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

MARCH 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 Outrage Rate
EGEAS	Electric Generation Expansion and System Analysis Model
FGT	Florida Gas Transmission
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	JEA's 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, Florida Power & Light Company (FPL) determined that it needed to add approximately 1,750 MW of additional generating resources to achieve its 20% reserve margin criterion in the summers of 2005 and 2006. FPL performs such resource planning on an ongoing basis, and FPL's next resource planning analysis (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, 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, which collectively offered over 14,500 MW of generating capacity under varying terms and conditions. The vast majority of the proposals were from as yet unbuilt gas-fired combined cycle units.

After necessary follow-up on the RFP proposals, FPL conducted a comprehensive evaluation of 80 of the 81 outside proposals as well as 13 FPL self-build options. [1] In addition, an independent evaluator was brought in to evaluate both the RFP proposals and the FPL construction options.

[1] As discussed below, one proposal was not reviewed because it relied on a gas tolling arrangement that was not allowed under the RFP.

Both FPL and the independent evaluator analyzed the most cost-effective portfolios of generating unit additions: (1) all outside proposals, (2) all FPL options and (3) combination portfolios consisting of the lowest cost 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.

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

Both economic evaluations showed that a portfolio 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. FPL's evaluation demonstrated that this portfolio would have, in terms of cumulative present value of revenue

Table ES -1

FPL's Power Supply Expansion Plan		
Year	Additions	Incremental Summer MW [1]
2005	**Martin Conversion Project** Convert Martin CT's 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 net peak MW ratings. Actual summer net ratings vary based on final design and performance testing.

requirements (CPVRR), a $12 million advantage over the next lowest cost portfolio, which consisted of the Manatee CC unit, a 25-year purchase from a 465 MW gas-fired facility and a 5 year 150 MW system purchase from another utility. The independent evaluator determined that Martin Unit 8 and Manatee Unit 3 would have a $36 million cost advantage over this same next lowest cost portfolio. FPL's proposed power supply plan is shown in Table ES-1.

The Martin Unit 8 and Manatee Unit 3 expansion portfolio also enjoys some significant additional non-price advantages. The next lowest cost alternative includes capacity from a financially distressed developer to be served by an as yet unbuilt (and unpermitted) gas pipeline from the Bahamas. The Martin Unit 8 and Manatee Unit 3 portfolio therefore involves significantly less risk than the alternative. In addition, the Martin Unit 8 and Manatee Unit 3 portfolio will result in benefits to customers from full utility control over the operation and dispatch of the units, off-system sales when not needed to meet FPL customer needs, residual value of the units at the end of twenty-five years, and FPL not having to incur costs to administer and enforce contract terms. Also, the 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 portfolio, FPL is proceeding with the licensing of Martin Unit 8 and Manatee Unit 3. This expansion 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 no 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 using two existing CTs at FPL's existing Martin site, along with 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.[2] 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:

[2] This is the summer net rating for both units. 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 planned generating units (Section III);
- an explanation of FPL's need for 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 analyses 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 are currently 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[3] 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 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, six CC units, twenty-one fossil steam units, fifty-six combustion/gas

