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July 16, 2002

-VIA HAND DELIVERY-

Ms. Blanca S. Bayó
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket Nos. 020262-EI and 020263-EI

Dear Ms. Bayó:

On March 22, 2002, Florida Power & Light Company ("FPL") filed a Petition for Determination of Need for an Electrical Power Plant - Martin Unit 8 and a Petition for Determination of Need for an Electrical Power Plant - Manatee Unit 3. FPL's two petitions were assigned Docket Nos. 020262-EI and 020263-EI, respectively.

On April 22, 2002, FPL moved to hold both proceedings in abeyance to allow FPL to undertake a Supplemental Request for Proposals (Supplemental RFP). On April 29, 2002, FPL filed an emergency motion for waiver of Rule 25-22.080(2), F.A.C., to allow deferral of the hearing schedule if, as a result of the Supplemental RFP, Martin Unit 8 and Manatee Unit 3 were determined to be the most cost-effective alternatives to meet FPL's 2005 and 2006 need. By Order No. PSC-02-0571-PCO-EI, Commissioner Deason, acting as prehearing officer, substantially granted FPL's emergency motion to hold both proceedings in abeyance, and by Order No. PSC-02-0703-PCO-EI, the Commission granted FPL's emergency waiver of Rule 25-22.080(2).

FPL has completed its Supplemental RFP. FPL's analysis shows that Martin Unit 8 and Manatee Unit 3 are the most cost-effective options to meet FPL's 2005 and 2006 need for capacity. Consequently, FPL is now prepared, consistent with Order Nos. PSC-02-0571-PCO-EI

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and PSC-02-0703-PCO-EI, for the Commission to proceed with its evaluation of the need for those two units in Docket Nos. 020262-EI and 020263-EI. The documents enclosed herewith, as described below, provide the information required for that evaluation.

Enclosed for filing on behalf of FPL in Docket Nos. 020262-EI and 020263-EI are the original and fifteen copies of:

(1) FPL's Motion for Leave to Amend Petitions for Determination of Need

(2) FPL's Amended Petition for Determination of Need for an Electrical Power Plant-Martin Unit 8

(3) FPL's Amended Petition for Determination of Need for an Electrical Power Plant-Manatee Unit 3

Because the same analysis supported FPL's assessment of its 2005 and 2006 capacity needs and its determination that Martin Unit 8 and Manatee Unit 3 were the most cost-effective alternatives to meet the needs, FPL previously filed a motion to consolidate both dockets. Consistent with its motion to consolidate, FPL filed along with its original Need Determination petitions a single Need Study for Electrical Power Plant and a single set of Need Study Appendices, as well as a common set of testimony for both dockets. FPL continues to seek consolidation of these dockets for hearing.

In support of its amended Petitions for Determination of Need for Martin Unit 8 and Manatee Unit 3, FPL is filing the original and 15 copies of the following documents:

(1) Need Study For Electrical Power Plant, 2005-2006

(2) Need Study Appendices A - D

(3) Need Study Appendices E - J

(4) Need Study Appendices K - O

(5) Direct Testimony of Dr. William E. Avera

(6) Direct Testimony of C. Dennis Brandt

(7) Direct Testimony of Moray P. Dewhurst

(8) Direct Testimony of Leonardo E. Green

(9) Direct Testimony of Rene Silva

(10) Direct Testimony of Dr. Steven R. Sim

(11) Direct Testimony of Donald R. Stillwagon

(12) Direct Testimony of Alan S. Taylor

(13) Direct Testimony of William L. Yeager

(14) Direct Testimony of Gerard Yupp

These documents reflect the results of FPL's Supplemental RFP and supercede the Need Study and Appendices and its Direct Testimony filed on March 22, 2002, in support of its initial Petitions for Determination of Need. Therefore, FPL hereby withdraws the March 22 Need Study and Appendices and the March 22 Direct Testimony.

Copies of the enclosed documents, are being provided to counsel for all parties of record. Under separate cover letter, FPL is filing its confidential appendices to the Need Study and a Request for Confidential Classification for the confidential appendices.

With the interruption of these proceedings for the Supplemental RFP, it is important that FPL's need determination proceedings be heard expeditiously. Prior to the Commission's granting of FPL's Emergency Motion To Hold The Proceedings In Abeyance, the parties had agreed to a schedule that would result in a hearing on October 2-4, 2002, a Commission decision on November 19, 2002, and a final order no later than December 4, 2002. FPL needs to preserve this schedule in order to meet its scheduled in-service date of June 2005 for both Martin Unit 8 and Manatee Unit 3. To facilitate this schedule, FPL has: (a) included more detailed data in the enclosed Need Study and Appendices than is required by Commission rule; (b) filed its direct testimony along with its amended petitions; (c) worked out with the intervenors free access to the primary analytical tools used in conducting the economic analysis of the Supplemental RFP; (d) agreed to a Confidentiality Agreement and process to allow intervenor access to most confidential data; and (e) agreed to expedited discovery. FPL will continue to work with the Commission and the parties to facilitate the Commission's prompt consideration of these proceedings.

Any delay in these proceedings would place at risk the in-service dates of Martin Unit 8 and Manatee Unit 3. In the event of delay, FPL would not achieve its 20 percent reserve margin criteria (or even a 15 percent reserve margin) in the summer of 2005. Without purchases of capacity to replace these facilities, an option which may not be available for the full capacity of these units, the reliability of FPL's system could be significantly adversely impacted to the detriment of FPL's customers. In the event of a delay, if FPL were to attempt to purchase capacity and energy to replace these units, FPL likely would pay higher costs than the costs it would incur if these units had met their in-service dates. Thus, delay also would adversely impact the costs paid by FPL's customers.

Because a delay would cause adverse impacts upon FPL's customers, FPL respectfully requests that these proceedings be processed according to the previously agreed schedule and that an Order on Procedure be issued. Such an order should place reasonable limits on discovery, encourage intervenors to coordinate discovery as they have previously agreed to do, expedite discovery as previously agreed and set forth the agreed-to schedule, thereby facilitating the administration of these proceedings.

Respectfully submitted,

Charles A. Guyton

R. Wade Litchfield
Charles A. Guyton

Attorneys for Florida Power
& Light Company

CAG/gc
Enclosures

cc: Counsel for Parties of Record

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Need Study For Electrical Power Plant 2005 - 2006

FPL

FPL

FLORIDA POWER & LIGHT COMPANY

NEED STUDY SUPPORTING THE PETITIONS TO DETERMINE NEED FOR MARTIN UNIT 8 AND MANATEE UNIT 3 2005-2006

July 2002

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AFUDC	Allowance for Funds Used During Construction
Btu	British Thermal Unit
CC	Combined Cycle
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CPVRR	Cumulative Present Value of Revenue Requirements
CT	Combustion Turbines
DLN	Dry Low NO_X Combustion Technology
DSM	Demand Side Management
EAF	Equivalent Availability Factor
EFOR	Equivalent Forced Outage Rate
EGEAS	Electric Generation Expansion and System Analysis Model
FGT	Florida Gas Transmission
FMPA	Florida Municipal Power Association
FPC	Florida Power Corporation
FPL	Florida Power & Light Company
FRCC	Florida Reliability Coordinating Council
GE	General Electric Corporation
GWh	Gigawatt Hour
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
IRP	Integrated Resource Planning

JEA	Jacksonville Electric Authority
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LOLP	Loss-of-Load Probability
LNTP	Limited Notice to Proceed
MGD	Million Gallons per Day
MW	Megawatt
MWh	Megawatt Hour
NEL	Net Energy for Load
NO_x	Nitrogen Oxides
O & M	Operation and Maintenance
PC	Pulverized Coal
PM_{10}	Particulate Matter (larger than 10 microns)
POF	Planned Outage Factor
ppmvd	Parts per Million Volume Dry
RFP	Request for Proposals
RH	Relative Humidity
ROW	Right of Way
RSM	Sedway Consulting, Inc.'s Response Surface Model
scf/hr	Standard Cubic Feet per Hour
SCR	Selective Catalytic NO_X Reduction
Sedway	Sedway Consulting, Inc., the Independent Evaluator

SJRPP	St. Johns River Power Park
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
SFWMD	South Florida Water Management District
SWFWMD	South West Florida Water Management District
TECO	Tampa Electric Company
TIGER	Tie-Line Assistance and Generation Reliability Model
UPS	Unit Power Sales
VOC	Volatile Organic Compounds

I. EXECUTIVE SUMMARY

In its 2000 resource planning analyses, Florida Power & Light Company (FPL) determined that it needed to add 1,708 MW of additional generating resources to achieve its 20% reserve margin criterion in the summers of 2005 and 2006. FPL performs such resource planning analyses on an ongoing basis, and FPL's next resource planning analyses (performed in 2001) showed a very similar resource addition need of 1,722 MW by the summer of 2006. The most cost-effective option to meet this need is the addition of generating units that require site certification under the Florida Electrical Power Plant Siting Act.

To satisfy Rule 25-22.082, i.e., the "Bidding Rule", Florida Administrative Code, FPL issued a Request for Proposals (RFP). In August 2001, FPL solicited proposals for generating capacity to meet its resource need of 1,150 MW in the summer of 2005 and another 600 MW in the summer of 2006. On September 28, 2001, FPL received 81 proposals from 15 different entities.

FPL then conducted a comprehensive evaluation of 80 of the 81 outside proposals as well as 13 FPL self-build options. In addition, an independent evaluator was brought in to evaluate both the outside proposals and the FPL construction options.

Both FPL's and the independent evaluator's analyses concluded that an All-FPL self build plan, consisting of the conversion of two existing combustion turbines (CTs) at the Martin plant site into a four-on-one combined cycle (CC) unit (Martin Unit 8) and a new four-on-one CC unit at the Manatee plant site (Manatee Unit 3), would be the most cost-effective means for FPL to meet its 2005 and 2006 reliability needs.

On March 22, 2002, FPL petitioned for determinations of need for Martin Unit 8 and Manatee Unit 3. In those proceedings, several intervenors raised issues regarding FPL's compliance with the Bidding Rule in the RFP. To allay those concerns and to assure it had the lowest cost alternatives available, FPL voluntarily undertook a Supplemental RFP.

FPL announced the Supplemental RFP on April 26, 2002. It subsequently received 53 proposals from 16 bidders, totaling roughly 12,500 MW. After determining eligibility, FPL evaluated 31 of these proposals to compare them with Martin Unit 8 and Manatee Unit 3.

Both FPL and the independent evaluator analyzed the most cost-effective plans of generating unit additions including plans consisting of: (1) all outside proposals, (2) All-FPL self build options, and (3) various combinations of FPL options and outside proposals. FPL's primary analytical tool for these evaluations was Stone and Webster's Electric Generation Expansion and System Analysis (EGEAS) model. The independent evaluator used its own Response Surface Model (RSM).

Once FPL and the independent evaluator finished their capacity and system production cost comparisons of the lowest cost plans, additional costs associated with plans were factored into the analysis: transmission integration costs and "equity penalty" -- costs associated with power purchase obligations. The independent evaluator also took into consideration the residual value of the various options.

Both FPL's and the independent evaluator's economic evaluations again showed that the All-FPL self build plan (i.e., a plan consisting of Martin Unit 8 and Manatee Unit 3) would be the most cost-effective means for FPL to meet its 2005 and 2006 reliability needs. FPL's evaluation demonstrated that the All-FPL self build plan would have, in terms of cumulative present value of revenue requirements (CPVRR), a \$21 million advantage over the 2nd best plan, which consisted of both FPL units plus a short-term, small firm purchase from another Florida utility system in 2005. The third best plan, consisting of FPL's Manatee unit and this same small purchase in 2005 followed by a large, long-term purchase from a non-utility bidder in 2006, was \$83 million (CPVRR) more expensive than the All-FPL self build plan. The independent evaluator determined that the All-FPL self build plan would have a \$135 million cost advantage over this same plan. FPL's proposed power supply plan is shown in Table ES-1.

The All-FPL self build plan is more than \$470 million more cost-effective than the lowest cost plan made up solely of outside proposals. Even when combined with one of the FPL units, most of the outside proposals resulted in plans in excess of \$100 million more costly than the All-FPL self build plan.

In an attempt to secure a plan less costly than the All-FPL self build plan, FPL conducted negotiations with a short list of bidders. Those negotiations did not close, and even increased, the already significant economic gap between the All-FPL self build plan and the next lowest cost plans with only a single FPL unit.

Table ES –1

FPL's Power Supply Expansion Plan		
Year	Additions	Incremental MW [1)]
2005	**Martin Conversion Project** Convert Martin CTs Nos. 8A & 8B into 4x1 Martin Combined Cycle Unit No. 8	789
2005	**Manatee Combined Cycle** Manatee Combined Cycle Unit No. 3	1,107
	Total	**1,896**

Notes:
1) For ease of presentation, FPL has used the planned summer peak MW ratings. Actual summer net ratings may vary based on final design and performance testing.

The Martin Unit 8 conversion project and the Manatee Unit 3 combined cycle also enjoy some significant additional non-price advantages. The All-FPL self build plan will result in benefits to customers from residual value of the units at the end of twenty-five years and by FPL not having to incur costs to administer and enforce contract terms. Also, the new FPL resources will make a net contribution to statewide reliability, unlike system sales from other Florida utilities. Finally, they will increase FPL's overall system efficiency.

Based upon the economic and non-economic advantages of the Martin Unit 8 and Manatee Unit 3 plan, FPL is proceeding with the licensing of Martin Unit 8 and Manatee Unit 3. This plan is FPL's most cost-effective alternative for maintaining electric system reliability and integrity and providing adequate electricity at a reasonable cost. There is not sufficient additional reasonably achievable, cost-effective demand side management (DSM) available to mitigate the need for these units. The remainder of this Need Study document contains the more detailed information, analyses and discussion supporting FPL's requested determination of need for Martin Unit 8 and Manatee Unit 3.

II. INTRODUCTION

A. Purpose and Overview of this Document

This document supports FPL's two petitions to the Commission to determine the need for two new generating units. The first of these units is Martin Unit 8. It will be created by converting two existing simple cycle CTs at FPL's existing Martin site and adding two new CTs to develop a new 4 CT-based CC unit. The second unit, Manatee Unit 3, is an entirely new 4 CT-based CC unit at FPL's existing Manatee site. Once completed, the new units will be very similar, each with a summer net capacity of approximately 1,107 MW.[1] The net increase in FPL's total generating capacity will be approximately 1,896 MW — 1,107 MW from Manatee Unit 3 and 789 incremental MW from Martin Unit 8 (after accounting for the 318 MW of capacity already supplied by the two existing CT units at Martin).

This document contains the information required by Rule 25-22.081, Florida Administrative Code. It provides the information that will "allow the Commission to take into account the need for electric system reliability and integrity, the need for adequate reasonable cost electricity, and the need to determine whether the proposed plant is the most cost-effective alternative available...." The following information is provided in subsequent sections:

[1] This is the summer net rating for each unit. The winter net rating is 1,197 MW. For ease of presentation, throughout this Need Study document only the summer net rating of the units will be mentioned unless the winter rating is specifically being discussed. Actual summer and winter ratings may vary based upon final design and performance testing.

- a description of the existing FPL system (Section II.B);
- a description of both of the proposed generating units (Section III);
- an explanation of FPL's need for the proposed generating units, Martin Unit 8 and Manatee Unit 3 (Section IV);
- a discussion of the analyses which determined that the planned generating units represent the best alternatives to meet FPL's need (Section V);
- a discussion of non-generating alternatives and an analysis of their potential for offsetting the need for Martin Unit 8 and Manatee Unit 3 (Section VI); and
- a discussion of the adverse consequences that would result from delay of the completion of Martin Unit 8 and Manatee Unit 3 (Section VII).

B. Description of FPL and Its System

FPL is the largest investor-owned electric utility in Florida and one of the largest in the United States. FPL served an average of 3,935,281 customer accounts in thirty-five counties during 2001. FPL's service area contains approximately 27,650 square miles and has a population of approximately 7.7 million. FPL is charged with providing service not only to its existing customers, but also to new customers requesting service. FPL's load forecasts predict substantial continued customer growth in its service territory.

FPL's customers currently are served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility-owned generation, DSM, and interchange/purchased power. Each type of resource is discussed in more detail later in this document.

FPL's bulk transmission system is composed of 1,107 circuit miles of 500 kilovolt (kV) lines[2] and 2,644 circuit miles of 230 kV lines. The underlying transmission network is composed of 1,578 circuit miles of 138 kV lines, 717 circuit miles of 115 kV lines, and 164 circuit miles of 69 kV transmission lines. Integration of the generation, transmission, and distribution system is achieved through FPL's 505 substations. FPL is directly interconnected with eight other electric utilities. A list of FPL's major interconnections with other utilities is presented in Appendix A.

1. FPL-Owned Generating Resources

FPL's existing generating resources are located at fourteen generating sites distributed geographically around its service territory and also include partial ownership of one unit located in Georgia and two units located in Jacksonville. The current generating facilities consist of four nuclear steam units, three coal units, eight CC units, twenty-one fossil steam units, fifty combustion/gas turbines[3], and five diesel units. The location of these generating units, their fuel type(s), and the projected summer capability for 2002 are shown on Figure II.B.1.1. More detailed information regarding FPL's existing generating resources is presented in Appendix B.

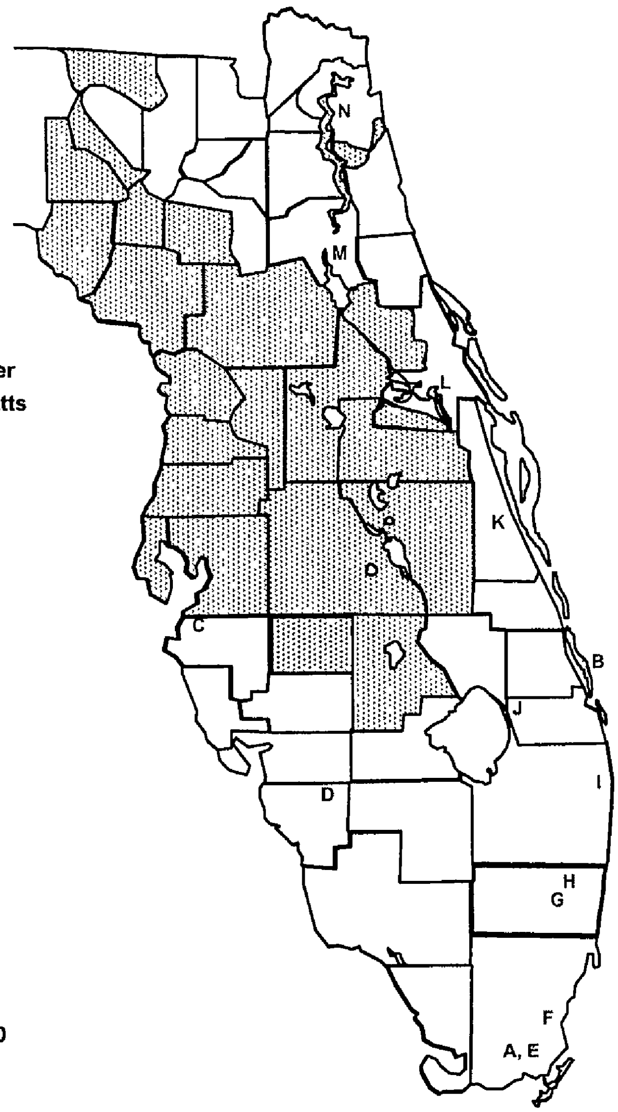
[2] This includes 75 miles of 500 kV lines, composed of two 37-1/2 mile lines, between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority.

[3] Two of the fifty turbines have recently been installed at Martin and will be used in the Martin Unit 8 project that is discussed throughout this document.

