Average Net Operating Heat Rate (ANOHR):	10,711 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	336.94
	c. Direct Construction Cost ($/kW):	298.90
	d. AFUDC Amount ($/kW):	22.91
	e. Escalation ($/kW):	15.13
	f. Fixed O&M ($/kW-yr):	2.38
	g. Variable O&M ($/mWh):	11.15
	h. K Factor:	NO CALCULATION

000120

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	PEAKER 2
(2)	Capacity	
	a. Summer:	158
	b. Winter:	188
(3)	Technology Type:	COMBUSTION TURBINE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	12/2005
	b. Commercial in-service date:	12/2006 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION (NATURAL GAS) WATER INJECTION (DISTILLATE FUEL OIL)
(7)	Cooling Method:	AIR
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.7 %
	c. Equivalent Availability Factor (EAF):	88.7 %
	d. Resulting Capacity Factor (%):	12.0 %
	e. Average Net Operating Heat Rate (ANOHR):	10,711 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	336.94
	c. Direct Construction Cost ($/kW):	298.90
	d. AFUDC Amount ($/kW):	22.91
	e. Escalation ($/kW):	15.13
	f. Fixed O&M ($/kW-yr):	2.38
	g. Variable O&M ($/mWh):	11.15
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	PEAKER 3
(2)	Capacity	
	a. Summer:	158
	b. Winter:	188
(3)	Technology Type:	COMBUSTION TURBINE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	12/2005
	b. Commercial in-service date:	12/2006 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION (NATURAL GAS) WATER INJECTION (DISTILLATE FUEL OIL)
(7)	Cooling Method:	AIR
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	4.7 %
	c. Equivalent Availability Factor (EAF):	88.7 %
	d. Resulting Capacity Factor (%):	12.0 %
	e. Average Net Operating Heat Rate (ANOHR):	10,711 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	336.94
	c. Direct Construction Cost ($/kW):	298.90
	d. AFUDC Amount ($/kW):	22.91
	e. Escalation ($/kW):	15.13
	f. Fixed O&M ($/kW-yr):	2.38
	g. Variable O&M ($/mWh):	11.15
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #4
(2)	Capacity	
	a. Summer:	461
	b. Winter:	517
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	9/2005
	b. Commercial in-service date:	12/2007 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.0 %
	b. Forced Outage Factor (FOF):	3.0 %
	c. Equivalent Availability Factor (EAF):	91.2 %
	d. Resulting Capacity Factor (%):	64.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,158 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	474.06
	c. Direct Construction Cost ($/kW):	428.47
	d. AFUDC Amount ($/kW):	45.59
	e. Escalation ($/kW):	0.00
	f. Fixed O&M ($/kW-yr):	1.20
	g. Variable O&M ($/mWh):	2.78
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #5
(2)	Capacity	
	a. Summer:	478
	b. Winter:	536
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	9/2007
	b. Commercial in-service date:	12/2009 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	6.7 %
	c. Equivalent Availability Factor (EAF):	86.9 %
	d. Resulting Capacity Factor (%):	50.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,124 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	513.42
	c. Direct Construction Cost ($/kW):	406.80
	d. AFUDC Amount ($/kW):	53.17
	e. Escalation ($/kW):	53.45
	f. Fixed O&M ($/kW-yr):	2.95
	g. Variable O&M ($/mWh):	2.41
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #6
(2)	Capacity	
	a. Summer:	478
	b. Winter:	536
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	2/2008
	b. Commercial in-service date:	5/2010 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	COOLING POND
(8)	Total Site Area:	8,200 ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	SITE PERMITTED
(11)	Status with Federal Agencies:	SITE PERMITTED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	6.7 %
	c. Equivalent Availability Factor (EAF):	86.9 %
	d. Resulting Capacity Factor (%):	50.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,124 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	526.26
	c. Direct Construction Cost ($/kW):	406.80
	d. AFUDC Amount ($/kW):	54.50
	e. Escalation ($/kW):	64.96
	f. Fixed O&M ($/kW-yr):	2.95
	g. Variable O&M ($/mWh):	2.41
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	COMBINED-CYCLE 1
(2)	Capacity	
	a. Summer:	478
	b. Winter:	536
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	2/2010
	b. Commercial in-service date:	5/2012 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	6.7 %
	c. Equivalent Availability Factor (EAF):	86.9 %
	d. Resulting Capacity Factor (%):	50.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,124 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	552.90
	c. Direct Construction Cost ($/kW):	406.80
	d. AFUDC Amount ($/kW):	57.26
	e. Escalation ($/kW):	88.84
	f. Fixed O&M ($/kW-yr):	2.95
	g. Variable O&M ($/mWh):	2.41
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

(1)	Plant Name and Unit Number:	COMBINED-CYCLE 2
(2)	Capacity	
	a. Summer:	478
	b. Winter:	536
(3)	Technology Type:	COMBINED-CYCLE
(4)	Anticipated Construction Timing	
	a. Field construction start date:	9/2011
	b. Commercial in-service date:	12/2013 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	NATURAL GAS
	b. Alternate fuel:	DISTILLATE FUEL OIL
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	6.9 %
	b. Forced Outage Factor (FOF):	6.7 %
	c. Equivalent Availability Factor (EAF):	86.9 %
	d. Resulting Capacity Factor (%):	50.0 %
	e. Average Net Operating Heat Rate (ANOHR):	7,124 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	25
	b. Total Installed Cost (In-service year $/kW):	566.72
	c. Direct Construction Cost ($/kW):	406.80
	d. AFUDC Amount ($/kW):	58.69
	e. Escalation ($/kW):	101.23
	f. Fixed O&M ($/kW-yr):	2.95
	g. Variable O&M ($/mWh):	2.41
	h. K Factor:	NO CALCULATION

PROGRESS ENERGY FLORIDA

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

HINES UNIT #3

(1)	POINT OF ORIGIN AND TERMINATION:	N/A
(2)	NUMBER OF LINES:	N/A
(3)	RIGHT-OF-WAY:	N/A
(4)	LINE LENGTH:	N/A
(5)	VOLTAGE:	N/A
(6)	ANTICIPATED CONSTRUCTION TIMING:	N/A
(7)	ANTICIPATED CAPITAL INVESTMENT:	N/A
(8)	SUBSTATIONS:	N/A
(9)	PARTICIPATION WITH OTHER UTILITIES:	N/A

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INTEGRATED RESOURCE PLANNING OVERVIEW

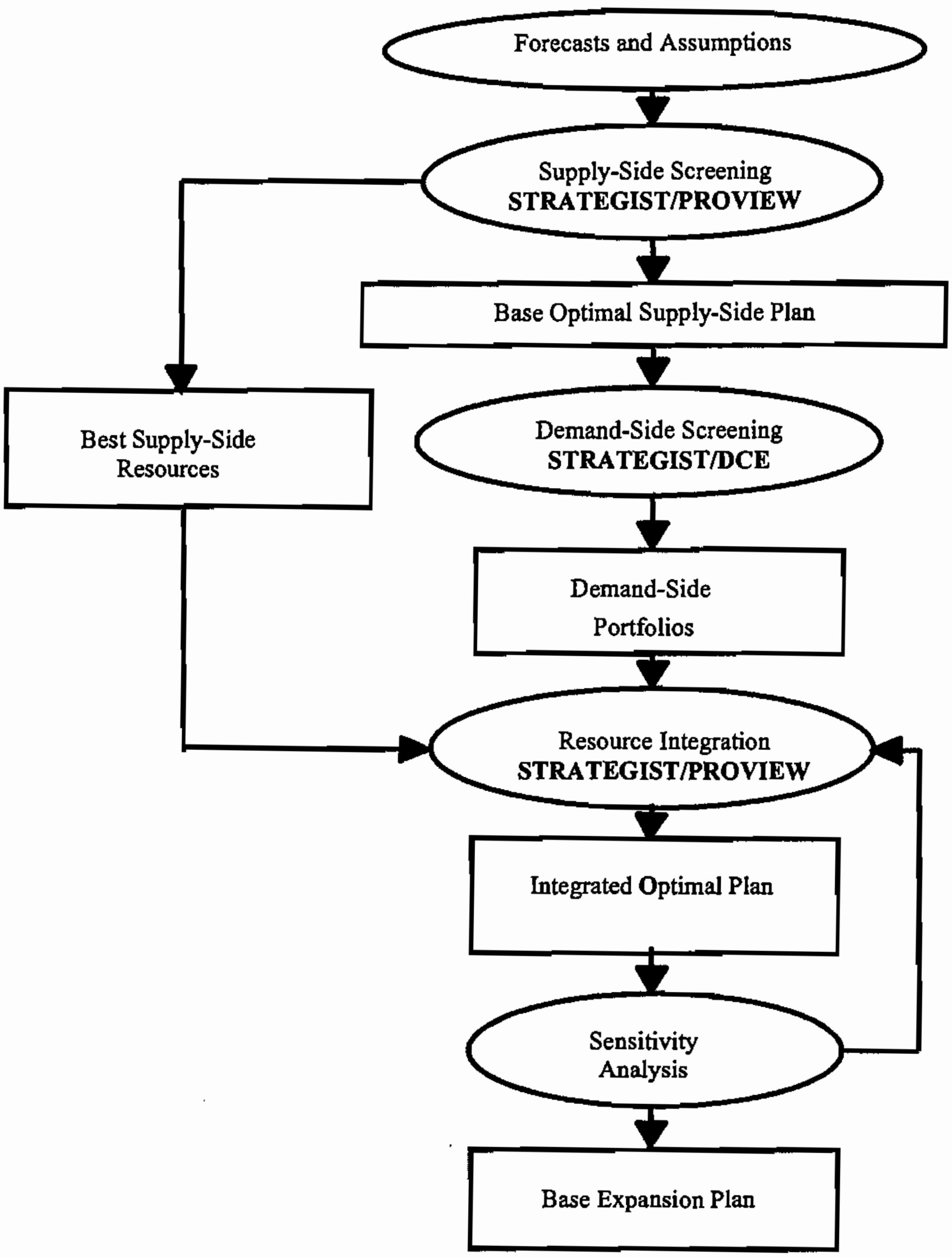
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future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

An overview of PEF's IRP Process is shown in Figure 3.1. The process begins with the development of various forecasts, including demand and energy, fuel prices, and economic assumptions. Future supply- and demand-side resource alternatives are identified and extensive cost and operating data are collected to enable these to be modeled in detail. These alternatives are optimized together to determine the most cost-effective plan for PEF to pursue over the next ten years to meet the company's reliability criteria. The resulting ten-year plan, the Integrated Optimal Plan, is then tested under different sensitivity scenarios to identify variances, if any, which would warrant reconsideration of any of the base plan assumptions. If the plan is judged robust under sensitivity analysis and works within the corporate framework, it evolves as the Base Expansion Plan. This process is discussed in more detail in the following section titled "The IRP Process".

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

FIGURE 3.1

IRP Process Overview



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THE IRP PROCESS

Forecasts and Assumptions

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

Reliability Criteria

Utilities require a margin of generating capacity above the firm demands of their customers in order to provide reliable service. Periodic scheduled outages are required to perform maintenance and inspections of generating plant equipment and to refuel nuclear plants. At any given time during the year, some capacity may be out of service due to unanticipated equipment failures resulting in forced outages of generation units. Adequate reserve capacity must be available to accommodate these outages and to compensate for higher than projected peak demand due to forecast uncertainty and abnormal weather. In addition, some capacity must be available for operating reserves to maintain the balance between supply and demand on a moment-to-moment basis.

PEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of PEF's ability to meet its forecasted seasonal peak load with firm capacity. The FPSC approved a joint proposal from the investor-owned utilities in peninsular Florida to increase the minimum planning Reserve Margin level to 20 percent by the summer of 2004 (Docket No. 981890-EU, Order No. PSC-99-2507-S-EU). PEF thus plans its resources to satisfy the 20 percent minimum Reserve Margin criterion.

Loss of Load Probability (LOLP) is a probabilistic criterion that measures the probability that a company will be unable to meet its load throughout the year. While Reserve Margin only considers the peak load and amount of installed resources, LOLP also takes into account generating unit sizes, capacity mix, maintenance scheduling, unit availabilities, and capacity assistance available from other utilities. A standard probabilistic reliability threshold commonly used in the electric utility industry, and the criterion employed by PEF, is a maximum of one day in ten years loss of load probability.

PEF has based its resource planning on the use of dual reliability criteria since the early 1990s, a practice that has been accepted by the FPSC. PEF's resource portfolio is designed to satisfy the minimum 20% Reserve Margin requirement and probabilistic analyses are conducted to ensure that the one day in ten years LOLP criterion is also satisfied. By using both the Reserve Margin and LOLP planning criteria, PEF's resource portfolio is designed to have sufficient capacity available to meet customer peak demand, and to provide reliable generation service under all expected load conditions.

Supply-Side Screening

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

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

Demand-Side Screening

Like supply-side resources, data for large numbers of potential demand-side resources is also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (building code), or not applicable to PEF's customers. The demand-side screening module of STRATEGIST, DCE (formerly known as 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. DCE calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test. Demand-side programs that pass the RIM test are then bundled together to create demand-side portfolios. These portfolios contain the appropriate DSM options and make the optimization solvable with the STRATEGIST model.

Resource Integration and the Integrated Optimal Plan

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

Developing the Base Expansion Plan

The plans that provide the lowest revenue requirements are then further tested using sensitivity analysis. The economics of the plan 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 using short-term and long-term market price projections from industry-recognized sources. Coal prices are expected to be relatively stable month to month; however, oil and natural gas prices are expected to be more volatile on a day-to-day and month-to-month basis.

In the short term, the base cost for coal is based on the existing contractual structure between Progress Fuels Corporation (PFC) and Progress Energy Florida and both contract and spot market coal and transportation arrangements between PFC and its various suppliers. For the longer term, the costs are based on market forecasts reflective of expected market conditions. Oil and natural gas prices are estimated based on current and expected contracts and spot purchase arrangements as well as near-term and long-term market forecasts. Oil and natural gas commodity prices are driven primarily by open market forces of supply and demand. Natural gas firm transportation cost is determined primarily by pipeline tariff rates and tends to change less frequently than commodity prices.

Financial Forecast

The key financial assumptions used in PEF's most recent planning studies were 48% debt and 52% equity PEF capital structure, projected debt cost of 6.5%, and an equity return of 12.0%. These assumptions resulted in a weighted average cost of capital of 9.36% and an after-tax discount rate of 8.16%. In recent planning work, PEF did not test the sensitivity of the base resource plan to varying financial assumptions. This is due to the fact that the most economical options are combined-cycle (CC) and combustion turbine (CT) gas-fired units with relatively short construction lead times and low capital costs. These options have lower capital costs than alternatives; therefore, higher financial assumptions would not be expected to alter the results in any significant way.

Lower cost of capital escalation rates would favor options with longer construction lead times and higher capital costs. However, PEF does not expect escalation rates to go much lower than the current base case forecast. Consequently, PEF does not believe that financial assumption sensitivity cases are needed.

CURRENT PLANNING RESULTS

TYSP Supply-Side Resources

In this TYSP, PEF's supply-side resources include the projected combined-cycle expansion of the Hines Energy Complex (HEC) with Units 3 through 5 forecasted to be in-service by December 2005, 2007, and 2009, and Unit 6 to be in-service by May 2010. The new units at Hines are state-of-the-art combined-cycle units similar to HEC Unit 2. As new advancements in combined-cycle technologies mature, PEF will continue to examine the merits of these new alternatives to ensure the lowest possible expansion costs. The TYSP also includes three combustion turbine units planned in-service December 2006 and two generic combined-cycle units with planned in-service dates of May 2012 and December 2013. PEF had previously projected the next peaking addition to be installed at the Intercession City site. However, the Company is currently conducting more detailed analyses of other existing generation sites including Anclote and DeBary, and has not finalized its decision on the preferred site(s) for these combustion turbine additions.

Plan Sensitivities

Sensitivities to load and fuel forecasts were analyzed against the base plan. The base plan of constructing combined-cycle and combustion turbine units on gas was determined to be robust with respect to changes in the load and fuel forecasts. The low load forecast sensitivity required less combined-cycle and combustion turbine generation; the high load forecast 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 higher fuel prices resulted in an improvement in the economics of pulverized coal, particularly beyond the 10-year planning horizon. The additional sensitivity, which assumes the current differential price of oil and gas to coal remains constant over time, did not demonstrate any significant change in the relative economics of alternatives when compared to the base plan. This current differential in oil and gas to coal prices, however, includes recent spikes in natural gas prices that historically have been of a short-term nature and, thus, are not expected to continue over the planning horizon. PEF will continue to monitor these fuel price relationships and watch for any signs of a long-term structural change.

Request for Proposals

In accordance with Rule 25-22.082 (F.A.C.), PEF issued a request for proposals (RFP) on October 7, 2003 to solicit competitive proposals for supply-side alternatives to its next planned combined-cycle unit, a fourth gas-fired combined-cycle unit at Hines Energy Complex. Proposals have been received and are currently being evaluated.

TRANSMISSION PLANNING

PEF's transmission planning assessment practices are developed to test the ability of the planned system to meet the reliability criteria as outlined in the FERC Form 715 filing. This involves the use of load flow and transient stability programs to model various contingency situations that may occur, and determining if the system response meets the reliability criteria. In general, this involves running simulations for the loss of any single line, generator, or transformer. PEF normally runs this analysis for system load levels from minimum to peak for all possible contingencies, and for both summer and winter. Additional studies are performed to determine the system response to credible, less probable criteria, to assure the system meets PEF and Florida Reliability Coordinating Council, Inc. (FRCC) criteria. These studies include the loss of multiple generators or lines, and combinations of each, and some load loss is permissible under these more severe disturbances. These credible, less probable scenarios are also evaluated at various load levels, since some of the more severe situations occur at average or minimum load conditions. In particular, critical fault clearing times are typically the shortest (most severe) at minimum load conditions, with just a few large base load units supplying the system needs.

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

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

- FRCC: FRCC ATC Calculation and Coordination Procedures, November 4, 2003, which is posted on the FRCC website: (http://www.frcc.com/downloads/frccatc.pdf)

- NERC: Transmission Transfer Capability, May 1, 1995

- NERC: Available Transfer Capability – Definitions and Determination, July 30, 1996

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

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

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

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

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TABLE 3.3

PROGRESS ENERGY FLORIDA

LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS

2004-2013

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT.-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1141	PEF/FPL	VANDOLAH	WHIDDEN	14	10 / 2004	230
1141	PEF	LAKE BRYAN	WINDERMERE #1	10 *	10 / 2006	230
1141	PEF	LAKE BRYAN	WINDERMERE #2	10	10 / 2006	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #1	21	5 / 2007	230
1141	PEF	INTERCESSION CITY	GIFFORD	10	4 / 2008	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #2	21	5 / 2009	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #1	30 *	6 / 2010	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #2	30	6 / 2010	230

* Rebuild existing circuit

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

Progress Energy

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

PEF's base expansion plan proposes new combined-cycle generation at the Hines Energy Complex (HEC) site in Polk County. New proposed peaking simple-cycle combustion turbine generation site options include Intercession City (Osceola County), Anclote (Pasco County), and DeBary (Volusia County). While the Intercession City, Anclote, and DeBary sites are suitable for new peaking generation, PEF continues to evaluate other available sites for future supply alternatives.

The next proposed combined-cycle unit at the HEC site is scheduled for commercial operation in December 2005. The next proposed peaking simple-cycle unit is scheduled for commercial operation in December 2006. The HEC, Intercession City, Anclote, and DeBary sites meet all of PEF's siting requirements for capacity throughout the planning horizon. PEF's existing sites, as identified in Table 3.1 of Chapter 3, include the capability to further develop generation. All appropriate permitting requirements will be addressed for PEF's preferred sites as discussed in the following site descriptions. The base expansion plan does not include any potential new sites for generating additions. Therefore, detailed environmental or land use data are not included.

HINES ENERGY COMPLEX SITE

In 1990, PEF completed a statewide search for a new 3,000 MW coal capable power plant site. As a result of this work, a large tract of mined-out phosphate land in south central Polk County was selected as the primary alternative. This 8,200-acre site is located south of the City of Bartow, near the cities of Fort Meade and Homeland, south of S.R. 640 and west of U.S. 17/98 (reference Figure 4.1). It is an area that has been extensively mined and remains predominantly unreclaimed.

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

The site's initial preparation involved moving over 10 million cubic yards of soil and draining 4 billion gallons of water. Construction of the energy complex will recycle the land for a beneficial use and promote habitat restoration.

The Hines Energy Complex is visited by several species of wildlife, including alligators, bobcats, turtles, and over 50 species of birds. The Hines site also contains a wildlife corridor, which creates a continuous connection between the Peace River and the Alafia River.

PEF arranged for the City of Bartow to provide treated effluent for cooling pond make-up. The complex's cooling pond initially covered 722 acres with an eventual expansion to 2,500 acres.

The Hines Energy Complex is designed and permitted to be a zero discharge site. This means that there will be no discharges to surface waters either from the power plant facilities or from storm water runoff. Based on this design, storm water runoff from the site can be used as cooling pond make-up, minimizing groundwater withdrawals.

The Florida Department of Environmental Protection air rules currently list all of Polk County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

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

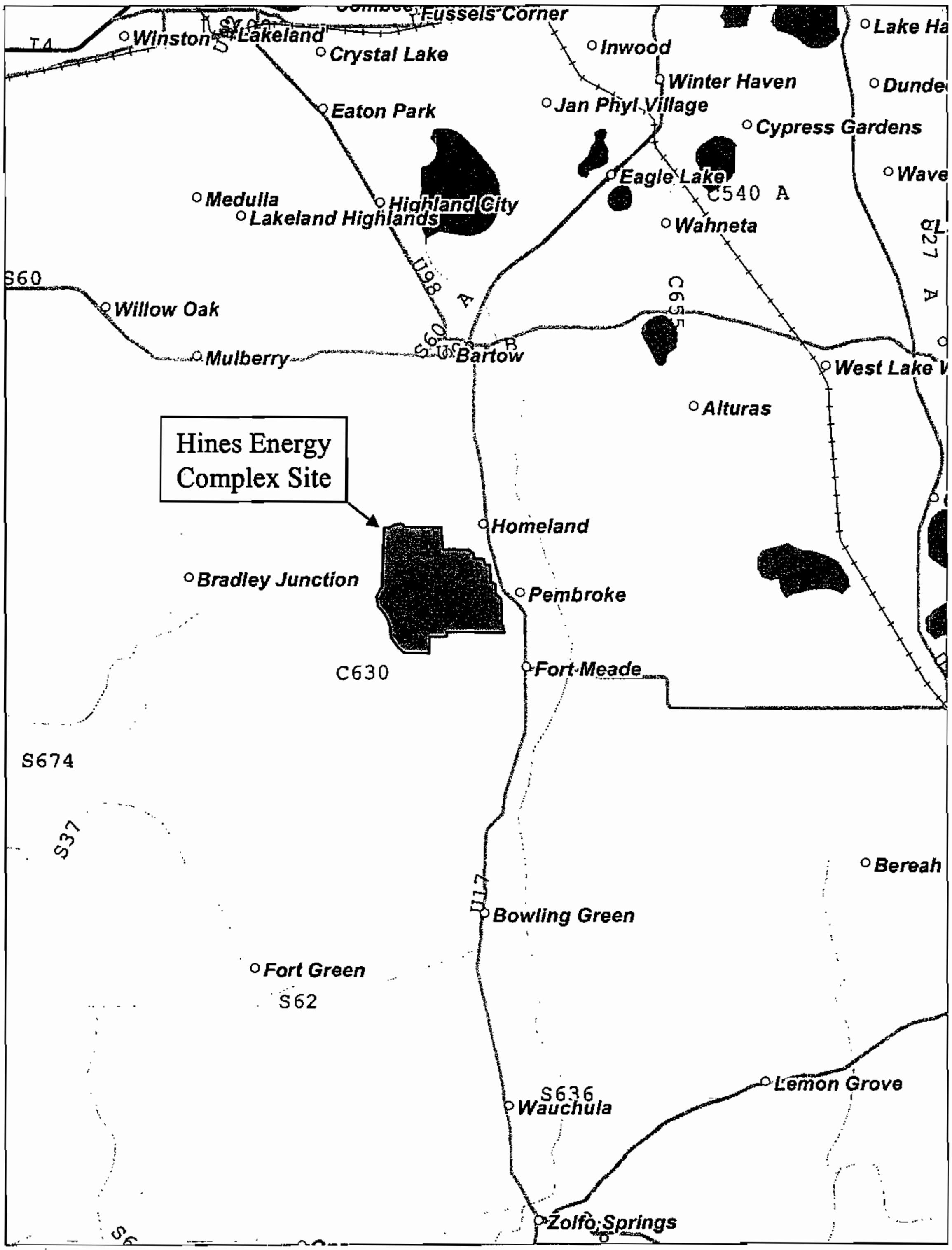
The first combined-cycle unit at this site, with a capacity of 482 MW summer and 529 MW winter, began commercial operation in April 1999. The transmission improvements associated with this first unit were the rebuilding of the 230/115 kV double circuit Barcola to Ft. Meade line by increasing the conductor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

The second combined-cycle unit at this site entered commercial operation in December 2003 with seasonal capacity ratings of 516 MW summer and 582 MW winter. The transmission improvement associated with the second combined-cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to Barcola.

The third HEC combined-cycle unit is planned for commercial operation in December 2005 with seasonal capacity ratings of 516 MW summer and 582 MW winter, and requires no transmission upgrades.

FIGURE 4.1

Hines Energy Complex Site (Polk County)



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INTERCESSION CITY SITE

Intercession City was chosen as a potential site for installation of peaking combustion turbine units. The seasonal ratings for each proposed peaking combustion turbine unit are projected to be 158 MW summer and 188 MW winter.

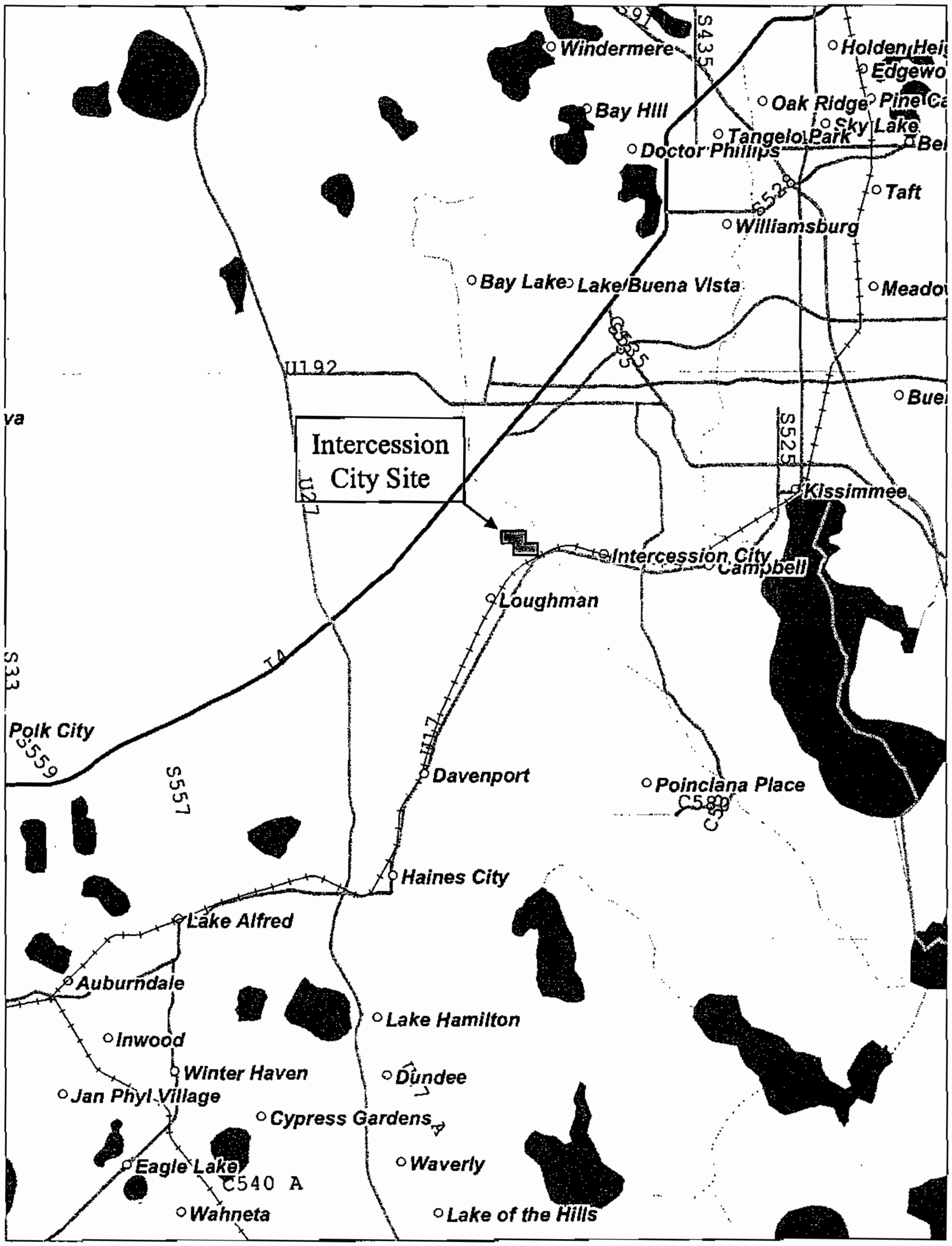
The Intercession City site (Figure 4.2) consists of 162 acres in Osceola County, two miles west of Intercession City. The site is immediately west of Reedy Creek and the adjacent Reedy Creek Swamp. The site is adjacent to a secondary effluent pipeline from a municipal wastewater treatment plant, an oil pipeline, and natural gas from the Florida Gas Transmission (FGT) and Gulfstream pipelines.

The Florida Department of Environmental Protection air rules currently list all of Osceola County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate the additional combustion turbine peaking units identified in this expansion plan.

FIGURE 4.2

Intercession City Site (Osceola County)



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ANCLOTE SITE

Anclote was chosen as a potential site for installation of peaking combustion turbine units. The seasonal ratings for each proposed peaking combustion turbine unit are projected to be 158 MW summer and 188 MW winter.