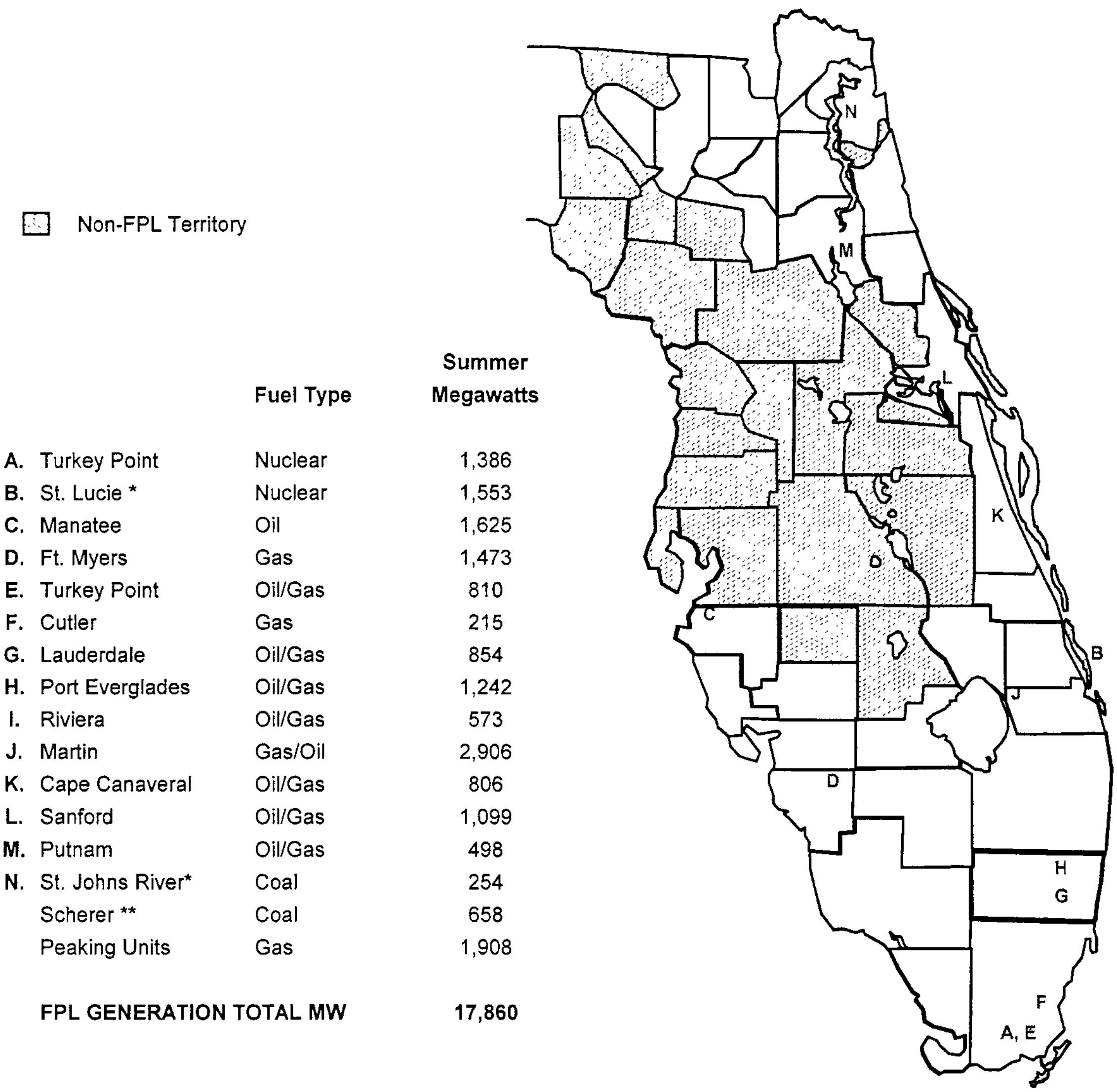
[3] This includes 75 miles of 500 kV lines, composed of two 37-1/2 mile lines, between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority.

turbines[4], 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.

[4] Six of the fifty-six turbines have recently been added at Ft. Myers and are currently operating in a stand-alone, simple cycle mode. These six were installed as part of FPL's the Ft. Myers repowering project and will soon be integrated into a new CC unit. Another two turbines were installed at Martin and will be used in the Martin Expansion project that is discussed throughout this document.

Figure II.B.1.1

FPL's Generating Resources
(Projected Summer 2002 Capabilities)



		Fuel Type	Summer Megawatts
A.	Turkey Point	Nuclear	1,386
B.	St. Lucie *	Nuclear	1,553
C.	Manatee	Oil	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 eight 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.[5]

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

[5] 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
Royster Mulberry	Polk	Waste Heat	8.0	4/1/92	3/31/02
			1.0	12/1/95	3/31/02
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, with a minimum of 380 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 in 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

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.[6] 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.

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[6] 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.[7] 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.