Figure II.B.1.1

FPL's Generating Resources
(Projected Summer 2002 Capabilities)

Non-FPL Territory



		Fuel Type	Summer Megawatts
A.	Turkey Point	Nuclear	1,386
B.	St. Lucie *	Nuclear	1,553
C.	Manatee	Oil/ Gas	1,625
D.	Ft. Myers	Gas	1,473
E.	Turkey Point	Oil/Gas	810
F.	Cutler	Gas	215
G.	Lauderdale	Oil/Gas	854
H.	Port Everglades	Oil/Gas	1,242
I.	Riviera	Oil/Gas	573
J.	Martin	Gas/Oil	2,906
K.	Cape Canaveral	Oil/Gas	806
L.	Sanford	Oil/Gas	1,099
M.	Putnam	Oil/Gas	498
N.	St. Johns River*	Coal	254
	Scherer **	Coal	658
	Peaking Units	Gas	1,908
	FPL GENERATION TOTAL MW		**17,860**

** Represents FPL's ownership share: St. Lucie nuclear: 100% unit 1, 85% unit 2; St. Johns River: 20% of two units.*

*** The Scherer unit is located in Georgia and is not shown on this map.*

2. Purchases from Cogeneration & Small Power Production Facilities

FPL currently has contracts to purchase firm capacity and energy from seven cogeneration and small power production facilities. A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW and uses solar, wind, waste, geothermal, or other renewable resources for at least half its energy. [4]

A summary of these firm capacity agreements with cogeneration and small power production facilities is presented in Table II.B.2.1

[4] Certain small power production facilities are exempt from the 80 MW size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990.

Table II.B.2.1

Florida Power & Light Company *Firm Capacity and Energy Contracts with* *Cogeneration/Small Power Production Facilities*					
Project	***County***	***Fuel***	***MW Capacity***	***In-Service Date***	***End Date***
Bio-Energy	Broward	Landfill Gas	10.0	5/1/98	1/1/05
Broward South	Broward	Solid Waste	50.6	4/1/91	8/1/09
			1.4	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			0.6	1/1/97	12/31/26
Broward North	Broward	Solid Waste	45.0	4/1/92	12/31/10
			7.0	1/1/93	12/31/26
			1.5	1/1/95	12/31/26
			2.5	1/1/97	12/31/26
Cedar Bay Generating Co.	Duval	Coal (CFB)	250.0	1/25/94	12/31/24
Indiantown Cogen., LP	Martin	Coal (PC)	330.0	12/22/95	12/1/25
Palm Beach SWA	Palm Beach	Solid Waste	43.5	4/1/92	3/31/10
Florida Crushed Stone	Hernando	Coal (PC)	110.0	4/1/92	10/31/05
			11.0	1/1/94	10/31/05
			12.0	1/1/95	10/31/05

3. Demand Side Management (DSM)

FPL has sought out and implemented cost-effective DSM programs since 1978. These programs include both conservation initiatives and load management. FPL's DSM efforts through 2001 have resulted in a cumulative summer peak reduction of approximately 3,076 MW and an estimated cumulative energy saving of approximately 19,713 GWh at the generator. After accounting for reserve margin requirements, FPL's DSM efforts have eliminated the need to construct the equivalent of nine new 400 MW generating units.

FPL's approved DSM Goals for summer MW reduction are presented in Table II.B.3.1. These DSM Goals are over and above the significant levels of DSM implementation FPL achieved prior to the year 2000. FPL's current DSM Plan was approved by the Commission in late 1999 and is designed to achieve these goals for the 2000 – 2009 time frame. FPL's projected need for additional capacity in 2005 and 2006 already accounts for the new DSM levels.

Table II.B.3.1

FPL's Approved DSM Goals
2000 - 2009
Summer MW Reduction

Year	Cumulative Summer MW
2000	122
2001	200
2002	269
2003	339
2004	410
2005	484
2006	554
2007	625
2008	697
2009	765

4. Purchased Power

FPL currently has power purchase contracts with seven organizations that are neither cogeneration nor small power production facilities. Two of these are other electric utilities.

FPL has a long-term unit power sales (UPS) contract to purchase up to 928 MW of coal-fired generation from the Southern Company. FPL also has long-term contracts with the Jacksonville Electric Authority (JEA) for the purchase of 382 MW (summer) and 389 MW (winter) of coal-fired generation from St. John's River Power Park (SJRPP) Unit Nos. 1 and 2. (FPL also has a separate 20% ownership interest in these units.)

In addition, FPL has a number of short-term, firm capacity purchased power contracts that expire by early 2007. These firm capacity purchases are projected to come from a variety of suppliers, and the capacity supplied will vary from 2002 through 2006. The summer capacity from such purchases in both 2005 and 2006 is projected to be 447 MW.

Both the long-term and short-term purchase amounts were incorporated in the analyses that led to FPL's projection of additional capacity needs in 2005 and 2006. The annual amounts from these long-term and short-term firm purchases are presented in Table II.B.4.1.

Table II.B.4.1

	FPL's Purchased Power MW							
	UPS		*SJRPP*		*Other Firm Capacity Purchases **		*Total*	
Year	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*
2002	928	928	389	382	50	1093	1367	2403
2003	928	928	389	382	774	1164	2091	2474
2004	928	928	389	382	813	1164	2130	2474
2005	928	928	389	382	1303	447	2620	1757
2006	928	928	389	382	540	447	1857	1757
2007	928	928	389	382	540	0	1857	1310
2008	928	928	389	382	0	0	1317	1310
2009	928	928	389	382	0	0	1317	1310
2010	928	0	389	382	0	0	1317	382
2011	0	0	389	382	0	0	389	382

* Note: The "Other Firm Capacity Purchases" include a 220 MW purchase based on a construction project that is currently on hold and which FPL believes will not be completed on schedule, if at all. Although this delay and possible cancellation will lower the purchased power amount for 2003 and 2004, it does not affect FPL's capacity needs in 2005 or 2006 because the purchase was scheduled to end in May 2005.

5. Current and Projected Electrical Demand and Sales

Even with the economic consequences of the events of September 11, 2001 and the 2001 recession, FPL forecasts significant customer growth and associated growth in per customer load and energy usage. For the period 1992 through 2001, FPL experienced an average compound growth in summer peak demand, winter peak demand and Net Energy for Load ("NEL") of 2.8%, 3.5% and 3.4%, respectively. FPL forecasts growth rates for summer and winter peak demand of 2.6% and 2.4%, respectively, for the period 2002 - 2006 and 1.8% and 1.9%, respectively, over the next two decades. NEL is projected to grow at an annualized rate of 3.7% from 2002 to 2006 and 1.9% over the next two decades.

In FPL's forecasting work, both coincident peak loads for summer and winter, as well as annual energy amounts, are projected for future years. The peak loads and annual energy amounts are forecasted to significantly increase beyond current levels.

In 2001 FPL experienced a winter coincident total peak load of 18,199 MW and a summer coincident total peak load of 18,754 MW. FPL's 2001 NEL was 98,404 GWh. For 2005 FPL is forecasting winter and summer coincident peak loads of 20,418 MW and 20,719 MW, respectively, before accounting for the impacts of DSM. The projected effects of DSM will result in winter and summer coincident peak loads of 18,680 MW and 19,068 MW, respectively, for 2005.[5] The NEL for 2005 is projected to be 111,772 GWh.

For 2006 the forecasted winter and summer coincident total peak loads before accounting for DSM are 20,854 MW and 21,186 MW, respectively. The projected effects of DSM will result in "firm" winter and summer peaks of 19,068 MW and 19,457 MW, respectively. The NEL for 2006 is projected to be 115,602 GWh.

[5] These projected "firm" peak loads are net of DSM and are the loads upon which FPL bases its capacity need calculations.

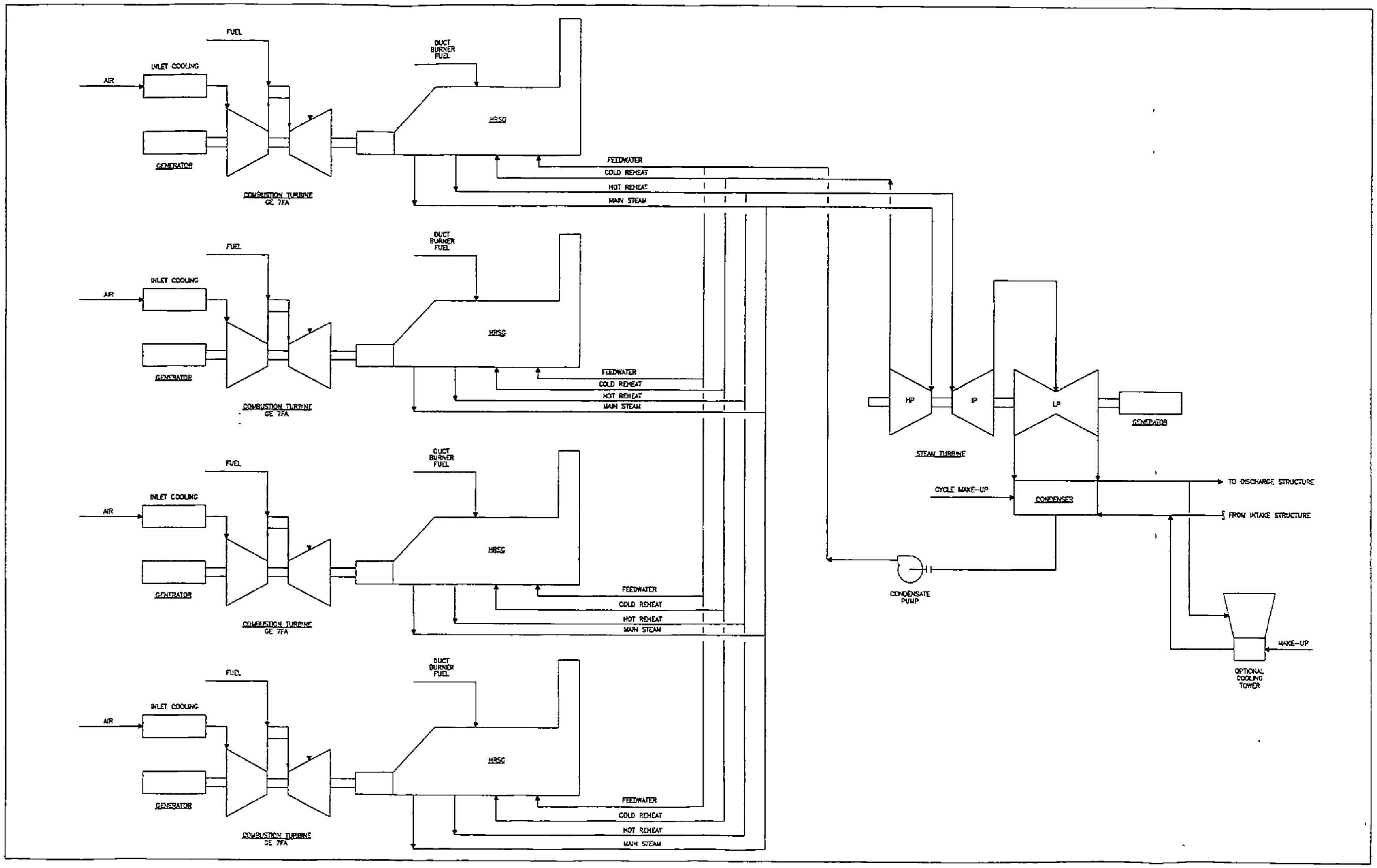
III. DESCRIPTIONS OF THE PROPOSED POWER PLANTS

FPL seeks a determination of need for a conversion of two existing CTs located at its Martin plant site into a four on one (4x1) CC unit, Martin Unit 8. This will increase the existing summer net capacity from 318 MW for the existing CT units to 1,107 MW for the converted CC unit, an incremental gain of 789 MW. FPL plans to have this unit in service by June 2005. FPL also seeks a determination of need for a new 1,107 MW 4x1 CC unit at its Manatee plant site, Manatee Unit 3. This unit is also scheduled to be in service in June 2005.

Martin Unit 8 and Manatee Unit 3 will be very similar CC units. As depicted in Figure III.1, each unit will utilize four CTs, four heat recovery steam generators (HRSGs), and a steam driven turbine generator. The CTs compress outside air into a combustion area where fuel, typically natural gas or light oil, is burned. The hot gases from the burning fuel-air mixture drive a turbine, which, in turn, directly rotates a generator to produce electricity. The exhaust gas produced by each turbine, with temperatures on the order of 1,100°F, then passes through a HRSG before exiting the stack at approximately 200°F.[6] The energy extracted by each HRSG produces steam, which is used to drive a steam turbine generator (STG). The CT/HRSG combination is called a "train." The number of CT/HRSG trains used dictates the size of the STG. For both Martin Unit 8 and Manatee Unit 3, four CT/HRSG trains will be connected to one STG, hence the terminology "four on one" (4x1) CC plant.

[6] Both the Martin Unit 8 and Manatee Unit 3 employ four HRSGs, one for each CT.

FIGURE III.1
DIAGRAM OF THE CC UNIT DEPICTING THE FOUR CTS AND
A STEAM DRIVEN TURBINE GENERATOR



The utilization of waste heat from the CTs provides an overall plant efficiency that is much better than that of the CTs alone or of a conventional steam-electric generating facility. In general, CC plants of this design can be expected to achieve fuel conversion rates of less than 7,000 Btu/kWh, which compares favorably to values on the order of 10,000 Btu/kWh for conventional steam-electric generating units, and results in a fuel savings of about 30 percent. FPL anticipates that the new Martin and Manatee combined cycle units will achieve a highly-efficient average base heat rate of 6,850 Btu/kWh (75°F).

Each of the proposed CC units will use General Electric (GE) 7-FA series advanced CTs.[7] In simple cycle mode, each of these turbines is peak-rated at 159 MW in summer. At the Martin site, there are already two such turbines installed and in-service. To convert the existing CTs into the proposed 4x1 CC unit, two new CTs will be added to the site, as well as four HRSGs, a steam turbine generator, and the balance of plant equipment. At the Manatee site, the same 4x1 configuration will be employed, with the primary difference being that all four CTs will be new to the site. Accordingly, the project planning, detailed design, procurement, construction, commissioning, and O & M will involve similar unit configuration, which should result in savings to FPL.

Both Martin Unit 8 and Manatee Unit 3 will have an approximate summer rating of 1,107 MW, based on ambient conditions of 95°F. The approximate winter rating (at

[7] The term "advanced CTs" refers to the fact that the GE F series CTs are designed to operate at a higher firing temperature than conventional CTs, which results in higher efficiency.

35°F) is 1,197 MW. Actual summer and winter ratings may vary, based upon final design and the results of performance testing.

The specific configuration and projected costs of Martin Unit 8 and Manatee Unit 3 are described below. This information reflects preliminary design specifications prepared solely for use in developing a cost estimate for licensing. Detailed engineering has not yet been completed for either project.

A. Martin Expansion Project

1. Overview

The Martin Plant was originally constructed in the mid-to-late 1970s with commercial in-service dates for steam Units 1 and 2 in December 1980 and June 1981, respectively. Combined cycle (CC) Units 3 and 4 were constructed in the early 1990s with commercial in-service dates of February and April 1994, respectively. The commercial in-service date for CT Units 8A and 8B was June 2001. The projected 2002 peak summer capacities of the existing units are as follows:

- Unit 1 – 814 MW
  Steam electric generating unit firing residual oil and natural gas
- Unit 2 – 799 MW
  Steam electric generating unit firing residual oil and natural gas
- Unit 3 – 467 MW
  CC generating unit firing natural gas with light oil capability
- Unit 4 – 468 MW
  CC generating unit firing natural gas with light oil capability
- Unit 8A – 159 MW
  Simple cycle generating unit firing natural gas with light oil capability
- Unit 8B – 159 MW
  Simple cycle generating unit firing natural gas with light oil capability

The Martin Plant site currently has a total summer net peak generating capability of approximately 2,866 MW. The site includes a 6,800-acre cooling pond that serves Units 1, 2, 3, and 4.

The Martin Plant site has long been identified as a possible site for additional generating capacity. It has continued to be identified as a preferred location for additional generating capacity in each of FPL's Ten Year Power Plant Site Plans for the past decade. It was also recognized as suitable for future capacity expansions by the Governor and Cabinet, acting as the Siting Board, in the 1991 certification of Martin Units 3 and 4.

The Martin Plant site is located on 11,300 acres in Martin County, east of Lake Okeechobee and northwest of the city of Indiantown. A map of the Plant site and the surrounding area is shown on Figure III.A.1.1. Figure III.A.1.2 is an aerial photograph of the existing generating units with the project area boundary superimposed. The project area within the Martin Plant site is approximately 110 acres, with temporary and permanent project facilities occupying roughly 44 of those acres. The project area is located south of Units 3 and 4, and the new CTs will be located adjacent to the existing CTs. Figure III.A.1.3 is a drawing or footprint of the proposed Martin Unit 8.