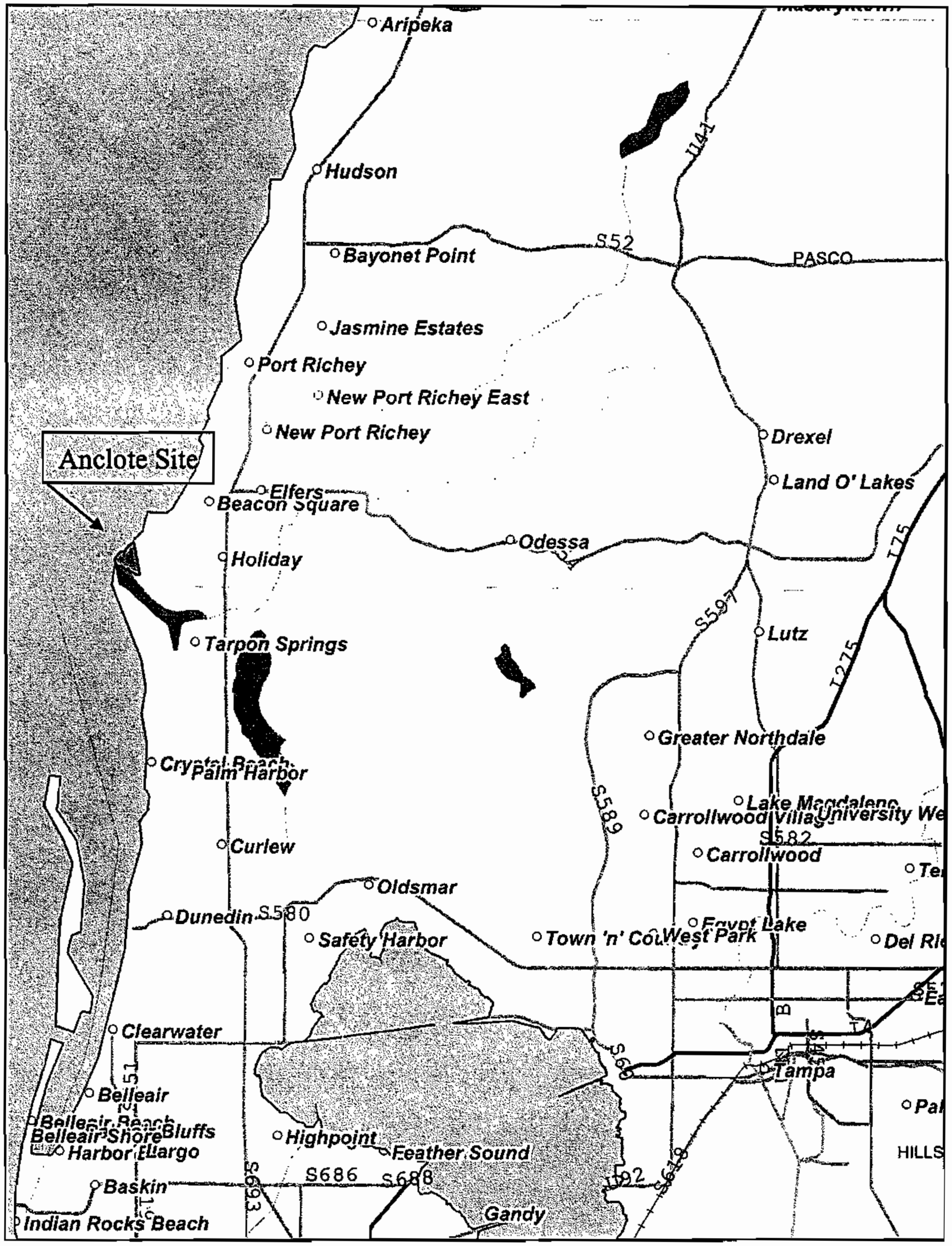
The Anclote site (Figure 4.3) consists of approximately 400 acres in Pasco County. The site is located in Holiday Florida at the mouth of the Anclote River. The site receives make-up water from the city of Tarpon Springs, fuel oil through a pipeline from the Bartow plant, and natural gas from the Florida Gas Transmission (FGT) Pipeline.

The Florida Department of Environmental Protection air rules currently list all of Pasco County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate the additional combustion turbine peaking units identified in this expansion plan.

FIGURE 4.3

Anclote Site (Pasco County)



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DEBARY SITE

DeBary was chosen as a potential site for installation of peaking combustion turbine units. The seasonal ratings for each proposed peaking combustion turbine unit are projected to be 158 MW summer and 188 MW winter.

The DeBary site (Figure 4.4) consists of 2,210 acres in Volusia County, immediately west of the town of DeBary. The site is bordered on the west by the St. Johns River and on the north by Blue Springs State Park.

The Florida Department of Environmental Protection air rules currently list all of Volusia County as attainment for ambient air quality standards. The environmental impact on the site will be minimized by PEF's close coordination with regulatory agencies to ensure compliance with all applicable environmental regulations.

Transmission modifications will be required to accommodate the additional combustion turbine peaking units identified in this expansion plan.

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122. Please provide the total natural gas requirements for Hines 4 on an annual basis, and seasonal requirements in MMBtu/day for each year of the proposed contracts. Please provide all assumptions used concerning gas usage at Hines 4, including the heat rate, capacity factor, and unit availability.

Answer:

Summary of Natural Gas consumption at Hines.
FPC GFF-AUG-2004

Year	Hines 4 - Annual Dths
2007	883,740
2008	18,860,390
2009	19,947,200
2010	21,503,460
2011	22,508,970
2012	22,457,160
2013	22,693,560
2014	23,344,330
2015	22,624,800
2016	20,960,640
2017	21,542,230
2018	20,650,800
2019	20,704,420
2020	20,298,060
2021	19,696,150
2022	19,856,040
2023	20,822,040

Please also refer to Attachment H.
Below are the assumptions that accompany the Hines 4 gas usage forecasted:

- Heat Rate: The average annual heat rate model output from 2008 through 2024 ranges from 7157 to 7251 kwh/btu, with an overall average heat rate of 7207 kwh/btu from 12/2007 through 2024 inclusively.
- Capacity Factor: The annual capacity factor model output from 2008 through 2024 ranges from 61 to 81, with an overall average capacity factor of 72.4 from 12/2007 through 2024 inclusively.
- Unit Availability: The modeled forced outage rate for Hines 4 is 3%. A planned maintenance rate of 22 days/year is also modeled.

123. What would be the estimated cost of delaying the in-service date of Hines 4 one year using existing capacity and short-term purchased power contracts? Would PEF be penalized for delaying the in-service date of Hines 4 under the provisions of its construction contracts?

Answer:

The cost of future purchased power contracts is difficult to estimate because it will depend on the amount and type of capacity available on the market at the time the power is purchased, and upon the amount of power actually purchased. For example, while Hines 4 is needed to maintain a minimum reserve margin of 20%, if it is delayed, it may only be necessary to replace part of the total capacity through a power purchase, which can be tailored to more closely achieve the 20% target. Purchases from a combined cycle source would more closely resemble the costs of Hines 4, including fuel and O&M costs, while purchases from a peaking source might show lower capacity costs and higher fuel costs. The characteristics of the power purchase would also influence system fuel costs to replace the Hines 4 energy. Based on this range of uncertainty, this question cannot be answered without specifying the relevant assumptions.

Regarding the construction contracts, the EPC contract provides time extensions for owner caused delays. The terms of the contract were intended to cover delays of a few days to a few weeks, not a year. Delaying the completion date of the project by a year may require the renegotiation of some terms of the EPC contract to change the date. It is not possible to know the outcome of the negotiation since it will occur at a time when the contracting environment has changed from the original negotiation.

The additional cost of construction for a one year delay in completion date would possibly fall into the following categories:

- AFUDC
- Storage costs for delivered equipment
- Renegotiated equipment contracts to extend warranties
- Cost resulting from changing the EPC contract
- Legal cost of modifying agreements
- Escalation of labor and material prices

As developed above, it is not possible for PEF to accurately estimate the impact of delaying the in-service date of Hines PB 4.

124. What are PEF's contingency plans to fuel Hines 4 in case of a gas supply disruption after the contract start date?

Answer:

PEF would attempt to purchase gas from other suppliers to fill its existing firm transportation capacity to serve Hines 4 and/or purchase delivered gas to Hines. In addition, the combustion turbines to be installed on Hines 4 are dual fuel units which will run on natural gas and No. 2, low sulfur fuel oil. PEF is constructing a new one million gallon fuel oil storage tank as a part of the Hines 4 project. The fuel oil system for Hines 4 will be interconnected with the existing fuel oil system at the site. This will provide storage of approximately four and a half million gallons of usable oil for the four power blocks. In addition, please see other options as described in responses to Interrogatories Nos. 42, 124, 129, and 130.

125. Does the proposed gas supply contract allow for PEF to resell the gas to another entity if not needed for its own system? If so, how does PEF propose to handle any revenues from these sales?

Answer:

The contract does not preclude PEF to resell gas to another entity if not needed for its own system. Consequently, if PEF does not need the gas for its own system, PEF would resell the gas to another entity and credit the Fuel Expense Account 5473000 with the revenue generated from the sale.

128. How did PEF evaluate the responses to its August 22, 2003 RFP? How was this information utilized in developing the 2004 RFP's and in formulating the strategy for natural gas supply and transportation for Hines 4?

Answer:

The August 22, 2003 RFP was non-binding and the purpose was to gather market intelligence for LNG supplies for Hines 4. The conclusions described in response to Interrogatory No. 88 aided PEF in its ability to properly structure the binding RFP, which was distributed in April 2004 to compare costs associated with the Cypress project and the Bahamas projects.

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129. Please refer to page 6, lines 6 through 16 of Samuel Waters' testimony. Would the interconnection of the Cypress pipeline to the FGT infrastructure allow for transportation of natural gas to be provided to Hines 4 from Southern Natural through other suppliers if the LNG supply at Elba Island is not available, or if the quality of the LNG does not meet the standards required by the contract?

Answer:

Yes. As a Firm Shipper on Southern Natural Gas Company by virtue of PEF's participation in the Cypress pipeline project, PEF will have access to alternate sources of supply on Southern Natural Gas Company when Elba Island is not available but at a reduced transportation priority level.

130. How will PEF meet its capacity needs and/or its fuel supply needs if the Cypress or FGT expansion schedules are not met?

Answer:

Regarding meeting capacity needs, PEF would evaluate alternatives and operate its system in the most economic manner. The most economic alternative might be short-term purchases or seasonal purchases of firm capacity. Another alternative might be to use backup fuels at dual fuel units, including Hines 4. The capability for dual fuel operation is maintained, to ensure reliability through loss of fuel supply situations, by enabling full unit capability at the time of system peak. This latter alternative might be combined with non-firm energy purchases to ensure both reliability and economic system operation. The choice of operating mode would depend on the length of the expected unavailability of the incremental gas supply. Fuel supply needs would be an important consideration from an overall strategy to meet system needs in the event of a delay in the Cypress or FGT expansions. In addition, please see other options described in responses to Interrogatories, 42, 124 and 129.

131. Why did PEF negotiate a start date for the BG/Cypress/FGT contracts of May 1, 2007, given the expected December 2007 in-service date of Hines 4? Please explain the fuel supply need for the May through December period. How does PEF plan to use any natural gas which is not needed for Hines 4 from the contracts during this time period?

Answer:

Please refer to Pamela R. Murphy's testimony on Page 6, lines 6 through 11. During the period prior to the in-service date of Hines 4, PEF will utilize the fuel supply at other existing PEF plants and for testing of the Hines 4 facility that is expected to occur during a four to six month time period prior to the in-service date. Additionally, because PEF has not purchased all of its natural gas requirements for the summer of 2007, this gas can be substituted in its place.

138. Page 5, lines 4 through 9, of Bruce Hughes' testimony states that Southern Natural's new pipeline will be installed adjacent to an existing power line right-of-way. Please identify the utility(ies) that operates in this right-of-way and discuss the status of any agreements which must be reached with this utility regarding installation of the new pipeline.

Answer:

PEF is informed that Southern Natural's plans are to install the pipeline adjacent to the existing power line easement. Southern Natural plans to acquire a fifty-foot easement immediately adjacent to the power line easement for most of the route. Deviations from the power line corridor will be required in some limited areas where obstructions are present. To minimize environmental and landowner impacts, Southern Natural plans to utilize a portion of the existing power line easement during construction for temporary work space. Southern Natural has contacted Savannah Electric and Georgia Power about these plans. Southern Natural will also contact Florida Power and Light and Jacksonville Electric Authority. Southern Natural expects to reach an amicable agreement with each of these utilities to minimize the impact of the project. At recent Open Houses and FERC Scoping Meeting, landowners strongly encouraged Southern Natural to consider where feasible co-location with the power lines in the existing easements. These options are being evaluated internally and will be considered.

139. Please discuss any provisions of the gas supply contract which provide protection for PEF if gas cannot be supplied at the required quality levels. What are PEF's contingency plans to fuel Hines 4 if periods occur when the required gas quality level is not achieved?

Answer:

Gas quality of LNG delivered to the Elba Island Regasification Terminal must meet the gas quality specification contained in the Southern LNG Inc. FERC Tariff which is further prescribed in Section 3 "Quality" of the General Terms and Conditions. Subsequently, gas delivered to Southern Natural Gas Company from Southern LNG Inc., must meet the gas quality specifications contained in Southern Natural's FERC Tariff which is further prescribed in Section 3 "Quality" of the General Terms and Conditions. Section 5 of the BG LNG contract provides that BG shall meet the requirements of the Receiving Transporter's (meaning Southern Natural) pipeline specifications for pipeline quality gas.

Sections 8.4 and 13 are the provisions of the BG LNG supply contract which provides protection for PEF if gas cannot be supplied at the required quality levels.

PEF's contingency plans to fuel Hines 4 if periods occur when the required gas quality level is not achieved, please refer to responses in Interrogatories 42, 124, 129 and 130.

142. Section 5 of the proposed contract with BG LNG Services includes a provision that "All gas..... shall meet the requirements.... for pipeline quality gas." Industry sources indicate that significant differences exist between the domestic natural gas supply compared to LNG obtained from various source worldwide. Specifically, variance in the Wobbe number, dew point curve, and other parameters must be controlled and limited in some way. Please describe the methods and technologies that are presently used at the Elba Island facility to manage the parameters as necessary to insure an acceptable product. Please describe any future upgrades planned, or planned additions to the processes currently employed, at the Elba Island facility in order to maintain quality as volume increases and LNG becomes a larger part of the total gas supply.

Answer:

All LNG deliveries at Elba Island must comply with the Gas Quality Specifications for both Southern LNG Inc., and Southern Natural Gas Company. Attempts by the Southern LNG and/or Southern Natural Gas Company or other parties to modify the existing Gas Quality specifications contained in each of the Southern tariffs will be met with direct opposition by PEF to the extent that such changes or modifications would adversely affect the operation of PEF's gas-fired generation facilities. Both PEF and Southern Natural are intervenors in both FERC proceedings (Docket No. PL04-3 and RP04-249) addressing Gas Quality and Interchangeability issues.

All LNG deliveries to the Southern LNG Inc.'s Elba Island Terminal must meet the Gas Quality specifications contained in their currently effective FERC Tariff. The currently effective FERC Tariff for Southern LNG Inc., does not address the Wobbe Index, or dew point curve but does manage the parameters by placing limitations on the gross heating value, up to 1075 BTU/scf, and other quality specifications. In addition, it provides that LNG received shall be merchantable in order to permit delivery into downstream facilities. As a result, gas coming from Elba Island Terminal meets the gas quality specifications necessary to run PEF's gas-fired generation facilities.

The FERC has conditioned Southern LNG's right to waive these specifications on Southern LNG's being able to blend combustible and inert gases to achieve an acceptable product and/or being able to demonstrate through an interchangeability study that different LNGs are nonetheless acceptable. Southern LNG has also conducted numerous studies and held extensive discussions with endusers, including generators of electricity, to determine whether the tariff specifications can be improved by the adoption of Wobbe number and other parameters and whether facilities such as nitrogen injection can help maintain quality while increasing supplies of gas at competitive prices. Those efforts continue but would not result in any tariff change or facility upgrades without support of customers and acceptance by FERC.

145. On a total delivered price, what is the relative % of total cost between commodity and transportation for PEF's existing natural gas contracts? Please provide the same percentages for the proposed contracts.

Answer:

For 2005, the total existing gas cost for PEF is approximately 89% commodity cost and approximately 11% fixed transportation cost. For 2008, the total estimated gas cost for PEF for the proposed contracts is approximately 86% commodity cost and approximately 14% fixed transportation cost.

147. For the proposed LNG contract, please provide the volume (mmbtu) that is a minimum or must take and the volume that is discretionary for each year of the contract term.

Answer:

Please see the must take volumes in Interrogatory No. 146. There are no discretionary volumes for each year of the contract term.

Interrogatories

148. Please explain in detail, how PEF will be compensated by BG LNG Services in the event that BG fails to deliver the contracted quantities of gas in those instances when force majeure cannot be invoked.

Answer: Section 13 of the Gas Sales and Purchase Contract provides:

"Except as set forth in Section 11.1(xii) above, if Seller fails to deliver or Buyer fails to receive Gas during a particular Day and such is not excused pursuant to Section 12 of this Contract, the sole and exclusive remedy of the performing Party shall be recovery of the following:

(i) in the event of a breach by Seller to deliver Gas during such Day, payment by Seller to Buyer in an amount equal to (A) the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard minus the Contract Price applicable to such Day, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by (B) the difference between the Contract Quantity applicable to such Day and the quantity actually delivered by Seller during such Day; or

(ii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available, payment to the performing Party in the amount equal to (A) any unfavorable difference between the Contract Price applicable to such Day and the Spot Price applicable to such Day, multiplied by (B) the difference between the Contract Quantity applicable to such Day and the quantity actually delivered by Seller and received by Buyer during such Day."

Definitions:

"Cover Standard" shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the performing Party shall use commercially reasonable efforts to (i) if Buyer is the performing Party, (1) obtain replacement Gas at a price reasonable for Gas in the Southern Natural Gas Company or the Florida Gas Transmission Company production area (or, if available at a lower price, at or near the Primary Delivery Point) (or an alternate fuel if elected by Buyer and replacement Gas is not available), and (2) utilize Buyer's then available secondary transportation that is not curtailed by a Transporter to effect delivery of such replacement gas; or (ii) if Seller is the performing Party, sell such Gas at a price reasonable for Gas at or near the Primary Delivery Point; and consistent with (a) the amount of notice provided by the non-performing Party; (b) the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; (c) the quantities involved; and (d) the anticipated length of failure by the non-performing Party.

"Spot Price" shall mean, with respect to any particular delivery Day, the price listed in the publication Gas Daily (as published by The McGraw-Hill Companies, Inc. or its successor), in the table entitled "Daily Price Survey" and reported as the "Louisiana-Onshore-South . . . SONAT . . . Midpoint" for Gas delivered during such Day for which such a price is then so published; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is so published for such Day, then the Spot Price shall be the average of the following: (i) the price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

151. Please refer to Table 1 of PEF's SONAT/FGT Supply Purchase Business Analysis Package. Please provide separate annual and cumulative values for each of the following: the total nominal cost, present value of total nominal cost, and up-front capital costs, for each of the three alternatives summarized in Table 1. Please provide all assumptions.

Answer:

Subsequent to the development of PEF's August 2004 SONAT/FGT Supply Purchase Business Analysis Package (Business Analysis Package), negotiations with Southern Natural Gas Company (SNG) and Florida Gas Transmission (FGT) resulted [redacted] (refer to the assumptions below). Thus, the costs for Cypress summarized in Table 1 of the Business Analysis Package do not reflect these changes. Additionally, during the course of preparing responses to this fifth set of interrogatories, PEF discovered a discrepancy with respect to the assumed variable transportation charges, specifically the pipeline commodity charge rates and fuel charge percentages, used in the analyses of the Cypress and [redacted] alternatives. Please refer to the assumptions below.

Accordingly, the information provided below reflects two sets of cost data for the Cypress and [redacted] alternatives: cost consistent with Table 1 of the Business Analysis Package and cost reflecting the correct pipeline commodity charges rates, fuel charge percentages and [redacted] for Cypress and the corrected commodity charge rates for the [redacted] alternative. Additionally, two sets of present value of nominal cost are provided for each alternative (Cypress, [redacted] and [redacted]). This data assumes discounting of the nominal cost to August 1, 2004, consistent with Table 1 of the Business Analysis Package, and assumes discounting of the nominal cost to December 1, 2004, consistent with the discounting reflected in Exhibit PRM-5 to Pamela Murphy's December 20, 2004 pre-filed testimony.

Cypress Annual Summary

(Per Table 1 - Business Analysis Package)

Nominal Dollars

Year [redacted]pr)	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

Cypress Annual Summary

(Per Table 1 - Business Analysis Package)

Cumulative Nominal Dollars

Year		Capital		
[redacted]	[redacted]			

000167

TPA#2007848.4

Cypress Annual Summary

(Per Table 1 - Business Analysis Package)

Present Value (Discounted to 8/1/2004)

Year		Capital		
[redacted]	Transportation	Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cypress Annual Summary

(Per Table 1 - Business Analysis Package)

Cumulative Present Value (Discounted to 8/1/2004)

Year		Capital		
[redacted]r)	Transportation	Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

000168

Cypress Annual Summary

(Consistent With Table 1 - Business Analysis Package)

Present Value (Discounted to 12/1/2004)

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cypress Annual Summary

(Consistent With Table 1 - Business Analysis Package)

Cumulative Present Value (Discounted to 12/1/2004)

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following 6 tables of Cypress information reflect the following corrections and final terms and conditions negotiated with SNG and FGT:

- [redacted]
- [redacted];
- Variable charge rates corrected; and
- Fuel charge rates corrected between SNG and FGT (which had a diminutive effect)

Cypress Annual Summary

(Reflecting Corrections and Final Terms & Conditions)

Nominal Dollars

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

000170

Cypress Annual Summary

(Reflecting Corrections and Final Terms & Conditions)

Cumulative Nominal Dollars

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

Cypress Annual Summary

(Reflecting Corrections and Final Terms & Conditions)

Present Value (Discounted to 8/1/2004)

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

Cypress Annual Summary

(Reflecting Corrections and Final Terms & Conditions)

Cumulative Present Value (Discounted to 8/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

Cypress Annual Summary

(Reflecting Corrections and Final Terms & Conditions)

Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

000172

Cypress Annual Summary

(Reflecting Corrections and Final Terms & Conditions)

Cumulative Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

[redacted]

(Per Table 1 - Business Analysis Package)

Nominal Dollars

Year [redacted] or)	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

000173

[redacted]

(Per Table 1 - Business Analysis Package)

Cumulative Nominal Dollars

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

(Per Table 1 - Business Analysis Package)

Present Value (Discounted to 8/1/2004)

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

(Per Table 1 - Business Analysis Package)

Cumulative Present Value (Discounted to 8/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

[redacted]

(Consistent With Table 1 - Business Analysis Package)

Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

[redacted]

(Consistent With Table 1 - Business Analysis Package)

Cumulative Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

000176

[redacted]

(Per Table 1 - Business Analysis Package)

Nominal Dollars

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

[redacted]

(Per Table 1 - Business Analysis Package)

Cumulative Nominal Dollars

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

000177

[redacted]

(Per Table 1 - Business Analysis Package)

Present Value (Discounted to 8/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

[redacted]

(Per Table 1 - Business Analysis Package)

Cumulative Present Value (Discounted to 8/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

000178

[redacted]

(Consistent With Table 1 - Business Analysis Package)

Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

[redacted]

(Consistent With Table 1 - Business Analysis Package)

Cumulative Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

000179

The following 6 tables of information regarding the [redacted] alternative reflect corrected pipeline commodity charge rates.

[redacted]

(Reflecting Corrected Variable Transport Rates)
Nominal Dollars

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

(Reflecting Corrected Variable Transport Rates)
Cumulative Nominal Dollars

Year	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

(Reflecting Corrected Variable Transport Rates)

Present Value (Discounted to 8/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

[redacted]

(Reflecting Corrected Variable Transport Rates)

Cumulative Present Value (Discounted to 8/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

000181

[redacted]

(Reflecting Corrected Variable Transport Rates)

Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]				

[redacted]

(Reflecting Corrected Variable Transport Rates)

Cumulative Present Value (Discounted to 12/1/2004)

Year [redacted]	Transportation	Capital Investment	Supply	Total
[redacted]	[redacted]			

000182

Assumptions

- **Transportation Rates**

Assumed For Analysis Reflected in Table 1 – Business Analysis Package

Alternative	Fixed Transportation -$/Dt Summer	Fixed Transportation -$/Dt Winter	Commodity Charge $/Dt	Fuel Charge
Cypress: Southern Natural Gas Florida Gas Transmission	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Assumed For Corrected Analysis Reflecting Final Terms & Conditions

Alternative	Fixed Transportation -$/Dt Summer	Fixed Transportation -$/Dt Winter	Commodity Charge $/Dt	Fuel Charge
Cypress: Southern Natural Gas Florida Gas Transmission	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] Reflects a negotiated rate of [redacted] plus estimated provision to cover future rate increases.
[2] Reflects a negotiated rate of [redacted] plus estimated provision to cover future rate increases.
[3] An effective fixed transportation rate derived given [redacted] requirement for [redacted] of annual fixed pipeline transportation [redacted] and seasonal volumes comparable with the [redacted] alternatives. See PEF response to #136 for further information.
[4] Reflects [redacted] negotiated with SNG and FGT subsequent to development of the Business Analysis Package.
[5] The change in fuel charge rates between Southern Natural Gas and Florida Gas Transmission had a diminutive impact on the total cost of the Cypress alternative.

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted] **Capital Cost** – This is a function of how much capital cost [redacted] (for Cypress), [redacted] and [redacted] were willing to absorb for certain gas infrastructure facility additions and/or improvements that are required in conjunction with delivering natural gas to Hines 4 (explained further in PEF's response to Interrogatory No. 26). Of the estimated [redacted] of required infrastructure improvements for Cypress, [redacted] was initially willing absorb the [redacted] cost associated with the [redacted], but later increased its offer to include the [redacted] for a total commitment of [redacted] proposed to absorb [redacted] of cost associated with various additions / improvements, resulting in PEF having to fund [redacted] of cost. [redacted] proposed to absorb the [redacted] cost of the [redacted], resulting in PEF having to fund [redacted]

- **Supply** - Commodity prices for all alternatives assumed PEF's forecast of Henry Hub (HH) prices, as of August 5, 2004, as summarized in PEF's response to Interrogatory No. 149. In addition to the HH commodity prices:
    1. The Cypress alternative reflects a $[redacted]Dth basis (or adder) per the terms negotiated with [redacted].; and
    2. The [redacted] alternative reflects PEF's forecast of [redacted] basis as of August 5, 2004 (summarized below).
    3.

Forecasted [redacted] Basis As of 08/05/04			
2008	[redacted]	2018	[redacted]
2009	[redacted]	2019	[redacted]
2010	[redacted]	2020	[redacted]
2011	[redacted]	2021	[redacted]
2012	[redacted]	2022	[redacted]
2013	[redacted]	2023	[redacted]
2014	[redacted]	2024	[redacted]
2015	[redacted]	2025	[redacted]
2016	[redacted]	2026	[redacted]
2017	[redacted]	2027	[redacted]

- **Discount Rate** – 8.16% per PEF's response to Interrogatory No. 28.

152. Has Southern Natural Gas Company achieved the sufficient commitments necessary to meet the requirements of Section 5(a)(3) of its precedent agreement with PEF?

Answer:

By letter dated April 1, 2005 (attached as Exhibit A), Southern Natural Gas Company informed PEF that it is waiving the condition precedent set forth in Section 5(a)(iii) contained in the precedent agreement.

Bruce H. Hughes
Director
Business Development

Southern Natural Gas
an El Paso company

April 1, 2005

Ms. Pamela R. Murphy
Progress Energy Florida, Inc.
410 S. Wilmington Street (PEB 10)
Raleigh, NC 27601

Attention: Contract Administration

Dear Pam:

This is to advise you that on January 17, 2005, Southern Natural Gas Company ("Southern") completed the open season for the Cypress Project to provide firm transportation service to shippers from its Elba Island Receipt Point. Southern received several subscriptions including the Precedent Agreement dated December 2, 2004, with Florida Power Corp., d/b/a Progress Energy Florida, Inc. ("FPC"), hereinafter the "Agreement." In the open season, Southern did not receive the total subscription required to satisfy the Condition Precedent in Section 5(a)(iii) of the Agreement.

Accordingly, Southern is hereby informing you that it is waiving the condition precedent set forth in Section 5(a)(iii) Agreement as of March 31, 2005.

Sincerely,

Bruce H. Hughes

cc: Mr. James Jefferies
Moore & Van Allen, PLLC
Bank of America Corporate Center
Suite 4700
100 North Tryon Street
Charlotte, NC 28202-4003

Mr. Norman Holmes
Ms. Patricia Francis

000186

Southern Natural Gas
1900 Fifth Avenue North Birmingham, Alabama 35203
PO Box 2563 Birmingham, Alabama 35202.2563
tel 205.325.7146 fax 205.325.3787

ATTACHMENT A

153. Given PEF's response to Staff Interrogatory No. 71, what are the total incremental costs (inclusive of both incremental gas costs and incremental costs of unit dispatch changes, additional purchase power, etc., balanced against any decremental costs) associated with each storm listed in the response?

Answer:

Date	Storm Name	Total Incremental Gas Cost	Total Incremental Power Cost
9/24/02-9/27/02	Tropical Storm Isidore Total	$132,816	$0
10/1/02-10/4/02	Hurricane Lili Total	$218,807	$217,160
7/14/03-7/16/03	Tropical Storm Claudette Total	$9,884	$0
8/10/04-8/13/04	Tropical Storm Bonnie Total	$140,778	$500,540
9/13/04-10/6/04	Hurricane Ivan Total	$6,631,796	$1,607,900

159. Given the expense of storm-related curtailments listed in response to Staff Interrogatory No. 72, has PEF studied whether it would be economic for the utility to contract for underground natural gas storage? If not, why not. If so, what were the results of the study?

Answer:

In February 2003, PEF conducted a study titled "Gas Storage Strategy," which identifies potential benefits for PEF of underground natural gas storage. The results of the study indicate that high deliverability underground gas storage can be utilized to mitigate (depending on the length of the gas interruption as stated in response to Interrogatory Nos. 73 and 74) some supply disruptions due to storms/hurricanes impacting PEF gas supply area. The potential benefits for PEF include enhanced reliability, managing price risk, managing daily imbalances to mitigate pipeline penalties, and providing for intraday supply needs. PEF is still in the process of identifying the optimum amount of storage capacity needed to meet PEF gas demands going forward. This gas storage strategy, while it provides additional benefits, cannot replace the Cypress project. PEF expects both projects to further enhance PEF's existing and future gas portfolio as a means to provide the potential benefits discussed above.

160. Please refer to PEF's response to Staff Interrogatory No. 80. In the last sentence of the response, PEF references "similar LNG offers". Did PEF mean "natural gas offers"?