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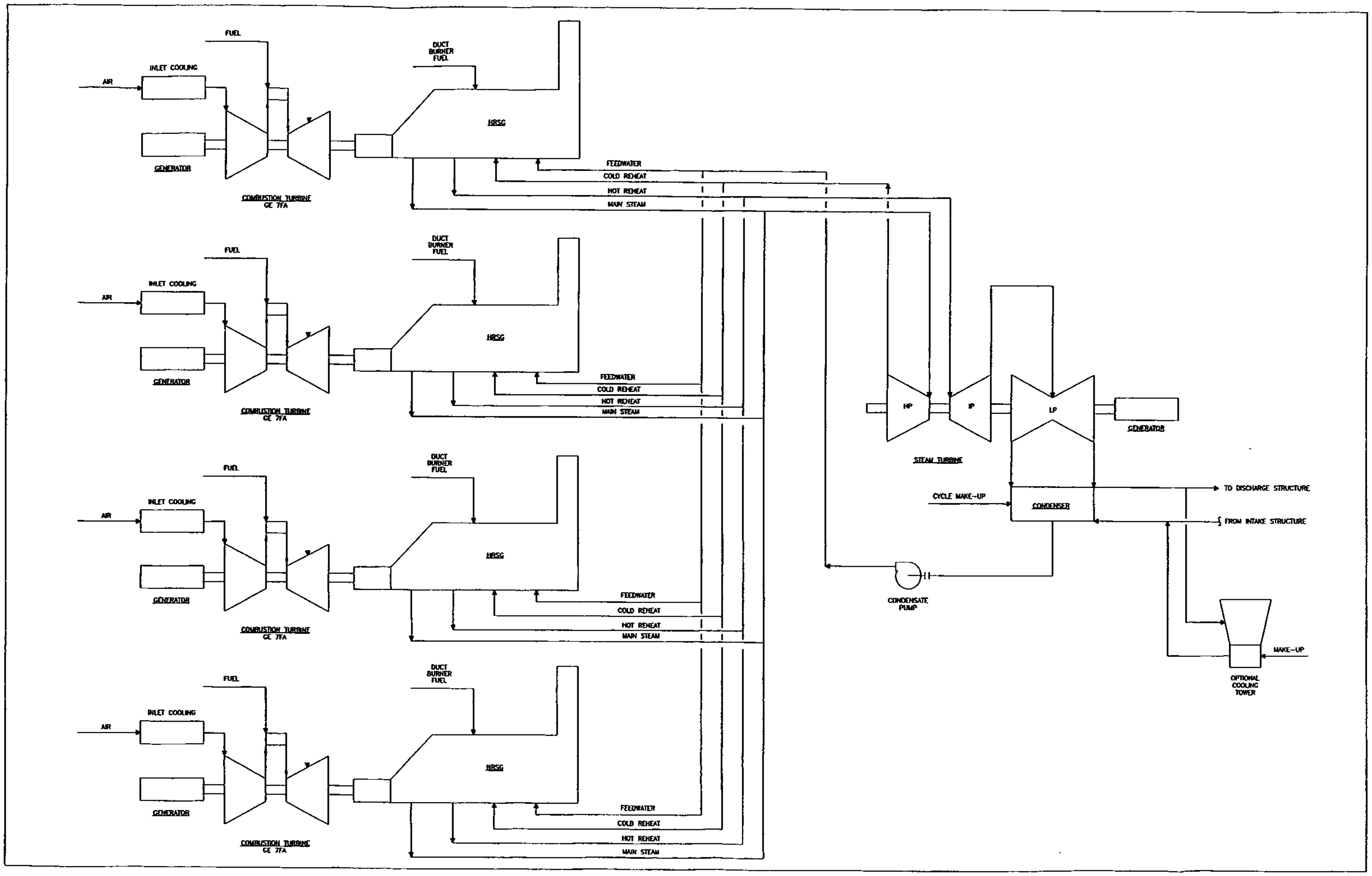
[7] Both the Martin Unit 8 and Manatee Unit 3 employ four HRSGs, one for each CT.