FIGURE III.A.1.1
MAP OF MARTIN PLANT SITE AND SURROUNDING AREA

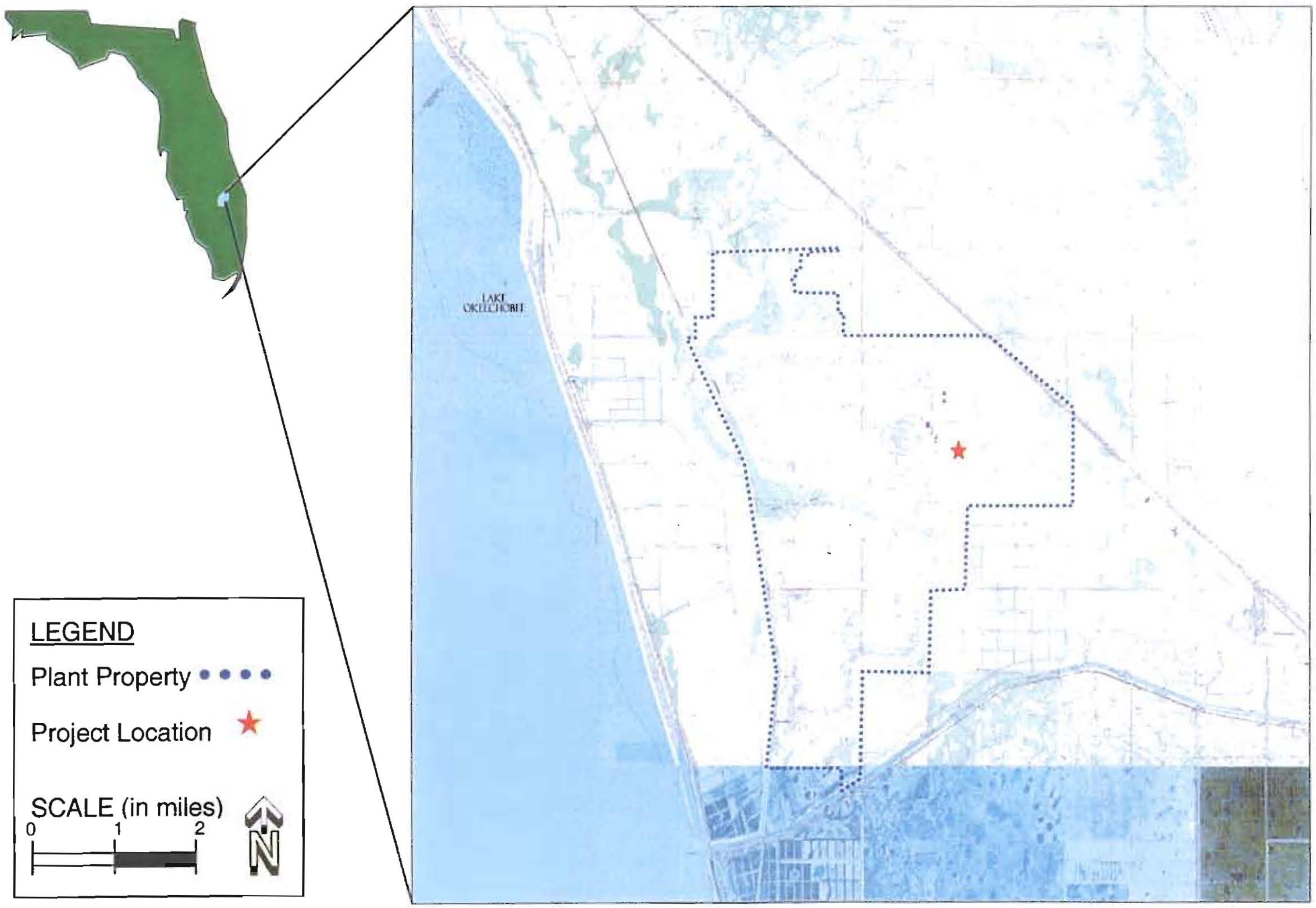
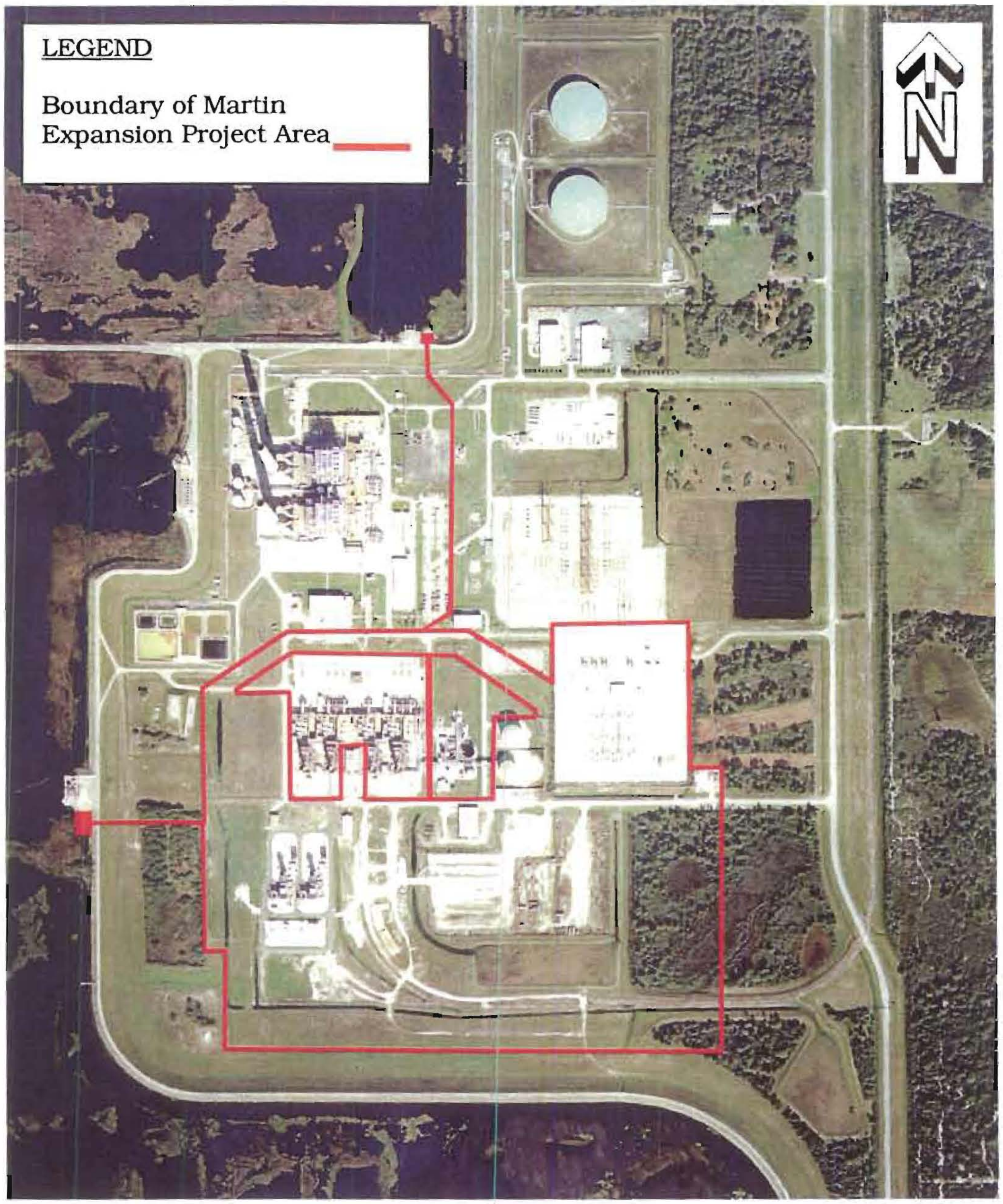
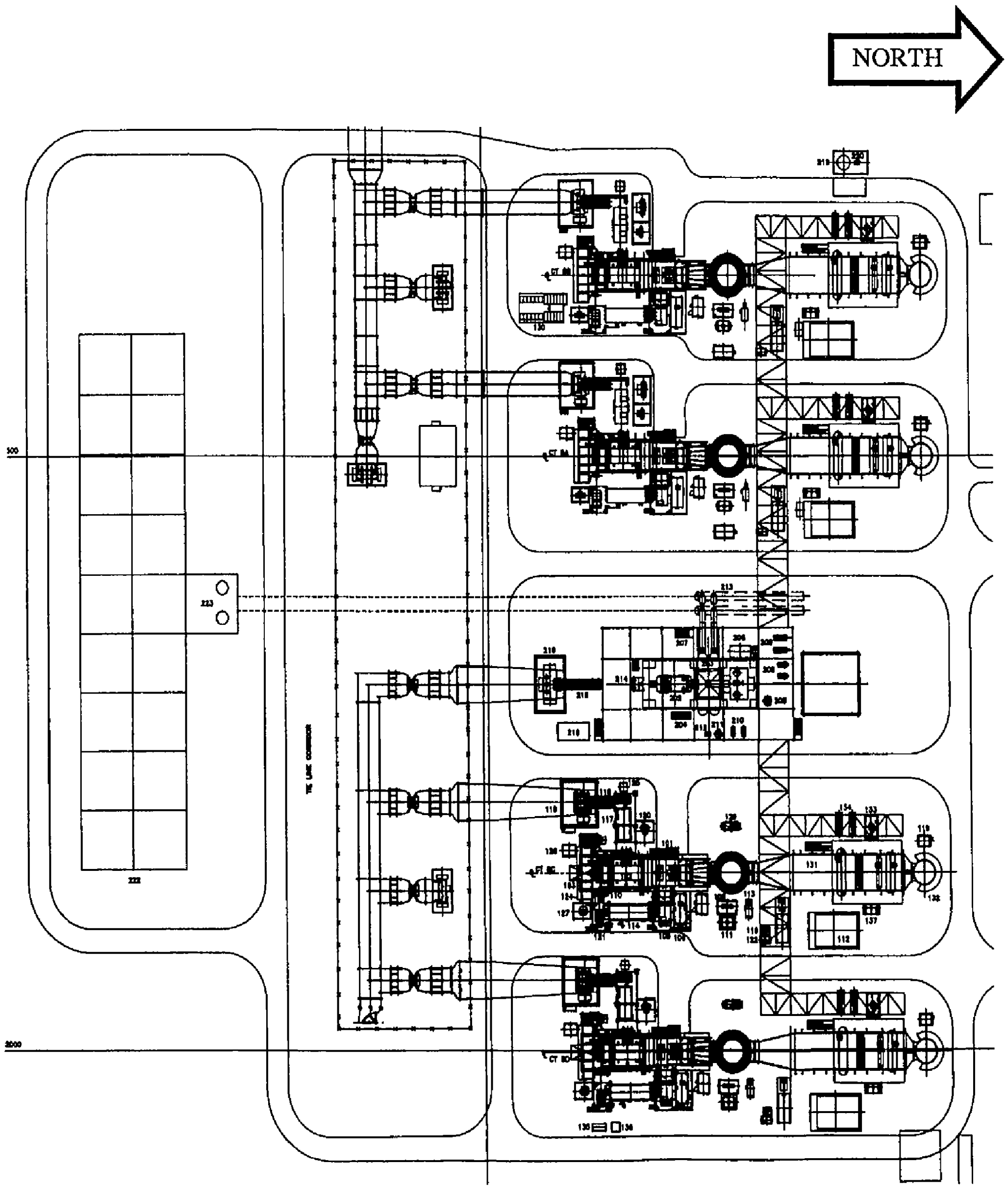


FIGURE III.A.1.2
AERIAL PHOTOGRAPH OF MARTIN PLANT DEPICTING THE PROJECT BOUNDARY



FPL
Martin Unit 8

FIGURE III.A.1.3
FOOTPRINT OR DRAWING OF PROPOSED MARTIN UNIT 8



FPL

Martin Unit 8

The entire project area is within the existing certified portion of the site. Existing Units 1-4 will remain in operation and will not be impacted by the project.

The project will utilize a number of existing facilities, increasing the generating capacity of the site without increasing its overall size. The location of the new Unit 8 at the existing Martin Plant site and the selection of the CC technology will maximize the beneficial use of the site while minimizing environmental, land use, and cost impacts typically associated with development of a nominal 1,107-MW power plant.

2. Martin Unit 8 Design

Martin Unit 8 will be a 4x1 CC unit consisting of four nominal 159-MW GE Frame 7 "F" Class advanced CTs, with dry low nitrogen oxide (NO_x) combustors and four HRSGs, which will utilize the waste heat from the CTs to produce steam and power a new steam turbine generator. Two CTs are currently operational on-site (Martin Units 8A and 8B) and will be integrated into the new Unit 8.

Each CT unit will utilize a type of inlet air evaporative cooling commonly referred to as "fogging". Fogging creates a cooler, more moisture-laden air stream, which allows power to be produced more efficiently and with lower emissions per MWh generated. For the GE Frame 7FA CT, an 8°F average decrease in temperature would result in an expected 3.0 percent increase in power and an expected 1.2 percent decrease in heat rate. The inlet foggers would normally be utilized when the ambient air temperature is greater than 60°F. Since the average annual temperature for the Martin site is approximately 75°F, the output and heat rate benefits associated with fogging are included in the base heat rate of 6,850 Btu/kWh (100% load @75°F) and the "base operation" summer capacity rating of 984 MW.

Duct burners are also proposed for each HRSG. The duct burners are used during peak demand periods to add an additional 96 MW of summer capacity to the unit at an incremental heat rate of 8,770 Btu/kWh (95°F).

An additional 27 MW of output also can be achieved by raising the fuel flow to the CT for "peak firing mode" operation. Peak firing reduces the heat rate of the entire unit, and the expected incremental heat rate for peak firing is 5,600 Btu/kWh (95°F). However, peak firing will shorten the normal replacement period for some CT components, so it will normally be reserved for peak need periods and not routinely dispatched ahead of duct firing.

The 984 MW of base operation, 96 MW of duct burner operation, and 27 MW of peak firing operation sum to a total unit summer capability of 1,107 MW. This results in a net summer increase for FPL of 789 MW after accounting for the 318 MW already supplied by the two existing CT's at Martin.

The CTs will use natural gas as the primary fuel, with light oil used as an alternative fuel for an equivalent of up to 500 hours/year per CT at baseload conditions. The HRSG duct burners will fire natural gas only.

Gas will be transported to the Martin Expansion Project through an existing or new pipeline. Two pipe lines currently service the Martin site. One serves as an oil and gas transport pipeline for the existing Martin Units 1 & 2. This dual-service pipeline is not utilized for gas transport to the existing Martin Units 3 & 4, nor would it be for the new Unit 8, due to potential fuel contamination issues caused by oil residue in the pipeline. The other existing natural gas pipeline is not adequate to supply the entire demands of Martin Units 3, 4 *and* 8; therefore, the addition of compression to this existing pipeline or the construction of an additional lateral will be required to ensure sufficient supply of natural gas to the Martin site during peak periods. Potential gas suppliers, such as Gulfstream and FGT, among others, would independently undertake the necessary permitting and construction activities for this new lateral.

Because the Martin site has the infrastructure to store and manage light oil, and given that the existing simple-cycle CTs (which are to be integrated into the 4x1 CC unit) already are configured to utilize light oil, Martin Unit 8 will be designed to use light oil as an alternative fuel for an equivalent of up to 500 hours/year per CT at baseload conditions. Light oil will be trucked to the site and stored in an existing 2 million-gallon tank and also in a new 2-million-gallon tank.

3. Environmental Controls

The use of clean fuels and combustion controls will minimize air emissions from Unit 8 and ensure compliance with applicable emission-limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO_2), particulate matter and other fuel-bound contaminants. Combustion controls similarly minimize the formation of nitrogen oxides (NO_x), and the combustor design will limit the formation of carbon monoxide and volatile organic compounds. When firing natural gas, NO_x emissions will be controlled using dry-low NO_x (DLN) combustion technology and selective catalytic reduction (SCR). Water injection and SCR will be used to reduce NO_x emissions during CC operation when firing light oil. These design alternatives constitute the Best Available Control Technology for air emissions and minimize such emissions while balancing economic, environmental, and energy impacts. Taken together, the design of Martin Unit 8 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

Primary water uses for Martin Unit 8 will be for condenser cooling, CT inlet foggers, steam cycle makeup and service water. Water also will be used on a limited basis for NO_x control when firing light oil. Condenser cooling for the steam cycle portion of Unit 8 will be accomplished with water from the existing cooling pond. Service and process water for the unit also will come from the cooling pond. Make up water to the pond will continue to come from the St. Lucie

Canal in accordance with the current South Florida Water Management District (SFWMD) consumptive use allocation for the site.

The facility has been designed to minimize direct discharge of process wastewater to offsite surface waters. Non-contact stormwater runoff will be collected and routed to a stormwater detention pond, which has been designed to meet SFWMD requirements. All process wastewaters, including process water pretreatment backwash, plant and equipment drains, and neutralization unit effluent, will be treated as appropriate and recycled to the existing cooling pond.

4. Transmission Interconnection

The project will connect to the existing onsite system substation via a new tie line. Additional bays will be added to the existing system substation to accommodate the new interconnection to FPL's electric transmission system.

5. Transmission Integration

The transmission integration study performed to identify the facilities necessary to integrate Manatee Unit 3 and Martin Unit 8 was performed on a plan basis. Consequently, the resulting facilities and costs are not separated for each resource. The transmission facilities necessary for the integration include two new transmission lines on the east coast, a 230 kV line from the Martin substation to the Indiantown substation and another 230 kV line from the Indiantown substation to the Bridge substation. The estimated direct cost for these new lines is $20.6 million. In addition, five existing lines will need to be upgraded at an estimated direct cost of $1.5 million. Four of these lines are on the west coast: the 230 kV line from the Charlotte substation to the Calusa substation, the 230 kV line from the Manatee substation to the Johnson substation, the 230 kV line from the Manatee substation to the Ringling substation, and the 230 kV line from the Charlotte substation to the Ft. Myers substation. One line is on the east coast, the 230 kV line from the Ranch substation to the Homeland substation. The total direct cost estimated for all the transmission integration facilities necessary for the Martin Unit 8 / Manatee Unit 3 plan is $22.1 million in 2002 dollars.

6. Construction Schedule

A summary of construction milestone dates is shown on table III.A.6.1. FPL will begin construction upon receipt of the necessary federal and state certifications and permits. Based on FPL's experience constructing Martin Units 3 & 4 and the rate of progress with its current construction projects at the Fort Myers and Sanford plants, the expected construction duration for the Martin Unit 8 project is 24 months. Therefore to meet a planned in-service date of June 2005, FPL must begin construction on or before June 1, 2003.

Table III.A.6.1
MARTIN UNIT 8
EXPECTED CONSTRUCTION SCHEDULE

<table>
<tr><th></th><th>Begin</th><th>End</th></tr>
<tr><td>Initiate sequence of HRSG orders (LNTPx4)</td><td>Nov 02</td><td>Dec 02</td></tr>
<tr><td>Initiate sequence of combustion turbine order (LNTPx2)</td><td>Nov 02</td><td>Dec 02</td></tr>
<tr><td>Issue LNTP for steam turbine</td><td></td><td>Nov 02</td></tr>
<tr><td>Receive approvals necessary to begin construction</td><td></td><td>May 03</td></tr>
<tr><td>Site Prep & Foundations</td><td>Jun 03</td><td>Jan 04</td></tr>
<tr><td>Balance of Plant</td><td>Aug 03</td><td rowspan="4">Dec 04</td></tr>
<tr><td>Erect HRSGs</td><td>Feb 04</td></tr>
<tr><td>Erect CTs</td><td>Apr 04</td></tr>
<tr><td>Erect steam turbine</td><td>Apr 04</td></tr>
<tr><td>Startup</td><td>Jan 05</td><td>May 05</td></tr>
<tr><td>Commercial operation</td><td></td><td>Jun 05</td></tr>
</table>

7. Estimated Capital Cost

The estimated total direct cost for Martin Unit 8 is $439 million (2005 dollars) exclusive of transmission integration. This cost estimate was used in FPL's comparative economic analysis, and it includes $389 million for the power block, $7 million for the transmission interconnection, and $43 million in allowance for funds used during construction (AFUDC). The components of this total plant cost are shown in Table III.A.7.1.

Table III.A.7.1
MARTIN UNIT 8
PLANT COST COMPONENTS
(2005 $ MILLION)

Power Block	$389
Transmission Interconnect	$7
AFUDC	$43
Total Plant Cost	$439

In addition to these costs, there will be transmission integration costs, but the estimate for those costs was performed on a plan basis with Manatee Unit 3 as previously discussed in section III.A.5. (A cumulative present value of revenue requirements total of $28 million in 2001 dollars was calculated for the transmission integration costs.)

B. Manatee Expansion Project

1. Overview

The Manatee Plant is an existing generating facility originally constructed in the mid-1970s, with the commercial in-service dates for steam Units 1 and 2 in October 1976 and December 1977, respectively. The peak summer capacity of the existing units are as follows:

- Unit 1 – 809 MW
  Steam electric generating unit firing residual oil
- Unit 2 – 810 MW
  Steam electric generating unit firing residual oil

The Manatee Plant site currently has a total peak summer net generating capability of approximately 1,619 MW. The site includes a 4,000-acre cooling pond that serves Units 1 and 2.

The location of the new Manatee Unit 3 at the existing Manatee Plant site, and the selection of the CC technology, will maximize the beneficial use of the site while minimizing environmental, land use, and cost impacts typically associated with development of a nominal 1,107 MW power plant. Manatee Unit 3 will utilize a number of existing facilities, while increasing the generating capacity of the site without increasing its overall size.

The Manatee Plant site is located on 9,500 acres in Manatee County, east of Parrish, Florida. A map of the Plant site and the surrounding area is shown on Figure III.B.1.1, and Figure III.B.1.2 is an aerial photograph of the existing generating units with the project area boundary superimposed. The project area within the Manatee Plant site is approximately 73 acres. Figure III.B.1.3 is a drawing or footprint of the proposed Manatee Unit 3.

The new CTs and associated HRSGs will be located in an area that has already been affected by existing uses at the plant. Existing Unit 1 and 2 will remain in operation and will not be impacted by the project.