Answer:

Yes. The June 2004 RFP solicited "natural gas offers" from Gulf of Mexico gas suppliers from our current supplier list that could deliver natural gas to the Gulfstream Natural Gas System.

161. Please reconcile PEF's response to Staff Interrogatory Nos. 115 and 117, which show different quantities of gas contracted in 2004 under various contract terms (years).

Answer:

PEF's response to Interrogatory No. 115 reflects the actual volumes received and the average total price of all term deals in effect during 2004. For example, this answer does not include any volumes not taken under the swing term supply contracts, any supply disruptions, spot daily transactions, or daily call contract transactions. The contracts were listed under remaining term based on the number of years remaining on the contract starting from 2004. By contrast, PEF's response to Interrogatory No. 117 identifies the contractual maximum volumes allowed for all term deals in effect from 2004 through 2013. For example, this answer includes maximum contract volumes under variable supply contracts. The contracts were listed under term years based on the number of years the contract is in existence and not based on the number of years remaining on the contract starting from 2004.

163. PEF's response to Staff Interrogatory No. 128 states that the purpose of the August 2003 RFP was to gain market intelligence for LNG supplies to Hines 4, yet Page 8 of the Direct Testimony of Pamela Murphy states that the RFP process began by soliciting proposals from all entities who could potentially meet the fuel requirements of Hines 4. Had PEF already determined that domestic supplies would not be viable to supply Hines 4 at the time of issuance of the August 2003 RFP?

Answer:

No. The statement made in response to Interrogatory No. 128, in context with the first sentence, means that PEF conducted a series of RFP's to solicit proposals from new and existing LNG projects as well as domestic suppliers who could potentially supply gas to Hines 4. PEF did not determine initially that domestic suppliers would not be viable to supply Hines 4, as mentioned in response to Interrogatory No. 76(A).

means of a confidentiality agreement, protective order, or other means of protection under the Florida Rules of Civil Procedure and other applicable statutes, rules and legal principles.

TIME AND PLACE OF PRODUCTION

PEF will make all documents and materials responsive to this request that are not privileged or confidential available for inspection and copying at the offices of Carlton Fields, P.A., 215 S. Monroe Street, Suite 500, Tallahassee, Florida, 32301 at a mutually-convenient time or, upon request from Staff, will provide copies of such documents and materials by U.S. or Overnight Mail.

DOCUMENTS REQUESTED

7. Please provide complete copies of all documents related to the development/ calculation of the 8.16% discount rate.

Responsive documents are enclosed herewith in Bates Ranges PEF-000205 through PEF-000210.

8. Please provide the most recent Standard and Poor's full credit report and analysis for Progress Energy Florida.

Responsive documents are enclosed herewith in Bates Ranges PEF-000211 through PEF-000217.

9. Please provide the most recent Moody's Investor Services full credit report and analysis for Progress Energy Florida.

Responsive documents are enclosed herewith in Bates Ranges PEF-000218 through PEF-000231.

10. Please provide the most recent Fitch full credit report and analysis for Progress Energy Florida.

Responsive documents are enclosed herewith in Bates Ranges PEF-000232 through PEF-000235.

FEDERAL RESERVE statistical release

These data are released each Monday. The availability of the release is announced on (202) 452-3206.

H.15 (519) SELECTED INTEREST RATES
Yields in percent per annum

For immediate release
May 3, 2004

Instruments	2004 Apr 26	2004 Apr 27	2004 Apr 28	2004 Apr 29	2004 Apr 30	Week Ending Apr 30	Week Ending Apr 23	2004 Apr
Federal funds (effective) [1 2 3]	1.01	0.99	1.01	1.03	1.03	1.00	1.00	1.00
Commercial paper [3 4 5]								
Nonfinancial								
1-month	0.99	0.99	0.98	0.97	0.99	0.98	1.01	1.00
2-month	1.06	1.01	1.01	1.03	1.02	1.03	1.00	1.01
3-month	1.09	1.06	1.08	1.07	1.08	1.08	1.05	1.05
Financial								
1-month	1.02	1.03	1.02	1.01	1.01	1.02	1.02	1.02
2-month	1.04	1.04	1.03	1.03	1.06	1.04	1.04	1.03
3-month	1.07	1.08	1.07	1.08	1.11	1.08	1.06	1.06
CDs (secondary market) [3 6]								
1-month	1.05	1.05	1.05	1.05	1.05	1.05	1.04	1.04
3-month	1.11	1.10	1.10	1.11	1.12	1.11	1.09	1.08
6-month	1.29	1.28	1.28	1.31	1.33	1.30	1.22	1.21
Eurodollar deposits (London) [3 7]								
1-month	1.03	1.03	1.03	1.03	1.03	1.03	1.02	1.02
3-month	1.09	1.09	1.08	1.10	1.10	1.09	1.07	1.07
6-month	1.26	1.26	1.26	1.28	1.29	1.27	1.21	1.19
Bank prime loan [2 3 8]	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Discount window primary credit [2 9]	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
U.S. government securities								
Treasury bills (secondary market) [3 4]								
4-week	0.86	0.90	0.86	0.83	0.81	0.85	0.88	0.89
3-month	0.98	0.97	0.98	0.95	0.96	0.96	0.96	0.94
6-month	1.17	1.15	1.14	1.13	1.14	1.15	1.13	1.09
Treasury constant maturities								
Nominal [10]								
1-month	0.88	0.91	0.87	0.85	0.83	0.87	0.89	0.91
3-month	0.99	0.98	0.97	0.97	0.98	0.98	0.97	0.96
6-month	1.19	1.17	1.16	1.15	1.17	1.17	1.15	1.11
1-year	1.57	1.53	1.54	1.55	1.55	1.55	1.50	1.43
2-year	2.28	2.21	2.30	2.34	2.31	2.29	2.17	2.07
3-year	2.78	2.74	2.82	2.88	2.86	2.82	2.87	2.57
5-year	3.57	3.52	3.60	3.66	3.63	3.60	3.49	3.39
7-year	4.05	4.01	4.08	4.14	4.11	4.08	3.99	3.89
10-year	4.46	4.43	4.50	4.55	4.53	4.49	4.43	4.35
20-year	5.25	5.22	5.28	5.33	5.31	5.28	5.24	5.16
Inflation indexed [11]								
5-year	1.20	1.14	1.26	1.32	1.29	1.24	1.10	1.02
7-year	1.66	1.63	1.72	1.78	1.75	1.71	1.57	1.49
10-year	2.03	2.00	2.10	2.15	2.11	2.08	1.98	1.90
Treasury long-term average								
Nominal [12 13]	5.29	5.27	5.32	5.36	5.34	5.32	5.28	5.20
Inflation indexed [14]	2.40	2.37	2.46	2.51	2.51	2.45	2.35	2.28
Interest rate swaps [15]								
1-year	1.78	1.77	1.77	1.81	1.82	1.79	1.68	1.63
2-year	2.60	2.58	2.58	2.64	2.67	2.61	2.46	2.38
3-year	3.20	3.19	3.19	3.25	3.29	3.23	3.07	2.97
4-year	3.64	3.64	3.64	3.70	3.75	3.67	3.53	3.43
5-year	3.98	3.96	3.97	4.04	4.09	4.01	3.88	3.78
7-year	4.45	4.45	4.44	4.51	4.56	4.48	4.38	4.28
10-year	4.89	4.89	4.88	4.95	5.00	4.92	4.84	4.75
30-year	5.55	5.55	5.56	5.59	5.63	5.57	5.54	5.47
Corporate bonds								
Moody's seasoned								
Aaa [16]	5.81	5.80	5.85	5.89	5.87	5.84	5.81	5.73
Baa	6.52	6.51	6.56	6.61	6.58	6.56	6.53	6.46
State & local bonds [17]				4.95		4.95	4.89	4.82
Conventional mortgages [18]					6.01	6.01	5.94	5.83

* Avg. 4.51%

See overleaf for footnotes

000193

PEF 000205
Docket No. 041414-EI

FOOTNOTES

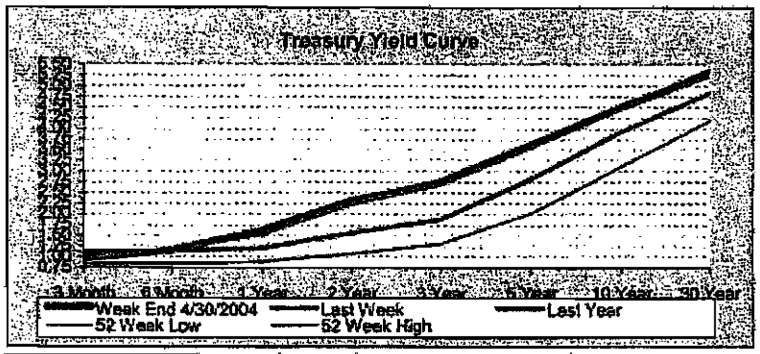
1. The daily effective federal funds rate is a weighted average of rates on brokered trades.
2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.
3. Annualized using a 360-day year or bank interest.
4. On a discount basis.
5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page (www.federalreserve.gov/releases/cp).
6. An average of dealer offering rates on nationally traded certificates of deposit.
7. Bid rates for Eurodollar deposits collected around 9:30 a.m. Eastern time.
8. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.
9. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm. The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at www.federalreserve.gov/releases/h15/data.htm.
10. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. Source: U.S. Treasury.
11. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html.
12. Based on the unweighted average of the bid yields for all non-inflation-indexed Treasury fixed-coupon securities with remaining terms to maturity of 25 years and over.
13. A factor for adjusting the daily long-term average in order to estimate a 30-year nominal rate can be found at www.treas.gov/offices/domestic-finance/debt-management/interest-rate/ltcompositeindex.html.
14. Based on the unweighted average of the bid yields for all TIPS with remaining terms to maturity of more than 10 years.
15. International Swaps and Derivatives Association (ISDA) mid-market par swap rates. Rates are for a Fixed Rate Payer in return for receiving three month LIBOR, and are based on rates collected at 11:00 a.m. by Garban Intercapital plc and published on Reuters Page ISDAFIX1. Source: Reuters Limited.
16. Moody's Aaa rates through December 6, 2001 are averages of Aaa utility and Aaa industrial bond rates. As of December 7, 2001, these rates are averages of Aaa industrial bonds only.
17. Bond Buyer Index, general obligation, 20 years to maturity, mixed quality; Thursday quotations.
18. Contract interest rates on commitments for fixed-rate first mortgages. Source: FHLMC.

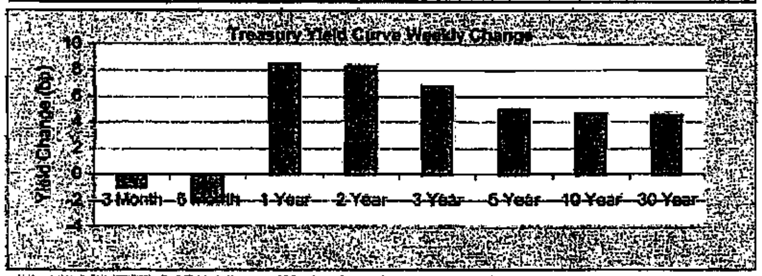
Note: Weekly and monthly figures are averages of business days unless otherwise noted.

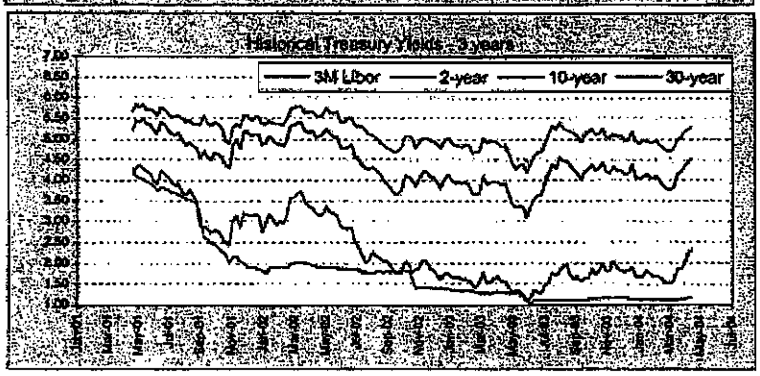
Current and historical H.15 data are available on the Federal Reserve Board's web site (www.federalreserve.gov/). For information about individual copies or subscriptions, contact Publications Services at the Federal Reserve Board (phone 202-452-3244, fax 202-728-5886). For paid electronic access to current and historical data, call STAT-USA at 1-800-782-8872 or 202-482-1986.

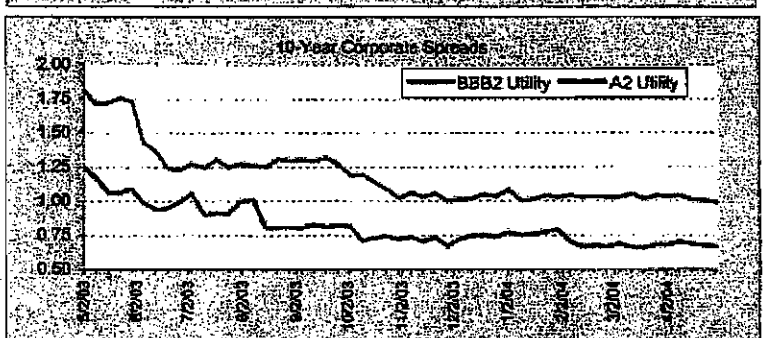
DESCRIPTION OF THE TREASURY NOMINAL AND INFLATION-INDEXED CONSTANT MATURITY SERIES

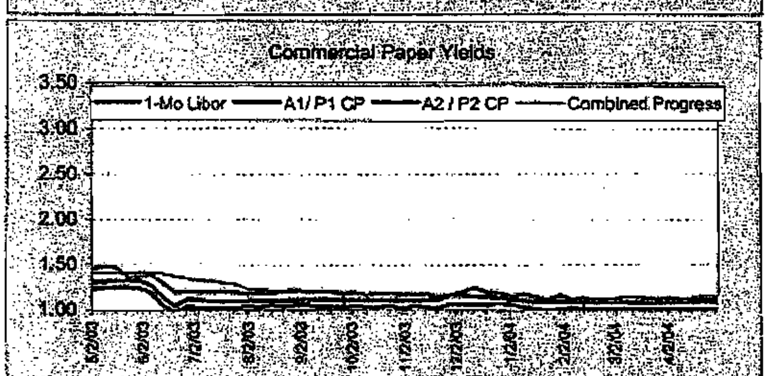
Yields on Treasury nominal securities at "constant maturity" are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3 and 6 months and 1, 2, 3, 5, 7, 10 and 20 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. Similarly, yields on inflation-indexed securities at "constant maturity" are interpolated from the daily yield curve for Treasury inflation protected securities in the over-the-counter market. The inflation-indexed constant maturity yields are read from this yield curve at fixed maturities, currently 5, 7, and 10 years.











The Fed increased rates 25bp at the February meeting. Fed Funds Futures indicate 108% probability of a 25bp rate increase at the March meeting and 120% for the May meeting. Values greater that 100% indicate that there is a chance of a 50bp move at one of the meetings.

Rolling 52-week Treasury Yields (%)

	Current	High	52-w Low
3 Mo LIBOR	1.18	1.29	1.02
2-year	2.32	2.32	1.09
10-year	4.51	4.53	3.12
30-year	5.29	5.40	4.18

Utility New Issue Spreads (bps)

	AA	A	BBB
5-year	77	74	98
Change	4	(1)	(1)
10-year	78	67	99
Change	4	(1)	(1)
30-year	98	76	114
Change	4	(1)	(2)

Current Progress "All-in" Financing Cost

Rating = PEF	Treasury	Spread	"All-in"
1-year	1.63%	0.92%	2.55%
2-year	2.32%	0.88%	3.20%
3-year	2.77%	0.87%	3.64%
5-year	3.63%	0.86%	4.49%
7-year	4.18%	0.90%	5.08%
10-year	4.51%	0.99%	5.50%
15-year	5.06%	1.03%	6.09%
30-year	5.29%	1.17%	6.46%

Commercial Paper Summary

	Current	Change
Progress Energy		
Outstandings (mm)	$ 314	$ -
Average Maturity	11	-
Bond Equiv Yield	1.15%	0.00%
CP&L		
Outstandings (mm)	$ 27	$ -
Average Maturity	5	-
Bond Equiv Yield	1.12%	0.00%
Florida Power		
Outstandings (mm)	$ 261	$ -
Average Maturity	8	-
Bond Equiv Yield	1.10%	0.00%
PGN Uncommitted Facility		
Outstandings (mm)	$ -	$ -
Average Maturity	-	-
Bond Equiv Yield	0.00%	0.00%
Total Programs		
Outstandings (mm)	$ 602	$ -
Average Maturity	09 days	00 days
Bond Equiv Yield	1.12%	0.00%

12 Month 24 Month 36 Month

<HELP> for explanation. [illegible] Govt **FWCV**

FORWARD CURVE ANALYSIS
US Dollar

BASE CURVE DEFAULTS BGN
Curve Dated: [illegible]
Settlement Date: [illegible]
Coupon/Spot: [illegible]
Bid/Ask/Mid: [illegible]
FMC # [illegible] or [illegible]

1 Graph
2 Update Curve
3 Forwards Analysis

		TERM	YIELD	[illegible]		[illegible]		[illegible]	
		[illegible]	[illegible]	2.6673	R	[illegible]		4.[illegible]	R
D		[illegible]	[illegible]	2.7227	O	[illegible]		4.7140	O
E	R	[illegible]	[illegible]	2.7590	J	[illegible]		4.7932	J
P	A	[illegible]	[illegible]	2.8636	E	[illegible]		4.8022	E
O	T	[illegible]	[illegible]	2.9963	C	[illegible]		4.8597	C
S	E	[illegible]	[illegible]	3.1069	T	[illegible]		4.8096	T
I	S	[illegible]	[illegible]	3.0762	E	[illegible]		4.9340	E
T			[illegible]	3.2987	D	[illegible]		5.0659	D
			[illegible]	3.4915		[illegible]		5.1949	
		2 Yr	[illegible]	4.0620		[illegible]		5.3918	
S	R	3 Yr	[illegible]	4.4271		[illegible]		5.5419	
W	A	4 Yr	[illegible]	4.6958		[illegible]		5.6596	
A	T	5 Yr	[illegible]	4.9052		[illegible]		5.7593	
P	E	7 Yr	[illegible]	5.2093		[illegible]		5.9065	
	S	10Yr	[illegible]	5.5047		[illegible]		6.0705	
		15Yr	[illegible]	5.7789		[illegible]		6.2142	
		20Yr	[illegible]	5.8868		[illegible]		6.2346	
		30Yr	[illegible]	n/a				n/a	

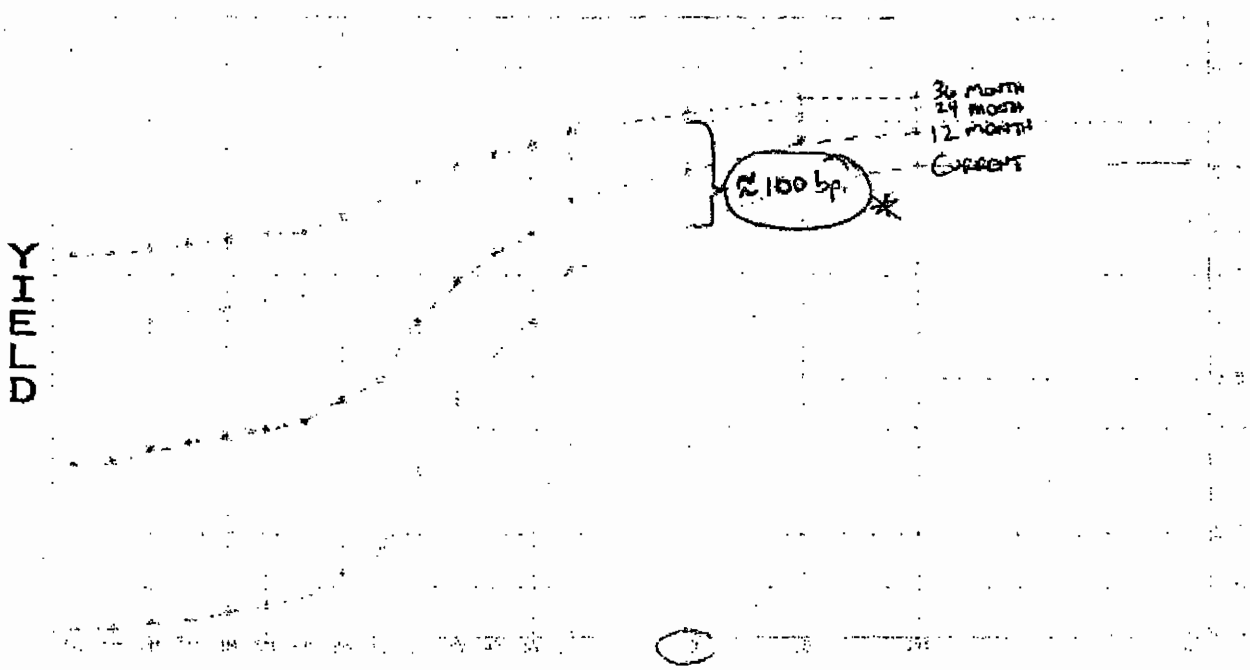
53 bp 87 bp. 110 bp

≈100 bp *

000196

HELP for explanation. Govt **FWCV**

FORWARD CURVE ANALYSIS
US Dollar



Graph Curves: COUPON 5/ 2/05 5/ 1/06 5/ 1/07

000197

WACC Summary - PEF
As of April 30, 2004

Pre-tax risk free debt cost

10-Year US Treasury Rate	4.51%

WACC Inputs

	Progress Energy Florida
Capital Structure Debt Percentage	48.0%
Capital Structure Equity Percentage	52.0%
Current PEF Spread over 10 year Treasury	0.99%
Forward Premium (for projects with spending in excess of 30 months in the future)	1.00%
Regulated Cost of Equity	12.00%
Tax Rate	38.58%

WACC Calculation

PEF Weighted Average Cost of Capital (WACC)	8.16%

000198

CONFIDENTIAL

Document Number: 04250-05
Order Number:
Fine/Settlement: N
Filing Date: 05/02/2005
Suffix: EI
Co. Name: Progress Energy Florida, Inc.

Is/Was Confidential: Y
Type: (•) Other
( ) Motion
( ) Order
( ) NOI

DESCRIPTION

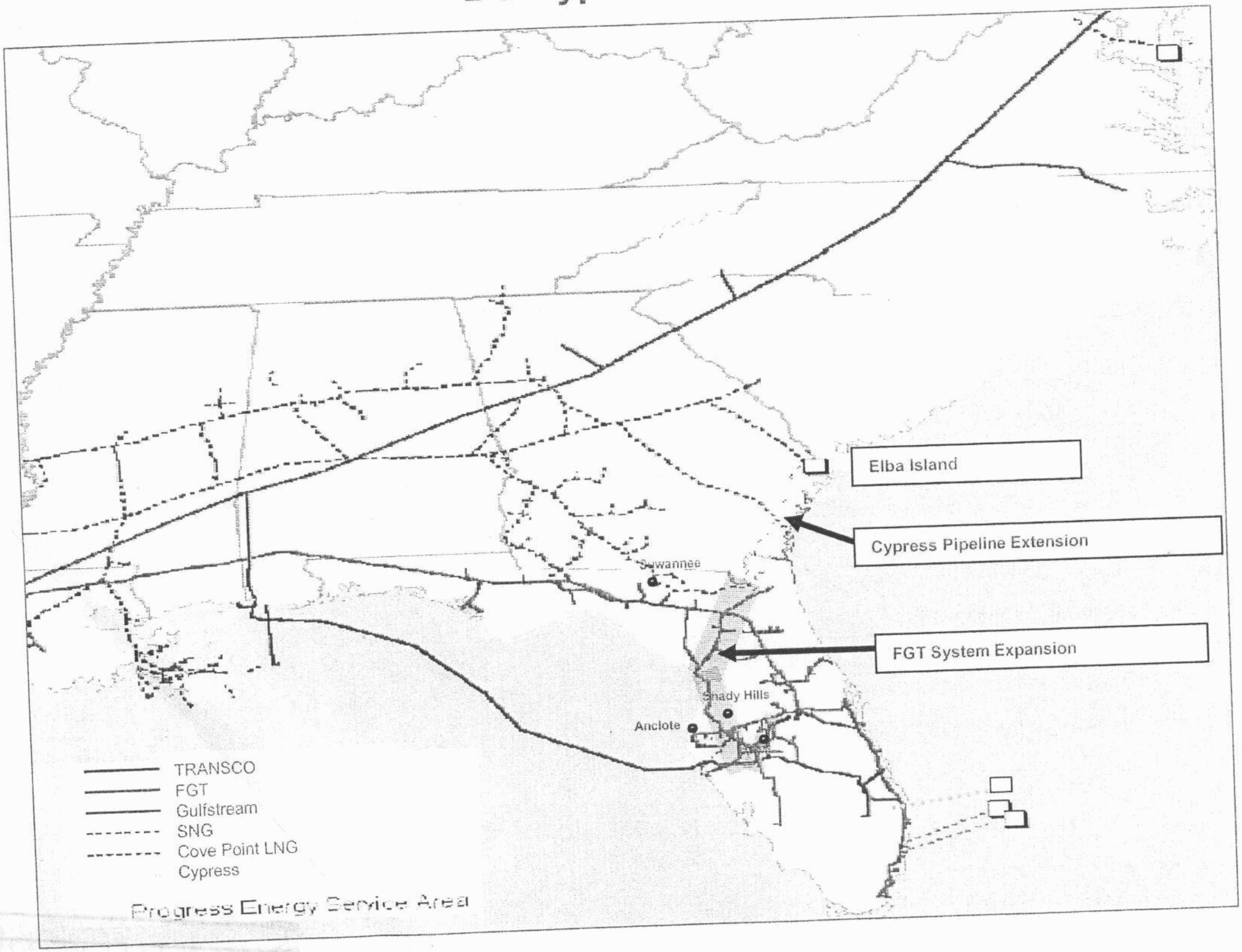
(CONFIDENTIAL) Composite hearing Exh No. 3 (CONF-1) from 4/29/05 hearing. [CCA note: Hearing Exh No. 3 (CONF-1) consists of DNs 02476-05, 03693-05, 03936-05, and portions of 01170-05, 01655-05, 03153-05, 03874-05, and 03887-05]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 041414-EI EXHIBIT NO. 3
COMPANY/ FPSC Staff
WITNESS: Composite Conf. Stip-3
DATE 04-29-05

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 4
COMPANY/ PEF
WITNESS. Robert F. Caldwell (RFC-1)
DATE 04-29-05

RFC-1

BG/Cypress/FGT



GAS SALE AND PURCHASE CONTRACT

This Gas Sale and Purchase Contract (this "Contract") is entered into on December 1, 2004 (the "Effective Date"), between BG LNG Services, LLC, a Delaware limited liability company ("Seller") and Florida Power Corporation, a Florida corporation, doing business as Progress Energy Florida, Inc. ("Buyer").

WITNESSETH

WHEREAS, Seller desires to deliver and sell, and Buyer desires to receive and purchase, certain quantities of Gas in accordance with the terms and conditions specified in this Contract;

NOW THEREFORE, in consideration of the foregoing and of the agreements contained herein, the Parties agree as follows:

SECTION 1. DEFINITIONS; INTERPRETATION

1.1 Definitions. Unless otherwise defined herein or in any annex hereto, the following terms, when used herein or in any annex hereto shall have the meanings set forth below.

"Affiliate" shall mean, with respect to a Party, any entity controlled, directly or indirectly, by such Party, any entity that controls, directly or indirectly, such Party, or any entity directly or indirectly under common control with such Party. For this purpose, "control" of any entity or Party means ownership of a majority of the issued shares or voting power or control in fact of the entity or Party.

"Alternate Delivery Point" shall mean any point of delivery other than the Primary Delivery Point as mutually agreed between the Parties pursuant to the procedures set forth in Section 3.5.

"British thermal unit" or "Btu" shall mean the International BTU, which is also called the Btu (IT).

"Business Day" shall mean any day except Saturday, Sunday or Federal Reserve Bank holidays and shall run from 8 a.m. to 5 p.m. Eastern Prevailing Time.

"Claims" shall have the meaning set forth in Section 8.3.

"Confirmation" shall mean a written document setting forth the terms of a Price Change or a Delivery Point Change, as applicable.

"Contract Price" shall mean, with respect to a particular delivery Day, the amount expressed in U.S. Dollars per MMBtu determined pursuant to Section 3.3.

"Contract Quantity" shall mean, with respect to a particular delivery Day, the Contract Quantity for Hines plus the Contract Quantity for System, as applicable.

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 041414-EI EXHIBIT NO. 5
COMPANY/ PEF
WITNESS: Pamela R Murphy (PRM-1)
DATE: 04-29-05

PRM-1

[redacted]

"Costs" shall mean, with respect to the Non-Defaulting Party, reasonable brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements to replace the quantity of Gas not delivered or received hereunder as a result of the early termination of this Contract, and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with a the early termination of this Contract pursuant to Section 11.3 hereof.

[redacted]

"Credit Rating" means, with respect to any entity, the rating then assigned by S&P or Moody's to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements), or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned by S&P or Moody's to such entity as a corporate or issuer rating.

[redacted]

"Cypress Pipeline" shall mean the proposed expansion of Southern Natural Gas Company's ("Southern's") natural gas pipeline system that extends from (i) a point of interconnection with Southern's existing natural gas pipeline system downstream of the Elba Island LNG Terminal; to (ii) an interconnection with the existing (as of the Effective Date), natural gas transmission facilities owned by Florida Gas Transmission Company in Clay County, Florida.

"Day" shall mean a period of 24 consecutive hours, coextensive with a "day" as defined by the Receiving Transporter.

"Defaulting Party" shall have the meaning set forth in Section 11.1.

"Delivery Period" shall be the period during which deliveries are to be made under this Contract and shall commence on the date that both of the Cypress Pipeline and the FGT Expansion have been placed into service and end on the date twenty (20) years thereafter.

"Delivery Point" shall mean either the Primary Delivery Point or and Alternate Delivery Point, as applicable.

"Delivery Point Change" shall have the meaning set forth in Section 3.5.

"Demand Charge" shall have the meaning set forth in Section 3.2.

"Early Termination Date" shall have the meaning set forth in Section 11.2.

"Elba Island LNG Terminal" shall mean the LNG terminal facility located in Chatham County, Georgia, which is, as of the Effective Date, owned and operated by Southern LNG, Inc.

"Event of Default" shall have the meaning set forth in Section 11.1.

"FERC" shall mean the Federal Energy Regulatory Commission or any successor thereto.