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 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 a fuel savings of about 25 percent. FPL anticipates that the new Martin and Manatee combined cycle units will achieve a highly-efficient 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.[8] 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

[8] 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.

rating (at 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 the 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. 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 – 824 MW
  Steam electric generating unit firing residual oil and natural gas
- Unit 2 – 816 MW
  Steam electric generating unit firing residual oil and natural gas
- Unit 3 – 474 MW
  CC generating unit firing natural gas with light oil capability
- Unit 4 – 474 MW
  CC generating unit firing natural gas with light oil capability
- Unit 8A – 159 MW
  Simple cycle generating unit firing natural gas and light oil

- Unit 8B – 159 MW
  Simple cycle generating unit firing natural gas and light oil

The Martin Plant site currently has a total summer net peak generating capability of approximately 2,906 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

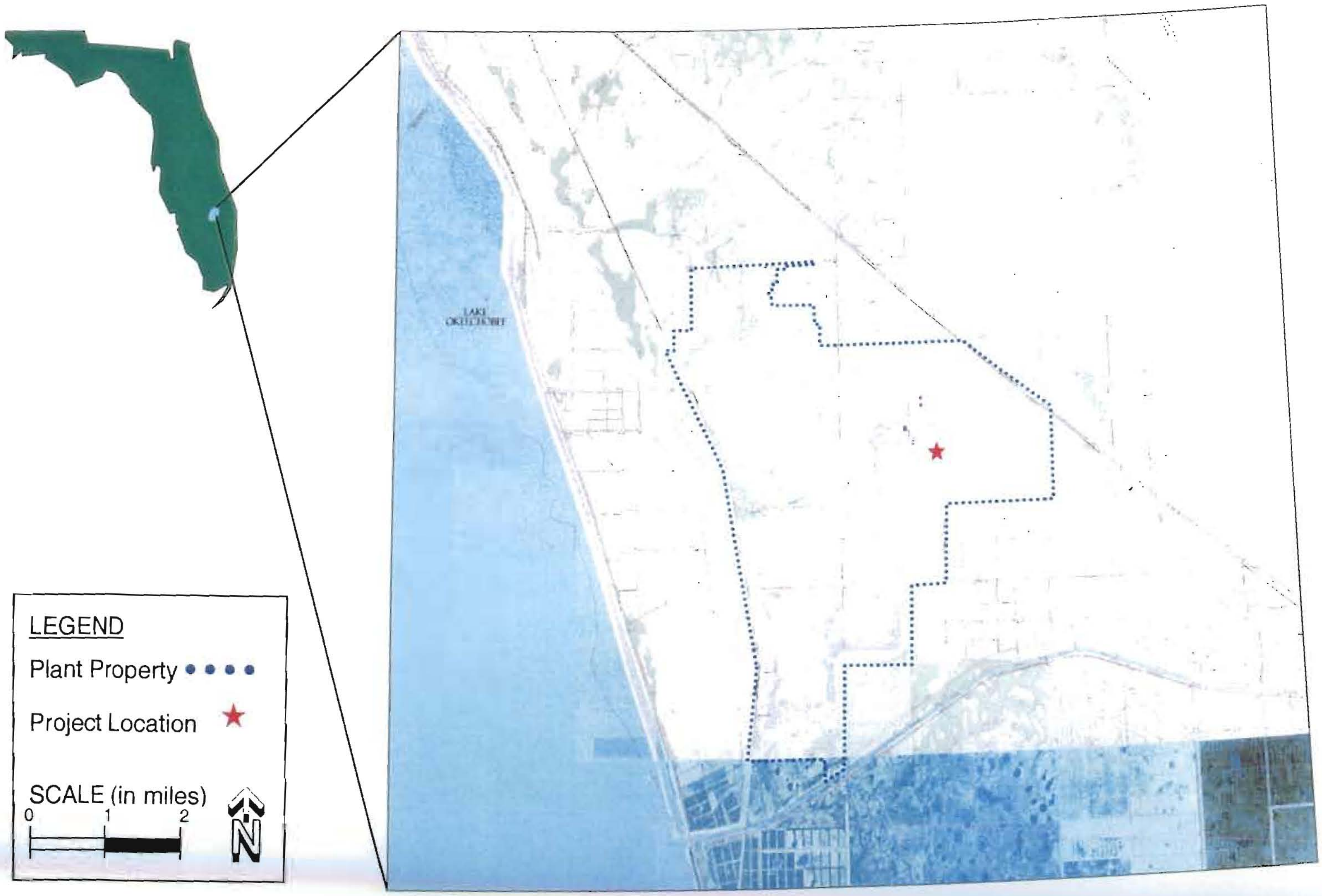
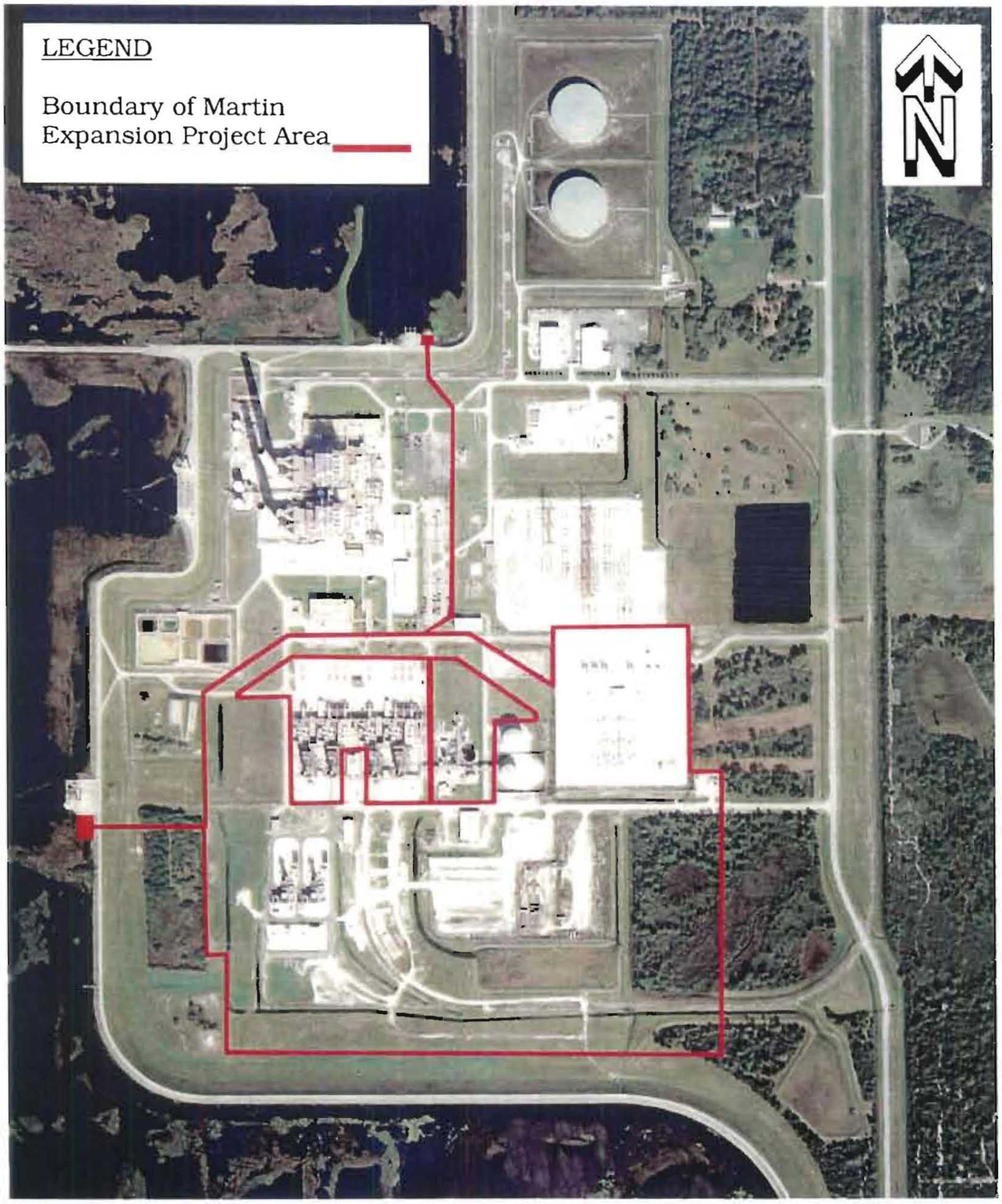