FIGURE III.B.1.1
MAP OF MANATEE PLANT SITE AND SURROUNDING AREA

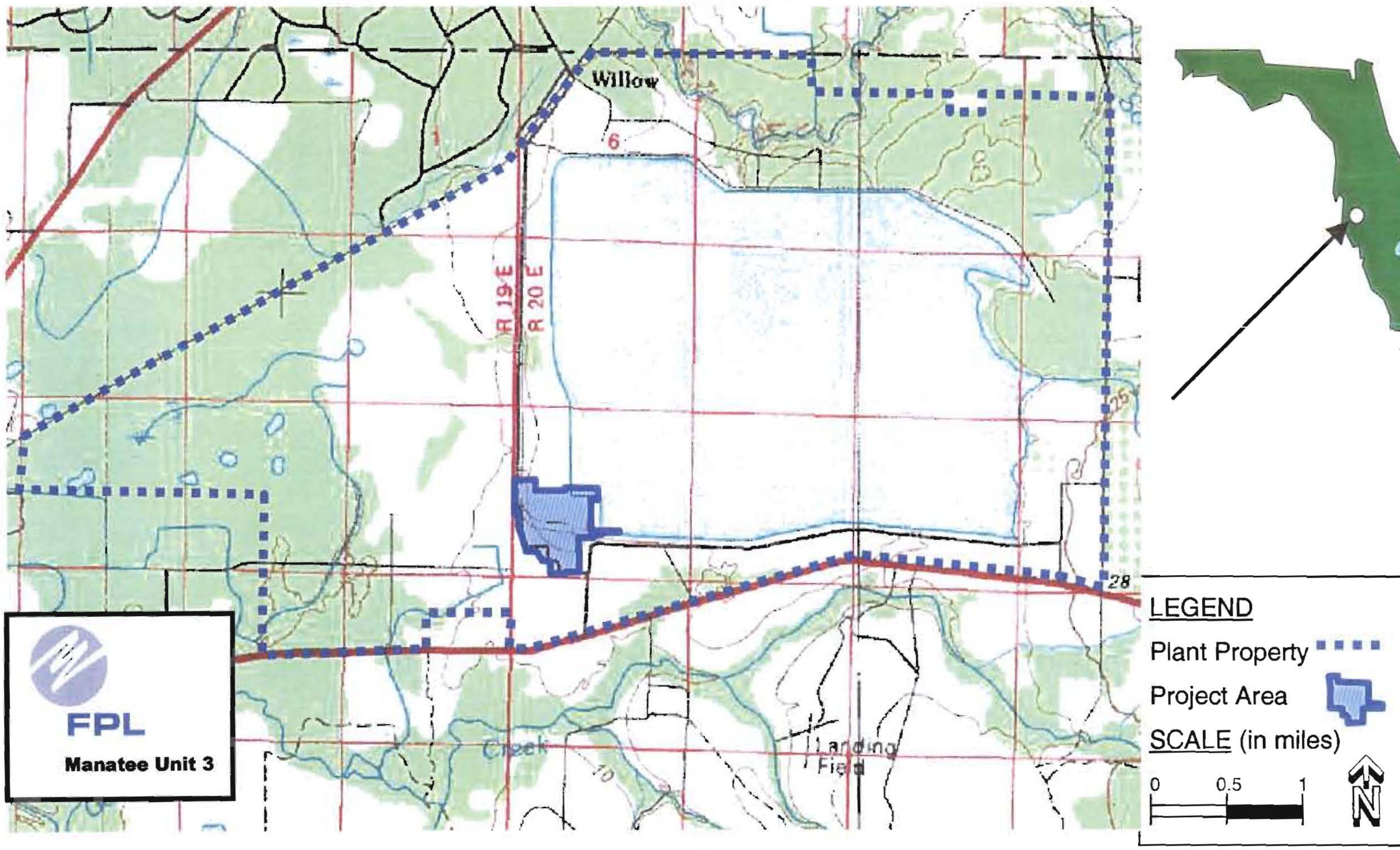
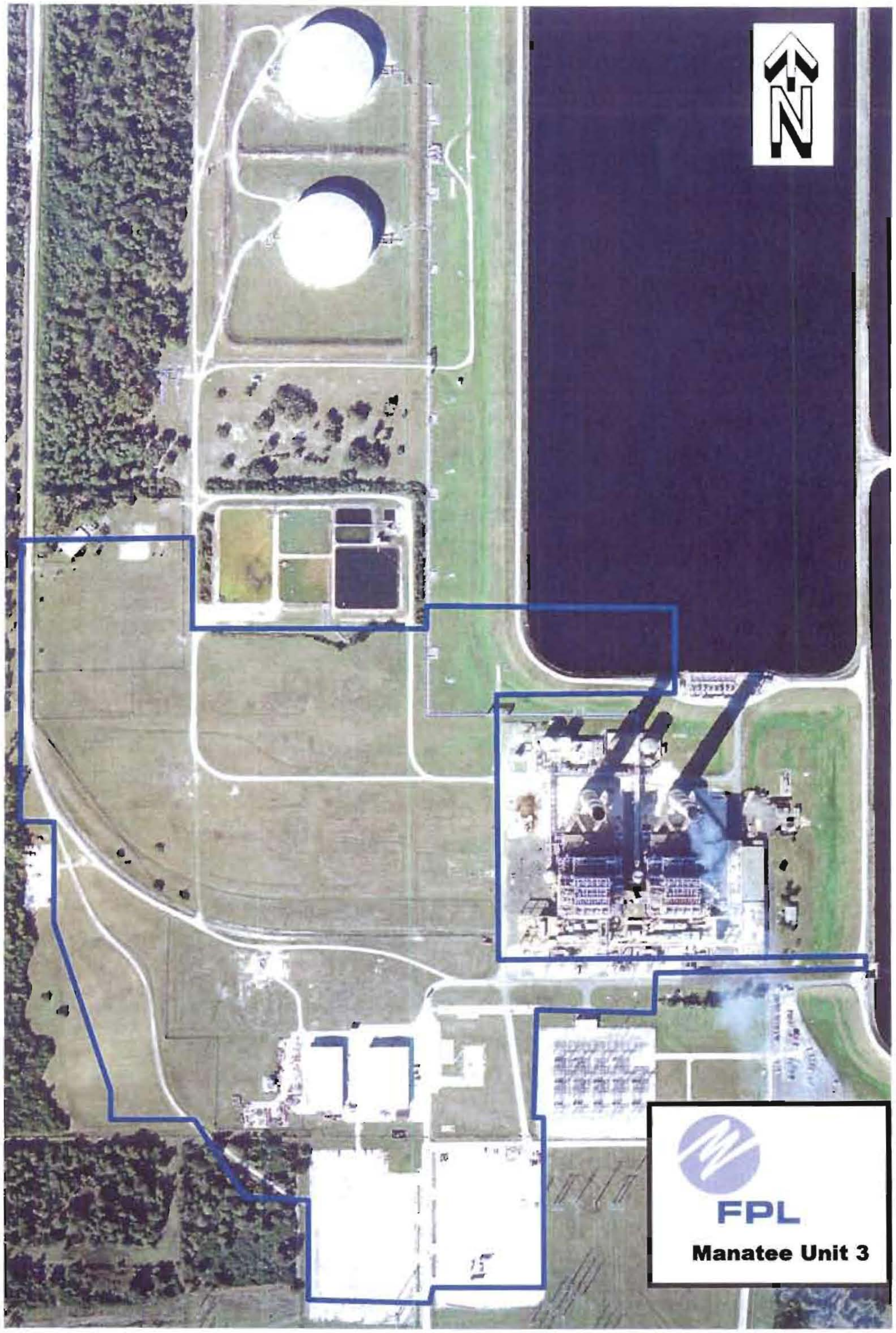
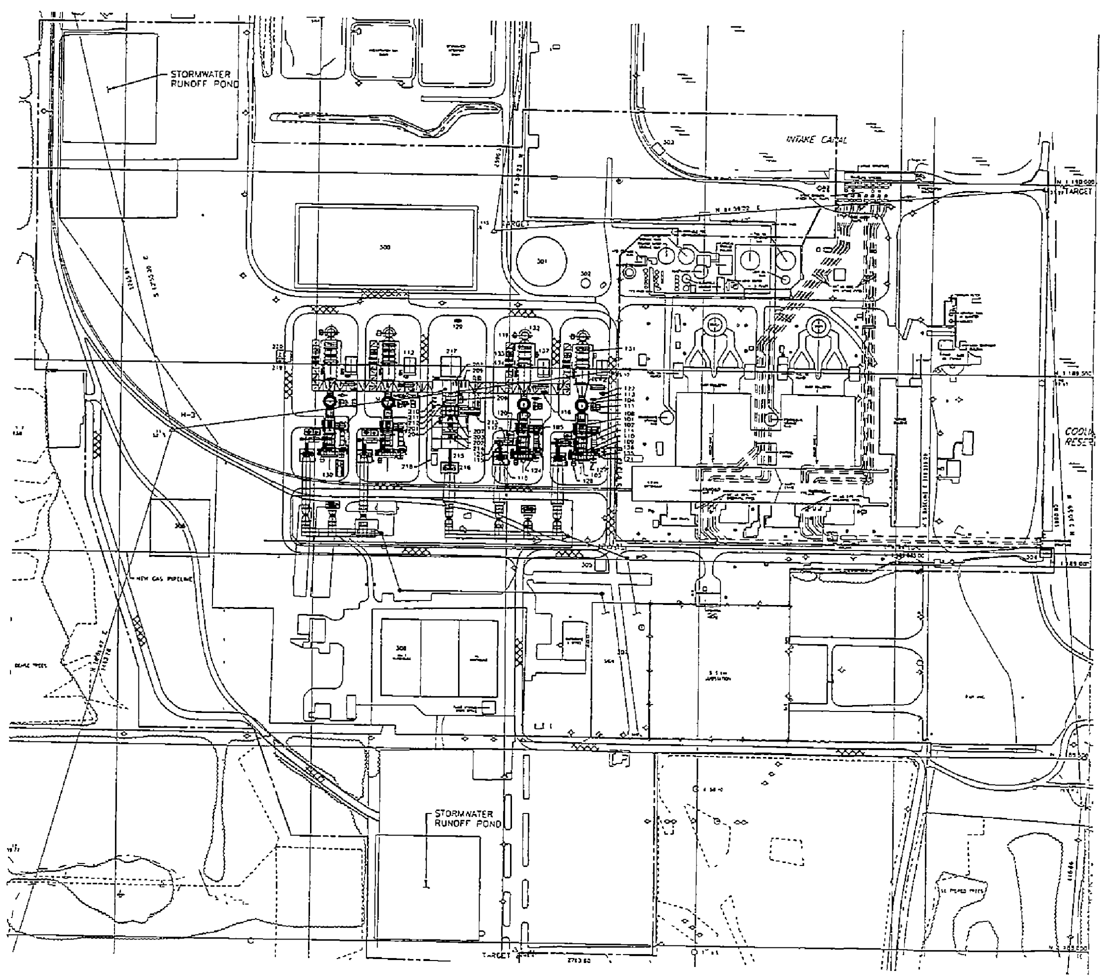


FIGURE III.B.1.2
AERIAL PHOTOGRAPH OF MANATEE PLANT DEPICTING THE PROJECT BOUNDARY



Boundary of Manatee Expansion Project Area

FIGURE III.B.1.3
FOOTPRINT OR DRAWING OF PROPOSED
MANATEE UNIT 3



FPL
Manatee Unit 3

2. Manatee Unit 3 Design

Manatee Unit 3 will be a 4x1 CC unit consisting of four nominal 159-MW GE Frame 7 "F" Class advanced CTs, with dry low NOx combustors and four HRSGs, which will utilize the waste heat from the CTs to produce steam and power a new steam turbine generator. Similar to the proposed Martin Unit 8, Manatee Unit 3 will utilize an inlet fogging system for each of the CTs, and each HRSG will have duct burners. Based on the average annual temperature for the Manatee site, the output and the heat rate benefits associated with fogger operation are included in the net summer "base" rating of 984 MW and base heat rate of 6,850 Btu/kWh (75°F). The duct burners can be fired during peak demand to add an additional 96 MW of capacity to the base unit at an incremental heat rate of 8,770 Btu/kWh (95°F).

An additional 27 MW can also be achieved by raising the fuel flow to the CT for "peak firing mode" operation. Peak firing reduces the heat rate of the entire unit and the expected incremental heat rate for peak firing is 5,600 Btu/kWh (95°F). However, peak firing will shorten the normal replacement period for some CT components, so it will normally be reserved for peak need periods and not routinely dispatched ahead of duct firing.

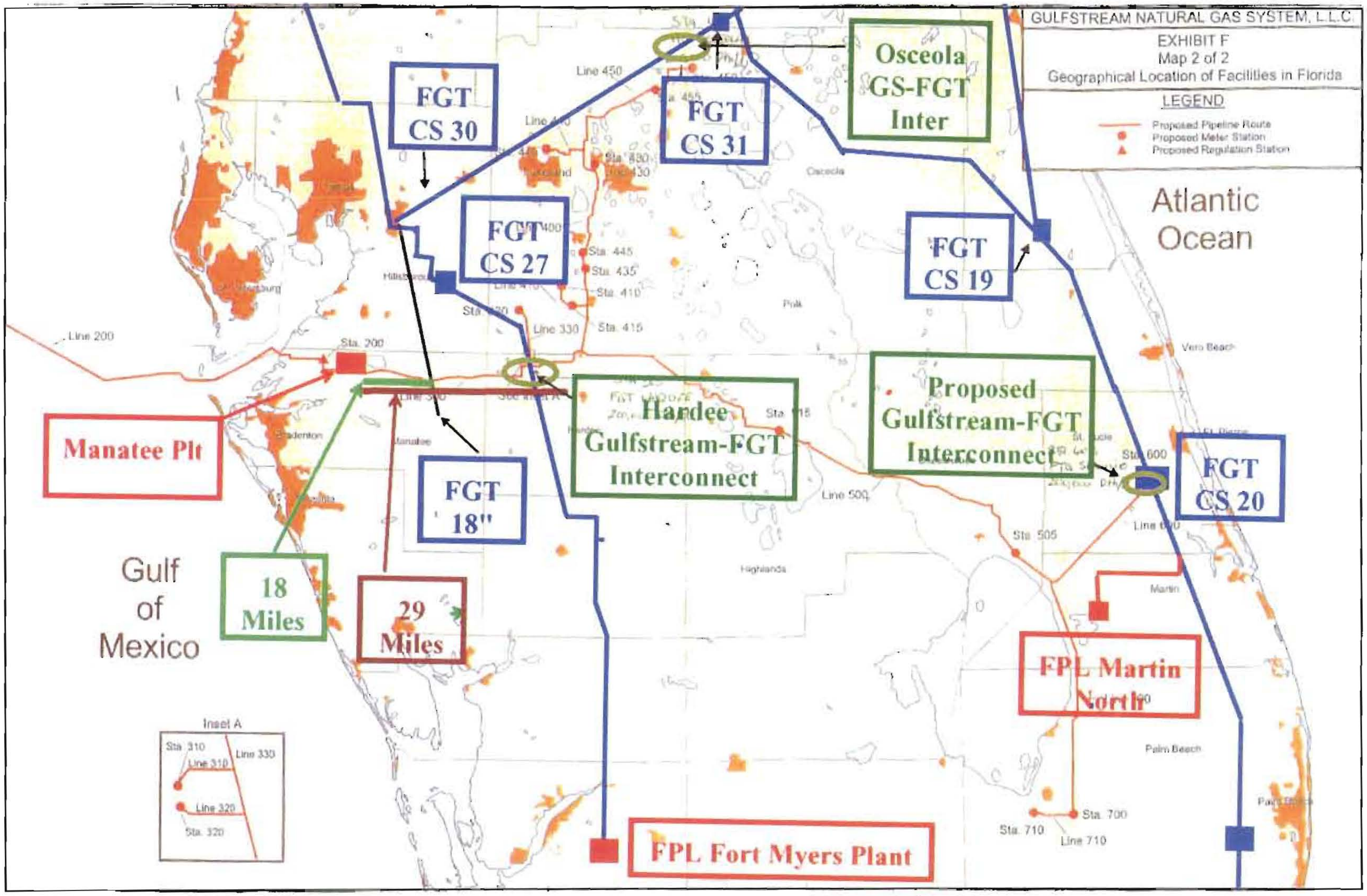
The 984 MW of base operation, 96 MW of duct burner operation, and 27 MW of peak firing operation sum to a total unit summer capability of 1,107 MW.

Unlike Martin Unit 8, Manatee Unit 3 will not have dual-fuel capability. However as discussed below, it will have the capability of securing natural gas from multiple sources, which will greatly increase the reliability of its fuel supply. The added reliability of dual natural gas suppliers and multiple pipelines in the Manatee area reduces the importance of having an alternative fuel source for this unit.

The CTs and HRSG duct burners will fire natural gas that will be transported to Manatee Unit 3 through a pipeline. FPL has an agreement with Gulfstream to supply natural gas for the existing Manatee Plant Units 1 and 2, and a new lateral from the Gulfstream mainline into the Manatee site is planned for that purpose. Natural gas for Manatee Unit 3 may be supplied by this new lateral or from another gas supplier. Gulfstream will soon have two interconnections with the Florida Gas Transmission (FGT) Pipeline System. These two interconnections, under normal conditions, will flow natural gas from the Gulfstream system into FGT. However when necessary, the flow from these two interconnections can be reversed, and natural gas can flow from the FGT system into the Gulfstream system. With the Hardee County interconnect only 29 miles from the Manatee plant, FPL will have the capability to receive natural gas from FGT, from either the Hardee County or Osceola County interconnect, should the Gulfstream system not be able to receive natural gas from its source into Florida. The gas pipeline interconnections are depicted in Figure III.B.2.1. No on-site fuel storage will be provided.

FIGURE III.B.2.1

DIAGRAM OF PIPELINE SERVICE TO MANATEE



3. Environmental Controls

As with Martin Unit 8, the use of clean fuels and combustion controls will minimize air emissions and ensure compliance with applicable emission limiting standards. Using clean fuels will limit SO2 and emissions, and combustion controls will minimize NOx, CO, and VOC emission. Also, like the Martin unit, the Manatee Unit 3 HRSGs will have a SCR system for control of NOx emissions.

Primary water uses for Manatee Unit 3 will be for condenser cooling, CT inlet foggers, steam cycle makeup, and service water. The water supply for the Manatee project will also be similar to the Martin project in that water will be obtained from an existing 4,000-acre cooling pond. With make up water provided from the Little Manatee River, this cooling pond will continue to be the source of cooling, service, and process water for the Manatee Plant after the addition of Unit 3. Total consumptive water use for the Manatee Plant site will continue to be within the amounts currently allocated by the Southwest Florida Water Management District (SWFWMD).

The facility has been designed to minimize direct discharge of process wastewater to offsite surface waters. Non-contact stormwater runoff will be collected and routed to a stormwater detention pond that is designed to meet or exceed all applicable requirements. All process wastewaters, including process water pretreatment backwash, plant and equipment drains, and neutralization unit effluent, will be treated as appropriate and recycled to the existing cooling pond.

4. Transmission Interconnection

The project will connect to the existing onsite system substation via a new tie line. The existing onsite system substation will be expanded to accommodate the new interconnection to FPL's electric transmission system. The estimated cost of transmission interconnection for Manatee Unit 3 is $10 million (2005 dollars).

5. Transmission Integration

The transmission integration study performed to identify the facilities necessary to integrate Manatee Unit 3 and Martin Unit 8 was performed on a plan basis. Consequently, the resulting facilities and costs are not separated for each resource. The transmission facilities necessary for the integration include two new transmission lines on the east coast, a 230 kV line from the Martin substation to the Indiantown substation and another 230 kV line from the Indiantown substation to the Bridge substation. The estimated direct cost for these new lines is $20.6 million. In addition, five existing lines will need to be upgraded at an estimated direct cost of $1.5 million. Four of these lines are on the west coast: the 230 kV line from the Charlotte substation to the Calusa substation, the 230 kV line from the Manatee substation to the Johnson substation, the 230 kV line from the Manatee substation to the Ringling substation, and the 230 kV line from the Charlotte substation to the Ft. Myers substation. One line is on the east coast, the 230 kV line from the Ranch substation to the Homeland substation. The total direct cost estimated for all the transmission integration facilities necessary for the Martin Unit 8 / Manatee Unit 3 plan is $22.1 million in 2002 dollars.

6. Construction Schedule

Manatee Unit 3 will be a sister to Martin Unit 8, so the expected construction duration will also be 24 months. To meet the planned in-service date of June 2005, FPL must commence construction on or before June 1, 2003. A summary of the construction milestone dates is shown on Table III.B.6.1.