"FGT Expansion" shall mean the proposed expansion (as of the Effective Date) of Florida Gas Transmission Company's natural gas pipeline system from (i) a bidirectional meter station at the interconnection of Southern Natural Gas Company's natural gas pipeline system and Florida Gas Transmission Company's natural gas pipeline system, to (ii) Buyer's Hines electrical generating facility located in Polk County, Florida.

"Firm" shall mean that either Party may interrupt its performance with respect to the delivery or receipt of Gas without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the Party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3 related to interruption by the Party invoking Force Majeure after the nomination is made to the relevant Transporter(s) and until the change in deliveries and/or receipts is confirmed by the Transporter(s).

"Fixed Price" shall have the meaning set forth in Section 3.6.

"Force Majeure" shall have the meaning set forth in Section 12.

"Gas" shall mean any mixture of hydrocarbons and noncombustible gases in a gaseous state consisting primarily of methane. Gas shall specifically include regasified LNG, which such LNG Seller has received from either domestic or foreign sources and that Seller (or an agent of Seller) has regasified such that it meets the requirements of the first sentence of this definition.

"Government Agency" means any federal, state, local, territorial or municipal government, governmental department, commission, board, bureau, agency, instrumentality, judicial or administrative body (or any agency, instrumentality or political subdivision thereof).

"Governmental Approval" means any authorization, consent, approval, license, lease, ruling, permit, exemption, filing, variance, order, judgment, decree, publication, notice to, declarations of or with or regulation by or with any Government Agency relating to the execution, delivery or performance of this Agreement.

"Guarantee" shall mean a guarantee from a party's corporate parent or other Affiliate that is issued to the other Party to this Contract (as a beneficiary thereof), to support the obligations of such first Party.

[redacted]

"Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balancing and/or nomination requirements.

"Law" means any statute, law, ordinance, code, rule or regulation, or other applicable legislative or administrative action of any Government Agency, or any judicial or administrative interpretation thereof.

"Liquefied Natural Gas" ("LNG") shall mean natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

"Market Value" shall have the meaning set forth in Section 11.3.

"Merger Event" shall mean, with respect to a Party or other entity, an event in which such Party or other entity consolidates or amalgamates with, or merges into or with, or transfers substantially all of its assets to another entity and (i) the resulting entity fails to assume all of the obligations of such Party or other entity hereunder or (ii) the benefits of any credit support provided pursuant to or related to this Contract fail to extend to the performance by such resulting, surviving or transferee entity of its obligations hereunder or (iii) the resulting entity's creditworthiness is materially weaker than that of such Party or other entity immediately prior to such action.

"MMBtu" shall mean one million British thermal units, which is equivalent to one dekatherm.

"Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.

"Monthly Deficiency" shall have the meaning set forth in Section 3.6.

"Moody's" means Moody's Investor Services, Inc. or its successor.

"Net Settlement Amount" shall have the meaning set forth in Section 11.4.

"Non-Defaulting Party" shall have the meaning set forth in Section 11.2.

"Notice" shall have the meaning set forth in Section 9.1 hereof.

"Party" shall mean Seller or Buyer individually.

"Parties" shall mean Seller and Buyer collectively.

"Payment Date" shall mean, the later of (i) the 25th day of the Month immediately following the Month during which such Gas is delivered, or (ii) 10 days after receipt of an invoice relating to such Gas; provided, however, that if such day is not a Business Day then the Payment Date shall be the immediately following Business Day.

[redacted]

"Person" means any individual, corporation, partnership, limited liability company, association, joint venture, trust, unincorporated organization, Government Agency or other entity.

"Price Change" shall have the meaning set forth in Section 3.5.

"Primary Delivery Point" shall mean the interconnection of (i) the Elba Island LNG Terminal and (ii) the Southern Natural Gas Company gas transportation pipeline system.

"Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.

"S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

"Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.

[redacted]

[redacted]

"Term" shall have the meaning set forth in Section 2.1 hereof.

"Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point(s).

[redacted]

1.2 Interpretation. Unless the context otherwise requires:

(a) Words singular and plural in number will be deemed to include the other and pronouns having masculine or feminine gender will be deemed to include the other.

(b) Any reference in this Contract to any Person includes its successors and permitted assigns and, in the case of any Government Agency, any Person succeeding to its functions and capacities.

(c) Any reference in this Contract to any Section or Annex means and refers to the Section contained in this Contract or in an Annex attached to this Contract.

(d) Other grammatical forms of defined words or phrases have corresponding meanings.

(e) A reference to writing includes typewriting, printing, lithography, photography and any other mode of representing or reproducing words, figures or symbols in a lasting and visible form.

(f) Unless otherwise specified, a reference to a specific time for the performance of an obligation is a reference to that time in the place where that obligation is to be performed.

(g) A reference to a Party to this Contract includes that Party's successors and permitted assigns.

(h) A reference to a document or agreement, including this Contract, includes a reference to that document or agreement as novated, amended, supplemented or restated from time to time.

1.3 Technical Meanings. Words not otherwise defined herein that have well-known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings, as of the Effective Date.

SECTION 2. TERM; DELIVERY PERIOD

2.1 The term of this Contract (the "Term") shall commence on the Effective Date and shall remain in effect until the expiration of the Delivery Period, unless otherwise extended by written agreement of the Parties.

2.2 In the event that, prior to the first date of the Delivery Period as defined above, Seller and Buyer mutually agree to move up the first day of the Delivery Period, the Parties shall execute a written amendment to this Contract re-defining "Delivery Period" to reflect the new start date thereof.

SECTION 3. PERFORMANCE OBLIGATIONS

3.1 Seller agrees to sell and deliver to Buyer, and Buyer agrees to receive and purchase from Seller, the Contract Quantity on a Firm basis at the Delivery Point(s) each Day during the Delivery Period in accordance with the terms and conditions of this Contract.

3.2 With respect to each Month during the Delivery Period, Buyer shall pay to Seller an amount equal to the product of: (i) the amount of Gas actually delivered by Seller to Buyer in such Month, and (ii) the Contract Price applicable to such Month (as determined pursuant to Section 3.3).

3.3 Unless otherwise agreed between the Parties pursuant to this Section 3.3, the Contract Price with respect to each delivery Day during a particular Month, shall be the price (expressed in U.S. Dollars per MMBtu) for such Month as published in *Inside FERC's Gas Market Report* (as published by The McGraw-Hill Companies, Inc. or its successor), under the heading "Market Center Spot-Gas Prices" "South Louisiana" "Henry Hub" "Midpoint", plus [redacted] per MMBtu. For any particular Month during the Term, the Parties may agree to change the Contract Price for such Month from that which is described in the previous sentence to either a fixed dollar amount per MMBtu, or a price based on another index (other than the *Inside FERC* index referenced above), in either case as mutually agreed by the Parties pursuant to the procedures set forth in Section 3.5.

3.4 Unless otherwise agreed between the Parties pursuant to this Section 3.4, the Delivery Point with respect to each delivery Day during a particular Month, shall be the Primary Delivery Point. For any particular Month during the Term, the Parties may agree to change the Delivery Point for such Month to an Alternate Delivery Point pursuant to the procedures set forth in Section 3.5.

3.5 To effect a change to the Contract Price for one or more Months (a "Price Change"), or to effect a change from the Primary Delivery Point to an Alternate Delivery Point for one or more Months (a "Delivery Point Change"), the Party seeking such change must make such request of the other Party prior to 2:30 P.M. Eastern Prevailing Time on the last trading day of the NYMEX gas futures contract (Henry Hub) of the Month immediately preceding the relevant Month or Months for which the change would be effective. Each Party shall exercise reasonable efforts to accept such a proposed change; provided, however, that a Party shall not be required to accept a change that would not be commercially reasonable for such a Party. The Parties acknowledge that Seller's source of Gas for use under this Contract is regasified LNG delivered to the Elba Island LNG Terminal, and therefore any proposed change in Delivery Point that does not allow delivery from the Elba Island LNG Terminal is not commercially reasonable for Seller. If the Party to whom the request is made accepts the proposed change, such agreement between the Parties may be effectuated through a recorded telephone conversation, with the offer and acceptance constituting the agreement of the Parties. The Parties shall be legally bound from the time they so agree to the terms of such Price Change or Delivery Point Change and may each rely thereon. Any such agreement shall be considered to be a "writing" and to have been "signed" for all purposes hereunder. Notwithstanding the foregoing sentence, the Parties agree that either Party may confirm a telephonic transaction by sending the other Party a Confirmation via facsimile or other mutually agreeable means within a reasonable time of such agreement; provided that the failure of either or both Parties to send a Confirmation shall not invalidate the oral agreement of the Parties. The confirming Party adopts its confirming letterhead, or the like, as its signature on any Confirmation as the identification and authentication of the confirming Party. If the Confirmation contains any provision other than those relating to the terms of the Price Change or Delivery Point Change (i.e. any terms other than the applicable Month and the newly-agreed Contract Price or Delivery Point for such Month), which modify or supplement this Contract, such provisions shall not be binding on the receiving Party; provided that the foregoing shall not invalidate any Price Change or Delivery Point Change agreed to by the Parties. Any failure by either or both Parties to send a Confirmation for any Price Change or Delivery Point Change shall not affect the enforceability of any such Price Change or Delivery Point Change actually entered into nor shall such failure constitute or be deemed to constitute a breach of this Contract. If a sending Party's Confirmation is materially different from the receiving Party's understanding of the agreement concerning the applicable Price Change or Delivery Point Change, such receiving Party shall notify the sending Party in writing (facsimile acceptable) within two Business Days of receipt of such Confirmation and the Parties shall work together to resolve the discrepancies. The failure of the receiving Party to so notify the sending Party in writing by such deadline constitutes the receiving Party's agreement to the terms of the applicable Price Change or Delivery Point Change described in the sending Party's Confirmation. If there are any material differences between timely sent Confirmations governing the same Price Change or Delivery Point Change, then neither Confirmation shall be binding with respect to the differing terms until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Confirmations. In the event of a conflict among the terms of (i) a binding Confirmation (including by deemed acceptance as described above), (ii) the oral agreement of the Parties which may be evidenced by a recorded conversation, and (iii) this Contract, the terms of the documents shall govern in the priory listed in this sentence.

3.6 The Parties may agree to a Price Change that results in a fixed price ("Fixed Price") as opposed to a Contract Price that floats based on NYMEX, industry postings, reference publications, or other external market factors or indices. If a Fixed Price is established and, for any reason whatsoever (other than a breach or default by either Party under this Contract), including, without limitation, an event of Force Majeure or any circumstance (other than a breach or default by either Party under this Contract) that would excuse a Party's obligation to deliver or receive Gas under this Contract, Seller delivers or Buyer takes less than the full Contract Quantity for such Month (a "Monthly Deficiency"), then (1) Buyer shall pay Seller an amount equal to such Monthly Deficiency (expressed in MMBtus) multiplied by the amount, if any, by which the Fixed Price exceeds the applicable NYMEX Natural Gas futures contract price for such Month, or (2) Seller shall pay to the Buyer an amount equal to such Monthly Deficiency (expressed in MMBtus) multiplied by the amount, if any, by which the applicable NYMEX Natural Gas futures contract for such Month exceeds the Fixed Price established for such Month.

SECTION 4. TRANSPORTATION, NOMINATIONS AND IMBALANCES

4.1 Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s). Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).

4.2 The Parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each Party shall give the other Party timely prior notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either Party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such Party shall promptly notify the other Party.

4.3 The Parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an Invoice from a Transporter that includes Imbalance Charges, the Parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer. Notwithstanding anything to the contrary herein, in the event of Force Majeure, the Parties shall follow the procedures set forth in Section 12.8 and each Party shall be responsible for any Imbalance Charges arising out of its non-conformance with such procedures.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the requirements of the Receiving Transporter's pipeline specifications for pipeline quality Gas. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any Government Agency ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, the Party responsible for such Taxes shall promptly reimburse the other Party for such Taxes. Any Party entitled to an exemption from any such Taxes or charges shall furnish the other Party any necessary documentation thereof. Failure by either Party to furnish such documentation shall not give rise to a breach of this Contract.

SECTION 7. BILLING, PAYMENT AND AUDIT

7.1 Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing or as soon thereafter as actual delivery information is available.

7.2 Buyer shall remit the amount due under Section 7.1 via wire transfer or ACH, in immediately available funds, on or before the Payment Date. Except as otherwise provided in Section 7.3, in the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with this Section 7.2.

7.3 In the event payments become due pursuant to Section 13, the performing Party may submit an invoice to the non-performing Party for an accelerated payment setting forth the basis upon which the invoiced amount was calculated. Payment from the non-performing Party shall be due within five (5) Business Days after receipt of invoice.

7.4 If the invoiced Party, in good faith, disputes the amount of any such invoice or any part thereof, such invoiced Party will pay the portion of such amount as it concedes to be correct; provided, however, if the invoiced Party disputes the amount due, it must provide supporting documentation acceptable in industry practice to support the amount paid or disputed. In the event the Parties are unable to resolve such dispute, either Party may pursue any remedy available at law or in equity to enforce its rights pursuant to this Section 7.

7.5 If the invoiced Party fails to remit the full amount payable when due, interest on the unpaid portion shall accrue from the date due until the date of payment at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum; or (ii) the maximum applicable lawful interest rate.

7.6 A Party shall have the right, at its own expense, upon reasonable Notice and at reasonable times, to examine and audit and to obtain copies of the relevant portion of the books, records and telephone recordings of the other Party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment or computation made under this Contract. This right to examine, audit and obtain copies shall not be available with respect to proprietary information not directly relevant to obligations under this Contract. Such right shall include, but not be limited to, copies of any and all statements and/or records pertaining to transportation of Gas with respect to which any such transportation charges are included in billing and/or invoices hereunder, and/or are the subject of any bona fide dispute between the Parties, and without regard as to whether such records and/or statements were generated by the Party being audited or the relevant Transporter. All invoices and billings shall be conclusively presumed final and accurate and all associated claims for underpayments or overpayments shall be deemed waived unless such invoices or billings are objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7 shall be paid in full by the Party owing payment within 30 Days of Notice and substantiation of such inaccuracy.

7.7 The Parties shall net all undisputed amounts due and owing, and/or past due, arising under this Contract such that the Party owing the greater amount shall make a single payment of the net amount to the other Party in accordance with Section 7.2; provided that no payment required to be made pursuant to the terms of Section 10 shall be subject to netting under this Section 7.7.

SECTION 8. TITLE, WARRANTY AND INDEMNITY

8.1 Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and assume any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).

8.2 Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances and claims. EXCEPT AS OTHERWISE PROVIDED HEREIN, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

8.3 Seller agrees to indemnify and defend Buyer and its Affiliates, and their respective agents, employees, officers and directors, and save them harmless from all losses, liabilities or claims including reasonable attorneys' fees and costs of court ("Claims"), from any and all Persons, arising from or out of claims of title, personal injury or property damage from said Gas or other charges thereon which attach before title passes to Buyer, except to the extent attributable to Buyer's negligence or willful misconduct. Buyer agrees to indemnify and defend Seller and its Affiliates, and their respective agents, employees, officers and directors, and save them harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury or property damage from said Gas or other charges thereon which attach after title passes to Buyer, except to the extent attributable to Seller's negligence or willful misconduct. Each Party shall indemnify, defend and hold harmless the other Party against any taxes for which such Party is responsible under Section 6.

8.4 Notwithstanding the other provisions of this Section 8, as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1 All correspondence, invoices, payments and other communications made pursuant to this Contract (each a "Notice") shall be made to the addresses set forth below for such Party or as otherwise may be specified in writing by the respective Parties from time to time by providing Notice in accordance with this Section 9.1.

If to Buyer:

With respect to Notices that do not relate to invoices or payments:

Progress Energy Florida, Inc.
Attn: Contracts Department
410 S. Wilmington Street (PEB 10)
Raleigh, NC 27601
Fax: 919-546-2649

A copy of any Notice above relating to Sections 8.3, 10, 11, and 19.10 shall also be sent to:

Attn: Assistant General Counsel – Energy Trading & Marketing
410 S. Wilmington Street (PEB 17)
Raleigh, NC 2760
Fax: 919-546-2920

With respect to Notices that relate to invoices or payments:

Attn: PEF Gas Accounting
410 S. Wilmington Street (PEB 10)
Raleigh, NC 27601
Fax: 919-546-3258

If to Seller:

With respect to Notices that do not relate to invoices or payments:

BG LNG Services, LLC
Attn: President
5444 Westheimer, Suite 1775
Houston, Texas 77056
Fax: 713-599-3781

A copy of any Notice above relating to Sections 8.3, 10, 11, and 19.10 shall also be sent to:

Attn: VP-Legal
5444 Westheimer, Suite 1775
Houston, Texas 77056
Fax: 713-599-3781

With respect to Notices that relate to invoices or payments:

Attn: Financial Controller
5444 Westheimer, Suite 1775
Houston, Texas 77056
Fax: 713-599-3781

9.2 All Notices required hereunder may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered. Any Notice sent pursuant to Sections 8.3, 10, 11, 12, 15.2, or 19.10 shall not be sent via electronic means.

9.3 Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions shall apply: Notices sent by facsimile shall be deemed to have been received upon the sending Party's receipt of its facsimile machine's confirmation of successful transmission. If the day on which such facsimile is received is not a Business Day or is after 5:00 p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day. Notice by overnight mail or courier shall be deemed received on the next Business Day after it was sent or such earlier time as confirmed by the receiving Party. Notice via first class mail shall be considered delivered five Business Days after mailing.

SECTION 10. CREDIT

[redacted]

[redacted]

SECTION 11. EVENTS OF DEFAULT; REMEDIES

REDACTED

REDACTED

REDACTED

SECTION 12. FORCE MAJEURE

REDACTED

REDACTED

SECTION 13. UNEXCUSED FAILURE TO DELIVER/RECEIVE GAS; REMEDY

REDACTED

REDACTED

SECTION 14. LIMITATIONS

THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

SECTION 15. CONDITIONS PRECEDENT

REDACTED

[redacted]

SECTION 16. Intentionally Omitted.

REDACTED

REDACTED

REDACTED

[redacted]

[redacted]

SECTION 18. REPRESENTATIONS AND WARRANTIES

18.1 At all times beginning with the Effective Date (unless otherwise provided below) and ending at the end of the Term, each Party represents and warrants to the other Party that:

(i) the execution, delivery and performance of this Contract are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any Law, rule, regulation order or the like applicable to it;

(ii) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(iii) beginning at the time of commencement of any delivery obligations hereunder, it will have all Governmental Approvals required for it to legally perform its obligations under this Contract;

(iv) this Contract, and each other document executed and delivered in accordance with this Contract constitutes its legally valid and binding obligations enforceable against it in accordance with their respective terms (subject to applicable bankruptcy, reorganization, moratorium or similar Laws affecting creditors' rights generally and subject, as to enforceability, to equitable principles of general application regardless of whether enforcement is sought in a proceeding in equity or at law);

(v) there are no proceedings similar to those described in Section 11.1 (i) through (v) pending or being contemplated by it or, to its knowledge, threatened against it;

(vi) except with respect to FERC proceedings in connection with the Cypress Pipeline, there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Contract;

(vii) no Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Contract;

(viii) it is acting for its own account, has made its own independent decision to enter into this Contract and as to whether this Contract is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Contract;

(ix) it has entered into this Contract in connection with the conduct of its business and it has the capacity or ability to make or take delivery of the Gas referred to hereunder and the material economic terms hereof have been subject to individual negotiation by the Parties.

(x) it is the understanding of both of the Parties that this Contract constitutes a "forward contract" within the meaning of the United States Bankruptcy Code and that each of Buyer and Seller is (i) a "forward contract merchant" within the meaning of the United States Bankruptcy Code, (ii) an "eligible contract participant" as such term is defined in the Commodity Exchange Act, as amended 7 U.S.C. § 1 (a) (12), and (iii) an "eligible commercial entity" as such term is defined in the Commodity Exchange Act, as amended 7 U.S.C. § 1 (a)(11).

18.2 Seller further represents and warrants to Buyer that Seller and/or its Affiliates will either own or hold firm rights to (i) terminalling capacity at the Elba Island LNG Terminal, (ii) LNG supplies; and (iii) transportation capacity to effect delivery to any Alternate Delivery Point(s) (to the extent that the Parties have agreed upon an Alternate Delivery Point that requires Seller to obtain transportation), all to the extent necessary to meet Seller's obligations to Buyer under this Contract.

SECTION 19. MISCELLANEOUS

19.1 Assignment. No assignment of this Contract, in whole or in part, whether by merger and operation of law or otherwise, will be made without the prior written consent of the non-assigning Party, which consent shall not be unreasonably withheld or delayed; provided, however, either Party may transfer its interest to any Affiliate by assignment, merger or otherwise without the prior approval of the other Party if (i) such transfer or assignment is to an entity whose creditworthiness is equal to or better than that of the transferee party immediately preceding the transfer, (ii) such transfer has no adverse tax consequences to the non-transferring Party, (iii) the assignee agrees in writing to be bound to all of the assignor's obligations under this Contract, and (iv) such transfer does not affect any Guarantee (or the benefit to the named beneficiary thereof) that has been previously provided to the non-transferring Party and that was still in effect immediately prior to such transfer.

19.2 Severability. If any term or provision of this Contract or the application thereof to any Person or circumstance is held to be illegal, invalid or unenforceable under any present or future Law or by any Governmental Agency, (a) such term or provision shall be fully severable, (b) this Contract shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (c) the remaining provisions of this Contract shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom and (d) the Parties shall negotiate in good faith to agree upon legal, valid and enforceable substitute provisions to carry out the purposes and intent of the illegal, invalid or unenforceable terms and provisions.

19.3 Waiver. Any term or condition of this Contract may be waived at any time by the Party hereto that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. The failure or delay of either Party to require performance by the other Party of any provision of this Contract shall not affect its right to require performance of such provision unless and until such performance has been waived by such Party in writing in accordance with the terms hereof. No waiver by either Party of any term or condition of this Contract, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Contract on any future occasion.

19.4 Entire Agreement. This Contract sets forth all understandings between the Parties respecting the transaction contemplated herein, and any prior contracts, understandings and representations, whether oral or written, relating to such transaction are merged into and superseded by this Contract. Except as otherwise provided in Section 3.4 hereof, this Contract may be amended only by a writing executed by both Parties.

19.5 Governing Law. The validity, interpretation and performance of this Contract and each of its provisions shall be governed by the applicable laws of the state of New York, without regard to the application of such state's laws relating to conflicts of laws (except for Section 5-1401 and 5-1402 of the General Obligations Laws).

19.6 Venue. EACH OF THE PARTIES HERETO HEREBY SUBMITS TO THE JURISDICTION OF ANY COURT SITTING OUTSIDE OF THE STATE OF TEXAS, THE STATE OF LOUISIANA, THE STATE OF ILLINOIS, OR THE STATE OF MISSISSIPPI FOR PURPOSES OF ALL LEGAL PROCEEDINGS ARISING OUT OF OR RELATING TO THIS CONTRACT OR THE TRANSACTIONS CONTEMPLATED HEREBY, AND AGREES THAT SUCH COURTS SITTING OUTSIDE OF THE STATE TEXAS, THE STATE OF LOUISIANA, THE STATE OF ILLINOIS, OR THE STATE OF MISSISSIPPI SHALL BE THE EXCLUSIVE FORUMS FOR RESOLVING ANY DISPUTE OR CONTROVERSY UNDER OR WITH RESPECT TO THIS CONTRACT. EACH OF THE PARTIES HERETO HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT IT MAY EFFECTIVELY DO SO, ANY OBJECTION WHICH IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF THE VENUE OF ANY SUCH PROCEEDINGS BROUGHT IN SUCH COURTS AND ANY CLAIMS THAT ANY SUCH PROCEEDINGS BROUGHT IN SUCH COURTS HAVE BEEN BROUGHT IN INCONVENIENT FORUMS.

19.7 Waiver of Jury Trial. EACH OF THE PARTIES HERETO HEREBY WAIVES ANY RIGHT TO HAVE A JURY PARTICIPATE IN RESOLVING ANY DISPUTE, WHETHER SOUNDING IN CONTRACT, TORT OR OTHERWISE AMONG ANY OF THEM ARISING OUT OF, CONNECTED WITH, RELATING TO OR INCIDENTAL TO THE RELATIONSHIP BETWEEN THEM IN CONNECTION WITH THIS CONTRACT.

19.8 Third Parties. This Contract is intended solely for the benefit of the Parties. Nothing in this Contract shall be construed to create any duty or liability to, or standard of care with reference to, any other Person.

19.9 Headings. The headings and subheadings contained in this Contract are used solely for convenience and do not constitute a part of this Contract between the Parties and shall not be used to construe or interpret the provisions of this Contract.

19.10 Confidentiality. Neither Party shall disclose directly or indirectly without the prior written consent of the other Party the terms of this Contract to a third party (other than the employees, lenders, royalty owners, counsel, accountants and other agents of the Party and its Affiliates, prospective purchasers of all or substantially all of a Party's assets or of any rights under this Contract, provided such Persons shall have agreed to keep such terms confidential) except (i) in order to comply with any applicable Law, order, regulation, or exchange rule (including without exclusion disclosures required by the Securities and Exchange Commission), (ii) to the extent necessary for the enforcement of this Contract, (iii) to the extent necessary to implement any delivery or receipt of Gas under this Contract, or (iv) to the extent such information is delivered to such third Party for the sole purpose of calculating a published index (provided, however, that such information shall be handled in an aggregate form with other data such that it cannot be used to identify the Parties to this Contract). Each Party shall notify the other Party of any proceeding of which it is aware which may result in disclosure of the terms of this Contract (other than as permitted hereunder), if and to the extent that such notification does not violate any order or decree with regard to such proceeding, and shall use reasonable efforts to prevent or limit the disclosure. Subject to Section 14, the Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation. Notwithstanding anything to the contrary in this Section 19.10, Buyer shall have the right to provide a copy of this Contract to the Florida Public Service Commission and any other entity that is a party to the relevant docket that has executed a confidentiality agreement to retain such information confidential, without prior notice to or the consent of Seller, in connection with Buyer's attempts to obtain the Florida Public Service Commission's approval of this Contract; provided, however, that at the time Buyer provides this Contract to the Florida Public Service Commission, Buyer shall petition the Florida Public Service Commission to keep confidential for a period of eighteen months certain information contained herein, including without limitation, all information related to the Contract Price and the Contract Quantity. Buyer shall inform Seller within two Business Days if the Florida Public Service Commission denies Buyer's request to keep such information confidential for such period. In such event, Seller shall have the right to immediately terminate this Contract by written notice to Buyer. During the Term of this Contract, at Seller's request, Buyer shall cooperate with Seller to petition the Florida Public Service Commission for extension of the confidential treatment of the information related to the Contract Price and the Contract Quantity for periods beyond the initial eighteen months.

19.11 Market Disruption Affecting Price Source. The following provisions shall be applicable where the Contract Price is determined by reference to a third-party information source or with respect to instances in which the Spot Price is applied:

19.11.1 Market Disruption. If a Market Disruption Event (as defined below) occurs during the Determination Period (as defined below), the Floating Price (as defined below) for the affected Trading Day(s) (as defined below) shall be determined pursuant to the Floating Price for the first Trading Day thereafter on which no Market Disruption Event exists; provided, however, that if the Floating Price is not so determined within three Business Days after the first Trading Day on which the Market Disruption Event occurred or existed, then the Parties shall negotiate in good faith to agree on a Floating Price (or a method for determining a Floating Price), and if the Parties have not so agreed on or before the 12th Business Day following the first Trading Day on which the Market Disruption Event occurred or existed, then the Floating Price shall be determined in good faith by Buyer by taking the average of two or more dealer quotes. "Market Disruption Event" means, with respect to any Price Source (as defined below), any of the following events (the existence of which shall be determined in good faith by Buyer): (i) the failure of the Price Source to announce or publish information necessary for determining the Floating Price; (ii) the failure of trading to commence or the permanent discontinuation or material suspension of trading in the relevant options contract or commodity on the Exchange (as defined below) or in the market specified for determining a Floating Price; (iii) the temporary or permanent discontinuance or unavailability of the Price Source (iv) the temporary or permanent closing of any Exchange specified for determining a Floating Price; or (v) a material change in the formula for the method of determining the Floating Price. "Price Source" means the publication (or such other origin of reference, including an Exchange) containing (or reporting) the specified price (or prices from which the specified price is calculated). "Floating Price" means the Contract Price that is based upon a Price Source. "Exchange" means, in respect of a price, the exchange or principal trading market specified in the calculation of such price. "Determination Period" means each calendar Month, a part or all of which is within the delivery period during which the relevant price applies. "Trading Day" means a day in respect of which the relevant Price Source published the Floating Price.

19.11.2 Corrections to Published Prices. For purposes of determining the relevant prices for any Day, if the price published or announced on a given Day and used or to be used to determine a relevant price is subsequently corrected and the correction is published or announced by the person responsible for that publication or announcement, either Party may notify the other Party of (i) that correction and (ii) the amount (if any) that is payable as a result of that correction. If a Party gives notice that an amount is so payable, the Party that originally either received or retained such amount will, not later than two Business Days after the effectiveness of that notice, pay, subject to any applicable conditions precedent, to the other Party that amount, together with interest at a rate equal to the lower of (x) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal; or (y) the maximum applicable lawful interest rate, for the period from and including the day on which payment originally was (or was not) made to but excluding the day of payment of the refund or payment resulting from that correction.

19.11.3 Calculation of Floating Price. For the purposes of the calculation of a Floating Price, all numbers shall be rounded to three decimal places. If the fourth decimal number is five or greater, then the third decimal number shall be increased by one, and if the fourth decimal number is less than five, then the third decimal number shall remain unchanged.

19.12 Construction. The language used in this Contract is the product of both Parties' efforts and each Party hereby irrevocably waives the benefit of any rule of contract construction which disfavors the drafter of a contract or the drafter of specific language in a contract.

19.13 Recording. The Parties agree that each Party may electronically record all telephone conversations with respect to this Contract between their respective employees, without any special or further notice to the other Party. Each Party shall obtain any necessary consent of its agents and employees to such recording. Each Party waives any objections to the introduction of the recorded conversations into evidence in any proceeding based on the Statute of Frauds, the parol evidence rule, or the best evidence rule. Each Party waives any objection or defense to its authority or the authority of its employee provided that such employee can be identified on the relevant employing Party's recording. No Party may knowingly destroy or erase a recording once the possessing Party becomes aware of an actual dispute in which the recording may reasonably be anticipated to be discoverable.