TABLE III.B.6.1
MANATEE UNIT 3
EXPECTED CONSTRUCTION SCHEDULE

<table>
<tr><th></th><th>Begin</th><th>End</th></tr>
<tr><td>Initiate sequence of HRSG orders (LNTP x 4)</td><td>Nov 02</td><td>Dec 02</td></tr>
<tr><td>Initiate sequence of combustion turbine orders (LNTP x 4)</td><td>Nov 02</td><td>Dec 02</td></tr>
<tr><td>Issue LNTP for steam turbine</td><td></td><td>Nov 02</td></tr>
<tr><td>Receive approvals necessary to begin construction</td><td></td><td>May 03</td></tr>
<tr><td>Site Prep & Foundations</td><td>Jun 03</td><td>Jan 04</td></tr>
<tr><td>Balance of Plant</td><td>Aug 03</td><td rowspan="4">Dec 04</td></tr>
<tr><td>Erect HRSGs</td><td>Feb 04</td></tr>
<tr><td>Erect CTs</td><td>Apr 04</td></tr>
<tr><td>Erect steam turbine</td><td>Apr 04</td></tr>
<tr><td>Startup</td><td>Jan 05</td><td>May 05</td></tr>
<tr><td>Commercial operation</td><td></td><td>Jun 05</td></tr>
</table>

7. Estimated Capital Cost

The estimated total installed cost for Manatee Unit 3 is $551 million (2005 dollars), exclusive of transmission integration. This cost estimate was used in FPL's comparative economic analysis, and it includes $482 million for the power block, $10 million for the transmission interconnection, and $59 million in AFUDC. The components of this total plant cost are shown in Table III.B.7.1.

TABLE III.B.7.1
MANATEE UNIT 3
PLANT COST COMPONENTS
(2005 $ MILLION)

Power Block	$482
Transmission Interconnect	$10
AFUDC (Excluding Transmission Integration)	$59
Total Plant Cost	$551

In addition to these costs, there will be transmission integration costs and associated AFUDC, but the estimate for these costs was developed on a plan basis with Martin Unit 8 as previously discussed in section III.A.5. (A cumulative present value of revenue requirements total of $28 million in 2001 dollars was calculated for the transmission integration costs.)

C. Summary of Self-Build Options

A summary of the various self-build characteristics and linear facilities for Martin Unit 8 and Manatee Unit 3 is shown in Figures III.C.1 and III.C.2, respectively.

FIGURE III.C.1
MARTIN UNIT 8
FACT SHEET

Generation Technology - "Four on One" (4x1) Combined Cycle Configuration:

- Four (4) → GE 7FA Combustion Turbines w/ Inlet Foggers (Two currently on-site operating in simple-cycle mode)
- Four (4) → Heat Recovery Steam Generators with Duct Burners and Selective Catalytic Reduction System for NO_x Control
- One (1) → Single-Reheat Steam Turbine

Expected Plant Peak Capacity:

Summer (95°F / 50% RH)	1,107 MW
Winter (35°F / 60% RH)	1,197 MW

Projected Unit Performance Data:

Average Forced Outage Rate (EFOR)	1%
Average Scheduled Maintenance Outages	1 wk/yr (2% POF)
Average Equivalent Availability Factor (EAF)	97%
Base Average Net Operating Heat Rate @ 75°F / 60% RH	6,850 Btu/kWh (HHV)
Annual Fixed O&M – incremental (2001 dollars)	$1.87/kW-yr
Variable O&M – excluding fuel (2001 dollars)	$0.037/MWh

Fuel Type and Base Load Typical Usage @ 75°F:

Primary Fuel	Natural Gas
Natural Gas Consumption	6,580,000 scf/hr
Alternate Fuel	Low Sulfur Light Oil
Light Oil Consumption	60,000 gal/hr

Expected Base Load Air Emissions Per Train @ 75°F:	**Natural Gas**	**Light Oil**
NO_x (@ 15% O_2)	2.5 ppmvd	12 ppmvd
CO	9 ppmvd	20 ppmvd
PM_{10}	10.9 lb/hr	36.2 lb/hr
SO_2	9.4 lb/hr	94.9 lb/hr

Water Balance:

- Total site consumptive use will continue to be within current SFWMD annual allocation
- Process wastewater recycled to cooling pond

Linear Facilities:

- Two (2) FGT gas laterals currently supply Martin site; possibility of contracting with another transporter
- No light oil pipeline – light oil delivered to site by truck

FIGURE III.C.2
MANATEE UNIT 3
FACT SHEET

Generation Technology - "Four on One" (4x1) Combined Cycle Configuration:

- Four (4) → GE 7FA Combustion Turbines w/ Inlet Foggers
- Four (4) → Heat Recovery Steam Generators with Duct Burners and Selective Catalytic Reduction System for NO_x Control
- One (1) → Single-Reheat Steam Turbine

Expected Plant Peak Capacity:

Summer (95°F / 50% RH)	1,107 MW
Winter (35°F / 60% RH)	1,197 MW

Projected Unit Performance Data:

Average Forced Outage Rate (EFOR)	1%
Average Scheduled Maintenance Outages	1 wk/yr (2% POF)
Average Equivalent Availability Factor (EAF)	97%
Base Average Net Operating Heat Rate @ 75°F / 60% RH	6,850 Btu/kWh (HHV)
Annual Fixed O&M – incremental (2001 dollars)	\$2.71/kW-yr
Variable O&M – excluding fuel (2001 dollars)	\$0.037/MWh

Fuel Type and Base Load Typical Usage @ 75°F:

Fuel	Natural Gas
Natural Gas Consumption	6,580,000 scf/hr

Expected Base Load Air Emissions Per Train @ 75°F:

NO_x (@ 15% O_2)	2.5 ppmvd
CO	9 ppmvd
PM_{10}	10.9 lb/hr
SO_2	9.4 lb/hr

Water Balance:

- Total site consumptive use will be within amounts currently allocated by SWFWMD
- Process wastewater recycled to cooling pond

Linear Facilities:

- FPL has an agreement with Gulfstream Natural Gas Pipeline System (Gulfstream) to supply natural gas for the existing Manatee Plant Units 1 and 2, and a new lateral from the Gulfstream mainline into the Manatee site is planned for that purpose. Natural gas for Manatee Unit 3 may be supplied by this new lateral or from another gas supplier.

IV. FPL'S NEED FOR THE PROPOSED POWER PLANTS

FPL first determined in its 2000 integrated resource planning (IRP) work that it would need significant additional generating resources in 2005 and 2006 to meet its reserve margin criterion. This was confirmed by the reliability assessment portion of its 2001 IRP. The reliability assessment is designed to determine both the magnitude and timing of FPL's resource needs. It is a determination of how many megawatts of load reduction, new capacity, or a combination of both load reduction and new capacity is needed, and when these resources need to be available. Based on this analysis, FPL determined that it would need a minimum of 1,722 MW of additional resources to meet its reserve margin requirements in 2005 and 2006, with 1,122 MW needed by the summer of 2005 and the remaining 600 MW needed by the summer of 2006.

A. Reliability Assessment

In the reliability assessment portion of its 2001 IRP, FPL started with an updated load forecast and updated power plant capability and reliability data. In addition, the reliability assessment utilized supply-side inputs that accounted for near-term construction capacity additions and near-term firm capacity purchase additions. It also accounted for long-term DSM implementation.

1. Near-Term Capacity Additions

FPL included in its 2000 and 2001 reliability assessments FPL's near-term, previously committed capacity construction projects. These projects included the repowering of several existing units and the addition of several new CTs at existing FPL plant sites. FPL undertook in 1998 to repower both existing steam units at its Fort Myers plant site and two of the three existing steam units at its Sanford plant site. These two repowering efforts will add significant capacity to FPL's system and will greatly increase the efficiency of the capacity at those two sites, as well as overall system efficiency.

The repowered Fort Myers capacity comes in-service in the summer of 2002. Six new CTs, which were components of the repowering effort, began coming in-service at Fort Myers in late 2000 and through their initial operation in a stand-alone, simple-cycle mode have already increased FPL's system capacity.

A somewhat different repowering schedule was planned for the two Sanford units. Both of these were to be repowered without the CT components coming into stand-alone service during the process. Sanford Unit 5 came out-of-service in the Fall of 2001 and was projected to be fully repowered by the summer of 2002. Sanford Unit 4 was forecast to come out-of-service in early 2002 and was projected to return fully repowered at the end of 2002. (Its return to service is now scheduled for mid-2003.) FPL factored in the capacity additions resulting from the Fort Myers and Sanford repowerings in its 2001 IRP.

FPL also took into account its previously announced decision to add four new CTs in the 2001 through 2003 time frame. The first two CTs came in-service at

FPL's existing Martin site in mid - 2001. The second two are scheduled to be in-service in 2003 at FPL's existing Fort Myers site.

2. Near-Term Firm Capacity Purchases

In its 2001 reliability assessment, FPL recognized a decision made during FPL's 2000 IRP to secure certain firm capacity, short-term purchases from a combination of utility and non-utility generators. These firm capacity purchases are discussed in Section II.B.4 and presented in Table II.B.4.1.

3. Long-Term DSM

Since 1994 FPL's IRP has used the DSM MW called for in FPL's approved DSM Goals in its analyses. (The currently approved DSM Goals for FPL were discussed in Section II.B.3 and presented in Table II.B.3.1.) This was again the case in FPL's 2001 planning as FPL's recently-approved new DSM goals through the year 2009 were utilized as a key assumption underlying the analysis.

B. FPL's Reliability Criteria

The three inputs discussed above, plus updated forecasts and power plant information, were used in the 2001 IRP to determine the magnitude and the timing of FPL's resource needs. This determination was accomplished by system reliability analyses that were based on the dual planning criteria of a minimum summer and winter peak period reserve margin (15% until summer of 2004 and

20% thereafter) and a maximum of 0.1 days/year Loss-of-Load-Probability (LOLP).[8]

Reserve margin analysis is a deterministic approach, while LOLP analysis is a probabilistic approach. The reserve margin approach is essentially a calculation of excess firm capacity at the time of the summer system peak hour and at the time of the winter system peak hour. This relatively simple calculation can be performed on a spreadsheet. It provides an indication of how well a generating system can meet its native load during peak periods. However, a deterministic approach such as a reserve margin calculation does not take into account probabilistic-related elements such as: the reliability of individual generating units, the total number of generating units, or the sizes of these generating units. A deterministic approach also does not fully account for the value of an interconnected system.

Therefore, FPL also utilizes a probabilistic approach, LOLP, to provide additional information on the reliability of its generating system. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the

[8] These criteria are commonly used throughout the utility industry. The change from a 15% to a 20% minimum reserve margin criterion is due to a voluntary agreement in 1999 among FPL, FPC, and TECO that was approved by the Commission in Docket No. 981890-EU.

unavailability of individual generators due to scheduled maintenance or forced outages. LOLP is expressed in units of "number of times per year" that the system demand could not be served, and requires a more complicated calculation than does reserve margin analysis. FPL calculates LOLP using the Tie-Line Assistance and Generation Reliability (TIGER) model. A listing and summary of the computer models utilized by FPL in its resource planning work, including the TIGER model, is given in Appendix C.

In a reliability assessment, either a reserve margin criterion or the LOLP criterion will be violated first. This means that, for a given future year, FPL's system will not have a reserve margin high enough to meet its criterion or it will have a projected LOLP value greater than its LOLP criterion of 0.1. Whichever criterion is violated first is said to "drive" FPL's future resource needs. For the last few years, the summer reserve margin criterion has driven FPL's future needs. This again was the case in FPL's most current reliability assessment performed as part of its 2001 IRP work.

C. FPL's 2001 Reliability Assessment Results

FPL's reliability analyses showed that with no additional resources beyond its existing generating units and purchases and the planned additions mentioned above, FPL would begin to violate its summer reserve margin criterion of 20% by the summer of 2005. A minimum of 1,122 MW of additional resources would be needed by mid-2005 and an additional 600 MW by mid-2006 for FPL to continue to meet its summer reserve margin criterion of 20% for those years. This is demonstrated in Table IV.C.1.

Table IV.C.1
Projection of FPL's 2005 and 2006 Capacity Needs (without Capacity Additions in those years)

Summer

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2005	19,135	2,625	21,760	20,719	1,651	19,068	2,692	14.1%	**1,122**
2006	19,135	2,491	21,626	21,186	1,729	19,457	2,169	11.1%	**1,722**

Winter

	(1)	(2)	(3) = (1)+(2)	(4)	(5)	(6)=(4)-(5)	(7)=(3)-(6)	(8)=(7)/(6)	(9)=((6)*1.20)-(3)
January of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projection of Total Capacity (MW)	Peak Load Forecast (MW)	Winter DSM Forecast * (MW)	Forecast of Firm Peak (MW)	Forecast of Winter Reserves (MW)	Forecast of Winter Res. Margins w/o Additions (%)	MW Needed to Meet 20% Reserve Margin (MW)
2005	20,369	3,487	23,856	20,418	1,738	18,680	5,176	27.7%	**(1,440)**
2006	20,369	2,591	22,960	20,854	1,786	19,068	3,892	20.4%	**(78)**

* DSM values shown represent cumulative load management and incremental conservation capability.

D. Consistency with Peninsular Florida Need

FPL's 1,722 MW of additional capacity needs, as determined in its 2001 IRP work, is also consistent with the Peninsular Florida's needs identified by the Florida Reliability Coordinating Council (FRCC) in its 2001 reliability work, as reported by the FRCC in its 2001 Regional Load & Resource Plan. The FRCC's 2001 reliability work used FPL-specific data contained in FPL's 2001 Ten-Year Site Plan. This Site Plan data is a reporting of FPL's 2000 IRP work that showed a total additional capacity need of 1,708 MW for 2005 and 2006. Therefore, the 2001 determination of a total additional capacity need of 1,722 MW for 2005 and 2006 is consistent with the FRCC's work that relied on FPL data from the previous year. The FRCC will use the data and assumptions behind FPL's current projection of a 1,722 MW need in its 2002 reliability work.

V. FPL'S PROCESS FOR DETERMINING THE BEST AVAILABLE OPTIONS

A. Overview of FPL's Selection Process

The genesis of the decision to add the two new combined cycle units is found in FPL's 2000 planning process. The results of that work are described in detail in FPL's 2001 Ten Year Site Plan that is attached as Appendix D. As previously discussed, FPL's 2000 IRP showed that FPL would need 1,108 MW of additional capacity in 2005 and an additional 600 MW in 2006.

FPL's 2000 planning work then evaluated the various options for adding the needed capacity to FPL's system and determined that the most cost-effective FPL resources to meet this additional capacity need were:

For 2005:

- Conversion of two CTs at FPL's Martin site into a two-on-one CC unit (249 incremental summer MW) ;
- Conversion of two CTs at FPL's Ft. Myers site into a two-on-one CC unit (249 incremental summer MW);
- Construction of a new two-on-one CC unit at FPL's Martin site (547 MW); and,
- Construction of a new two-on-one CC unit at FPL's Midway site (547 MW).

For 2006:

- Construction of another new two-on-one CC unit at FPL's Martin site (547 MW).

This information was presented in FPL's 2001 Ten Year Site Plan (Site Plan). After reviewing this Site Plan, the Commission judged it to be "suitable."

As shown above, FPL's 2000 resource planning work had found that the most cost-effective type of new generation for FPL to add to its system would be new CC units. This type of generating unit falls Rule 25-22.082, Florida Administrative Code, which requires electric utilities to solicit bids from interested parties to determine whether the utility's construction of a unit is the most cost-effective alternative available. Consequently, FPL issued a RFP in mid-August of 2001.

FPL ultimately received 81 RFP proposals from 15 entities. FPL's analysis, as well as the analysis of an independent evaluator, showed that the most cost-effective alternative to meet FPL's 2005 and 2006 capacity needs was the plan consisting of Martin Unit 8 and Manatee Unit 3.

Based on the results of the economic analyses as well as associated non-price advantages, FPL decided to undertake the licensing of Martin Unit 8 and Manatee Unit 3. On March 22, 2002, FPL petitioned for determination of need for Martin Unit 8 and Manatee Unit 3. The Commission assigned Docket Nos. 020262-EI and 020263-EI to the Martin Unit 8 and Manatee Unit 3 proceedings. In April, 2002, FPL showed these units as FPL's next planned generating units in FPL's 2002 Ten Year Site Plan that is attached as Appendix E.

In the above-referenced Commission proceedings, several intervenors raised issues regarding FPL's compliance with the Bidding Rule with regard to the initial RFP. Additionally, Reliant Energy Power Generation, Inc. ("Reliant") filed a separate complaint raising many of the same issues. Although FPL believed that its initial RFP complied with the Bidding Rule, to address the concerns of the disappointed bidders and to assure it had the lowest cost alternatives available, FPL decided voluntarily to undertake a new Supplemental RFP. A copy of the Supplemental RFP document is attached as Appendix F.

The Supplemental RFP was announced on April 26, 2002. The due date for proposals was May 24, 2002. FPL received 53 proposals from 16 bidders. Of these 53, four proposals were voluntarily withdrawn and 18 proposals were rejected as a result of three bidders being deemed ineligible to participate. As a result, 31 eligible outside proposals were evaluated.

FPL performed economic evaluations of the 31 eligible outside proposals and compared them with the two FPL construction options, Manatee Unit 3 and Martin Unit 8. Additionally, an outside evaluator was hired to perform an independent evaluation. Both FPL's and the independent evaluator's analyses concluded that the two FPL construction options offered the most cost-effective plans for meeting FPL's additional power needs for 2005-2006.

However, based on the results of the economic analyses, FPL identified the bidders with the most cost effective non-FPL proposals comprising the two next lowest cost plans and named them to a short list for negotiations. Negotiations quickly revealed there would be no further price concessions, and that the third most competitive plan actually had higher costs than FPL had modeled. Based upon these negotiations, FPL revised its economic analysis and concluded that the construction of Manatee Unit 3 and Martin Unit 8 in 2005 continued to be the cost-effective alternative to meet its 2005 and 2006 need.

B. Forecasts and Assumptions

Generation expansion plans are based on a number of forecasts and assumptions. One of the major factors driving the timing of FPL's future capacity needs is the peak load forecast. Once a need for additional capacity has been identified, the determination of the most economic options with which to meet that need depends on other key forecasts and assumptions such as the sales forecast, the fuel price and availability forecast, and financial and economic data assumptions. This section discusses these major forecasts and assumptions that serve as inputs to the resource planning process.

1. The Load Forecast

Long-term (20-year) forecasts of sales, Net Energy for Load (NEL), and peak loads are developed on an annual basis for resource planning work at FPL. These forecasts are a key input to the models used to develop the integrated resource plan. The following pages describe how forecasts are developed for each component of the long-term forecast: sales, NEL, and peak loads.

a. Forecast Assumptions

The primary drivers to develop these forecasts are demographic trends, weather, economic conditions, and prices of electricity. In addition to these drivers, the resulting forecasts are an integration of economic evaluations, inputs of local economic development boards, weather assessments from the National Oceanographic and Atmospheric Association (NOAA), and inputs from FPL's own customer service planning areas. Demographics assessed include population trends by county and housing characteristics such as housing starts, housing size, and vintage of homes.

Econometric models are developed for each revenue class using the statistical tool called MetrixND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

b. Forecast Methodology

(i) Sales

(A) Residential electric usage per customer is estimated by using a regression model which contains the real residential price of electricity, Florida per capita income, and Cooling and Heating Degree Days as explanatory variables.

(B) Commercial sales are forecast using a regression model for the long and short term. Commercial sales are a function of the following variables: Florida's commercial employment, commercial real price of electricity, Cooling Degree Days, and an autoregressive term.

(C) Industrial sales are forecast through a linear multiple regression model using Florida manufacturing employment, the price of electricity, and an autoregressive term as explanatory variables.

(D) Resale (Wholesale) customers are composed of municipalities and/or electric cooperatives. These customers differ from jurisdictional customers in that they are not the ultimate users of the electricity they buy. Instead, they resell this electricity to their own customers. Currently, there are four customers in this class: the Florida Keys Electric Cooperative (Florida Keys), City Electric System of the Utility Board of the City of Key West, Florida (City of Key West), Miami-Dade County, and Florida Municipal Power Association (FMPA).

Sales forecasts for these and other classes are summed to produce a total sales forecast. After an estimate of annual total sales is obtained, an expansion factor is applied to generate a forecast of annual NEL.

(ii) Net Energy for Load (NEL)

A separate annual econometric model is also developed to produce a NEL forecast.[9] The key inputs to the model are: the price of electricity, Heating & Cooling Degree Days, and Florida Non-Agricultural Employment. Once the annual NEL forecast is obtained using this methodology, the results are compared for reasonability to the separate NEL forecast generated using the revenue class sales forecasts. The sales by class are then adjusted to match the NEL from the annual NEL model.