19.14 Independent Contractors. The Parties are independent contractors. Nothing contained in this Contract shall be deemed to create an association, joint venture, partnership or principal/agent relationship between the Parties hereto or to impose any partnership obligation or liability on either Party. Neither Party shall have any right, power or authority hereunder to enter into any agreement or commitment, act on behalf of, or otherwise bind the other Party in any way.

19.15 Survival. The rights of either Party pursuant to Sections 7, 8.3, 11, 19.10 and any other provision(s) of this Contract that expressly or by implication comes into or remains in force following the termination or expiration of this Contract shall survive the termination or expiration of this Contract.

19.16 Imaged Agreement. Any original executed counterpart of this Contract, or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, a tape or other electronic recording of an oral agreement to a Price Change made pursuant to Section 3.4 (the "Transaction Tape"), if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the Transaction Tape, or the Imaged Agreement (or photocopies of the transcription of the Transaction Tape, or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under the hearsay rule, the best evidence rule, or the parol evidence rule.

19.17 Counterparts. This Contract may be executed in several counterparts, and all such counterparts shall constitute one agreement binding on both Parties hereto and shall have the same force and effect as an original instrument.

(Remainder of page intentionally left blank. Signature page to follow.)

IN WITNESS WHEREOF, the Parties have caused this Contract to be executed by their respective duly authorized officers as of the Effective Date.

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.

By:____________________________

Name: ROBERT F. CALDWELL

Title: VICE PRESIDENT - Reg'l Ops

BG LNG SERVICES, LLC

By:____________________________

Name: ELIZABETH SPOMER

Title: VICE PRESIDENT

Annex A

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

[redacted]

Annex B

REDACTED

REDACTED

REDACTED

REDACTED

PRECEDENT AGREEMENT
BY AND BETWEEN

Southern Natural Gas Company

AND

Florida Power Corporation
d/b/a Progress Energy Florida, Inc.
(Hines Plant and System Supply)

DATED: December 2, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 6
COMPANY/ PEF
WITNESS: Pamela R. Murphy (PRM-2)
DATE: 04-29-05

PRM-2

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PRECEDENT AGREEMENT

This Precedent Agreement is made and entered into as of the 2nd day of December, 2004, by and between Southern Natural Gas Company (**"Southern"**), a Delaware corporation, and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (**"Shipper"**), a Florida Corporation (hereinafter Shipper and Southern are sometimes referred to individually as **"Party"** or collectively as the **"Parties"**) pursuant to the following terms, conditions, and representations:

WITNESSETH:

WHEREAS, Southern proposes to design, construct, own and operate an expansion of its existing natural gas pipeline system (the **"Cypress Project"**) that extends from a point of interconnection with Southern's existing pipeline facilities downstream of Southern LNG Company, L.L.C.'s (**"Southern LNG"**) Elba Island LNG Terminal (**"Elba Island"**) in Chatham County, Georgia, to an interconnection with the existing natural gas transmission facilities of Florida Gas Transmission Company (**"FGT"**) in Clay County, Florida; and

WHEREAS, the Cypress Project is proposed to consist of and shall herein be defined as (i) approximately 166 miles of 24-inch pipeline; and (ii) a bidirectional meter station at the interconnection of Southern and FGT in Clay County, Florida (**"FGT Interconnection"**); and

WHEREAS, Shipper desires to receive firm transportation service from Southern pursuant to (i) the terms of a Service Agreement containing substantially the same terms and conditions as set forth below in Section 1; and (ii) Rate

Schedule FT under Volume I of Southern's FERC Gas Tariff (**"Tariff"**), hereinafter the **"FT Service"**; and

WHEREAS, Shipper will also subscribe to an expansion on FGT's pipeline system into or from Southern's system at the FGT Interconnection in order to receive gas at Shipper's generating plant in Polk County, Florida, and other delivery points on FGT's system for Shipper's system supply (**"FGT Expansion"**); and

WHEREAS, to effectuate this proposal to construct the Cypress Project and provide FT service to Shipper, Southern will file an application with the Federal Energy Regulatory Commission (**"FERC"**) for authorization to construct, install, operate and maintain the Cypress Project for the purpose of providing the FT Service to Shipper; and

WHEREAS, Southern will hold an open season to solicit bids from other prospective shippers interested in subscribing for firm transportation service; and

WHEREAS, Southern and Shipper now desire to enter into this binding precedent agreement (**"Precedent Agreement"**) setting forth the terms and conditions under which the Parties may subsequently execute a definitive service agreement for the FT Service on Southern's system (**"Service Agreement"**).

NOW THEREFORE, in consideration of the mutual covenants set forth in this agreement, and other good and valuable consideration the receipt and sufficiency of which are hereby acknowledged, Southern and Shipper agree as follows:

1. <u>Firm Service Obligation</u>.

Subject to the terms and conditions of this Precedent Agreement, any terms and conditions which may be imposed by the FERC and the terms and conditions of Southern's Tariff, Southern agrees to provide to Shipper FT Service as described below. Such FT Service shall be provided in accordance with the terms of a Service Agreement to be executed between Southern and Shipper. A profórma copy of the Service Agreement is set forth in Exhibit "B" attached hereto and made a part hereof. Such Service Agreement shall contain the terms and conditions that are substantially in accordance with the following:

(a) The FT Service will be for the Transportation Demand (**"TD"**) stated in MMBtu as set forth on Exhibit "A" attached hereto, commencing on the date that both of (1) the Southern facilities comprising the Cypress Project, and (2) the FGT Expansion are capable of providing such transportation service on a firm daily basis (the **"Commencement Date"**).

(b) The firm Receipt Point designated on Exhibit "A" to the Service Agreement shall be the Elba Island Receipt Point and the firm Delivery Point designated on Exhibit "B" to the Service Agreement shall be the FGT Interconnection. Shipper shall have secondary rights to alternate receipt and delivery points on Southern's system as set forth in Southern's Tariff.

(c) The initial term of the FT Service described in Section (a) above shall be twenty (20) years from the Commencement Date of FT

Service set forth above (the "**Primary Term**"). Shipper shall have the right to extend the Primary Term of the Service Agreement for the FT Service described in Section (a) above for one or more periods of three (3) years at Southern's then applicable maximum lawful rate (any such period being hereinafter referred to as an "**Evergreen Extension**") by providing Southern with written notice of the exercise of such right at least two (2) years prior to the end of the Primary Term or any Evergreen Extension thereto.

(d) The rate to be charged Shipper for the FT Service shall be a negotiated reservation rate of [redacted] per MMBtu for the Primary Term of this Precedent Agreement and successor Service Agreement, plus the maximum commodity charge for the applicable zone(s) of service as set forth in Southern's Tariff. The rate to be charged Shipper for fuel under this Precedent Agreement and successor Service Agreement shall be Southern's generally applicable and approved fuel charge established pursuant to Southern's Tariff.

(e) In addition to the rates provided for under Section 1(d) above, Shipper will compensate Southern for any other FERC approved, generally applicable charges or surcharges applicable to the FT Service.

(f) Southern shall have the unilateral right to file for generally applicable changes in its maximum rates or any other provisions in its FERC Gas Tariff and the Service Agreement including, but not limited to, provisions relating to compensation for fuel and lost and unaccounted for gas or electric usage applicable to the service hereunder. Subject to the provisions in Section 1(d) above, such changes shall be effective and applicable, subject to refund as determined by the FERC, after the required notice or at the end of any suspension period ordered by the FERC, and any such rates, charges, surcharges or terms and conditions of service accepted by the FERC shall be effective under the Service Agreement. It is understood and agreed that the generally applicable fuel retention percentage and the surcharges set forth in Section 1(e) above are designed to change from time to time consistent with Southern's FERC Gas Tariff and FERC Regulations. With respect to the services provided under this Precedent Agreement (and any successor Service Agreement), and notwithstanding the foregoing, (i) Shipper shall not have the right to intervene and protest in any rate filing by Southern with respect to changes in Southern's recourse rates during the Primary Term of this Precedent Agreement or the Service Agreement, and (ii) Shipper shall have the right to intervene and protest (a) any filing involving generally applicable charges or surcharges in accordance with Sections 1(e) above, or (b) any filing involving the terms and conditions of service in Southern's Tariff, or (c) any rate filing applicable to services received by Shipper from Southern other than those provided hereunder.

(g) Notwithstanding the rate cap set forth in Section 1(d) above, if, while the negotiated reservation rate of [redacted] per MMBtu is in effect, Southern's costs to provide transportation services are adversely affected as a result of State, local or federal legislation or regulation specifically including, but not limited to orders, regulations, rules or opinions by the FERC, Environmental Protection Agency, Department of Transportation, U.S. Army Corps of Engineers, Internal Revenue Service, U. S. Fish and Wildlife Service or any other State or federal agency or court of law and/or any changes in Generally Accepted Accounting Principles (GAAP), that has a general or industry wide effect which causes the total cost of service to Southern of providing Shipper the transportation service to be materially and adversely increased; then Southern may provide written notice to Shipper requesting to increase Shipper's rates to take into account the costs associated with the legislation or regulation. For purposes of the previous sentence, "materially and adversely" shall be defined as an overall increase in Southern's total cost of service to provide service to Shipper as contemplated by this Precedent Agreement of 25% or more (after taking into consideration any offsetting decreases in other costs or increases in other revenues from regulatory events such as those described above), calculated on a net present value basis, discounted at an 8% discount rate. Such written notice requesting an adjustment in the rates shall specifically state (i) the legislation or regulation impacting such costs or revenues; (ii) the obligation by Southern to comply with such regulation or legislation; and (iii) how, and the extent to which, such legislation or regulation materially and adversely increases Southern's total cost of service to provide service to Shipper as contemplated by this Precedent Agreement. Once Southern has provided such notice, the Parties shall meet within thirty (30) days to discuss possible means of correcting the material and adverse impact and shall attempt in good faith to negotiate a mutually acceptable solution, including, but not limited to, an amendment to the rate discount through an increase of the reservation or transportation charges. If the Parties are unable within 120 days after the receipt of such notice to agree upon a mutually acceptable solution, then either Party may, upon 30 days prior written notice to the other, invoke alternative dispute resolution procedures consistent with the commercial arbitration rules of the American Arbitration Association in order to determine how to mitigate the adverse impact in light of all of the facts and circumstances existing at that time. Any rate increase agreed upon by Southern and Shipper or that is approved through the alternate dispute resolution procedures shall only go into effect prospectively commencing upon the date that either the Parties agree upon the rate change or such rate change is approved through the alternate dispute resolution procedures. Notwithstanding the foregoing, no rate increase or increases adopted pursuant to this Section 1(g), whether agreed to by Southern and Shipper or approved through the alternate dispute resolution procedures described herein, shall result in an aggregate increase in the negotiated reservation rate provided hereunder of more than twenty-five per cent (25%).

2. **Approvals; Cooperation.**

(a) Upon execution of this Precedent Agreement, Southern and Shipper agree to promptly seek, and to exercise good faith efforts to cause any and all other parties whose participation is required to promptly seek the regulatory approvals, including from the FERC all necessary authorizations under the Natural Gas Act (the "**FERC Authorizations**"), as may be necessary to construct, install and operate the Cypress Project consistent with the terms of this Precedent Agreement. Southern and Shipper reserve the right to file and prosecute applications for any required authorizations, any supplement or amendment to an application, and any court review as each deems in its best interests.

(b) Southern shall provide Shipper from time to time, but in no event less frequently than once a month, with updates of its progress in obtaining the FERC Authorizations to construct the Cypress Project.

(c) Southern and Shipper each agree to execute and deliver all other additional instruments and documents, and to do all other acts, as may be reasonably necessary to effectuate the terms and provisions of this Precedent Agreement.

(d) Southern shall not be obligated to prosecute its application with the FERC or seek any other regulatory approvals or permit applications or proceed with the construction of the Cypress Project unless and until it holds an open season soliciting bids from other shippers.

(e) Once the open season for subscription for the Cypress Project has closed and been finalized, Southern will actively pursue design, engineering and title work as necessary to facilitate the filing of the FERC Authorizations and the FERC review process, but it shall not be required to commit significant capital expenditures for right-of-way or materials for the project unless and until it receives a Preliminary Determination, as defined in Section 5(a)(i)(B) below, from the FERC approving the commercial aspects of the filing in a manner acceptable to Southern or until all conditions precedent set forth in Section 5(b) below are met by Shipper.

3. **Acceptance of FERC Authorization.**

Within 10 business days of Southern receiving the FERC Authorizations, Southern shall notify Shipper of its intent to accept or reject the FERC Authorizations. Shipper shall, within fifteen (15) days after the date Southern provides an electronic copy to Shipper by e-mail of FERC's

Preliminary Determination on the Cypress Project, notify Southern in writing of any terms or conditions in the Preliminary Determination that materially and adversely affect Shipper, as further defined below, and whether Shipper has any material objections to such Preliminary Determination. Neither Southern, in the case of the FERC Authorizations, nor Shipper, in the case of the Preliminary Determination, shall be under any obligation to accept the respective terms of the FERC Authorizations or Preliminary Determination if they contain terms or conditions which are reasonably likely to have a material and adverse effect. A material and adverse effect shall be defined as (i) having a material and adverse impact on the financial benefits to either Southern or Shipper arising out of the transactions contemplated hereby, or (ii) imposing upon Southern or Shipper material business or regulatory risks, as Southern or Shipper, respectively, in their sole discretion shall determine or (iii) being directly contrary to the terms and conditions contained in this Precedent Agreement. Such material business or regulatory risks could include, but not be limited to, the ability of Southern to obtain rolled-in rate treatment for the Cypress Project.

Notwithstanding the above, in the event the FERC Authorizations or Preliminary Determination contain unsatisfactory, material terms and conditions consistent with the provision described above, Shipper and Southern agree that, prior to the date by which rehearing must be requested of the Preliminary Determination in the case where Shipper objects to the

Preliminary Determination or the date that Southern must accept the certificate under Section 157.20 of the FERC Regulations in the case where Southern objects to the FERC Authorizations, Southern and Shipper will discuss potential options to adjust the rate set forth above in Paragraph 1(d) in order to compensate, as appropriate, (i) Southern for accepting the certificate and proceeding with the Cypress Project and the transaction contemplated herein, and (ii) Shipper for accepting the Preliminary Determination and proceeding with the transaction contemplated herein. If the Parties can agree on the means to adjust the rate, then they will document such agreement by execution of an amendment to this agreement or execution of a Service Agreement with the applicable terms prior to the date by which rehearing requests are due for the Preliminary Determination or Southern is required to accept the FERC certificate. In the event that Shipper issues notice in writing to Southern of its objection to the terms of the Preliminary Determination or Southern issues notice in writing to Shipper of its objection to the terms of the FERC Authorizations, and the Parties cannot agree on the means to adjust the rate, then the Party issuing the notice of objections shall have the right to terminate this Precedent Agreement. Such right must be exercised by written notice to the other Party provided, respectively, by Shipper no later than the date upon which rehearing requests for the Preliminary Determination are due or by Southern no later than twenty-nine (29) days after issuance of the certificate and such right to terminate under this Section 3 shall be deemed to be waived if such right is not exercised by providing such notice in the manner and within the times specified herein. In the event either Party provides the other Party with notice of its objection to the Preliminary Determination or the terms of the FERC Authorizations as set forth above but does not exercise its right to terminate this Precedent Agreement under this Section 3, the Parties shall remain bound to perform their obligations under this Precedent Agreement.

Nothing contained herein shall prevent Southern or Shipper from seeking rehearing of any unfavorable term or condition contained in the Preliminary Determination or the FERC Authorizations in a manner that is consistent with the terms of this Precedent Agreement or the Service Agreement, even if Southern accepts the certificate as provided above.

4. **Service Agreement; In-Service Date.**

(a) Subject to the satisfaction or waiver of the conditions precedent set forth in Section 5 below, within ten (10) days of Southern filing with the FERC a letter of acceptance, Southern and Shipper shall execute and deliver a standard form of firm Service Agreement as set forth in Exhibit "B", attached hereto and made a part hereof, that incorporates terms and conditions that are substantially in accordance with Section 1 above.

(b) Upon execution and delivery of the Service Agreement by each Party and once all of the Conditions Precedent set forth in Section 5 below are met or waived, Southern will use due diligence to construct and install the Cypress Project to commence the FT Service by May 1, 2007, or such other mutually agreeable date (the "**In Service Date**"). Shipper agrees and understands that any delays in receiving FERC approval may cause delays in reaching the In Service Date. Southern and Shipper will discuss any changes to the In Service Date based on the status of the regulatory process. At Shippers request, Southern agrees to timely review with Shipper its design drawings and specifications, bill of material, bid results, and construction contract and specifications (collectively, the "**Construction Documents**") for the construction of the Cypress Project to Shipper so that Shipper is kept abreast of Southern's construction progress.

5. <u>Conditions Precedent</u>.

(a) Notwithstanding any of the foregoing to the contrary, the obligation of Southern to construct, install and operate the Cypress Project and to execute the Service Agreement is subject to the fulfillment of condition (i)(A) and the waiver by Southern or fulfillment of conditions (i)(B), (ii), and (iii) as follows:

(i) receipt and acceptance by Southern, as provided in Section 3 above, of (A) and (B) below which shall be collectively referred to as the "**Government Authorizations.**"

(A) authorizations from the FERC; the United States Army Corps of Engineers, the U.S. Fish and Wildlife Service, and any other state and federal regulatory agencies, as necessary, to construct, install and operate the Cypress Project on or before [redacted] This condition precedent may not be waived by Southern; and

(B) FERC approval of the terms of service set forth above in Section 1, including, without limitation, the rates hereunder in accordance with the terms of this Precedent Agreement in the form of a Preliminary Determination ("Preliminary Determination") on or before [redacted] and

(ii) receipt by Southern of approval from the El Paso Corporation Board of Directors to construct, install and operate the Cypress Project on or before January 31, 2005; and

(iii) receipt by Southern from Shipper and an additional shipper or shippers for FT Service from the Cypress Project of [redacted]

Southern shall pursue satisfaction of each of the foregoing conditions precedent on a due diligent basis. If each of the conditions precedent shall not have been satisfied on terms and conditions acceptable to Southern or, with respect to conditions (i)(B), (ii), and (iii) only, waived by Southern on or before the date indicated, then Southern or Shipper may terminate this Agreement by giving written notice to the non-terminating Party at any time after the date the applicable condition precedent was to be satisfied or waived as set forth above, but prior to the satisfaction or waiver of the applicable condition precedent. Upon such termination, neither Southern nor Shipper shall have any further obligations under this Precedent Agreement. Such notice shall be effective as of the date it is delivered to the U. S. Mail for delivery by certified mail, return receipt requested.

(b) Notwithstanding any of the foregoing to the contrary, the obligation of Shipper to execute the Service Agreement and to perform the obligations hereunder is subject to the fulfillment or waiver by Shipper of the following conditions precedent (i), (ii), (iii), (iv), and (v), and the fulfillment of the following condition precedent (vi):

(i) receipt by Shipper of approval from the Progress Energy Florida, Inc. Board of Directors to execute the Service Agreement and subscribe to the FT Service as provided herein on or before January 31, 2005; and

(ii) execution by Shipper of an agreement with FGT to provide Shipper with firm transportation on FGT's system from the FGT interconnection with a TD equal to the FGT/TD's shown on Exhibit "A" attached hereto, on or before December 6, 2004; and

(iii) receipt and acceptance by Shipper of all authorizations, approvals and/or exemptions from the Florida Public Service Commission and from any other regulatory body having jurisdiction necessary for Shipper to construct, own and operate an expansion at the Hines Generating Plant in Polk County, Florida, on or before May 1, 2005; and

(iv) execution by Shipper of a satisfactory agreement, as determined in Shipper's sole discretion, with BG LNG Services, LLC to provide the natural gas supplies at Elba Island to serve Shipper's Hines Generating Plant and Shipper's other system supply requirements on or before December 6, 2004; and

(v) receipt and acceptance by Shipper of all authorizations, approvals and/or exemptions from the Florida Public Service Commission and from any other regulatory body having jurisdiction necessary for Shipper on or before June 15, 2005 to (a) to contract for fuel from BG LNG Services, LLC at Elba Island to serve Shipper's Hines Generating Plant in Polk County, Florida, and Shipper's other system supply requirements, (b) to contract for firm transportation pursuant to this Precedent Agreement (and any successor service agreement), and (c) to contract for firm transportation on

FGT pursuant to the agreement referenced in subsection 5(b)(ii) above; and

(vi) demonstration to Southern's satisfaction on or before January 31, 2005, that Shipper is creditworthy to perform its financial obligations required under the terms of this Precedent Agreement that would support the construction of the Cypress Pipeline by demonstrating Shipper's ability to sustain the transaction under its own capital structure, or produce Southern with credit assurances of either (i) an acceptable intracorporate guarantee or (ii) letter of credit or other comparable surety with the value of at least two and one-half (2 ½) years of transportation demand payments at Shipper's MDQ set forth above in Section 1(a). Notwithstanding the date set forth above in which the condition precedent must be satisfied, Shipper shall be obligated to sustain its showing of creditworthiness throughout the term of the Service Agreement by providing Southern with one of the acceptable credit assurances listed above. This condition precedent may not be waived by Shipper.

Shipper shall pursue satisfaction of each of the foregoing conditions precedent on a due diligent basis. If each of the conditions precedent shall have not been satisfied or, with respect to conditions (i), (ii), (iii), (iv), and

(v) only, waived by Shipper on or before the date indicated, then Shipper or Southern may terminate this Agreement by giving written notice to the other Party thereof at any time after the date the applicable condition precedent was to be satisfied or waived, but prior to the satisfaction or waiver of the applicable condition precedent. Upon such termination, neither Southern nor Shipper shall have any further obligations under this Precedent Agreement. Such notice shall be effective as of the date it is delivered to the U. S. Mail for delivery by certified mail, return receipt requested.

(c) The Government Authorizations required by Sections 5(a)(i) and 5(b)(iii) and (v) shall be final and duly granted without contingency by the authorities having jurisdiction; provided, however, that Southern or Shipper may, at their option, elect to waive the condition that such approvals be final.

6. <u>Notices.</u> Notices made pursuant to the terms of this Precedent Agreement shall be sent to:

If Southern: Southern Natural Gas Company
Post Office Box 2563
Birmingham, Alabama 35202-2563
Attention: Director, Business Development
Phone: 205/325-7146
Fax: 205/325-3787

If Shipper: Progress Energy Florida, Inc.
410 S. Wilmington Street (PEB 10)
Raleigh, North Carolina 27601
Attention: Contract Administration
Phone: 919/546-4280
Fax: 919/546-2649

James H. Jeffries IV.
Nelson Mullins Riley & Scarborough L.L.P.
Bank of America Corporate Center, Suite 2400
100 North Tryon Street
Charlotte, North Carolina 28202-4000
Office: (704) 417-3103
Facsimile: (704) 417-3014

Either Party may change its address by written notice to the other Party. Notices given to change the above addresses shall be deemed to have been effectively given (i) upon the fifth business day after the notice, properly addressed and postpaid, has been placed in the United States mail; (ii) upon confirmation of receipt, if delivered by facsimile or other similar means; or (iii) in accordance with the dates and time provided for overnight delivery service.

7. **Assignment and Delegation.**

(a) Any entity that succeeds by purchase, merger, or consolidation to the properties substantially as an entirety of either Southern or Shipper, as the case may be, shall be entitled to the rights and subject to the obligations set out in this Precedent Agreement and the executed Service Agreement.

(b) Either Party may, without the consent of the other Party, assign any of its rights hereunder to an Affiliate of assignor, but the assignor shall not be relieved of its obligations under this Precedent Agreement until the nonassigning Party receives an agreement from the assignee that it is assuming all the terms and conditions hereto and such assignee is financially and technically capable of meeting such terms and conditions. The assignor shall provide written notice of the assignment to the other Party to this Precedent Agreement as soon as practicable after such assignment. For the purpose of this Section 7(b), the term "Affiliate" shall mean an individual or entity that directly, or indirectly through one or more intermediaries, controls, is controlled by or is under common control with another individual or entity. The terms "controls," "controlled," and "control" in the preceding sentence shall mean the possession, direct or indirect, of the power to direct the management and policies of an entity, whether through the ownership of voting securities or otherwise.

(c) Except as provided above in Sections 7(a) or 7(b) of this Precedent Agreement, no assignment of rights or delegation of duties under this Precedent Agreement shall be made unless there first shall have been obtained the written consent of Shipper, in the event of an assignment or delegation by Southern, or the written consent of Southern, in the event of an assignment or delegation by Shipper, such consents not to be unreasonably withheld. Southern and Shipper agree, however, that the restrictions on assignment contained in this Paragraph shall not in any way prevent either Southern or Shipper from pledging or mortgaging its rights hereunder as security for its indebtedness.

8. <u>Term.</u>

Subject to the provisions of Section 5 hereof, this Precedent Agreement shall remain in full force and effect until it is superceded by the execution by the

Parties of an effective Service Agreement as provided in Section 4 above or otherwise terminated in accordance with the provisions of this Precedent Agreement, except for the provisions of Sections 1and 9 hereof which shall survive the execution of an effective Service Agreement and remain binding and effective on the Parties in accordance with their respective terms.

9. <u>Negotiated Rate for Future Cypress Project Expansions</u>

In the event that BG LNG Services LLC does not satisfy or waive the conditions precedent in its Precedent Agreement with Southern for the Cypress Project to subscribe to Phase II and/or Phase III of the Cypress Project by the dates set forth in such Precedent Agreement, as such Phases are defined in the FERC Authorizations for the Cypress Project referenced above in Section 2(a), Shipper shall have the right to subscribe to up to [redacted] MMbtu of such expansion capacity per phase provided that Southern can achieve adequate subscription from other shippers to make the project economical to Southern. In conjunction with such right, Southern and Shipper agree that the reservation rate to be charged Shipper for each phase, respectively, shall be the lower of: (a) the recourse rate filed by Southern for the applicable expansion facilities; or (b) the lowest rate charged by Southern or paid by other shippers for the respective Cypress expansion capacity; or (c) for Phase II only, [redacted] if Shipper subscribes for the expansion capacity within ninety (90) days after being notified by Southern that the expansion capacity is available; provided, however, that such notice shall not be sent to Shipper any earlier than January 2, 2008.

10. **<u>Miscellaneous Provisions.</u>**

(a) Except as provided otherwise in this Precedent Agreement, no modification of the terms and provisions of this Precedent Agreement shall have effect unless contained in a writing executed by both Southern and Shipper.

(b) This Precedent Agreement may be executed in multiple counterparts, each of which shall be deemed an original, but all of which shall constitute one and the same agreement.

(c) This Precedent Agreement shall become effective on the date first written above and shall continue in effect until terminated pursuant to the terms and condition herein.

(d) Anything in this Agreement to the contrary notwithstanding, neither party hereto shall be liable to the other party for any consequential, incidental or punitive damages arising out of, or related to a breach of this Agreement.

(e) If a court of competent jurisdiction declares any provision of this Precedent Agreement unenforceable, then that provision shall be severed from this Precedent Agreement, which shall otherwise remain in full force and effect and be construed as if it did not contain the severed provision.

(f) Except as expressed otherwise in this Precedent Agreement, nothing expressed or implicit in this Precedent Agreement shall confer on any person other than Southern and Shipper any rights or remedies under or by reason of this Precedent Agreement.

(g) The titles to the paragraphs in this Precedent Agreement are included only for the convenience of reference and shall have no effect on, or be deemed a part of, the text of this Precedent Agreement.

(h) The Parties expressly agree that the laws of the State of Alabama, without regard for any rules for conflicts of law, shall govern the validity, effect, construction, and interpretation of this Precedent Agreement.

(i) This Precedent Agreement constitutes the entire agreement between the Parties and no waiver by either Party or any default of either Party under this agreement shall operate as a waiver of any subsequent default whether it is of a like or different character.

IN WITNESS WHEREOF, the Parties hereto have caused this Precedent Agreement to be duly executed by their proper officers, duly authorized as of the date first hereinabove written.

Southern Natural Gas Company

James C. Yardley
President

Florida Power Corporation
d/b/a Progress Energy Florida, Inc.

By: ROBERT F. CALDWELL

Its: VICE PRESIDENT-REG. COML. OPS.

EXHIBIT "A"
SHIPPER TRANSPORTATION DEMAND

YEARS[1]	SEASON	SPAN	TD/MMBtu	FGTTD
2007	Summer	May-Sept.	[redacted]	[redacted]
2007-08	Winter	Oct.-Apr.	[redacted]	[redacted]
2008	Summer	May-Sept.	[redacted]	[redacted]
2008-09	Winter	Oct.-Apr.	[redacted]	[redacted]
2009-26	Summer	May-Sept.	[redacted]	[redacted]
2009-27	Winter	Oct.-Apr.	[redacted]	[redacted]

[1] The actual start date and end date for the FT Service will be determined based on the "Commencement Date" as set forth in Section 1(a) above in the Precedent Agreement and the "Primary Term" as set forth in Section 1(c) above.

Exhibit "B"

Service Agreement No.

PRO FORMA
FIRM TRANSPORTATION SERVICE AGREEMENT
UNDER RATE SCHEDULE FT AND/OR RATE SCHEDULE FT-NN

THIS AGREEMENT, made and entered into as of this ______ day of ____________, ____, by and between Southern Natural Gas Company, a Delaware corporation, hereinafter referred to as "Company", and Florida Power Corporation d/b/a Progress Energy Florida, Inc., a Florida corporation, hereinafter referred to as "Shipper".

WITNESSETH

WHEREAS, Company is an interstate pipeline, as defined in Section 2(15) of the Natural Gas Policy Act of 1978 (NGPA); and

WHEREAS, Shipper has requested firm transportation pursuant to Rate Schedule FT and/or FT-NN of various supplies of gas for redelivery for Shipper's account and has submitted to Company a request for such transportation service in compliance with Section 2 of the General Terms and Conditions applicable to such Rate Schedules; and/or

WHEREAS, Shipper may acquire, from time to time, released firm transportation capacity under Section 22 of the General Terms and Conditions of Company's FERC Gas Tariff; and

WHEREAS, Company has agreed to provide Shipper with transportation service of such gas supplies or through such acquired capacity release in accordance with the terms and conditions of this Agreement.

NOW, THEREFORE, the parties hereto agree as follows:

ARTICLE I
TRANSPORATION QUANTITY

1.1 Subject to the terms and provisions of this Agreement, Rate Schedule FT and/or FT-NN, as applicable, and the General Terms and Conditions thereto, Shipper agrees to deliver or cause to be delivered to Company at the Receipt Point(s) described in Exhibit A and Exhibit A-1 to this Agreement, and Company agrees to accept at such point(s) for transportation under this Agreement, an aggregate quantity of natural gas per day up to the total Transportation Demand set forth on Exhibit B hereto. Company's obligation to accept gas on a firm basis at any Receipt Point is limited to the Receipt Points set out on Exhibit A and to the Maximum Daily Receipt Quantity (MDRQ) stated for each such Receipt Point. The sum of the MDRQ's for the Receipt Points on Exhibit A shall not exceed the Transportation Demand.