(iii) System Peak Forecasts

In recent years, the absolute growth in FPL system load has been associated with a larger customer base, weather conditions, economic growth, changing patterns of customer behavior (including an increasing stock of electricity-consuming appliances), and more efficient heating and cooling appliances. The Peak Forecast models were developed to capture these behavioral relationships.

(A) Summer Peak demand is developed using an econometric regression model developed on a per-customer basis. The key variables included in the summer

[9] This is an independent calculation from that used to determine NEL by applying an expansion factor to the revenue class sales forecasts.

peak model are total average customers, the price of electricity, Florida total personal income, and the maximum peak day temperature.

(B) Winter Peak demand is forecast using the same methodology and taking into account weather-related variables. In addition, the model incorporates variables that account for Florida total personal income and the effects of larger homes, and another variable designed to provide additional emphasis for the more recent weather data.

c. Forecast Results

The historical and projected average annual growth rates in customers, demand and energy are summarized in the table below.

Table V.B.1

FPL's 2001 Forecast Results
(Most Likely)
Compound Average Annual Growth

Years	Total Customers	Net Energy For Load	Summer Peak	Winter Peak
1991 - 2001	2.0%	3.0%	2.9%	4.4%
2001 - 2010	1.5%	2.5%	1.9%	2.1%
2010 - 2020	1.2%	1.2%	1.6%	1.7%

The forecasts of peak demands and NEL used in the Supplemental RFP analyses are presented in Appendix G. Also presented in Appendix G are the output from the models used to develop FPL's peak load forecast and work papers supporting the peak load forecast used in FPL's reliability assessment.

2. The Fuel Price and Availability Forecast

Fossil fuel price and availability forecasts, and the resulting projected price differentials between alternative fuels, are major factors used in evaluating alternatives for meeting future generating capacity needs. FPL's forecasts are generally consistent with other published forecasts prepared at the same time.

a. Fuel Price Forecast Methodology

FPL's fuel price forecast methodology is consistent for all fuels. It is also consistent with the methodology used by The PIRA Energy Group, Cambridge Energy Research Associates, and many other energy consultants.

FPL uses a scenario approach for the development of its long-term fossil fuel price forecasts. The major steps in the forecast development process include: (1) the development of a plausible, integrated set of economic, fundamental supply and demand, environmental, and geopolitical assumptions or drivers for each scenario; (2) a qualitative and quantitative translation of these assumptions into price forecasts on a constant dollar basis; (3) a comparison to historical values and a current set of published forecasts, on a constant dollar basis, for reasonableness; and (4) a conversion from constant dollar to nominal dollar prices.

FPL develops a base case scenario, as well as alternative fuel price scenarios, which reflect a large range of reasonable changes in the various fuel markets. Each scenario utilizes potential international and domestic events which can affect the supply, demand, and/or price of fuels over time. Scenarios are not predictions of specific events, but rather descriptions of potential resulting market conditions, which could result in different fuel prices and availabilities. The base case scenario describes market conditions that are considered the most likely to occur. The alternative scenarios are considered less likely to occur and describe market conditions that result in higher and lower prices than the base case. Together, these scenarios bound the range of uncertainty in fossil fuel price forecasts and provide the mechanism to evaluate the study results under a reasonable range of price forecasts.

These scenarios are used to support the various price forecasts for crude oil and mine mouth coal. Forecasts for fuel oil and natural gas are then developed based on expected market price relationships between those fuels and crude oil. Real price forecasts are also prepared for fuel transportation costs. Delivered real fuel prices are derived by adding the transportation cost component. The resulting forecasts are multiplied by DRI-WEFA's forecast of the GDP implicit price deflator to produce nominal delivered fuel price forecasts. These final forecasts are reviewed to ensure reasonableness and consistency.

b. Fuel Price Forecast

The detailed fuel price and availability base forecast for these fuels is presented in tabular form in Appendix H.

c. Fuel Supply and Availability

(i) Natural gas

Natural gas is the primary fuel for the proposed Martin and Manatee CC units. The alternate fuel for the Martin site is distillate fuel oil ("light oil"). It is anticipated that light oil will be used in the event of natural gas supply disruptions, although on rare occasions, it may be the more economic fuel. FPL does not plan the use of distillate fuel oil as a backup fuel at Manatee. With the potential for alternative gas supplies at Manatee, light oil capability is not necessary, and FPL has sufficient oil-fired capability on its system to take advantage of the rare instances when distillate fuel oil may be more economic than gas.

FPL is evaluating several alternatives to deliver natural gas to the Martin and Manatee sites to support the two new CCs. For both sites, FPL is evaluating receiving firm natural gas from either FGT or Gulfstream. For the Manatee site, FPL will have the capability to utilize both systems due to planned interconnections between the pipelines. The opportunities to receive natural gas from multiple sources will provide both the security of supply and lower competitive costs for FPL's customers.

Currently, there are significant quantities of proven natural gas reserves in the United States, as well as supply from U.S. production, Canadian imports and Liquified Natural gas (LNG) imports, to sufficiently meet the growing natural gas demand of the United States. According to recent data from the Department of Energy (DOE-EIA), there is adequate supply and projected natural gas reserves available in the United States to meet the natural gas demand for al least the next 25 years.

(ii) Oil

The alternate fuel for Martin Unit 8 is light oil, which would be trucked from local markets to the plant site where it would be stored on-site. Sufficient distillate fuel oil is available in that local market to ensure reliability and economic dispatch of the unit. As explained, light oil will not be used at Manatee Unit 3.

3. Financial and Economic Data

The financial and economic assumptions used in the analyses of the outside proposals and FPL construction options are presented in Appendix I.

C. FPL's Supplemental Request for Proposals

As previously mentioned, all of the FPL construction options selected in FPL's 2000 IRP (and presented in the subsequent 2001 Site Plan) were CC units. Because CC units fall under the Commission's Bidding Rule, it was apparent that FPL would need to issue a RFP. Consequently, in 2001 FPL issued a RFP that solicited proposals for 1,150 MW beginning on or before mid-2005, and an additional 600 MW on or before mid-2006, for a total of 1,750 MW for the years 2005 and 2006. After completing its evaluation and concluding that FPL's Martin Unit 8 and Manatee Unit 3 were the most cost-effective options, FPL filed for determination of need for these two units. Subsequently, after receiving objections made by certain unsuccessful bidders to the initial RFP, FPL voluntarily undertook to issue a Supplemental RFP to address those objections and to ensure that it had identified the most cost-effective capacity options available.

The primary objective in issuing the Supplemental RFP was to solicit outside proposals for meeting FPL's capacity needs for 2005 and 2006. The submitted proposals would be compared to FPL's construction options; i.e., the Martin and Manatee projects, to determine the most cost-effective alternatives for meeting FPL's 2005 and 2006 capacity needs.

Aside from the changes in the key dates associated with the evaluation and decision steps that would subsequently take place, there were several key changes in the Supplemental RFP compared to the RFP.

First, the Supplemental RFP forms were changed to make it easier to distinguish between cost and performance data for the different operational modes (base operation, duct firing, etc.) of combined cycle generating units that were expected to be the basis for many of the proposals.

Second, the fee structure was changed to allow bidders to the initial RFP to submit the same number of proposals for Supplemental RFP evaluation without having to incur any additional evaluation fees. These "repeat" bidders who wanted to submit a greater number of bids, or new bidders submitting a bid for the first time, were charged a one-time $10,000 Supplemental RFP evaluation fee rather than separate fees (that totaled to $10,000) for registering for the initial RFP, for submitting a Notice of Intent to Bid, and for evaluating the proposal.

Third, FPL's 5 "next planned generating units" that were published in the initial RFP were replaced in the Supplemental RFP with two FPL generating units: a new 4x1 combined cycle unit at Manatee (Manatee Unit 3) and a conversion of two existing simple cycle combustion turbine units at Martin into a similar 4x1 combined cycle unit (Martin Unit 8). Since at the time of issuing the initial RFP (August 2001) FPL had not yet determined from its 2001 planning studies what the most cost-effective capacity options were, it provided 5 capacity additions that had been identified in the 2000 planning studies as the most cost-effective choices for FPL's 2005 and 2006 needs.

Manatee Unit 3 and Martin Unit 8 were subsequently identified as the most cost-effective options in the 2001 planning work and were used in the initial RFP evaluation work. Consequently, FPL included only these two units as the "next planned generating units" in the Supplemental RFP.

Finally, several other changes were made in response to comments made by bidders on the initial RFP. Although none of these issues had been serious enough to prevent FPL from receiving 80 eligible bids in response to the initial RFP, FPL chose to change several potentially contentious items in the Supplemental RFP. These included: allowing natural gas "tolling" proposals that were previously disallowed, reducing the requirement to hold proposals (and their prices) firm from 390 days to 120 days, softening the "regulatory out" language from the possibility of terminating contracts to reducing payments to cost recoverable levels, and removing the "legislative out" language.

The Supplemental RFP document was announced on April 26, 2002, in an advertisement in the *Wall Street Journal* and in news releases to numerous newspapers throughout Florida. Additional Supplemental RFP advertisements subsequently appeared in Florida newspapers. Copies of these advertisements and news releases are attached as Appendix J. On April 26, 2002, FPL sent by overnight mail a copy of the Supplemental RFP document to all of the parties who had submitted a bid to FPL's initial RFP. FPL later received a number of requests for the Supplemental RFP from parties who had not submitted a bid to the initial

RFP, and these parties were then sent a copy of the Supplemental RFP document by overnight mail

FPL informed each Supplemental RFP document recipient that a special FPL website was set up to post questions from potential bidders regarding bid submittal and the cost and performance specifications for FPL's two "next planned generating units" that were included in the Supplemental RFP. Answers to those questions were published on the website. This website, designed to be available only to parties who had received the Supplemental RFP, allowed questions to be posed until one week before bids were due. A copy of the questions and answers posted on FPL's Supplemental RFP website is attached as Appendix K.

The due date for proposals was May 24, 2002. On that date, FPL received 53 proposals from 16 organizations that, in the aggregate, offered over 12,500 MW of capacity for the 2005 and 2006 time frame. Four of the 53 proposals were later withdrawn, and 18 proposals from three bidders were found to be ineligible. Thus, FPL evaluated 31 Supplemental RFP proposals in its economic analysis.

D. FPL Construction Options

The identification of the Martin and Manatee sites as preferred candidates for the construction of new CC units was the result of site and technology evaluation efforts performed by FPL. For environmental considerations, identification of initial candidate options focused on development at existing FPL power plant sites. Because all of FPL's power generation sites are at least 25 years old, the surrounding environment at these sites would be congruent with an 1,107 MW capacity addition. These locations also should have economic advantages over greenfield development in that they are located at beneficial transmission grid locations with local access to water and natural gas supplies, thereby minimizing potential impacts due to associated linear facilities. The combination of using existing power plant sites and modern gas-fired technology will minimize the environmental impact and help keep FPL customers' electric rate low. More detailed information about the two FPL self-build construction options is presented in Appendix L.

E. Economic Evaluation of the Options

FPL used a 4-step evaluation approach to determine the economics of the Supplemental RFP proposals and Martin Unit 8 and Manatee Unit 3. This approach is based on creating capacity expansion plans that utilize either the outside proposals only, the FPL construction options only, or a combination of these two types of capacity options to meet FPL's 2005 and 2006 capacity needs. For 2007 and beyond, greenfield "filler" units were added as needed to maintain FPL's reserve margin. The 4-step evaluation approach can be summarized as follows:

Step 1: Individual Rankings of Outside Proposals:

This involved economic analyses of each individual outside proposal and then rankings of these results. One ranking was made for all outside proposals with a 2005 starting date and another separate ranking was made for all outside proposals with a 2006 starting date. Independent rankings were performed by both FPL and the independent evaluator, Sedway Consulting, Inc. (Sedway).

Step 2: Creation of Two "Tiers" of Outside Proposals:

Based on the results of the individual rankings of the 2005-start-date outside proposals and the 2006-start-date outside proposals by both FPL and Sedway, the outside proposals were then separated into two "tiers," Tier 1 and Tier 2. Tier 1 included a number of outside proposals that were the highest ranked (i.e., had the lowest costs in the individual rankings) for each "start year" and Tier 2 contained the remaining outside proposals for each start year. In a number of cases, a Bidder submitted several mutually exclusive proposals that were identical except for the proposed length of service: 10 years, 15 years, etc. These similar proposals often appeared closely bunched in the individual rankings. In such cases, only the highest ranked proposal would be named to Tier 1 and the rest of the similar proposals would be placed in Tier 2.

Step 3: Expansion Plan Analyses (Using Tier 1 Starting Points and Tier 2 "Challenges"):

The two FPL construction options, Manatee Unit 3 and the Martin Unit 8, had emerged from the initial RFP analyses as the most cost-effective options. Therefore, these two FPL options were carried over into the Supplemental RFP analyses to compete with the new outside proposals. The individual outside proposals and two FPL construction options were then used to create 5 "types" of capacity plans designed to meet FPL's 2005 and 2006 capacity needs.

The 5 types of capacity plans were designed to maximize each option's opportunity to combine within a capacity plan that would be economically competitive. These 5 types of capacity plans were:

1) All Outside Plan (outside proposals only for both the 2005 and 2006 capacity needs);
2) Combination Plan with Manatee Only (outside proposals combined with FPL's Manatee unit that could start in either 2005 or 2006);
3) Combination Plan with Martin Only (outside proposals combined with FPL's Martin project that could start in either 2005 or 2006);
4) Combination Plan with Manatee and Martin Separated (Manatee and Martin starting in different years with one or more outside proposal completing the remaining capacity needs for 2005 since neither the

Martin nor Manatee units alone are sufficient to meet FPL's 2005 capacity needs); and,

5) All-FPL self build Plan (Martin Unit 8 and Manatee Unit 3 both starting in 2005).

A large number of plans for each of these 5 types (except the All-FPL self build plan) were developed and analyzed. The more economic plans of each type were then carried forward for the further analysis. This further analysis resulted in a number of the three combination plan types, plus several All Outside plans and the single All-FPL self build Plan, being carried forward to capture two types of additional costs in order to obtain a picture of the total costs of each of these plans.

Step 4: Total Cost Analyses: After identifying the most economic plans from the Step 3 analyses, additional cost information not included in the Step 3 analyses was incorporated. The two additional costs were transmission integration costs and the costs that would be incurred by FPL as a result of entering into additional power purchases ("equity penalty" costs). These two costs for each plan were calculated and added to each plan's costs developed in Step 3. The sum of these costs was the total cost of each plan. The results of this total cost analysis of the plans were then compared to determine the most cost-effective plan. This most cost-effective plan, in turn, identified the most cost-effective individual options.

1. FPL's Analysis

The "tier" approach was an alternative to completely dropping a number of outside proposals after the initial ranking. It allowed all of these proposals to stay in the evaluation and ensured them a number of opportunities at being selected in a capacity plan. It is perhaps best explained by describing how the All Outside plan analysis was carried out.

Once the Tier 1 outside proposals were named, FPL's Electric Generation Expansion and Analysis System (EGEAS) model that had been used in FPL's individual ranking evaluation was again used to determine the best All Outside plan that used only Tier 1 proposals. The entire group of Tier 1 proposals was used as a starting point from which the most economical subset of Tier 1 proposals to meet FPL's 2005 and 2006 capacity needs was selected. Once that plan was determined, each of the Tier 2 proposals "challenged" this plan one at a time in a challenge "run." In a challenge run, a specific Tier 2 proposal was "fixed" into the plan in its appropriate starting year by requiring EGEAS to select it in that year. Then EGEAS would optimize a new plan "around" the fixed proposal considering all of the Tier 1 proposals that were not mutually exclusive to the "fixed" Tier 2 proposal. Once EGEAS had selected the best possible plan from this mix, this best All Outside plan and its costs were noted.

At that point, the specific Tier 2 proposal was removed and the next highest ranked Tier 2 proposal was "fixed" into the plan and the process was repeated.

This continued until all of the Tier 2 proposals had participated in a challenge run. The best All Outside plans from each challenge run were then compared, and the lowest cost plan from the original Tier 1 case and all the Tier 2 challenge runs became the best All Outside plan.

The two tiers were developed from the individual rankings. Using the EGEAS results, FPL developed individual rankings of the outside proposals that had a 2005 start date and individual rankings of the outside proposals that had a 2006 start date. Based on the individual rankings that had been performed by June 4, 2002 by FPL and Sedway, 11 of the 31 proposals were placed in the Tier 1 grouping. Of these, 7 had a 2005 start date and 4 had a 2006 start date.

A greater number of 2005 start date proposals (7) than 2006 start date proposal (4) were selected for Tier 1 because FPL's 2005 capacity need (1,122 MW) is greater than its 2006 capacity need (600 MW). These Tier 1 proposals were:

With a 2005 start date:	With a 2006 start date:
1) P32	1) P42
2) P5	2) P44
3) P26	3) P33
4) P20	4) P28
5) P3	
6) P50	
7) P1	

All of the remaining 20 outside proposals were placed in the Tier 2 grouping. Using the tier challenge approach previously described, All Outside, All-FPL self build, and various types of combination plans were developed. The most economic All Outside plan as determined in Step 3 of FPL's analyses was as follows:

<u>For 2005:</u> P5, P20, and P 32

<u>For 2006:</u> P42

The EGEAS cost in cumulative present value of revenue requirements (CPVRR) of this best All Outside plan is $41,975 million. (All costs described throughout the remainder of this document are given in terms of 2001 – 2030 costs in 2001 dollars.)

The EGEAS cost of this plan, and of all of the plans that will be discussed in the remainder of this document, includes the proposed total payments to each of these outside proposals (including startup costs), the costs of the necessary filler units from 2007-on, and the costs of fuel for the entire FPL system over the time period. The proposed startup costs for each outside proposal were included in the EGEAS optimization evaluations for the Supplemental RFP. The startup cost calculations utilized the proposed "cold" startup costs and an assumed number of annual startups of 6 per CC unit and 100 per CT unit. This is the same calculation that was performed in the initial RFP evaluation work but it is being calculated as part of the EGEAS optimization for the Supplemental RFP analysis instead of separately from the EGEAS work, then added to the EGEAS results, as was the case in the initial RFP analysis.

A comparison of a number of the most economic plans of each of the 5 types of capacity plans is shown in Table V.E.1. Results as of June 18, 2002 for 36 capacity plans are shown in this table. These results include the EGEAS results plus a cost adjustment to the FPL construction option if only one of the two FPL construction options is built. The costs presented in the Supplemental RFP document for FPL's "next planned generating units" accurately portray the total costs if both projects are built with these total costs apportioned to each project. However, because both projects are similar – a 4x1 CC unit is the end result of both projects – the two projects will share certain items such as engineering design, spare parts, etc. and will be able to take advantage of bulk material purchase discounts. This results in cost savings that benefit both two projects. However, if only one of the two projects is built, these cost savings disappear and greater costs will be borne by the one project to be built. Consequently, a cost adjustment is needed to combination plans in which only one FPL project is built. At this stage of the work, the assumption was that a "Manatee only" plan would incur $14 million (CPVRR) of extra cost while a "Martin only" plan would incur no such extra cost.

Table V.E.1

Summary of Best Plans : with EGEAS and One FPL Unit Only Adjustment Costs
(as of June 18, 2002)

				Costs (NPV, 2001-2030, millions, 2001$)						
Plan Ranking	Plan Description	2005 Additions	2006 Additions	EGEAS Costs	Transmission Integration Costs	Equity Penalty Costs	Subtotal Costs	Adjustment For One FPL Unit Only	Total Costs	Total Cost Differential
1	Combination w/ Martin only	Martin,P3, P24	P42	41,603			41,603	0	41,603	0
2	Combination w/ Martin only	Martin, P3, P25	P42	41,606			41,606	0	41,606	3
3	Combination w/ Martin only	Martin, P3, P26	P 42	41,612			41,612	0	41,612	9
4	Combination w/ Martin only	Martin, P3, P24	P 44	41,616			41,616	0	41,616	13
5	Combination w/ Manatee only	Manatee, P5	P 42	41,604			41,604	14	41,618	15
6	Combination w/ Martin only	Martin, P3, P25	P 44	41,618			41,618	0	41,618	15
7	Combination w/ Manatee only	Manatee, P6	P 42	41,605			41,605	14	41,619	16
8	Combination w/ Martin only	Martin, P3, P6, P26	P 42	41,620			41,620	0	41,620	17
9	Combination w/ Martin only	Martin, P3, P26	P 44	41,624			41,624	0	41,624	21
10	Combination w/ Manatee only	Manatee, P5	P 44	41,615			41,615	14	41,629	26
11	Combination w/ Martin only	Martin, P31	P42	41,633			41,633	0	41,633	30
12	Combination w/ Martin only	Martin, P3, P6, P26	P 44	41,633			41,633	0	41,633	30
13	Combination w/ Manatee only	Manatee, P5	P4, P42	41,626			41,626	14	41,640	37
14	Combination w/ Martin & Manatee separated	Manatee, P26	Martin	41,642			41,642	0	41,642	39
15	Combination w/ Martin & Manatee separated	Manatee, P32	Martin	41,642			41,642	0	41,642	39
16	Combination w/ Manatee only	Manatee, P3	P 42	41,631			41,631	14	41,645	42
17	Combination w/ Martin only	Martin, P31	P44	41,645			41,645	0	41,645	42
18	Combination w/ Manatee only	Manatee, P26	P4, P44	41,638			41,638	14	41,652	49
19	Combination w/ Martin & Manatee separated	Manatee, P5	Martin	41,655			41,655	0	41,655	52
20	Combination w/ Manatee only	Manatee, P3	P 44	41,643			41,643	14	41,657	54
21	All FPL Plan	Manatee, Martin	-----	41,658			41,658	0	41,658	55
22	Combination w/ Martin only	Martin, P6, P20	P 42	41,661			41,661	0	41,661	58
23	Combination w/ Martin only	Martin, P32	P 42	41,667			41,667	0	41,667	64
24	Combination w/ Martin & Manatee separated	Martin, P32	Manatee	41,670			41,670	0	41,670	67
25	Combination w/ Martin only	Martin, P6, P20	P 44	41,674			41,674	0	41,674	71
26	Combination w/ Martin only	Martin, P6, P32	P 42	41,676			41,676	0	41,676	73
27	Combination w/ Manatee only	Manatee, P24	P 42	41,663			41,663	14	41,677	74
28	Combination w/ Martin only	Martin, P32	P 44	41,680			41,680	0	41,680	77
29	Combination w/ Manatee only	Manatee, P24	P 44	41,674			41,674	14	41,688	85
30	Combination w/ Martin only	Martin, P6, P32	P 44	41,689			41,689	0	41,689	86
31	Combination w/ Martin & Manatee separated	Martin, P3, P26	Manatee	41,693			41,693	0	41,693	90
32	Combination w/ Martin only	Martin, P20	P 42	41,693			41,693	0	41,693	90
33	Combination w/ Manatee only	Manatee, P31	P 42	41,683			41,683	14	41,697	94
34	Combination w/ Manatee only	Manatee, P31	P 44	41,695			41,695	14	41,709	106
35	All Outside Plan	P5, P20, P32	P 42	41,975			41,975	0	41,975	372
36	All Outside Plan	P6, P20, P31	P 42	41,986			41,986	0	41,986	383

The Table V.E.1 results show that a combination plan with only one FPL unit (Martin) has the lowest cost at $41,603 million (CPVRR). This plan is then followed by numerous other combination plans and the All-FPL self build plan. Finally, the two best All Outside plans are shown to be significantly more expensive than any of the other plans since the lowest cost All Outside plan has a cost of $41,975 million (CPVRR), which is more than $370 million more expensive than the lowest cost combination plan at this point.

It is clear from these results that even the most economic capacity plans made up solely of outside proposals (i.e., the All Outside plans) were not competitive with either combination plans made up of at least one FPL construction option or with the All-FPL self build plan. The decision as to whether a combination plan or the All-FPL self build plan is most economical could be decided only after the remaining costs not included in the Step 3 calculations were incorporated in Step 4 of the analysis.

Step 4 incorporated two additional types of costs: transmission integration costs and equity penalty costs. These two types of costs were calculated and added to the costs previously developed in Step 3. A description of each type of cost and an explanation of how these costs were calculated follows.

1) Transmission integration costs: All of the outside proposals and the two FPL construction options included a cost for interconnecting the unit with the FPL system. The interconnection cost can be thought of as the transmission capital cost needed to simply interconnect that unit with the electrical grid. However, the Supplemental RFP directions called for no inclusion of proposed or projected transmission integration costs. While the interconnection costs are the transmission capital expenditures necessary to get a unit's power to the grid, the integration costs are the transmission capital costs necessary to deliver that unit's power output throughout the grid to the customers.

A transmission assessment for 28 capacity plans was performed under the direction of Mr. Donald Stillwagon. The selection of these 28 plans was designed to develop transmission integration costs that would be representative for all 36 plans previously presented in Table V.E.1.

Estimates of the transmission integration direct construction costs for the 28 plans were provided by Mr. Stillwagon. These direct construction cost values were given in monthly cash flows in 2002 dollars. These values were escalated as appropriate for the years in which they were to be incurred, then these costs had AFUDC costs added to them (except for the All Outside Plan). Next, this new subtotal of integration costs with AFUDC were converted into annual revenue requirements. Finally, the cumulative present value of revenue requirements (CPVRR) of these transmission integration costs, discounted to 2001 dollars, were then added to the previously calculated costs from Step 3 for each of the 36 capacity plans. Appendix M provides detail on the transmission integration cost calculations.

2) Equity Penalty Costs: Equity penalty costs are costs associated with the entering into purchased power agreements with an outside party. Rating agencies attribute a portion of a utility's capacity payment obligation to a power supplier as debt equivalent on the utility's balance sheet. If a utility does not rebalance its capital structure with additional equity, this debt equivalent can negatively impact a utility's financial ratios, influencing rating agencies to downgrade their opinion of the utility's creditworthiness and increasing the utility's cost of borrowing. Consequently, an adjustment acknowledging this incremental cost of capital must be made to all capacity purchase options in order to put them on an equal footing with internal build or turnkey options. Equity penalty costs are applicable only to outside power purchase proposals, not to FPL construction or outside turnkey project options. The cost of the equity needed to support FPL's own construction projects or turnkey projects is already reflected in the CPVRR values for these options.

Equity penalty cost calculations for each of the outside power purchase proposals that appeared in the 36 plans carried forward were then reviewed by FPL's Finance Department and Dr. William Avera of FINCAP, Inc.

The cumulative present value of these annual equity penalty costs for each of these outside proposals was then calculated and summed for the groups of outside proposals making up each of these 36 plans. This total net present value of the equity penalty costs for each group were then added to the other costs described above to derive a total cost estimate for each of the 36 plans. Appendix N presents the equity penalty totals for the outside proposals that appear in Table V.E.1.

The total CPVRR costs for the 36 plans were then compared at the end of the Step 4 analyses. These total cost results as of June 18, 2002 are presented in Table V.E.2. The format for this document is identical to that of Table V.E.1 with the addition of the transmission integration and equity penalty costs.

Table V.E.2

Summary of Best Plans : with Total Costs
(as of June 18, 2002)

Plan Ranking	Plan Description	2005 Additions	2006 Additions	Costs (NPV, 2001-2030, millions, 2001$) EGEAS Costs	Transmission Integration Costs	Equity Penalty Costs	Subtotal Costs	Adjustment For One FPL Unit Only	Total Costs	Total Cost Differential
1	All FPL Plan	Manatee, Martin	-----	41,658	28	0	41,686	0	41,686	0
2	Combination w/ Martin & Manatee separated	Manatee, P5	Martin	41,655	52	1	41,708	0	41,708	21
3	Combination w/ Manatee only	Manatee, P5	P 42	41,604	45	81	41,730	14	41,744	58
4	Combination w/ Martin only	Martin,P3, P24	P42	41,603	40	102	41,745	0	41,745	59
5	Combination w/ Manatee only	Manatee, P6	P 42	41,605	45	82	41,732	14	41,746	60
6	Combination w/ Martin only	Martin, P3, P24	P 44	41,616	26	105	41,748	0	41,748	61
7	Combination w/ Martin & Manatee separated	Manatee, P26	Martin	41,642	70	49	41,761	0	41,761	75
8	Combination w/ Martin only	Martin, P3, P25	P42	41,606	40	116	41,762	0	41,762	76
9	Combination w/ Martin only	Martin, P3, P25	P 44	41,618	26	119	41,763	0	41,763	77
10	Combination w/ Martin & Manatee separated	Manatee, P32	Martin	41,642	52	78	41,772	0	41,772	85
11	Combination w/ Martin only	Martin, P31	P42	41,633	32	108	41,773	0	41,773	87
12	Combination w/ Martin & Manatee separated	Martin, P32	Manatee	41,670	28	78	41,776	0	41,776	89
13	Combination w/ Manatee only	Manatee, P5	P4, P42	41,626	45	92	41,763	14	41,777	91
14	Combination w/ Martin only	Martin, P31	P44	41,645	26	111	41,782	0	41,782	96
15	Combination w/ Martin only	Martin, P3, P26	P 42	41,612	40	138	41,790	0	41,790	103
16	Combination w/ Martin only	Martin, P3, P6, P26	P 42	41,620	31	139	41,791	0	41,791	104
17	Combination w/ Martin only	Martin, P3, P26	P 44	41,624	26	141	41,791	0	41,791	105
18	Combination w/ Martin & Manatee separated	Martin, P3, P26	Manatee	41,693	45	58	41,796	0	41,796	110
19	Combination w/ Manatee only	Manatee, P3	P 42	41,631	64	89	41,784	14	41,798	111
20	Combination w/ Martin only	Martin, P3, P6, P26	P 44	41,633	26	142	41,802	0	41,802	115
21	Combination w/ Manatee only	Manatee, P5	P 44	41,615	112	84	41,811	14	41,825	139
22	Combination w/ Martin only	Martin, P6, P20	P 42	41,661	32	139	41,831	0	41,831	145
23	Combination w/ Manatee only	Manatee, P24	P 42	41,663	64	93	41,820	14	41,834	148
24	Combination w/ Martin only	Martin, P6, P20	P 44	41,674	26	142	41,842	0	41,842	156
25	Combination w/ Manatee only	Manatee, P24	P 44	41,674	63	96	41,834	14	41,848	161
26	Combination w/ Manatee only	Manatee, P31	P 42	41,683	45	108	41,836	14	41,850	164
27	Combination w/ Martin only	Martin, P32	P 42	41,667	32	158	41,857	0	41,857	170
28	Combination w/ Manatee only	Manatee, P26	P4, P44	41,638	63	143	41,844	14	41,858	172
29	Combination w/ Martin only	Martin, P20	P 42	41,693	32	137	41,862	0	41,862	175
30	Combination w/ Martin only	Martin, P32	P 44	41,680	26	161	41,867	0	41,867	181
31	Combination w/ Martin only	Martin, P6, P32	P 42	41,676	32	159	41,867	0	41,867	181
32	Combination w/ Martin only	Martin, P6, P32	P 44	41,689	26	163	41,878	0	41,878	192
33	Combination w/ Manatee only	Manatee, P3	P 44	41,643	132	92	41,868	14	41,882	195
34	Combination w/ Manatee only	Manatee, P31	P 44	41,695	64	111	41,870	14	41,884	198
35	All Outside Plan	P6, P20, P31	P 42	41,986	5	166	42,157	0	42,157	471
36	All Outside Plan	P5, P20, P32	P 42	41,975	5	215	42,195	0	42,195	509

Four main conclusions can be drawn from the results shown in table V.E.2. First, the relative rankings of a number of the plans changed. Second, the changes did not improve the relative economics of the best All Outside plan. In fact, when total costs are accounted for, the best All Outside plan is $471 million (CPVRR) more expensive than the most economical plan. Third, the second best plan includes both FPL's Manatee and Martin projects, coming in-service one year apart, with a small, short-term purchase also added in 2005. This second best plan is a combination plan that is $21 million (CPVRR) more expensive than the most economical plan.

The fourth, and most important, conclusion is that the All-FPL self build Plan is the most economical capacity plan. Consequently, the Manatee CC unit and the Martin Conversion project are the two most cost-effective options with which to meet FPL's 2005 and 2006 capacity needs.

FPL continued to check and refine calculations behind the results shown in Table V.E.2 as negotiations were being held with short listed bidders. As a result, four changes were subsequently made to the values shown in Table V.E.2. Two of these changes were to the "one FPL unit only" cost adjustment that had been made. When combination plans with only one FPL unit were introduced to the analysis, the previously stated assumption was that "Manatee Only" combination plans would need their cost adjusted upwards by approximately $14 million (CPVRR) while no adjustment would be needed for "Martin Only" combination plans. Further analysis showed that the "Manatee Only" plans should be adjusted by $16 million (instead of by $14 million) (CPVRR) and the "Martin Only" plans should be adjusted by $15 million (CPVRR) instead of no adjustment being needed.

A third change was to the cash flows of four of the transmission integration cases. These revised cash flows were developed by Mr. Stillwagon after his review of the integration calculations was completed. New AFUDC and revenue requirements calculations were then performed for these four cases. The net effect of the changes to these transmission integration cases was relatively small: a change of less than $1 million for three of the four cases and a change (an increase) of approximately $3 million for the fourth case.

A fourth change was to the equity penalty calculations for two outside proposals, P4 and P25. The original calculations for these two proposals had inadvertently been carried out for more years than their proposals called for. Correcting these calculations reduced the equity penalties for two plans that included the P4 proposal by $5 million and for another two plans that included the P25 proposal by $2 million.

The impact of all three of these changes on the total costs of the 36 plans is presented in Table V.E.3. The All-FPL self build plan was the most economical plan before these changes were made by \$21 million (CPVRR) and by \$58 million (CPVRR) over the 2nd best and 3rd best plans, respectively. After the changes were made the ranking of these 3 plans stayed the same. The All-FPL self build plan remained the most economical plan with no change in its economic advantage over the 2nd best plan and with an increase of \$1 million (CPVRR) in its economic advantage over the 3rd best plan (i.e., the \$58 million advantage had increased to \$59 million).

Table V.E.3

Summary of Best Plans : with Total Costs
(Final)

				Costs (NPV, 2001-2030, millions, 2001$)						
Plan Ranking	Plan Description	2005 Additions	2006 Additions	EGEAS Costs	Transmission Integration Costs	Equity Penalty Costs	Subtotal Costs	Adjustment for One FPL Unit Only	Total Costs	Total Cost Differential
1	All FPL Plan	Manatee, Martin	-----	41,658	28	0	41,686	0	41,686	0
2	Combination w/ Martin & Manatee separated	Manatee, P5	Martin	41,655	52	1	41,708	0	41,708	21
3	Combination w/ Manatee only	Manatee, P5	P 42	41,604	45	81	41,730	16	41,746	59
4	Combination w/ Manatee only	Manatee, P6	P 42	41,605	45	82	41,732	16	41,748	61
5	Combination w/ Martin only	Martin,P3, P24	P42	41,603	40	102	41,745	15	41,760	74
6	Combination w/ Martin & Manatee separated	Manatee, P26	Martin	41,642	70	49	41,761	0	41,761	75
7	Combination w/ Martin only	Martin, P3, P24	P 44	41,616	26	105	41,748	15	41,762	76
8	Combination w/ Martin & Manatee separated	Manatee, P32	Martin	41,642	52	78	41,772	0	41,772	85
9	Combination w/ Manatee only	Manatee, P5	P4, P42	41,626	45	87	41,758	16	41,774	88
10	Combination w/ Martin only	Martin, P3, P25	P42	41,606	40	114	41,760	15	41,774	88
11	Combination w/ Martin & Manatee separated	Martin, P32	Manatee	41,670	28	78	41,776	0	41,776	89
12	Combination w/ Martin only	Martin, P3, P25	P 44	41,618	26	117	41,761	15	41,776	89
13	Combination w/ Martin only	Martin, P31	P42	41,633	32	108	41,773	15	41,788	101
14	Combination w/ Martin & Manatee separated	Martin, P3, P26	Manatee	41,693	45	58	41,796	0	41,796	110
15	Combination w/ Martin only	Martin, P31	P44	41,645	26	111	41,782	15	41,797	111
16	Combination w/ Manatee only	Manatee, P3	P 42	41,631	64	89	41,784	16	41,799	113
17	Combination w/ Martin only	Martin, P3, P26	P 42	41,612	40	138	41,790	15	41,804	118
18	Combination w/ Martin only	Martin, P3, P6, P26	P 42	41,620	31	139	41,791	15	41,805	119
19	Combination w/ Martin only	Martin, P3, P26	P 44	41,624	26	141	41,791	15	41,806	120
20	Combination w/ Martin only	Martin, P3, P6, P26	P 44	41,633	26	142	41,802	15	41,816	130
21	Combination w/ Manatee only	Manatee, P5	P 44	41,615	112	84	41,811	16	41,826	140
22	Combination w/ Manatee only	Manatee, P24	P 42	41,663	64	93	41,820	16	41,835	149
23	Combination w/ Martin only	Martin, P6, P20	P 42	41,661	32	139	41,831	15	41,846	160
24	Combination w/ Manatee only	Manatee, P24	P 44	41,674	63	96	41,834	16	41,849	163
25	Combination w/ Manatee only	Manatee, P31	P 42	41,683	45	108	41,836	16	41,852	166
26	Combination w/ Martin only	Martin, P6, P20	P 44	41,674	26	142	41,842	15	41,857	170
27	Combination w/ Manatee only	Manatee, P26	P4, P44	41,638	66	138	41,842	16	41,858	171
28	Combination w/ Martin only	Martin, P32	P 42	41,667	32	158	41,857	15	41,871	185
29	Combination w/ Martin only	Martin, P20	P 42	41,693	32	137	41,862	15	41,876	190
30	Combination w/ Martin only	Martin, P32	P 44	41,680	26	161	41,867	15	41,882	196
31	Combination w/ Martin only	Martin, P6, P32	P 42	41,676	32	159	41,867	15	41,882	196
32	Combination w/ Manatee only	Manatee, P3	P 44	41,643	132	92	41,868	16	41,883	197
33	Combination w/ Manatee only	Manatee, P31	P 44	41,695	64	111	41,870	16	41,886	200
34	Combination w/ Martin only	Martin, P6, P32	P 44	41,689	26	163	41,878	15	41,893	206
35	All Outside Plan	P6, P20, P31	P 42	41,986	5	166	42,157	0	42,157	471
36	All Outside Plan	P5, P20, P32	P 42	41,975	5	215	42,195	0	42,195	509

2. The Independent Evaluation

Sedway Consulting, Inc., the independent evaluator, developed its own economic assessment of the Supplemental RFP proposals and the FPL construction options utilizing a spreadsheet-based model called the Response Surface Model (RSM). As part of its input, RSM used data from prior EGEAS runs that gave information about system production cost impacts on the FPL system both in its current configuration and from future capacity additions. The model also used the same cost inputs for the outside proposals and FPL construction options as were used in

FPL's EGEAS approach. These costs were combined with the RSM model's projection of system production cost impacts from these projects and with an idealized (an exact MW-for-MW match) projection of filler unit capacity additions at the end of a project's term in order to maintain the MW supplied in 2005 and 2006. In this way, the RSM model developed a cost picture similar in concept to that developed by EGEAS.

Using the RSM model, Sedway first developed rankings of individual outside proposals. Then, Sedway combined outside proposals into All Outside, All-FPL self build, and combination plans (similar in concept to EGEAS's expansion plans) that met FPL's 2005 and 2006 capacity needs. The RSM model-calculated costs for these plans were then compared. Finally, Sedway utilized the FPL calculations of transmission integration costs and equity penalty costs, plus its own calculation of a cost component not utilized by FPL - the residual value of utility-owned generating units - to derive total cost values for the best of these plans.