1.2 Subject to the terms and provisions of this Agreement, Rate Schedule FT and/or FT-NN, as applicable, and the General Terms and Conditions thereto, Company shall deliver a thermally equivalent quantity of gas, less the applicable fuel charge as set forth in the applicable FT or FT-NN Rate Schedule, to Shipper at the Delivery Point(s) described in Exhibit B and Exhibit B-1 hereto. Company's obligation to redeliver gas at any Delivery Point on a firm basis is limited to the Delivery Points specified on Exhibit B and to the Maximum Daily Delivery Quantity (MDDQ) stated for each such Delivery Point and in no event shall Shipper be entitled to deliveries in excess of the MDDQ such that if Shipper elects to take gas at an Exhibit B-1 Delivery Point then the MDDQ at its Exhibit B Delivery Points will be reduced proportionately. The sum of the MDDQ's for the Delivery Points on Exhibit B shall equal the Transportation Demand.

1.3 In the event Shipper is the successful bidder on released firm transportation capacity under Section 22 of the Company's General Terms and Conditions, Company will promptly email to Shipper the terms of the Capacity Release Transaction. Upon the issuance of the email, subject to the terms, conditions and limitations hereof and of Company's Rate Schedules FT and FT-NN, Company agrees to provide the released firm transportation service to Shipper under Rate Schedule FT or FT-NN, the General Terms and Conditions thereto, and this Agreement.

ARTICLE II
CONDITIONS OF SERVICE

2.1 It is recognized that the transportation service hereunder is provided on a firm basis pursuant to, in accordance with and subject to the provisions of Company's Rate Schedule FT and/or FT-NN, and the General Terms and Conditions thereto, which are contained in Company's FERC Gas Tariff, as in effect from time to time, and which are hereby incorporated by reference. In the event of any conflict between this Agreement and the terms of the applicable Rate Schedule, the terms of the Rate Schedule shall govern as to the point of conflict. Any limitation of transportation service hereunder shall be in accordance with the priorities set out in Rate Schedule FT and/or FT-NN, as applicable, and the General Terms and Conditions thereto.

2.2 This Agreement shall be subject to all provisions of the General Terms and Conditions applicable to Company's Rate Schedule FT and/or FT-NN as such conditions may be revised from time to time. Unless Shipper requests otherwise, Company shall provide to Shipper the filings Company makes at the Federal Energy Regulatory Commission ("Commission") of such provisions of the General Terms and Conditions or other matters relating to Rate Schedule FT or FT-NN.

2.3 Company shall have the right to discontinue service under this Agreement in accordance with Section 15.3 of the General Terms and Conditions hereto.

2.4 The parties hereto agree that neither party shall be liable to the other party for any special, indirect, or consequential damages (including, without limitation, loss of profits or business interruptions) arising out of or in any manner related to this Agreement.

2.5 This Agreement is subject to the provisions of Part 284 of the Commission's Regulations under the NGPA and the Natural Gas Act. Upon termination of this Agreement, Company and Shipper shall be relieved of further obligation to the other party except to complete the transportation of gas underway on the day of termination, to comply with the provisions of Section 14 of the General Terms and Conditions with respect to any imbalances accrued prior to termination of this Agreement, to render reports, and to make payment for all obligations accruing prior to the date of termination.

ARTICLE III
NOTICES

3.1 Except as provided in Section 8.6 herein, notices hereunder shall be given pursuant to the provisions of Section 18 of the General Terms and Conditions to the respective party at the applicable address, telephone number, facsimile machine number or e-mail addresses provided by the parties on Appendix E to the General Terms and Conditions or such other addresses, telephone numbers, facsimile machine numbers or e-mail addresses as the parties shall respectively hereafter designate in writing from time to time.

ARTICLE IV
TERM

4.1 Subject to the provisions hereof, this Agreement shall become effective as of the date first hereinabove written and shall be in full force and effect for the primary term(s) set forth on Exhibit B hereto, if applicable, and shall continue and remain in force and effect for successive evergreen terms specified on Exhibit B hereto unless canceled by either party giving the required amount of written notice specified on Exhibit B to the other party prior to the end of the primary term(s) or any extension thereof.

4.2 In the Event Shipper has not contracted for firm Transportation Demand under this Agreement directly with Company, as set forth on Exhibit B hereto, then the term of this Agreement shall be effective as of the date first hereinabove written and shall remain in full force and effect for a primary term through the end of the month and month to month thereafter unless canceled by either party giving at least five (5) days written notice to the other party prior to the end of the primary term or any extension thereof, provided however, this agreement will automatically terminate if no nominations are requested during a period of 12 consecutive months It is provided, however that this Agreement shall not terminate prior to the expiration of the effective date of any Capacity Release Transaction.

ARTICLE V
CONDITIONS PRECEDENT

5.1 Unless otherwise agreed to by the parties, the terms of Rate Schedule FT and/or FT-NN, as applicable, and the General Terms and Conditions thereto, shall apply to the acquisition of construction of any facilities necessary to effectuate this Agreement. Other provisions of this Agreement notwithstanding, company shall be under no obligation to commence service hereunder unless and until (1) all facilities, of whatever nature, as are required to permit the receipt, measurement, transportation, and delivery of natural gas hereunder have been authorized, installed, and are in operating condition, and (2) Company, in its reasonable discretion has determined that such service would constitute transportation of natural gas authorized under all applicable regulatory authorizations and the Commission's Regulations.

ARTICLE VI
REMUNERATION

6.1 Shipper shall pay Company monthly for the transportation services rendered hereunder the charges specified in Rate Schedule FT, Rate Schedule FT-NN, and under each effective Capacity Release Transaction, as applicable, including any penalty and other authorized charges assessed under the applicable FT or FT-NN Rate Schedule and the General Terms and Conditions. For service requested from Company under Rate Schedule FT or FT-NN, Company shall notify Shipper as soon as practicable of the date services will commence hereunder, and if said date is not the first day of the month, the Reservation Charge for the first month of service hereunder shall be adjusted to reflect only the actual number of days during said month that transportation service is available. Company may agree from time to time to discount the rates charged Shipper for services provided hereunder in accordance with the provisions of Rate Schedule FT and/or FT-NN, as applicable. Said discounted charges shall be set forth on Exhibit E hereto or the parties may agree to a Negotiated Rate for such services in accordance with the provisions of Rate Schedule FT or FT-NN. Said discounted or Negotiated Rates shall be set forth on Exhibit E or Exhibit F, respectively, hereto and shall take precedence over the charges set forth in Rate Schedules FT or FT-NN during the period in which they are in effect.

6.2 The rates and charges provided for under Rate Schedule FT shall be subject to increase or decrease pursuant to any order issued by the Commission in any proceeding initiated by Company or applicable to the services performed hereunder. Shipper agrees that Company shall, without any further agreement by Shipper, have the right to change from time to time, all or any part of its Proforma Service Agreement, as well as all or any part of Rate Schedule FT or FT-NN, as applicable, or the General Terms and Conditions thereto, including without limitation the right to change the rates and charges in effect hereunder, pursuant to Section 4(d) of the Natural Gas Act as may be deemed necessary by Company, in its reasonable judgment, to assure just and reasonable service and rates under the Natural Gas Act. It is recognized, however, that once a Capacity Release Transaction has been awarded, Company cannot increase the Reservation Charge to be paid by Shipper under that Capacity Release Transaction, unless in its bid the Acquiring Shipper has agreed to pay a percentage of the maximum tariff rate in effect and the maximum tariff rate increases during the term of the Capacity Release Transaction. Nothing contained herein shall prejudice the rights of Shipper to contest at any time the changes made pursuant to this Section 6.2, including the right to contest the transportation rates or charges for the services provided under this Agreement, from time to time, in any subsequent rate proceedings by Company under Section 4 of the Natural Gas Act or to file a complaint under Section 5 of the Natural Gas Act with respect to such transportation rates or charges, the Rate Schedules, or the General Terms and Conditions thereto.

ARTICLE VII
SPECIAL PROVISIONS

7.1 If Shipper is a seller of gas under more than one Service Agreement and requests that company allow it to aggregate nominations for certain Receipt Points for such Agreements, Company will allow such an arrangement under the terms and conditions set forth in this Article VII. To be eligible to aggregate gas, Shipper must comply with the provisions of Section 2.2 of the General Terms and Conditions and the terms and conditions of the Supply Pool Balancing Agreement executed by Shipper and Company pursuant thereto.

7.2 If Shipper is a purchaser of gas from a seller that is selling from an aggregate of Receipt Points, and Shipper wishes to nominate to receive gas from such seller's aggregate supplies of gas, Company will allow such a nomination, provided that the seller (i) has entered into a Supply Pool Balancing Agreement with Company and (ii) submits a corresponding nomination to deliver gas to Shipper from its aggregate supply pool.

ARTICLE VIII
MISCELLANEOUS

8.1 This Agreement constitutes the entire Agreement between the parties and no waiver by Company or Shipper of any default of either party under this Agreement shall operate as a waiver of any subsequent default whether of a like or different character.

8.2 The laws of the State of Alabama shall govern the validity, construction, interpretation, and effect of this Agreement.

8.3 No modification of or supplement to the terms and provisions hereof shall be or become effective except by execution of a supplementary written agreement between the parties except that (i) a Capacity Release Transaction may be issued, and (ii) in accordance with the provisions of Rate Schedule FT and/or FT-NN, as applicable, and the General Terms and Conditions thereto, Receipt Points may be added to or deleted from Exhibit A and the Maximum Daily Receipt Quantity for any Receipt Point on Exhibit A may be changed upon execution by Company and Shipper of a Revised Exhibit A to reflect said change(s), and (iii) Delivery Points may be added to or deleted from Exhibit B and the Maximum Daily Delivery Quantity for any Delivery Point may be changed upon execution by Company and Shipper of a Revised Exhibit B to reflect said change(s). It is provided, however, that any such change to Exhibit A or Exhibit B must include corresponding changes to the existing Maximum Daily Receipt Quantities or Maximum Daily Delivery Quantities, respectively, such that the sum of the changed Maximum Daily Receipt Quantities shall not exceed the Transportation Demand and the sum of the Maximum Daily Delivery Quantities equals the Transportation Demand.

8.4 This Agreement shall bind and benefit the successors and assigns of the respective parties hereto. Subject to the provisions of Section 22 of the General Terms and Conditions applicable hereto, either party may assign this Agreement to an affiliated company without the prior written consent of the other party, provided that the affiliated company is creditworthy pursuant to Section 2.1(d) of the General Terms and Conditions, but neither party may assign this Agreement to a nonaffiliated company without the prior written consent of the other party, which consent shall not be unreasonably withheld; provided, however, that either party may assign or pledge this Agreement under the provisions of any mortgage, deed or trust, indenture or similar instrument.

8.5 Exhibits A, A-1, B, B-1, and F attached to this Agreement constitute a part of this Agreement are incorporated herein.

8.6 This Agreement is subject to all present and future valid laws and orders, rules, and regulations of any regulatory body of the federal or state government having or asserting jurisdiction herein. After the execution of this Agreement for firm transportation capacity from Company, each party shall make and diligently prosecute all necessary filings with federal or other governmental bodies, or both, as may be required for the initiation and continuation of the transportation service which is the subject of this Agreement and to construct and operate any facilities necessary therefore. Each party shall have the right to seek such governmental authorizations as it deems necessary, including the right to prosecute its requests or applications for such authorization in the manner it deems appropriate. Upon either party's request, the other party shall timely provide or cause to be provided to the requesting party such information and material not within the requesting party's control and/or possession that may be required for such filings. Each party shall promptly inform the other party of any changes in the representations made by such party herein and/or in the information provided pursuant to this paragraph. Each party shall promptly provide the party with a copy of all filings, notices, approvals, and authorizations in the course of the prosecution of its filings. In the event all such necessary regulatory approvals have not been issued or have not been issued on terms and conditions acceptable to Company or Shipper within twelve (12) months from the date of the initial application therefor, then Company or Shipper may terminate this Agreement without further liability or obligation to the other party by giving written notice thereof at any time subsequent to the end of such twelve-month period, but prior to the receipt of all such acceptable approvals. Such notice will be effective as of the date it is delivered to the U.S. Mail, for delivery by certified mail, return receipt requested.

8.7 If Shipper experiences the loss of any load by direct connection of such load to the Company's system, Shipper may reduce its Transportation Demand under this Service Agreement or any other Service Agreement for firm transportation service between Shipper and Company by giving Company 30 days prior written notice of such reduction within six (6) months of the date Company initiates direct service to the industrial customer; provided, however, that any such reduction shall be applied first to the Transportation Demand under the Service Agreement with the shortest remaining contract term.

In order to qualify for a reduction in its Transportation Demand, Shipper must certify and provide supporting data that:

(i) The load was actually being served by Shipper with gas transported by Company prior to November 1, 1993.

(ii) If the load lost by Shipper was served under a firm contract, the daily contract quantity shall be provided.

(iii) If the load lost by Shipper was served under an interruptible contract, the average daily volumes during the latest twelve months of service shall be provided.

Shipper may reduce its aggregate Transportation Demand under all its Service Agreements by an amount up to the daily contract quantity in the case of the loss of a firm customer and/or up to the average daily deliveries during the latest twelve month period in the case of the loss of an interruptible customer. Such reduction shall become effective thirty days after the date of Shipper's notice that it desires to reduce its Transportation Demand.

8.8 (If applicable) This Agreement supersedes and cancels the Service Agreement (#________) dated ________________ between the parties hereto.

IN WITNESS WHEREOF, this Agreement has been executed by the parties as of the date first written above by their respective duly authorized officers.

Attest/Witness: SOUTHERN NATURAL GAS COMPANY

________________________ By________________________________
Its________________________________

FLORIDA POWER CORPORATION d/b/a
Progress Energy Florida, Inc.

________________________ By________________________________
Its________________________________

Service Agreement No.

FIRM TRANSPORTATION SERVICE AGREEMENT

EXHIBIT "A"

SERVICE TYPE	SERVICE CODE	RECEIPT POINTS/CODE	MDRQ (Mcf)	SEASON[1]	YEAR[2]

[redacted]

[redacted]

By: ______________________________
Florida Power Corporation d/b/a/ Progress Energy Florida, Inc.

By: ______________________________
Southern Natural Gas Company

Effective Date: _______________

[redacted]

EXHIBIT A-1
RECEIPT POINTS

All active Receipt Points on Company's contiguous pipeline system, a current list of which shall be maintained by Company on its SoNet Premier bulletin board.

Service Agreement No.

EXHIBIT B
DELIVERY POINTS

SERVICE TYPE	SERVICE CODE	START DATE[3]	PRIMARY PT TERM[4]	NOTICE	EVERGREEN TERM	EVRG NOTICE	DEL.POINT/CODE NAME	TD MDDQ (Mcf)
[redacted]								

By: ______________________________
Florida Power Corporation d/b/a/ Progress Energy Florida, Inc.

By: ______________________________
Southern Natural Gas Company

Effective Date: _______________

[redacted]

EXHIBIT B-1
DELIVERY POINTS

All active Delivery Points on Company's *contiguous* pipeline system, a current list of which shall be maintained by Company on its SoNet Premier bulletin board.

Service Agreement No.

EXHIBIT "F"
NEGOTIATED RATE

The rate to be charged Shipper for the firm Transportation Demand provided by Company under this Service Agreement shall be [redacted] for the Primary Term of this Service Agreement, plus the [redacted]

The rate to be charged Shipper for fuel under this Service Agreement shall be [redacted]

____
Southern Natural Gas Company

____
Florida Power Corporation d/b/a Progress Energy Florida, Inc.

Effective Date: ______________

End Date: ____________

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 7
COMPANY/ PEF
WITNESS: Pamela R. Murphy (PRM-3)
DATE: 04-29-05

Florida Gas Transmission Company
1331 Lamar Street, Suite 650, Houston, TX 77010-1331
P.O. Box 4657, Houston, TX 77210-4657
713.853.0300

December 2, 2004

Progress Energy Florida, Inc.
Attention: Ms. Pamela Murphy
P. O. Box 1551
410 South Wilmington St., PEB10A
Raleigh, North Carolina27602-1551

Re: Proposal for Transportation Services by and between Florida Power Corporation, d/b/a Progress Energy Florida, Inc., and Florida Gas Transmission Company (regarding expansion of Florida Gas Transmission Company's system to provide incremental capacity for receipts of LNG from Southern Natural Gas Company)

Dear Ms. Murphy:

Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("Progress" or "Shipper") and Florida Gas Transmission Company ("FGT") hereby enter into this letter agreement ("Letter Agreement") regarding the expansion of the FGT system to provide incremental capacity to Progress as part of a project to bring liquefied natural gas ("LNG") to the State of Florida via Southern Natural Gas Company's ("SNG") proposed Cypress Pipeline project. In consideration of the premises and mutual covenants set forth herein, FGT and Shipper agree as follows:

1. Upon satisfaction of the conditions precedent set forth below, the parties will enter an FTS-2 service agreement (with terms and conditions substantially similar to those contained in the draft attached hereto as Attachment A), providing for firm natural gas transportation service to be provided by FGT for Shipper:

a. Completion of an open season for an FGT 2007-2008 expansion of its system, and

b. A determination by FGT, after the close of such open season, but in any case, by February 1, 2005, that the capacity desired by Shipper can be economically provided, in FGT's sole opinion, under the terms set forth in the attached draft agreements.

2. In the event that the conditions precedent set forth in "1" above are met, the parties shall execute the Service Agreement attached hereto as Attachment A, and shall also

execute an amendment to certain existing service agreements between the parties, in order to increase the minimum delivery pressure at the Progress-Hines Delivery Point from 500 psig to 575 psig, effective upon the in-service date of the Incremental Facilities (as defined in Section 1.3 of the FTS-2 Agreement attached as Attachment A hereto), such agreements being: (a) the FTS-1 Transportation Service Agreement dated April 1, 1998, (b) the FTS-2 Transportation Service Agreement dated April 1, 1998, (c) the FTS-2 Transportation Service Agreement dated October 7, 1998, and (d) the FTS-2 Transportation Service Agreement dated December 2, 2004.

3. This Letter Agreement shall become effective on the date of its execution by both parties and shall remain in effect until the earlier of: (a) the date of execution of FTS-2 Agreement (in form substantially similar to the attached draft agreement), (b) the date that either party notifies the other party that such condition(s) precedent will not be met, or (c) February 1, 2005. In the event that the parties do not execute the agreements attached as Attachment A by February 1, 2005, all obligations of the parties shall terminate and this Letter Agreement, as well as any agreements of the parties (oral or otherwise) with respect to such Letter Agreement, shall become null and void and of no further force and effect.

If this Letter Agreement meets with your approval, please sign below and return one of the two originals to us.

Yours truly,

R. E. Hayes
Senior Vice President &
Chief Commercial Officer

FLORIDA POWER CORPORATION
d/b/a PROGRESS ENERGY FLORIDA, INC.

By: ______________________
Name: ROBERT F. CALDWELL
Title: VICE PRESIDENT - REG COM GS.

Attachment

DLM/Ph7/FPC-cover-final

Florida Gas Transmission Company
1331 Lamar Street, Suite 650, Houston, TX 77010-1331
P.O. Box 4657, Houston, TX 77210-4657
713.853.0300

December 2, 2004

Progress Energy Florida, Inc.
Attn: Ms. Pamela Murphy
P. O. Box 1551
410 South Wilmington St., PEB10A
Raleigh, NC 27601

Re: Discount of Rate Under the Firm Transportation (FTS-2) Service Agreement dated December 2, 2004 ("Agreement") Between Florida Gas Transmission Company ("FGT" or "Transporter") and Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("Progress" or "Shipper") (collectively the "Parties" or singularly "Party").

Dear Ms. Murphy:

Shipper has requested a competitive discount. Based upon current market conditions, Transporter has agreed to charge and Shipper has agreed to pay a discounted rate for transportation of quantities of gas under the Agreement. The terms and conditions of the discount agreed upon are expressed in this Discount Agreement ("Discount Agreement").

This Discount Agreement shall be effective from [redacted] provided, however, in the event that the referenced Agreement is terminated, this Discount Agreement shall immediately terminate..

The Maximum Daily Transportation Quantity (MDTQ) shall be as follows, and, unless expressly agreed otherwise, FGT's maximum rates shall apply to volumes exceeding such amounts:

[redacted]

The primary receipt and delivery points for the term(s) of this discount shall be as follows:

Effective Time Period	Receipt (RP)/Delivery (DP) Points
[redacted]	

Effective for the periods stated below, Shipper shall pay the following Discounted Reservation Charges per MMBtu ("Discounted Demand Charge"), plus all applicable surcharges; provided, however, FGT shall discount the any research and development ("R&D") surcharges (whether demand or volumetric) to $0.00 per MMBtu for transportation of quantities under the Agreement:

Effective Time Period	Volume (MMBtu /day)	Discounted Demand Charge Dollars ($)/MMBtu
[redacted]		

In addition to the above rate(s), Shipper shall also pay any applicable fuel use and unaccounted for charges, as well as any fuel surcharge.

Except for the posting of information by FGT pursuant to 18 C.F.R. Parts 161, 284, and 358 and any other applicable regulations of the Federal Energy Regulatory Commission ("FERC"), each Party agrees that it will maintain this discount, all of its contents and subsequent discount documentation and communications in strict confidence and that it will not cause or permit disclosure thereof to any third party without the express written consent of the other Party except to the extent necessary to comply with valid laws, regulations, or orders of any court or agency having jurisdiction. However, in the event either Party becomes aware of a judicial or administrative proceeding or request that has resulted or that may result in such disclosure, it shall notify the other Party immediately and will also take all actions necessary to maintain the confidentiality of all discount communications and documents. Notwithstanding anything to the contrary in this paragraph, Shipper shall have the right to provide a copy of this Discount Agreement to the Florida Public Service Commission and any other entity that is a party to the relevant docket that has executed a confidentiality agreement to retain such information confidential, without prior notice to or consent of Transporter, in connection with Shipper's attempts to obtain the Florida Public Service Commission's approval of this Discount Agreement and the Agreements.

As stated above, any R&D surcharge shall be discounted to $0.00; provided, however that such discount shall immediately terminate in the event FGT is required to absorb any costs associated with discounting any R&D surcharge or FGT is prohibited by law from granting such discount.

Shipper shall affirmatively support the continuation of FERC's discount rate adjustment policy (providing for recognition of volumes flowing at less than maximum rates in rate proceedings). In the event that Shipper takes a contrary position in any future rate, rulemaking, or other proceeding before the FERC (or other governmental body having jurisdiction in the premises), this Discount Agreement shall immediately terminate.

In the event the maximum and minimum rates applicable to Rate Schedule FTS-2 are changed pursuant to an Order issued by the FERC, such that the transportation rates provided for herein are above FGT's maximum rates or below FGT's minimum rates, this Agreement shall terminate immediately prior to the effectiveness of such revised rates, and FGT and Shipper shall negotiate to arrive at new rates applicable to the transportation service. It is the intent of FGT and Shipper that such renegotiated discounted rates will leave both FGT and Shipper in substantially the same economic position as the transportation rates provided for herein.

THIS AGREEMENT SHALL BE GOVERNED BY AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, WITHOUT REFERENCE TO ANY CONFLICT OF LAWS DOCTRINE WHICH WOULD APPLY THE LAWS OF ANOTHER JURISDICTION. ANY SUIT BROUGHT WITH RESPECT TO OR RELATING TO THIS LETTER AGREEMENT SHALL BE BROUGHT IN THE COURTS OF HARRIS COUNTY, TEXAS OR THE SOUTHERN DISTRICT OF TEXAS, HOUSTON DIVISION.

The Parties have caused this Discount Agreement to be executed by their respective duly authorized officers as of the date first mentioned above.

FLORIDA GAS TRANSMISSION COMPANY

By: R.E. Hayes RMc
Name: R.E. Hayes
Title: Sr. V.P. + C.C.O.

FLORIDA POWER CORPORATION,
d/b/a PROGRESS ENERGY FLORIDA, INC.

By: [signature]
Name: ROBERT F CALDWELL
Title: VICE PRESIDENT - REG COUNCIL

DLM/Ph7/FPC-disct-ltr-final

ATTACHMENT A

FIRM TRANSPORTATION SERVICE AGREEMENT
RATE SCHEDULE FTS-2

THIS AGREEMENT entered into this day _____ of __________, 2005 by and between Florida Gas Transmission Company, a corporation of the State of Delaware (herein called "Transporter"), and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (herein called "Shipper"),

WITNESSETH:

WHEREAS, Shipper is interested in obtaining firm incremental seasonal transportation service from Transporter, in conjunction with other upstream supply and capacity arrangements, in order to make available to Shipper (1) supplies needed to operate an additional combined-cycle generating unit #4 at Shipper's Hines electric power generating facility in Polk County, Florida ("Hines Unit #4 Capacity"), and (2) additional system supplies to serve its existing electric power generation facilities ("System Supply Capacity"); and

WHEREAS, Transporter is willing to provide such firm incremental seasonal transportation services to Shipper; and

WHEREAS, such services will be provided by Transporter for Shipper in accordance with the terms hereof.

NOW THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the sufficiency of which is hereby acknowledged, Transporter and Shipper do covenant and agree as follows:

ARTICLE I
Definitions

In addition to the definitions incorporated herein through Transporter's Rate Schedule FTS-2, the following terms when used herein shall have the meanings set forth below:

1.1 The term "Rate Schedule FTS-2" shall mean Transporter's Rate Schedule FTS-2 as filed with the FERC and as may be changed and adjusted from time to time by Transporter in accordance with Section 4.2 hereof or in compliance with any final FERC order affecting such rate schedule.

1.2 The term "FERC" shall mean the Federal Energy Regulatory Commission or any successor regulatory agency or body, including the Congress, which has authority to regulate the rates and services of Transporter.

1.3 The term "Incremental Facilities" shall mean any additional facilities necessary to be constructed by Transporter and by Southern Natural Gas Company ("SNG") in connection with the seasonal incremental service to be provided under this Agreement.

1.4 The term "In-Service Date" shall mean the date the Incremental Facilities, as defined in 1.3, shall go into service provided that all conditions set forth in Article XI hereof have first been satisfied, which In-Service Date shall be no later than May 1, 2009.

ARTICLE II
Quantity

2.1 The Maximum Daily Transportation Quantity ("MDTQ") with respect to each component of the Hines Unit #4 Capacity and System Supply Capacity provided for herein is set forth on a seasonal basis, and by Division if applicable, on Exhibit B attached hereto as the same may be amended from time to time. The respective applicable MDTQs (as of May 1, 2009, the MDTQs of [redacted] for the Hines Unit #4 Capacity, and [redacted] for System Supply Capacity) shall be the largest daily quantity of gas expressed in MMBtu, that Transporter is obligated to transport and make available for delivery to Shipper under this Service Agreement on any one day.

2.2 Upon the In-Service Date, Shipper may tender natural gas for transportation to Transporter on any day, up to the MDTQ plus Transporter's Fuel, if applicable. Transporter agrees to receive the aggregate of the quantities of natural gas that Shipper tenders for transportation at the Receipt Points, up to the maximum daily quantity ("MDQ") specified for each receipt point as set out on Exhibit A, plus Transporter's Fuel, if applicable, and to transport and make available for delivery to Shipper at each Delivery Point specified on Exhibit B, up to the amount scheduled by Transporter less Transporter's Fuel, if applicable (as provided in Rate Schedule FTS-2), provided however, that Transporter shall not be required to accept for transportation and make available for delivery more than the MDTQ on any day.

ARTICLE III
Payment and Rights in the Event of Non-Payment

3.1 Upon the commencement of service hereunder (following the In-Service Date), Shipper shall pay Transporter, for all service rendered hereunder, the rates established in Article IV herein.

3.2 Termination for Non-Payment. In the event Shipper fails to pay for the service provided under this Agreement, pursuant to the conditions set forth in Section 15 of the General Terms and Conditions of Transporter's FERC Gas Tariff, Transporter shall have the right to suspend or terminate this Agreement pursuant to the conditions set forth in said Section 15.

ARTICLE IV
Rates and Terms and Conditions of Service

4.1 This Agreement in all respects shall be and remain subject to the provisions of Rate Schedule FTS-2 and of the applicable provisions of the General Terms and Conditions of Transporter on file with the FERC (as the same may hereafter be legally amended or superseded), all of which are made a part hereof by this reference.

4.2 Transporter shall have the unilateral right to file with the appropriate regulatory authority and seek to make changes in (a) the rates and charges applicable to its Rate Schedule FTS-2, (b) Rate Schedule FTS-2 including the Form of Service Agreement and the existing Service Agreement pursuant to which this service is rendered; provided however, that the firm character of service shall not be subject to change hereunder by means of a Section 4 Filing by Transporter, and/or (c) any provisions of the General Terms and Conditions of Transporter's Tariff applicable to Rate Schedule FTS-2. Transporter agrees that Shipper may protest or contest the aforementioned filings, or seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing

FERC Gas Tariff as may be found necessary in order to assure that the provisions in (a), (b) or (c) above are just and reasonable.

4.3 Notwithstanding Section 4.1 above, as of the In-Service Date and during the primary term of this Agreement, Shipper shall pay Transporter, for all services rendered hereunder, the lower of: (I) the rates established under Transporter's Rate Schedule FTS-2 (inclusive of all applicable surcharges), as filed with and approved by the FERC and as said Rate Schedule may hereafter be legally amended or superseded, or (2) the Final Rate Cap as determined below:

(a) The Base Rate Cap shall be as follows: [redacted]

(b) The Base Rate Cap assumes the levelized rate methodology through March 31, 2005, and thereafter, the traditional cost of service methodology. For purposes of this section with respect to this Agreement, a "levelized rate" shall mean a rate designed by adjusting the annual depreciation expense such that it results in a levelized cost of service.

(c) The Base Rate Cap is stated in nominal dollars, and shall exclude all applicable surcharges and fuel.

(d) Beginning on January 1, 2005, and annually thereafter ("Escalation Date"), the Base Rate Cap then in effect shall be escalated in accordance with the following formula; provided that in no event shall the Base Rate Cap, as it may be escalated pursuant to this subsection (d), [redacted]. On each Escalation Date, the Base Rate Cap to be effective for the subsequent twelve (12) month period shall be the sum of: (i) [redacted]

[redacted]

(e) (i) For any billing month, the Final Rate Cap (stated on a per unit basis) shall be determined by adding the Base Rate Cap and an amount equal to the aggregate of the applicable surcharges (as defined in section (e)(ii) below).

(ii) The type of surcharges contemplated under Rate Schedule FTS-2 to be included in the calculation of the Final Rate Cap are applicable surcharges, such as ACA, fuel, and Capital surcharges; provided, however, Transporter shall not collect under this Agreement any surcharge associated with GRI, Gas Supply Realignment ("GSR"), the recovery of take-or-pay costs or gas purchase reformation costs, FERC Account No.191 costs ("restructuring costs"), or any similar surcharge associated with the restructuring of Transporter's merchant service under orders in FERC Docket No. RS92-16-000 or similar proceedings, any separately stated surcharge related to the recovery of restructuring costs of any upstream provider of transportation or sales services to Transporter, or, to the extent such charges may be discountable, any industry-wide research and development surcharges such as those currently proposed in FERC Docket No. RP04-378.

(f) If, at any time after the In-Service Date and during the primary term of this Agreement, the effective rate that Transporter is authorized by the FERC to charge Shipper, including surcharges, exceeds the Final Rate Cap, then Transporter shall discount such authorized FERC rate down to the Final Rate Cap in accordance with the order of discounting provided for in Transporter's FERC Gas Tariff.

(g) Unless otherwise mutually agreed by the Parties, after the expiration of the primary term of this Agreement, Shipper shall pay Transporter the rates established under Transporter's Rate Schedule FTS-2, as filed with and approved by the FERC.

(h) If Shipper proposes or supports a change in the rate design methodology on which the currently effective FTS-2 rates are based, as set forth in Sections III.2.c and d, and III.3.b of the Phase III Settlement, and such proposals or changes are approved by a final non-appealable order, the Final Rate Cap shall be deemed waived. Notwithstanding the foregoing, if Transporter proposes, or any other party proposes and Transporter either supports or does not oppose, a change to any of such rate design methodologies in any Section 4 or Section 5 proceeding, then Shipper may take a position on that particular rate design methodology in that proceeding, whether or not consistent with the position taken by Transporter, without waiving the Final Rate Cap, and unless otherwise agreed by Transporter and Shipper, approval of such a proposed change in the rate design methodology by a final non-appealable order, in such Section 4 or Section 5 proceeding, shall not affect the continuing applicability of the Final Rate Cap. Specifically, the rate design methodology issues referenced above in this Section (h) are as follows:

(i) the straight fixed variable method of rate design, and of classifying and allocating costs,

(ii) unless otherwise agreed to by both parties hereto, the system-wide postage stamp rate for FTS-2 service to the Market Area,

(iii) the levelized rate methodology through March 31, 2005, and thereafter, the traditional cost-of-service methodology, and

(iv) the methodology of allocating the operation and maintenance ("O&M") costs between Rate Schedules FTS-1 and FTS-2; provided, however, that without waiving its final Rate Cap under this Section (h) (iv), and with respect to the allocation of administrative and general ("A&G") expenses only, a Shipper may challenge, on a prospective basis only, Transporter's use of the Kansas-Nebraska methodology in the Section 4 rate case to be filed by Transporter in accordance with Article XI of the Settlement approved by the FERC in Docket No. RP04-12; and provided further, that Shipper may, without waiving its Final Rate Cap (and regardless of any position taken by

Transporter), argue for any allocation methodology that allocates no more O&M costs to Rate Schedule FTS-2 than would otherwise be allocated by use of:

a. the Phase III Settlement methodology for allocating all O&M costs except for A&G expenses, and

b. the *Kansas-Nebraska* methodology for allocating A&G expenses.

4.4 [Deleted– Not Applicable]

ARTICLE V
Term of Agreement

5.1 This Agreement shall become effective upon the date first written above and shall continue in effect for a primary term of Twenty (20) years commencing with the In-Service Date.

5.2 In the event the capacity being contracted for was acquired pursuant to Section 18.E. of Transporter's Tariff, then this Agreement shall terminate on the date set forth in Section 5.1 above. Otherwise, in accordance with the provisions of Section 20 of the General Terms and Conditions of Transporter's Tariff, Shipper has elected [Right of First Refusal or Roll-over Option] and upon the expiration of the primary term and any extension or roll-over, termination will be governed by the provisions of Section 20 of the General Terms and Conditions of Transporter's Tariff.

5.3 [deleted – not applicable]

5.4 Shipper may buy out of a Service Agreement for all or a portion of its transportation capacity ("MDTQ") thereunder, at any time, by paying Transporter the net present value of Shipper's remaining reservation charge obligations for such capacity, discounted at a reasonable rate to be mutually agreed upon by the parties at the time of such buy-out.

5.5 Notwithstanding any other provision in this Agreement, after the In-Service Date , in the event that: (1) Shipper is capable of using gas and (2) Transporter is unable to deliver

Shipper's designated volumes at the specified Delivery Point(s) and at the pressures provided for in this Agreement for a period of two consecutive days ("Service Cessation"), Shipper shall have the right to reduce the MDTQ by the volumes not delivered, without costs or penalty, by providing written notice to Transporter within forty-five (45) days of such occurrence; provided, however, that if a Service Cessation occurs more than five (5) times in any calendar year, Shipper shall have the right to terminate this Agreement by providing written notice to Transporter within forty-five (45) days of such occurrence; provided further, however, that if Transporter's failure to deliver is due to events of Transporter's force majeure as defined in Rate Schedule FTS-2, Shipper shall have the right to terminate or to reduce the MDTQ only in the event such force majeure continues for more than one hundred eighty-five (185) consecutive days of any three hundred sixty-five (365) day period.

ARTICLE VI
Point(s) of Receipt and Delivery and Maximum Daily Quantities

6.1 The Primary Point(s) of Receipt and maximum daily quantity for each Primary Point of Receipt with respect to the Hines Unit #4 Capacity and System Supply Capacity, for all gas delivered by Shipper to Transporter under this Agreement shall be at the Point(s) of Receipt on the pipeline system of Transporter or any Transporting Pipeline as set forth in Exhibit A attached hereto, as the same may be amended from time to time. In accordance with the provisions of Section 8.A. of Rate Schedule FTS-2 and Section 21.C. of the General Terms and Conditions of Transporter's Tariff, Shipper may request changes in its Primary Point(s) of Receipt. Transporter may make such changes in accordance with the terms of Rate Schedule FTS-2 and the applicable General Terms and Conditions of its Tariff.

6.2 The Primary Point(s) of Delivery and maximum daily quantity for each point for all gas made available for delivery by Transporter to Shipper, or for the account of Shipper, under this Agreement and with respect to the Hines Unit #4 Capacity and System Supply Capacity shall be at the Point(s) of Delivery as set forth in Exhibit B hereto, as same may be amended from time to time, and shall be in Transporter's Market Area. In accordance with the provisions of Section 9.A. of Rate Schedule FTS-2 and Section 21.C. of the General Terms and Conditions of Transporter's Tariff, Shipper may request changes in its Primary Point(s) of Delivery provided that such new requested Primary Delivery Points must be located in Transporter's Market Area. Transporter may make such changes in accordance with the terms of Rate Schedule FTS-2 and the applicable General Terms and Conditions of its Tariff. Transporter is not obligated to accept changes where the new Primary Delivery point is also a delivery point under a Rate Schedule SFTS Service Agreement and the load to be served is an existing behind-the-gate customer of a Rate Schedule SFTS Shipper as defined in Section 11 of Rate Schedule SFTS.

ARTICLE VII
Notices

All notices, payments and communications with respect to this Agreement shall be in writing and sent to the addresses stated below or at any other such address as may hereafter be designated in writing:

ADMINISTRATIVE MATTERS

Transporter: Florida Gas Transmission Company
1331 Lamar Street, Suite #650
Houston, Texas 77010
Attention: Market Services
Telephone No. (713) 853-5655

Shipper: Florida Power Corporation d/b/a Progress Energy Florida, Inc.
410 South Wilmington St., PEB19
Raleigh, NC 27601
Attention: Contracts Dept.
Telephone No. 919-546-4280
Fax No. 919-546-2649

PAYMENT BY WIRE TRANSFER

Transporter: Florida Gas Transmission Company
Transporter to provide at a later date]

Shipper: Florida Power Corporation d/b/a Progress Energy Florida, Inc.
[Shipper to provide at a later date]

ARTICLE VIII
Facilities

8.1 To the extent that construction of facilities is necessary to provide service under this Service Agreement, such construction, including payment for the facilities, shall occur in accordance with Section 21 of the General Terms and Conditions of Transporter's Tariff.

8.2 Transporter shall seek authorization to roll in the cost of the Incremental Facilities necessary to render service hereunder, including the mainline facilities and any modifications and upgrades required to the existing Progress-Hines delivery station facilities to provide a delivery capacity of up to [redacted]

ARTICLE IX
Regulatory Authorizations and Approvals

(a) Transporter's obligation to provide service is conditioned upon receipt and acceptance of any necessary regulatory authorization, in a form acceptable to Transporter in its sole discretion, to provide Firm Transportation Service to Shipper in accordance with the terms of Rate Schedule FTS-2, this Service Agreement, and the General Terms and Conditions of Transporter's Tariff.

(b) [deleted – not applicable]

ARTICLE X
Pressure

10.1 The quantities of gas delivered or caused to be delivered by Shipper to Transporter hereunder shall be delivered into Transporter's pipeline system at a pressure sufficient to enter Transporter's system, but in no event shall such gas be delivered at a pressure exceeding the maximum authorized operating pressure or such other pressure as Transporter permits at the Point(s) of Receipt.

10.2 Transporter shall have no obligation to provide compression and/or alter its system operation to effectuate deliveries at the Point(s) of Delivery hereunder.

10.3 The quantities of gas to be delivered by Transporter to Shipper hereunder shall be delivered to Shipper at a minimum pressure of 575 psig at the Progress-Hines delivery point.

ARTICLE XI
Other Provisions

11.1 Prior to Transporter's execution of this Agreement, Shipper must demonstrate creditworthiness satisfactory to Transporter, In the event Shipper fails to establish creditworthiness within fifteen (15) days of Transporter's notice, Transporter shall not execute this Agreement and this Agreement shall not become effective.

11.2 Service pursuant to this Agreement is expressly subject to the following conditions:

(a) (i) The issuance, and acceptance by Transporter, of all necessary authorizations from the FERC pursuant to the Natural Gas Act or Natural Gas Policy Act, permitting Transporter to construct, own, and operate the Facilities and to effectuate the proposed service hereunder. All such authorizations shall be in form and substance satisfactory to Transporter, and shall be final before the respective governmental authority and no longer subject to appeal or rehearing; provided, however, that Transporter may waive the condition that such authority be final and/or no longer subject to appeal or rehearing.

(ii) Shipper shall have the right to terminate this Agreement in the event that it determines, in good faith, that a condition in the FERC authorization materially adversely affects its business and operations. If Shipper elects to terminate under this provision, it will notify Transporter in writing within fifteen (15) days of the issuance of such authorization.

(b) This agreement is subject to approval of the board of directors of Transporter and receipt and acceptance by Transporter of all other approvals required to construct the Facilities, including all necessary authorizations from federal, state, local, and/or municipal agencies or other governmental authorities. All such approvals shall be in form and substance satisfactory to Transporter, and shall be final before the respective governmental authority and no longer subject to appeal or rehearing; provided, however, that Transporter may waive the condition that such authority be final and/or no longer subject to appeal or rehearing.

(c) The receipt of executed firm transportation service agreements sufficient to economically justify construction of the Facilities, if required, in Transporter's sole opinion, and the execution of all necessary interconnect and balancing agreements with Southern Natural Gas Company ("SNG"), relating to the Cypress Pipeline project.

(d) So long as the FTS-2 rates are designed on an incremental basis, Shipper agrees to support the rate methodology underlying the existing FTS-2 rates for the Facilities and service rendered under its FTS-2 agreements, in any proceeding before the FERC during the term of this Agreement.

(e) Receipt by Transporter of all necessary right-of-way easements or permits in form and substance acceptable to Transporter.

(f) Transporter obtaining financing to construct the Facilities, in a form, and under terms, satisfactory to Transporter, in Transporter's sole opinion. Shipper agrees to provide reasonable cooperation in Transporter's effort to obtain financing.

(g) Completion of all of the following:

(i) The approval of this Agreement by Shipper's senior management and if necessary, Shipper's Board of Directors, by January 31, 2005;

(ii) The entry by the Florida Public Service Commission of an order approving this Agreement without the need for significant alteration (which shall be determined by Shipper in its sole discretion), by June 15, 2005;

(iii) The entry by Florida Public Service Commission of an order approving a determination of the need for the additional proposed combined-cycle Unit #4 that is planned to be installed at Shipper's Hines electric power generating facility located in Polk County, Florida, by May 1, 2005;

(iv) The execution by Shipper of agreements with each of (1) Southern Natural Gas Company (for firm transportation on its system for quantities related to the MDTQ's reflected in Attachment A and Attachment B hereto); and (2) BG

LNG Services, LLC (for the supply of natural gas to Shipper for quantities related to the MDTQ's reflected in Attachment A and Attachment B hereto), each in a form and containing terms and conditions satisfactory to Shipper in its sole discretion (collectively, the "Related Agreements"), by December 6, 2004;

(v) The entry by the Florida Public Service Commission of an order approving each of the Related Agreements without the need for significant alteration (which shall be determined by Shipper in its sole discretion), by June 15, 2005;

(vi) Completion and commencement of operation of (which shall be determined by Shipper in its sole discretion), the proposed expansion of SNG's natural gas pipeline system that extends from (i) a point of interconnection with the Elba Island LNG Terminal; to (ii) an interconnection with the existing (as of the effective date hereof), natural gas transmission facilities owned by Transporter in Clay County, Florida no later than March 1, 2009; and

(vii) The granting of all governmental approvals by October 1, 2006, in form and substance satisfactory to Shipper, as may be deemed necessary by Shipper in its sole discretion related to Shipper's purchase, transportation, and utilization of the supplies of natural gas referenced hereunder and in the Related Agreements.

In the event that any of these conditions are not met by the date specified ("deadline") in this section 11.2(g), Shipper may elect to terminate this Agreement by giving written notice, within ten (10) days of the deadline, of such termination to Transporter, and this Service Agreement shall terminate upon FGT's receipt of Shipper's notice; provided, however, in no event shall such notice be given by Shipper to Transporter any later than March 10, 2009.

(h) The final approval by the FERC, without modification or condition that is unacceptable to any Settling Party, of the rate case Stipulation and Agreement of Settlement filed on August 13, 2004 in Docket No. RP04-12.

11.3 Subject to the other provisions of this Article XI, Transporter agrees to make all reasonable efforts to obtain the necessary authorizations, financing commitments, and all other approvals necessary to effectuate service under this Agreement. Shipper agrees to exercise good faith in the performance of this Agreement by supporting Transporter's efforts to obtain all necessary authorizations, financing, and other approvals necessary to effectuate service under this Agreement.

11.4 Notwithstanding any other provision herein, at any time prior to Transporter's acceptance of all authorizations necessary to construct the Facilities, Transporter retains the right to terminate this Agreement, and to withdraw any requests or applications for regulatory approvals.

11.5 [Deleted – Not Applicable]

ARTICLE XII
Miscellaneous

12.1 (a) This Agreement shall bind and benefit the successors and assigns of the respective parties hereto; provided however, that neither party shall assign this Agreement or any of its rights or obligations hereunder without first obtaining the written consent of the other party, which consent shall not be unreasonably withheld.

(b) Shipper may also assign its rights under the Final Rate Cap but only in the event that such assignment is to a third party that has a Moody's credit rating equal to or greater than that of Shipper.

12.2 No waiver by either party of any one or more defaults by the other in the performance of any provisions of this Agreement shall operate or be construed as a waiver of any future defaults of a like or different character.

12.3 This Agreement contains Exhibits A and B (each for the periods May through September 2007, May through September 2008, and commencing May 2009), which are incorporated fully herein.

12.4 THIS AGREEMENT SHALL BE GOVERNED BY AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, WITHOUT REFERENCE TO ANY CONFLICT OF LAWS DOCTRINE WHICH WOULD APPLY THE LAWS OF ANOTHER JURISIDCTION.

ARTICLE XIII
Superseding Prior Service Agreements

This Agreement supercedes and cancels the following Service Agreements between Transporter and Shipper:

None.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement by their duly authorized officers effective as of the date first written above.

TRANSPORTER:	SHIPPER:
FLORIDA GAS TRANSMISSION COMPANY	FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.
By ______________________________	By ______________________________
Title ______________________________	Title ______________________________
Attest: (to be attested if not signed by an officer of the company)	Attest: (to be attested if not signed by an officer of the company)
By ______________________________	By ______________________________
Title ______________________________	Title ______________________________
Date ______________________________	Date ______________________________

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

REDACTED

FIRM TRANSPORTATION SERVICE AGREEMENT
RATE SCHEDULE FTS-2

THIS AGREEMENT entered into this the 2nd day of December, 2004 by and between Florida Gas Transmission Company, a corporation of the State of Delaware (herein called "Transporter"), and Florida Power Corporation d/b/a Progress Energy Florida, Inc. (herein called "Shipper"),

WITNESSETH:

WHEREAS, Shipper is interested in obtaining firm seasonal transportation service from Transporter, in conjunction with other upstream supply and capacity arrangements, in order to make available to Shipper (1) supplies needed to operate an additional combined-cycle generating unit #4 at Shipper's Hines electric power generating facility in Polk County, Florida ("Hines Unit #4 Capacity"), and (2) additional system supplies to serve its existing electric power generation facilities ("System Supply Capacity"); and

WHEREAS, Transporter is willing to provide such firm seasonal transportation services to Shipper; and

WHEREAS, such services will be provided by Transporter for Shipper in accordance with the terms hereof.

NOW THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein contained, the sufficiency of which is hereby acknowledged, Transporter and Shipper do covenant and agree as follows:

ARTICLE I
Definitions

In addition to the definitions incorporated herein through Transporter's Rate Schedule FTS-2, the following terms when used herein shall have the meanings set forth below:

1.1 The term "Rate Schedule FTS-2" shall mean Transporter's Rate Schedule FTS-2 as filed with the FERC and as may be changed and adjusted from time to time by Transporter in accordance with Section 4.2 hereof or in compliance with any final FERC order affecting such rate schedule.

1.2 The term "FERC" shall mean the Federal Energy Regulatory Commission or any successor regulatory agency or body, including the Congress, which has authority to regulate the rates and services of Transporter.

1.3 [deleted – not applicable]

1.4 [deleted – not applicable]

1.5 The term "Service Commencement Date" shall mean the date on which the conditions set forth in Article XI hereof have first been satisfied, which Service Commencement Date shall be no later than March 1, 2009.

ARTICLE II
Quantity

2.1 The Maximum Daily Transportation Quantity ("MDTQ") with respect to each component of the Hines Unit #4 Capacity and System Supply Capacity provided for herein is set forth on a seasonal basis, and by Division if applicable, on Exhibit B attached hereto as the same may be amended from time to time. The respective applicable MDTQs (as of May 1, 2009, the MDTQs of [redacted] for the Hines Unit #4 Capacity, and [redacted] for System Supply Capacity) shall be the largest daily quantity of gas expressed in MMBtu, that Transporter is obligated to transport and make available for delivery to Shipper under this Service Agreement on any one day.

2.2 Upon the Service Commencement Date, Shipper may tender natural gas for transportation to Transporter on any day, up to the MDTQ plus Transporter's Fuel, if applicable. Transporter agrees to receive the aggregate of the quantities of natural gas that Shipper tenders for transportation at the Receipt Points, up to the maximum daily quantity ("MDQ") specified for each receipt point as set out on Exhibit A, plus Transporter's Fuel, if applicable, and to transport and make available for delivery to Shipper at each Delivery Point specified on Exhibit B, up to the amount scheduled by Transporter less Transporter's Fuel, if applicable (as provided in Rate Schedule FTS-2), provided however, that Transporter shall not be required to accept for transportation and make available for delivery more than the MDTQ on any day.

ARTICLE III
Payment and Rights in the Event of Non-Payment

3.1 Upon the Service Commencement Date, Shipper shall pay Transporter, for all service rendered hereunder, the rates established in Article IV herein.

3.2 Termination for Non-Payment. In the event Shipper fails to pay for the service provided under this Agreement, pursuant to the conditions set forth in Section 15 of the General Terms and Conditions of Transporter's FERC Gas Tariff, Transporter shall have the right to suspend or terminate this Agreement pursuant to the conditions set forth in said Section 15.

ARTICLE IV
Rates and Terms and Conditions of Service

4.1 This Agreement in all respects shall be and remain subject to the provisions of Rate Schedule FTS-2 and of the applicable provisions of the General Terms and Conditions of Transporter on file with the FERC (as the same may hereafter be legally amended or superseded), all of which are made a part hereof by this reference.

4.2 Subject to the Discount Agreement between Transporter and Shipper, Transporter shall have the unilateral right to file with the appropriate regulatory authority and seek to make changes in (a) the rates and charges applicable to its Rate Schedule FTS-2, (b) Rate Schedule FTS-2 including the Form of Service Agreement and the existing Service Agreement pursuant to which this service is rendered; provided however, that the firm character of service shall not be subject to change hereunder by means of a Section 4 Filing by Transporter, and/or (c) any provisions of the General Terms and Conditions of Transporter's Tariff applicable to Rate Schedule FTS-2. Transporter agrees that Shipper may protest or contest the aforementioned filings, or seek authorization from duly constituted regulatory authorities for such adjustment of Transporter's existing FERC Gas Tariff as may be found necessary in order to assure that the provisions in (a), (b) or (c) above are just and reasonable.

4.3 Notwithstanding Section 4.1 above, as of the Service Commencement Date and during the primary term of this Agreement, Shipper shall pay Transporter, for all services rendered hereunder, unless otherwise agreed by Shipper and Transporter, the lower of: (I) the rates established under Transporter's Rate Schedule FTS-2 (inclusive of all applicable surcharges), as filed with and approved by the FERC and as said Rate Schedule may hereafter be legally amended or superseded, or (2) the Final Rate Cap as determined below:

(a) The Base Rate Cap shall be as follows: [redacted]

(b) The Base Rate Cap assumes the levelized rate methodology through March 31, 2005, and thereafter, the traditional cost of service methodology. For purposes of this section with respect to this Agreement, a "levelized rate" shall mean a rate designed by adjusting the annual depreciation expense such that it results in a levelized cost of service.

(c) The Base Rate Cap is stated in nominal dollars, and shall exclude all applicable surcharges and fuel.

(d) Beginning on January 1, 2005, and annually thereafter ("Escalation Date"), the Base Rate Cap then in effect shall be escalated in accordance with the following formula; provided that in no event shall the Base Rate Cap, as it may be escalated pursuant to this subsection (d), exceed [redacted]. On each Escalation Date, the Base Rate Cap to be effective for the subsequent twelve (12) month period shall be the sum of:

[redacted]

(e) (i) For any billing month, the Final Rate Cap (stated on a per unit basis) shall be determined by adding the Base Rate Cap and an amount equal to the aggregate of the applicable surcharges (as defined in section (e)(ii) below).

(ii) The type of surcharges contemplated under Rate Schedule FTS-2 to be included in the calculation of the Final Rate Cap are applicable surcharges, such as ACA, fuel, and Capital surcharges; provided, however, Transporter shall not collect under this Agreement any surcharge associated with GRI, Gas Supply Realignment ("GSR"), the recovery of take-or-pay costs or gas purchase reformation costs, FERC Account No.191 costs ("restructuring costs"), or any similar surcharge associated with the restructuring of Transporter's merchant service under orders in FERC Docket No. RS92-16-000 or similar proceedings, any separately stated surcharge related to the recovery of restructuring costs of any upstream provider of transportation or sales services to Transporter, or, to the extent such charges may be discountable, any industry-wide research and development surcharges such as those currently proposed in FERC Docket No. RP04-378.

(f) If, at any time after the Service Commencement Date and during the primary term of this Agreement, the effective rate that Transporter is authorized by the FERC to charge Shipper, including surcharges, exceeds the Final Rate Cap, then Transporter shall discount such authorized FERC rate down to the Final Rate Cap in accordance with the order of discounting provided for in Transporter's FERC Gas Tariff.

(g) Unless otherwise mutually agreed by the Parties, after the expiration of the primary term of this Agreement, Shipper shall pay Transporter the rates established under Transporter's Rate Schedule FTS-2, as filed with and approved by the FERC.

(h) If Shipper proposes or supports a change in the rate design methodology on which the currently effective FTS-2 rates are based, as set forth in Sections III.2.c and d, and III.3.b of the Phase III Settlement, and such proposals or changes are approved by a final non-appealable order, the Final Rate Cap shall be deemed waived. Notwithstanding the foregoing, if Transporter proposes, or any other party proposes and Transporter either supports or does not oppose, a change to any of such rate design methodologies in any Section 4 or Section 5 proceeding, then Shipper may take a position on that particular rate design methodology in that proceeding, whether or not consistent with the position taken by Transporter, without waiving the Final Rate Cap, and unless otherwise agreed by Transporter and Shipper, approval of such a proposed change in the rate design methodology by a final non-appealable order, in such Section 4 or Section 5 proceeding, shall not affect the continuing applicability of the Final Rate Cap. Specifically, the rate design methodology issues referenced above in this Section (h) are as follows:

(i) the straight fixed variable method of rate design, and of classifying and allocating costs,

(ii) unless otherwise agreed to by both parties hereto, the system-wide postage stamp rate for FTS-2 service to the Market Area,

(iii) the levelized rate methodology through March 31, 2005, and thereafter, the traditional cost-of-service methodology, and

(iv) the methodology of allocating the operation and maintenance ("O&M") costs between Rate Schedules FTS-1 and FTS-2; provided, however, that without waiving its final Rate Cap under this Section (h) (iv), and with respect to the allocation of administrative and general ("A&G") expenses only, a Shipper may challenge, on a prospective basis only, Transporter's use of the Kansas-Nebraska methodology in the Section 4 rate case to be filed by Transporter in accordance with Article XI of the Settlement approved by the FERC in Docket No. RP04-12; and provided further, that Shipper may, without waiving its Final Rate Cap (and regardless of any position taken by Transporter), argue for any allocation methodology that allocates no more O&M costs to Rate Schedule FTS-2 than would otherwise be allocated by use of:

   a. *the Phase III Settlement* methodology for allocating all O&M costs except for A&G expenses, and

   b. the *Kansas-Nebraska* methodology for allocating A&G expenses.

4.4 [Deleted– Not Applicable]

ARTICLE V
Term of Agreement

5.1 This Agreement shall become effective upon the date first written above and shall continue in effect for a primary term of Twenty (20) years commencing with the Service Commencement Date.

5.2 In the event the capacity being contracted for was acquired pursuant to Section 18.E. of Transporter's Tariff, then this Agreement shall terminate on the date set forth in Section 5.1 above. Otherwise, in accordance with the provisions of Section 20 of the General Terms and Conditions of Transporter's Tariff, Shipper has elected [Right of First Refusal or Roll-over Option] and upon the expiration of the primary term and any extension or roll-over, termination will be governed by the provisions of Section 20 of the General Terms and Conditions of Transporter's Tariff.

5.3 [deleted – not applicable]

5.4 Shipper may buy out of a Service Agreement for all or a portion of its transportation capacity ("MDTQ") thereunder, at any time, by paying Transporter the net present value of Shipper's remaining reservation charge obligations for such capacity, discounted at a reasonable rate to be mutually agreed upon by the parties at the time of such buy-out.

5.5 Notwithstanding any other provision in this Agreement, after the Service Commencement Date, in the event that: (1) Shipper is capable of using gas; and (2) Transporter is unable to deliver Shipper's designated volumes at the specified Delivery Point(s) and at the pressures provided for in this Agreement for a period of two consecutive days ("Service Cessation"), Shipper shall have the right to reduce the MDTQ by the volumes not delivered, without costs or penalty, by providing written notice to Transporter within forty-five (45) days of such occurrence; provided, however, that if a Service Cessation occurs more than five (5) times in any calendar year, Shipper shall have the right to terminate this Agreement by providing written notice to Transporter within forty-five (45) days of such occurrence; provided further, however, that if Transporter's failure to deliver is due to events of Transporter's force majeure as defined in Rate Schedule FTS-2, Shipper shall have the right

ARTICLE VII
Notices

All notices, payments and communications with respect to this Agreement shall be in writing and sent to the addresses stated below or at any other such address as may hereafter be designated in writing:

ADMINISTRATIVE MATTERS

Transporter: Florida Gas Transmission Company
1331 Lamar Street, Suite #650
Houston, Texas 77010
Attention: Market Services
Telephone No. (713) 853-5655

Shipper: Florida Power Corporation d/b/a Progress Energy Florida, Inc.
410 South Wilmington St., PEB19
Raleigh, NC 27601
Attention: Contracts Dept.
Telephone No. 919-546-4280
Fax No. 919-546-2649

PAYMENT BY WIRE TRANSFER

Transporter: Florida Gas Transmission Company
[Transporter to provide at a later date]

Shipper: Florida Power Corporation d/b/a Progress Energy Florida, Inc.
[Shipper to provide at a later date]

ARTICLE VIII
Facilities

8.1 [Deleted – Not Applicable]

8.2 [Deleted – Not Applicable]

ARTICLE IX
Regulatory Authorizations and Approvals

(a) Transporter's obligation to provide service is conditioned upon receipt and acceptance of any necessary regulatory authorization, in a form acceptable to Transporter in its sole discretion, to provide Firm Transportation Service to Shipper in accordance with the terms of Rate Schedule FTS-2, this Service Agreement and the General Terms and Conditions of Transporter's Tariff.

(b) [deleted – not applicable]

ARTICLE X
Pressure

10.1 The quantities of gas delivered or caused to be delivered by Shipper to Transporter hereunder shall be delivered into Transporter's pipeline system at a pressure sufficient to enter Transporter's system, but in no event shall such gas be delivered at a pressure exceeding the maximum authorized operating pressure or such other pressure as Transporter permits at the Point(s) of Receipt.

10.2 Transporter shall have no obligation to provide compression and/or alter its system operation to effectuate deliveries at the Point(s) of Delivery hereunder.

10.3 The quantities of gas to be delivered by Transporter to Shipper hereunder shall be delivered to Shipper at a minimum pressure of 500 psig at the Progress-Hines delivery point.

ARTICLE XI
Other Provisions

11.1 Prior to Transporter's execution of this Agreement, Shipper must demonstrate creditworthiness satisfactory to Transporter, In the event Shipper fails to establish creditworthiness within fifteen (15) days of Transporter's notice, Transporter shall not execute this Agreement and this Agreement shall not become effective.

11.2 Service pursuant to this Agreement is expressly subject to the following conditions:

(a) (i) [Deleted – Not Applicable]

(ii) [Deleted – Not Applicable]

(b) This agreement is subject to approval of the board of directors of Transporter.