The independent evaluator's economic analyses also showed the All-FPL self build plan consisting of Martin Unit 8 and Manatee Unit 3 to be the most cost-effective alternative to meet FPL's 2005 and 2006 capacity needs. In fact, this analysis showed even larger cost savings than FPL computed. Sedway showed the All-FPL self build plan to be $135 million (CPVRR) more cost-effective than the next lowest cost plan.

F. Non-Price Attributes Affecting the Selection of the Best Available Option

The economic analysis of competing alternatives identified the most cost-effective alternatives for FPL's customers. However, a number of non-price attributes, which may ultimately determine the best available option, may also be considered.

Seven (7) non-price factors FPL considers when choosing among its own options or between outside proposals and FPL options are: (1) fuel diversity; (2) technology risk; (3) environmental risk; (4) financial strength of the supplier; (5) the feasibility of licensing and construction requirements; (6) the delivery risk related to firmness of fuel supply and the experience of the seller; and (7) the degree of control offered including dispatchability and rights to sell power. A brief summary of thee 7 non-price factors in presented.

(1) Fuel diversity relates to two concepts, the diversity of sources of fuel (*e.g.*, coal vs. oil vs. natural gas), and the diversity of supply for a single fuel source (for example alternative pipeline suppliers for natural gas). All other factors being equal, supply options that increase fuel supply diversity would be favored over those that do not.

(2) Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology which has not achieved

general commercial acceptance has a higher risk than a technology in wide use, and, therefore, is less desirable.

(3) Environmental risk is an assessment of the relative environmental acceptability of competing technologies. Technologies which might be regarded as more acceptable from an environmental perspective (*e.g.*, natural gas) might be considered more favorably.

(4) The financial strength of the supplier is an assessment of the ability of a project developer to marshal the financial resources required to bring a capital-intensive project to completion. While it has always been a concern, this issue has become even more prominent recently due to the recent, and highly publicized financial problems affecting a number of IPPs. It is FPL's customers that ultimately bear the risk of nonperformance of a project resulting from the financial instability of a developer.

(5) Feasibility of licensing and construction plans is an assessment of the reasonableness of the timing of a proposal, taking into account the lead times required to site, license and construct a power plant, and considering the possibility of delay or cancellation resulting from opposition or any other factor. For example, the possibility of delay in licensing and construction is greater for a nuclear plant than a gas turbine. As another example, a combined cycle unit not "fully committed" to serving retail load might face greater difficulty in securing a

Determination of Need than a fully committed plant. Again, FPL's customers bear the risk associated with any potential delay.

(6) <u>Delivery risk related to firmness of fuel supply, the construction schedule, and the experience of the seller</u> relate to an assessment of whether a seller and its proposed project will deliver power on schedule and reliably. Firmness of fuel supply relates to reliability of the electricity from a facility. A proposed unit that offers power without firm fuel suppliers, for example a gas-fired unit without firm gas transportation, is a higher risk than that same facility with firm transportation. The experience of the seller must also be assessed to assure that the proposed project will be available on schedule. A proposal offered by a developer that has not shown a history of bringing projects in on time or that has been accused of misconduct would obviously be less favored than one from a developer with a strong project management record.

(7) <u>The degree of control offered to FPL, including dispatchability and rights to sell power from a project</u>, involves a comparison of a proposed contractual structure to the characteristics FPL would have with its self-built units. For example, an FPL-owned unit is fully controllable by FPL's system operator, within technology limits, so that the unit can be turned on or off, or up or down, to meet system requirements. When the unit is not needed to meet system native load requirements, it is available to provide power for system sales, providing gains back to FPL's customers.

All of these seven factors can play a part in FPL's planning and decisions, including its decisions to purchase power. With regard to FPL's Supplemental RFP analysis, consideration of two of these factors led to the elimination of bidders. The other factors discussed below would not change the outcome of the economic analysis. They serve to reinforce FPL's conclusion that the All-FPL self build plan is the best plan to meet the needs of FPL's customers.

Fuel diversity (1) and technology risk (2) would not significantly advantage any plan considered in FPL's Supplemental RFP analysis. FPL's self-build options were fueled by natural gas and based on commercially available gas turbine technology. Regarding the diversity introduced by competing pipelines, most of the more economic alternatives were supplied by the same natural gas pipeline. Regarding the technology risk, FPL enjoyed a slight advantage over bidders using equipment new to them.

Likewise, the assessment of environmental risk (3) associated with both FPL and non-FPL options did not differentiate to any significant degree between alternatives. Although it was recognized that development of an existing power plant site involved lower environmental risk than development of a greenfield site, this consideration did not play a significant role in FPL's Supplemental RFP decision.

The feasibility of licensing and construction requirements (5), did not differentiate between FPL's self - build plan and the most competitive plans to any significant degree. All of the competitive plans consist, at least in significant part, of CC technologies that would be expected to have similar construction requirements. Thus, this factor did not have a significant impact on FPL's ultimate decision. However, if some proposals with less than fully-committed CCs had been more economical, there would have been a concern over certification of need by the Commission.

Another factor, delivery risk related to firmness of fuel supply, the construction schedule, and the experience of the seller (6), was also not a significant factor in FPL's final decision although this factor lead directly to FPL's decision to declare three potential bidders as ineligible for the Supplemental RFP based on either their failure to meet the Supplemental RFP Completion Security Minimum Requirement, their recent business dealings with FPL, or general familiarity with their alleged misconduct.

With regard to financial strength of suppliers (4), there is a heightened concern over the financial health of virtually all independent power developers. This concern reflects a general tightening of the financial markets. Any threat to project financing increases the risk of delay or cancellation of the project. Although FPL determined two bidders ineligible based upon their prior conduct, both bidders also have a weak financial position. In addition, evaluation of the plans most competitive to FPL's self-build options showed that one included a project offered by a supplier that was known to be facing current financial difficulties. This developer did not have an investment grade bond rating. For this and other reasons, the financial viability of this bidder was a real concern to FPL.

The final consideration, which is the degree of control offered by a project (7), is multifaceted and cannot be addressed fully and specifically until a final contract is negotiated. However, a contract for power is largely an effort to duplicate specific ownership rights that FPL would have in FPL-owned units. For example, FPL can dispatch its units in any manner necessary, within technology limits, to maintain reliability and economic operation of the system to its customers' benefit. Scheduling of maintenance on FPL units is entirely under control of FPL and flexible in response to changing conditions. FPL also may sell power from any FPL-owned unit when that unit is not required to meet its own customers' demand, with benefits of the sale flowing back to customers. Any of these ownership rights can, and have been, specified in contracts with third party producers over the years. However, FPL's experience with contract administration, and resulting litigation, has demonstrated a natural and irreconcilable tension created when customers' interests and owners' interests reside with different parties. Thus, where economics are relatively equal between building and buying, ownership is preferable and presents tangible advantages to customers.

In summary, there were two qualitative factors that played a significant role in the evaluation leading to the selection of the All-FPL self build plan:

- The prior experience of three bidders led to their being declared ineligible.
- The financial weakness of one bidder who had a portion of one relatively competitive plan contributed to that bidder not making the short list.

Other non-price factors might also have been more significant if there had not been such a significant economic advantage for the Martin and Manatee projects.

G. Short List Determination and Negotiations

Based upon the economic analyses of the various plans, there were five plans other than plans containing both Martin Unit 8 and Manatee Unit 3 that were discussed in the determination of a "short list" for negotiations. These plans ranged from $58 to $145 million more costly in FPL' s analysis than the All-FPL self build plan. Two of the plans with a cost in excess of $100 more than the All-FPL self build plan were dropped as being too costly.

Ultimately, only Florida Power Corporation ("FPC") and El Paso Merchant Energy ("El Paso") were named to the short list. These were the entities, other than FPL, in the two plans with the next lowest cost after the All-FPL self build plan. Other bidders considered for the short list included Bidder W, Bidder X, Bidder Y and Bidder Z. These were not included for several reasons. First, the more economic plans in which each of these bidders had proposals were competitive only because the plans included a 2006 El Paso unit, and, therefore, FPL chose to negotiate with the real economic driver, El Paso. Second, FPL had concerns about a plan comprised of a Bidder W proposal and a Bidder X proposal along with an FPL unit and an El Paso unit, because Bidder W did not appear to have sufficient reserves to make the sale and sustain a 20% reserve margin and Bidder X had questionable financial viability. Third, the plan with Bidders W, X, Y, and Z were more costly than the plans with only FPC and El Paso, so FPL focused on the bidders whose outside proposals made up the most competitive combination plans.

FPL informed both FPC and El Paso that they were on the short list, but they were not part of the lowest cost plan. FPL posed questions to them regarding their proposals and provided them the opportunity to refine their bids. Neither entity offered to lower its price. FPL met with El Paso to discuss its proposal, its price, and a potential purchased power agreement. In that discussion it became clear not only that El Paso was not going to improve its price, but also that FPL had modeled El Paso's proposals too favorably, in essence understating the cost of every capacity plan containing an El Paso unit.

Based upon negotiations and the analyses correcting the El Paso proposal, FPL determined that there was no plan within $80 million (CPVRR) of the All-FPL self build plan, except for the plan consisting of FPL's Manatee unit and 50 MW purchase in 2005, followed by FPL's Martin unit in 2006. Given these economics, coupled with El Paso's presence in every plan within $100 million of the All-FPL self build plan and the fact that neither FPC nor El Paso would lower its price, FPL terminated negotiations and announced its intent to reinitiate the Martin Unit 8 and Manatee Unit 3 need determinations.

Based upon FPL's economic analysis, the independent economic analysis and negotiations, it is clear that the All-FPL self build plan consisting of Manatee Unit 3 and Martin Unit 8 is the most cost-effective alternative to meet FPL's 2005 and 2006 need for capacity.

VI. NON-GENERATING ALTERNATIVES

A. FPL's Demand Side Management Efforts

FPL has a long history of identifying, developing, and implementing DSM resources to avoid or defer the construction of new power plants. FPL first began offering DSM programs in the late 1970's with its introduction of the Watt-Wise Home Program. An increasing number of additional DSM programs were then offered throughout the 1980s and 1990s. These programs have included both conservation and load management and have addressed the residential, commercial and industrial markets.

The plan of DSM programs FPL has offered has evolved over time. Indeed, FPL continually looks for new DSM opportunities in its research and development activities. When a new DSM opportunity is projected to be cost-effective, FPL has attempted to roll out a new DSM program or to incorporate this DSM opportunity into one or more of its existing DSM programs. In addition, FPL has modified DSM programs over the years whenever possible to maintain the cost-effectiveness of the program, thereby allowing FPL to continue to offer it. On occasion, FPL also has terminated DSM programs that were no longer cost-effective and could not be modified so that they once again became cost-effective.

FPL's DSM efforts have made it a recognized leader in DSM in the United States. These efforts have resulted in summer peak demand reduction through 2001 of 3,076 MW at the generator. After accounting for reserve margin requirements, this amount of peak reduction is equivalent to 9 power plants of 400 MW capacity that otherwise would have been needed. FPL has achieved this level of demand reduction and avoidance of new generating units without penalizing customers who are non-participants in its DSM programs. FPL has been able to avoid penalizing non-participating customers by offering only DSM programs that reduce electric rates for all customers, DSM participants and non-participants alike.

B. FPL's Current DSM Goals

DSM Goals were first set for Florida utilities in 1994 in Order No. PSC-94-1313 FOF. In 1999 new DSM Goals were set for FPL and other Florida utilities in Order No. PSC-99-1942-FOF. In that order the Commission established for FPL an aggressive goal of achieving 765 MW of incremental summer MW through DSM during the period from 2000 through 2009. This goal reflected what FPL and the Commission believed to be the reasonably achievable, cost-effective levels of incremental DSM on FPL's system. FPL's current DSM Goals were presented in Table II.B.3.

The Goals call for FPL to implement 554 incremental MW of summer peak reduction during the 2000 through 2006 time frame. As mentioned in Section III, FPL assumed that these DSM Goals would be met as it determined what its future capacity needs are.

Without this additional DSM, FPL's future capacity needs would have significantly increased. In fact, FPL's capacity needs would have advanced a year from 2005 to 2004 if the incremental DSM MW called for in the Goals were not implemented. This 2004 capacity need would have been for more than 400 MW.

FPL forecasts that it will achieve its DSM goals of 554 MW of DSM by 2006 (and, subsequently, the 2009 Goal of 765 MW) through a number of DSM programs. These programs are part of FPL's DSM Plan that was approved by the Commission in Order No. PSC-00-0915-PAA-EG. The DSM Plan consists of six residential DSM programs, eight commercial/industrial DSM programs, one research program, and five research projects. A brief summary of each of these programs and research projects appears in Appendix O.

C. The Potential for Additional Cost-Effective DSM

In regard to the question of whether additional, cost-effective DSM could meet FPL's capacity needs for 2005 and 2006, FPL is confident that the answer is "no." There are several bases for this conclusion.

First, the Commission has previously determined that the reasonably achievable, cost-effective summer MW levels of DSM on FPL's system between 2000 and 2005 and 2006 are 484 MW and 554 MW, respectively. This determination was made based upon a comprehensive analysis and record.

Second, FPL has already counted this level of reasonably achievable DSM in its reliability assessment that resulted in the projected need to add 1,722 MW of new supply side resources. In other words, FPL's analysis has already captured the cost-effective DSM available on FPL's system and determined that FPL still needed additional capacity resources.

Third, even if there were some modest potential for additional cost-effective DSM on FPL's system, it is unrealistic to conclude that FPL could implement sufficient new DSM programs in the next three years to mitigate the need for even the smaller projected unit, Martin Unit 8 and its 789 MW of incremental capacity. After accounting for a 20% reserve margin requirement, 658 MW of additional, cost-effective DSM would be needed by the summer of 2005 to avoid this capacity addition. The Commission previously determined there was only 765 MW of additional, achievable, cost-effective DSM for the entire ten-year period, 2000-2009. It would defy reality to conclude that FPL could achieve an additional 658 MW of cost-effective DSM in the next years. This is particularly so given the time necessary to secure approval of new programs or modify existing programs, and the fact that FPL is close to reaching the maximum cost-effective level of load management on its system. So, even if there were cost-effective DSM potential out there not previously found by FPL or the Commission, not enough could be added in the time remaining to meet FPL's 2005 reliability needs or to substantially lower the 2005 and 2006 resource needs that FPL sought to meet through the Supplemental RFP process.

Consequently, FPL's 2005 and 2006 capacity needs can only be met by acquiring new supply side resources.

VII. ADVERSE CONSEQUENCES IF THE PROPOSED CAPACITY ADDITIONS ARE NOT ADDED ON SCHEDULE

FPL needs to keep on schedule in its Determination of Need filings and siting applications, if it is to meet its 2005 and 2006 reserve margin requirements. A delay in securing approval a Determination of Need for these projects will lead to negative consequences for the licensing of these units, and potentially for FPL's system reliability.

A. Adverse Effects Upon FPL System Reliability

Both of the planned capacity additions, Martin Unit 8 and Manatee Unit 3, are currently scheduled to come in-service in mid-2005. These two additions will add approximately 1,900 MW of capability to FPL's system for the summer of 2005, thus, enabling FPL to meet its summer reserve margin criterion of 20%.

The addition of both projects by the summer of 2005 results in a projected reserve margin of 24.0 %. However, if either project is delayed beyond the summer of 2005, FPL would fail to meet its 20% reserve margin criterion. The amount by which the 20% reserve margin would be missed depends upon which project(s) is delayed as shown in Table VII.A.1.

Table VII.A.1

Effects of Project Delays on FPL's 2005 and 2006 Summer Reserve Margins Without Unit Additions

	Scenario	Projected 2005 Summer Reserve Margin	Projected 2006 Summer Reserve Margin
1)	Both Martin Unit 8 & Manatee Unit 3 are in-service by mid - 2005	24.0%	20.9%
2)	Martin Unit 8 only is delayed one year	19.9%	20.9%
3)	Manatee Unit 3 only is delayed one year.	18.2%	20.9%
4)	Both Martin Unit 8 & Manatee Unit 3 are delayed one year	14.1%	20.9%
5)	Both Martin Unit 8 & Manatee Unit 3 are delayed two years (past 2006)	14.1%	11.1%

If both projects are delayed beyond the summer of 2005, FPL's summer reserve margin for 2005 drops significantly to 14.1 %, and FPL's customers will have less reliable electric service. If both projects are delayed past 2006, FPL's projected summer reserve margin for 2006 would be 11.1%, and FPL's customers will have far less reliable electric service.

B. Adverse Impact on Adequate Electricity at Reasonable Cost

Both Martin Unit 8 and Manatee Unit 3 are highly efficient, reasonable cost units. If the projects are delayed, FPL's customers would forgo the lower costs associated with this generation. It would have to be replaced with higher-cost generation, and FPL's resulting fuel and purchased power cost recovery factor would be higher than it might have been. FPL customers would be denied the benefits of adequate electricity at reasonable cost provided by Martin Unit 8 and Manatee Unit 3 to the extent the units are delayed.

C. Adverse Effects Upon Unit Licensing

The impact of delays in licensing on the in-service dates of the new generating capacity depends on the licensing and construction lead times required to meet the proposed in-service dates. Table VII.C.1 shows the time frames generally required to complete state and federal licensing and to construct the units. These are based on prior FPL licensing and construction experience. The time frames shown for licensing are measured from the submission of the Site Certification Application (SCA) under the Florida Electrical Power Plant Siting Act. They do not include the time required for site evaluation, data collection and preparation of the licensing applications. Table VII.C.1 also shows, based on these time frames, the times by which the Commission need certification actions must normally be completed in order to avoid delaying the overall licensing process.

Table VII.C.1					
Lead Times and Licensing Schedule					
Capacity Addition	Latest SCA Filing	Latest Need Decision	Licensing Complete	Construction Period	In-Service Date
Martin CC Unit 8	01Feb02	Nov02	May03	24 months	June 2005
Manatee CC Unit 3	22Feb02	Nov02	May03	24 months	June 2005

VIII. CONCLUSION

FPL needs 1,122 MW of new capacity by the summer of 2005, and another 600 MW of new capacity by the summer of 2006, in order to meet its reliability criterion of a 20% summer reserve margin. With no new capacity additions, FPL's projected summer reserve margins for 2005 and 2006, respectively, are 14.1% and 11.1%.

New baseload capacity additions of the type projected to be the most cost-effective for FPL (*i.e.,* combined cycle) fall under the Commission's Bidding Rule. This Rule requires a utility planning to build such a unit(s) to first solicit proposals so that the utility can determine which approach, building its own unit, purchasing from others, or a combination of both, is the most economical. Consequently, FPL issued an RFP in mid-August of 2001, and a Supplemental RFP in April, 2002.

FPL and an independent evaluator separately analyzed these outside proposals received in response to the Supplemental RFP. First, these outside proposals were individually ranked. Then, using the outside proposals and the two FPL construction options, a number of All Outside expansion plans and an All-FPL self build expansion plan were developed. In each expansion plan, FPL's 2005 and 2006 capacity needs were met solely with either outside proposals or with FPL construction options while FPL's resource needs for 2007-on in each expansion plan were met with generic CC or CT "filler" units. In addition, the outside proposals and FPL construction options were also mixed to create numerous combination expansion plans. Both FPL's and the independent evaluator's analyses showed that the All-FPL self build plan consisting of both FPL construction options being added in 2005 to be more cost-effective than any All Outside or combination plan. Negotiations with short list bidders reinforced this conclusion.

In addition, there are non-price advantages associated with the All-FPL self build plan that make that plan an even clearer choice. Consequently, the All-FPL self build plan consisting of Martin Unit 8 and Manatee Unit 3 is the most cost-effective and best means available to meet FPL's 2005 and 2006 capacity needs.

These two units will be each highly efficient and reliable and will provide FPL's customers with adequate electricity at reasonable cost. Moreover, any delay in licensing will adversely affect FPL's customers, delaying the introduction of new cost-effective power plants and potentially adversely affecting the future reliability and integrity of FPL's electric system.

For the foregoing reasons, the Commission should grant an affirmative determination of need for both Martin Unit 8 and Manatee Unit 3.