(c) [Deleted – Not Applicable]

(d) [Deleted – Not Applicable]

(e) [Deleted – Not Applicable]

(f) [Deleted – Not Applicable]

(g) Approval of this Agreement by Shipper's senior management and/or Board of Directors by January 31, 2005, the issuance and acceptance by Shipper by June 15, 2005, of all federal, state or local authorizations, if any, requested by Shipper to receive service hereunder, and the execution by Shipper of binding upstream gas transportation and supply arrangements by January 31, 2005, and the completion of construction, by March 1, 2009, of any facilities necessary to deliver Shipper's gas to Transporter, for delivery to Shipper hereunder. In the event that any of these conditions are not met by the dates specified ("deadline") in this section 11.2(g), Shipper may elect to terminate this Agreement by giving written notice, within ten (10) days of the deadline, of such termination to Transporter, and this Service Agreement shall terminate upon Transporter's receipt of Shipper's notice; provided, however, in no event shall such notice be given by Shipper to Transporter any later than March 10, 2009.

(h) The approval without modification or condition that is unacceptable to any Settling Party, of the rate case Stipulation and Agreement of Settlement filed on August 13, 2004 in Docket No. RP04-12.

11.3 [Deleted – Not Applicable]

11.4 [Deleted – Not Applicable]

11.5 [Deleted – Not Applicable]

11.6 In the event that Shipper does not receive, on terms and conditions acceptable to Shipper in its sole determination, by May 1, 2005, all of the final and non-appealable authorizations, approvals and or exemptions from the Florida Public Service Commission and from any other regulatory body having jurisdiction necessary for Shipper to construct, own and operate Shipper's Hines Plant Expansion ("Shippers Regulatory Approvals"), Shipper may give written notice of termination to Transporter, and this Service Agreement shall terminate upon FGT's receipt of Shipper's notice; provided, however, in no event shall such notice be given by Shipper to Transporter any later than June 10, 2005.

ARTICLE XII
Miscellaneous

12.1 (a) This Agreement shall bind and benefit the successors and assigns of the respective parties hereto; provided however, that neither party shall assign this Agreement or any of its rights or obligations hereunder without first obtaining the written consent of the other party, which consent shall not be unreasonably withheld.

(b) Shipper may also assign its rights under the Final Rate Cap but only in the event that such assignment is to a third party that has a Moody's credit rating equal to or greater than that of Shipper.

12.2 No waiver by either party of anyone or more defaults by the other in the performance of any provisions of this Agreement shall operate or be construed as a waiver of any future defaults of a like or different character.

12.3 This Agreement contains Exhibits A and B (each for the periods October 2007 through April 2008, October 2008 through April 2009, and commencing October 2009), which are incorporated fully herein.

12.4 THIS AGREEMENT SHALL BE GOVERNED BY AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, WITHOUT REFERENCE TO ANY CONFLICT OF LAWS DOCTRINE WHICH WOULD APPLY THE LAWS OF ANOTHER JURISIDCTION.

ARTICLE XIII
Superseding Prior Service Agreements

This Agreement supercedes and cancels the following Service Agreements between Transporter and Shipper:

None.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement by their duly authorized officers effective as of the date first written above.

TRANSPORTER

FLORIDA GAS TRANSMISSION COMPANY

By ______________________

Title Sr. V. P. + CCO

Attest: (to be attested if not signed by an officer of the company)

By ______________________

Title ______________________

Date ______________________

SHIPPER

FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

By ______________________

ROBERT F. CALDWELL

Title VICE PRESIDENT – REG. COML. OPS

Attest: (to be attested if not signed by an officer of the company)

By ______________________

Title ______________________

Date ______________________

REDACTED

REDACTED

REDACTED

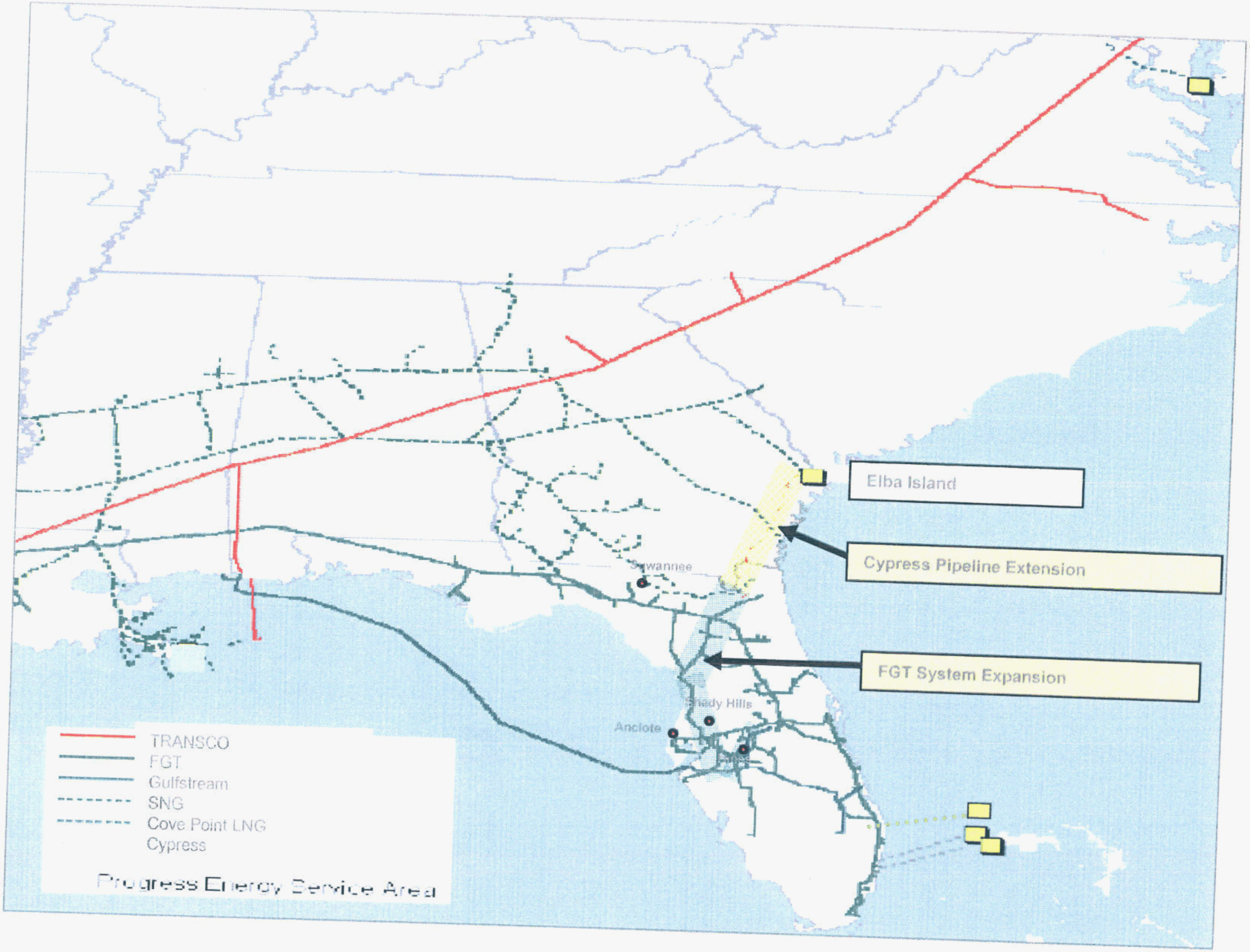
REDACTED

REDACTED

REDACTED

PRM - 4

BG/Cypress/FGT



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 8
COMPANY/ PEF
WITNESS: Pamela R. Murphy (PRM-4)
DATE: 04-29-05

REDACTED

PRM-6

REDACTED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 10
COMPANY/ PEF
WITNESS. Pamela R. Murphy (PRM-6)
DATE: 04-29-05

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 11
COMPANY/ PEF
WITNESS: Bruce H. Hughes (BHH-1)
DATE 04-29-05

Southern Natural Cypress Project

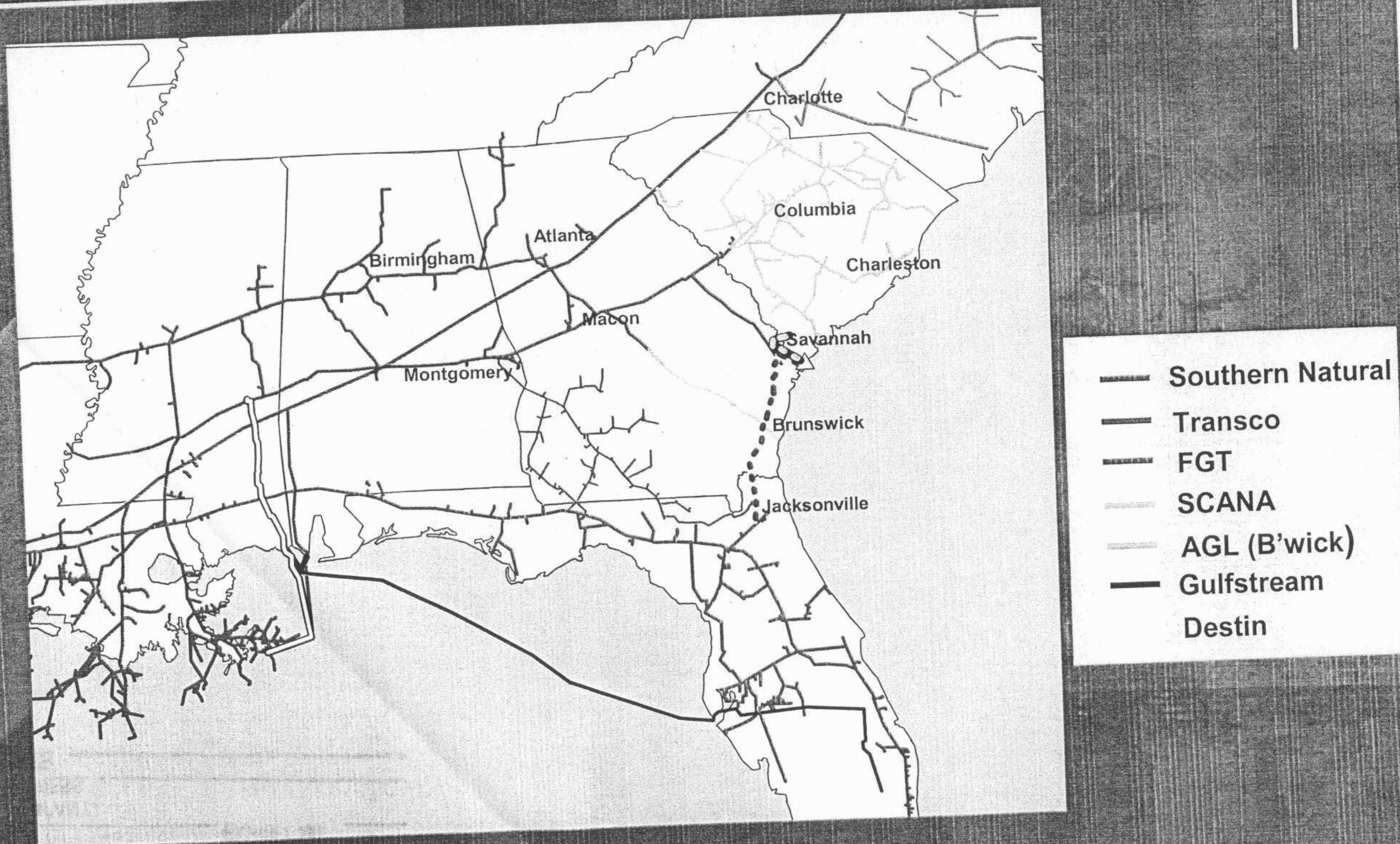


Exhibit BHH-1 Page 1 of 2

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Southern Natural Cypress Project

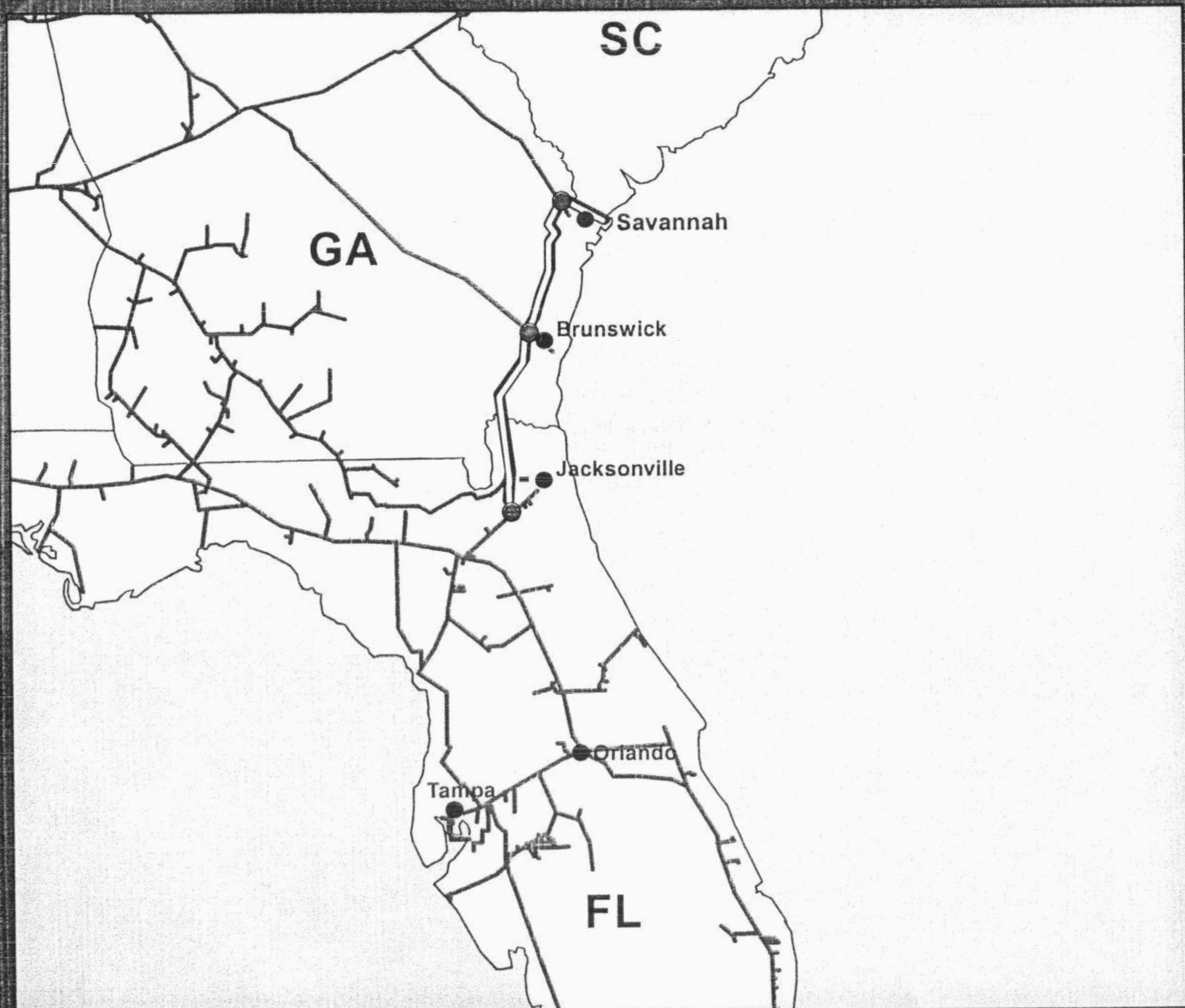
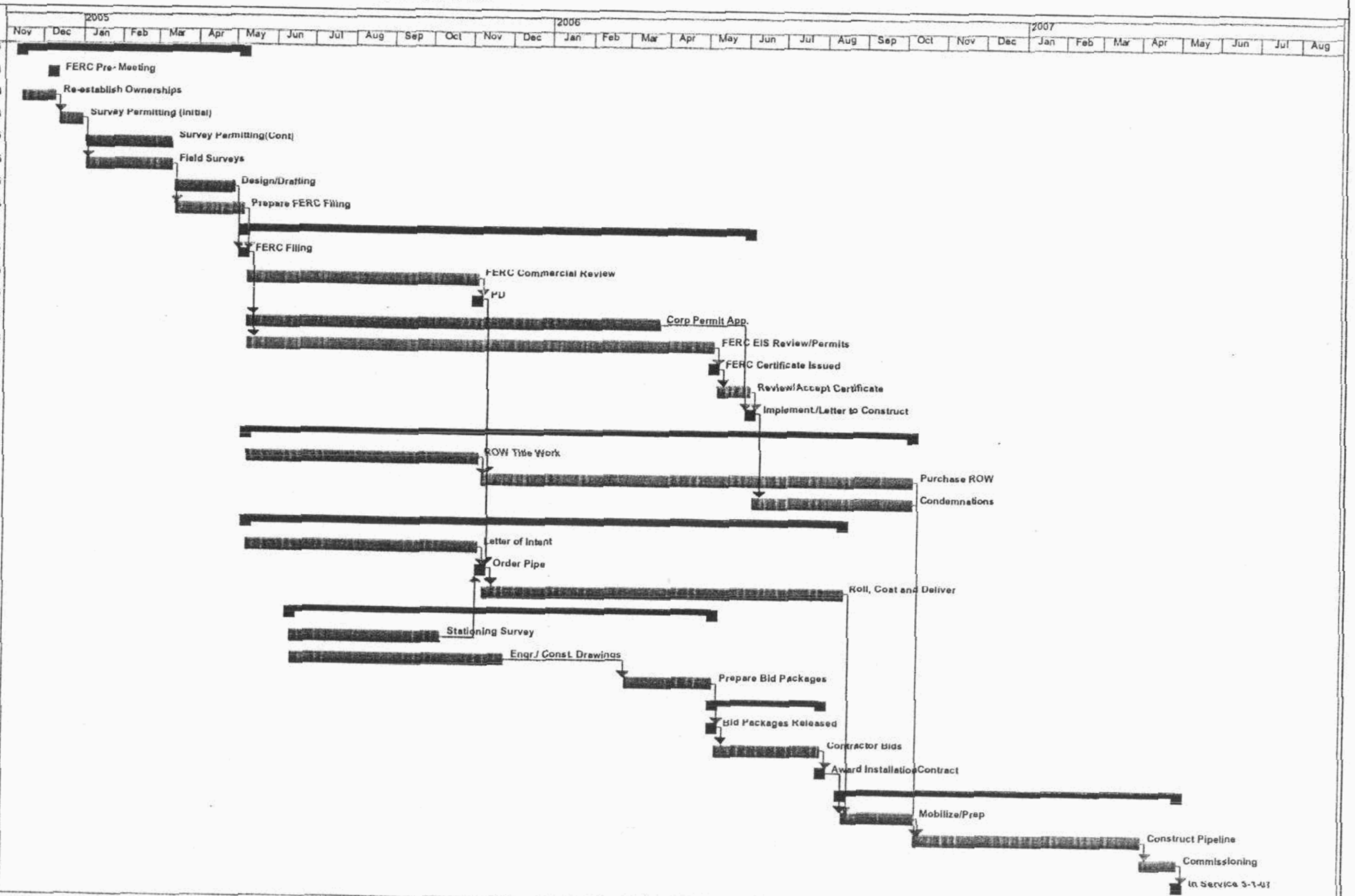


Exhibit BHH-1 Page 2 of 2

EXHIBIT BHH-2

Cypress Project - Phase 1 - 166 mile 24" Pipe
Project Schedule
December 1, 2004

ID	Task Name	Duration	Start	Finish
1	**Pre-FERC Filing**	125 days	Mon 11/15/04	Fri 5/6/05
2	FERC Pre- Meeting	0 days	Thu 12/9/04	Thu 12/9/04
3	Re-establish Ownerships	20 days	Mon 11/15/04	Fri 12/10/04
4	Survey Permitting (Initial)	15 days	Mon 12/13/04	Fri 12/31/04
5	Survey Permitting(Cont)	50 days	Mon 1/3/05	Fri 3/11/05
6	Field Surveys	50 days	Mon 1/3/05	Fri 3/11/05
7	Design/Drafting	35 days	Mon 3/14/05	Fri 4/29/05
8	Prepare FERC Filing	40 days	Mon 3/14/05	Fri 5/6/05
9	**FERC Process**	280 days	Fri 5/6/05	Fri 6/2/06
10	FERC Filing	0 days	Fri 5/6/05	Fri 5/6/05
11	FERC Commercial Review	130 days	Mon 5/9/05	Fri 11/4/05
12	PD	0 days	Fri 11/4/05	Fri 11/4/05
13	Corp Permit App.	230 days	Mon 5/9/05	Fri 3/24/06
14	FERC EIS Review/Permits	260 days	Mon 5/9/05	Fri 5/5/06
15	FERC Certificate Issued	0 days	Fri 5/5/06	Fri 5/5/06
16	Review/Accept Certificate	20 days	Mon 5/8/06	Fri 6/2/06
17	Implement./Letter to Constr	0 days	Fri 6/2/06	Fri 6/2/06
18	**ROW**	370 days	Mon 5/9/05	Fri 10/6/06
19	ROW Title Work	130 days	Mon 5/9/05	Fri 11/4/05
20	Purchase ROW	240 days	Mon 11/7/05	Fri 10/6/06
21	Condemnations	90 days	Mon 6/5/06	Fri 10/6/06
22	**Materials**	331 days	Mon 5/9/05	Mon 8/14/06
23	Letter of Intent	130 days	Mon 5/9/05	Fri 11/4/05
24	Order Pipe	0 days	Mon 11/7/05	Mon 11/7/05
25	Roll, Coat and Deliver	200 days	Tue 11/8/05	Mon 8/14/06
26	**Engineering**	235 days	Mon 6/13/05	Fri 5/5/06
27	Stationing Survey	85 days	Mon 6/13/05	Fri 10/7/05
28	Engr./ Const. Drawings	120 days	Mon 6/13/05	Fri 11/25/05
29	Prepare Bid Packages	50 days	Mon 2/27/06	Fri 5/5/06
30	**Contracting**	60 days	Fri 5/5/06	Fri 7/28/06
31	Bid Packages Released	0 days	Fri 5/5/06	Fri 5/5/06
32	Contractor Bids	60 days	Mon 5/8/06	Fri 7/28/06
33	Award InstallationContract	0 days	Fri 7/28/06	Fri 7/28/06
34	**Construction**	186 days	Tue 8/15/06	Tue 5/1/07
35	Mobilize/Prep	40 days	Tue 8/15/06	Mon 10/9/06
36	Construct Pipeline	125 days	Tue 10/10/06	Mon 4/2/07
37	Commissioning	21 days	Tue 4/3/07	Tue 5/1/07
38	In Service 5-1-07	0 days	Tue 5/1/07	Tue 5/1/07



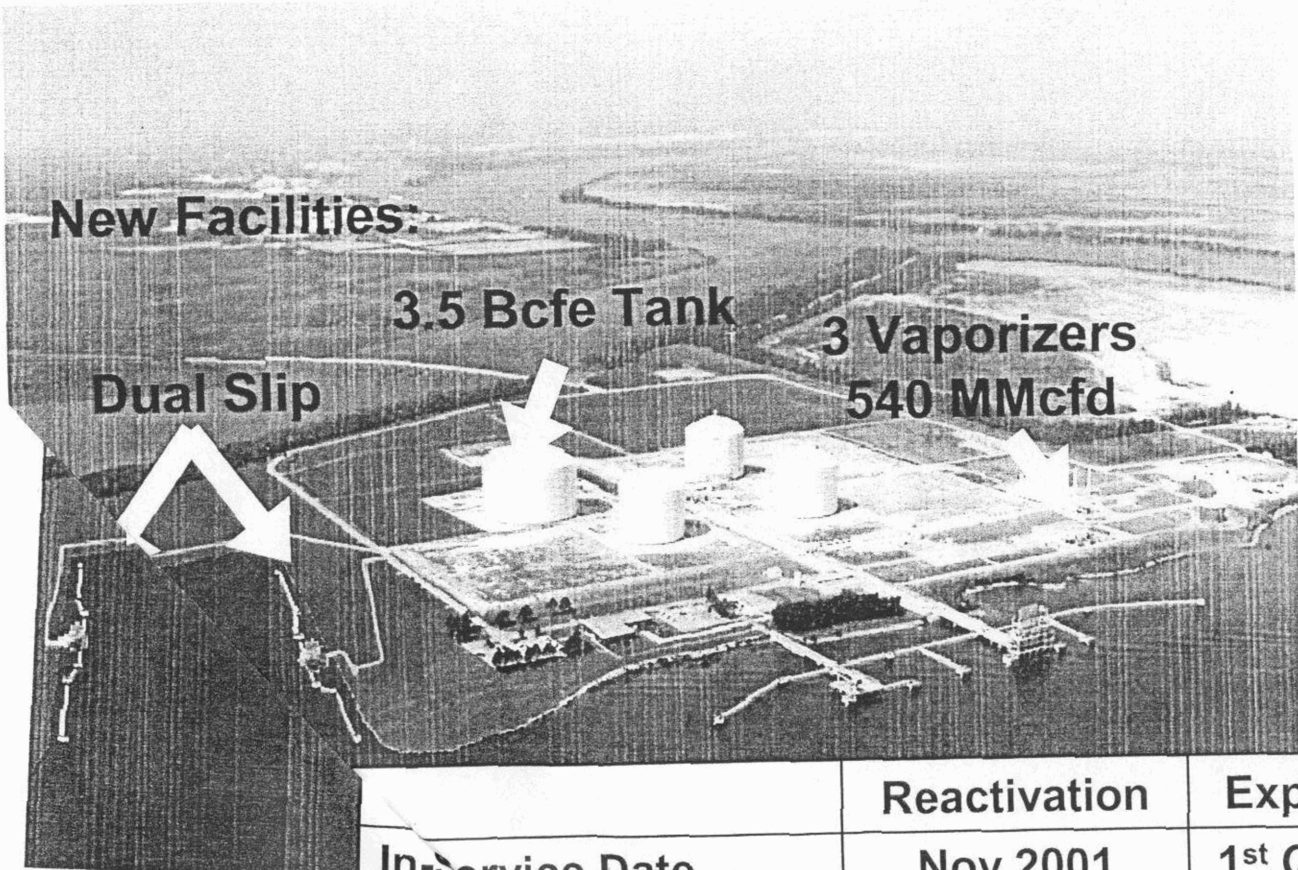
Project: Cypress Pipeline
Date: Wed 12/1/04

Task · Progress · Milestone · Summary · Rolled Up Task · Rolled Up Milestone · Rolled Up Progress · Split · External Tasks · Project Summary · Group By Summary

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 12
COMPANY/ PEF
WITNESS: Bruce H. Hughes (BHH-2)
DATE: 04-29-05

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 13
COMPANY/ PEF
WITNESS: Bruce H. Hughes (BHH-3)
DATE: 04-29-05

Southern LNG
Elba Island LNG Import Terminal



Major Gas Suppliers
- British Gas
- Shell

	Reactivation	Expansion	Combined
In-Service Date	Nov 2001	1st Qtr 2006	
Storage Capacity	4.0 Bcf	3.33 Bcf	7.33 Bcf
Base Load Sendout	446 MMcfd	360 MMcfd	806 MMcfd
Peak Sendout	675 MMcfd	540 MMcfd	1215 MMcfd

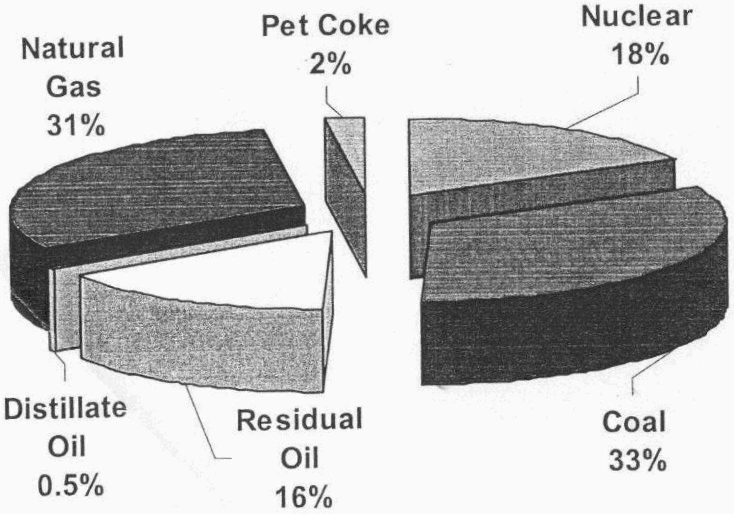
Exhibit BHH-3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 14
COMPANY/ PEF
WITNESS: Samuel S. Waters (SSW-1)
DATE: 04-29-05

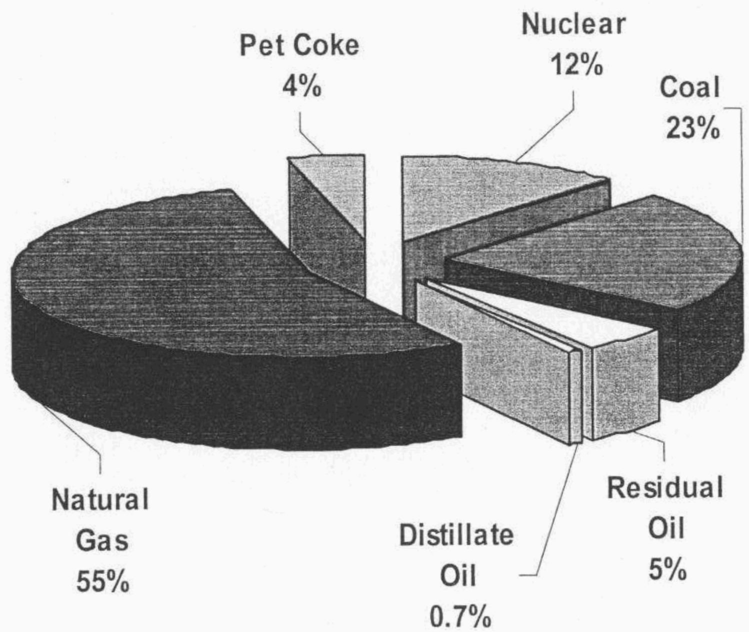
Exhibit ___ (SSW-1)

Historical and Projected Energy by Fuel Type for Peninsular Florida

2003 GWh generated by Fuel Type



2013 GWh generated by Fuel Type



Source: 2004 Ten Year Site Plans

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041414-EI EXHIBIT NO. 15
COMPANY/ PEF
WITNESS: Pamela Murphy - Conf. Version of testimony & Exhibits
DATE: 04-29-05