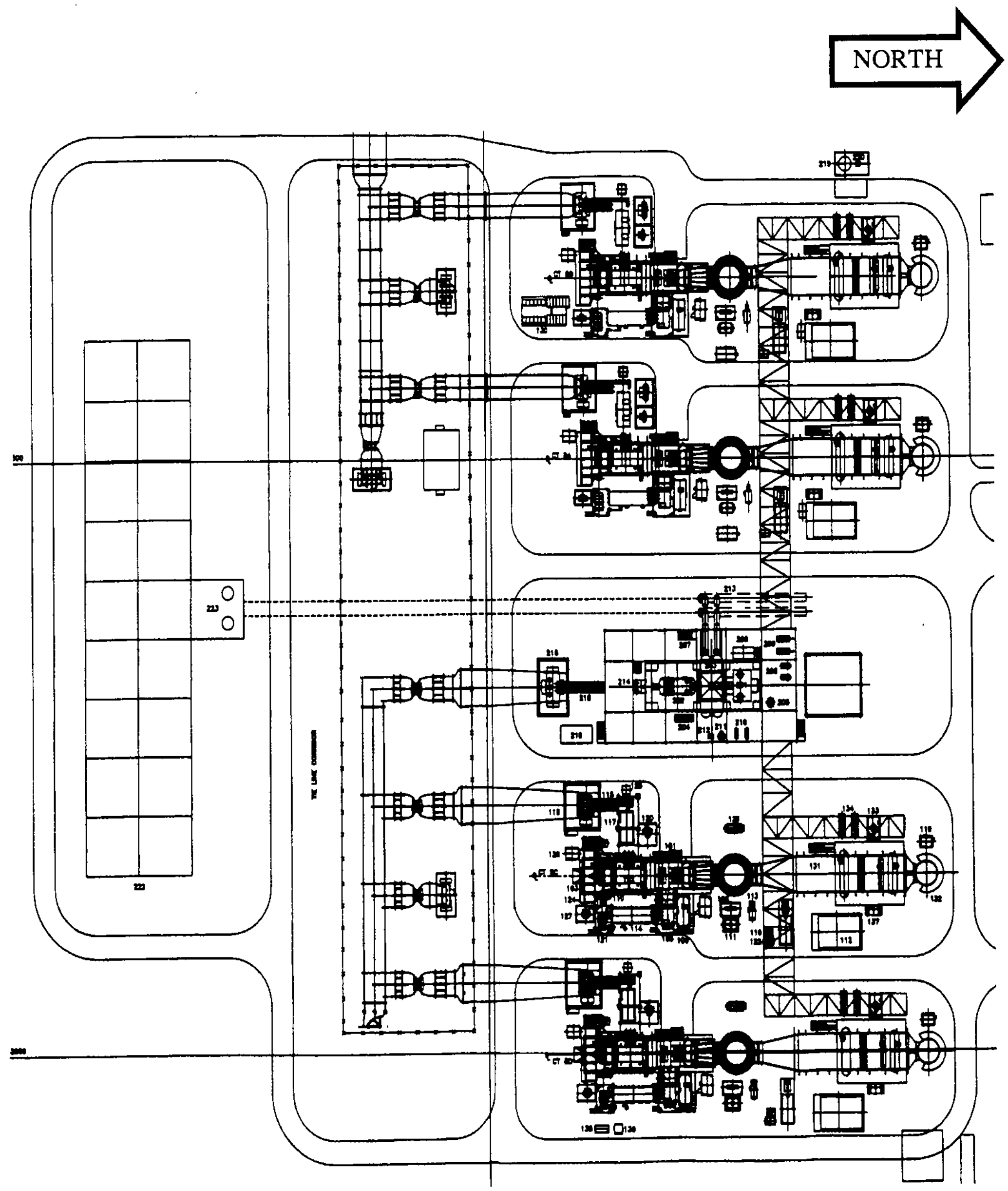
FIGURE III.A.1.2
AERIAL PHOTOGRAPH OF MARTIN PLANT DEPICTING THE PROJECT BOUNDARY



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 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 (75°F).

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

An additional 27 MW of output 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 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, and light oil will be trucked to the site. No onsite storage will be provided for natural gas.

Two gas 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, so 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, amongst others, would independently undertake the necessary permitting and construction activities for this new lateral.

Since 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) are already 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 will also 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 will also 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.

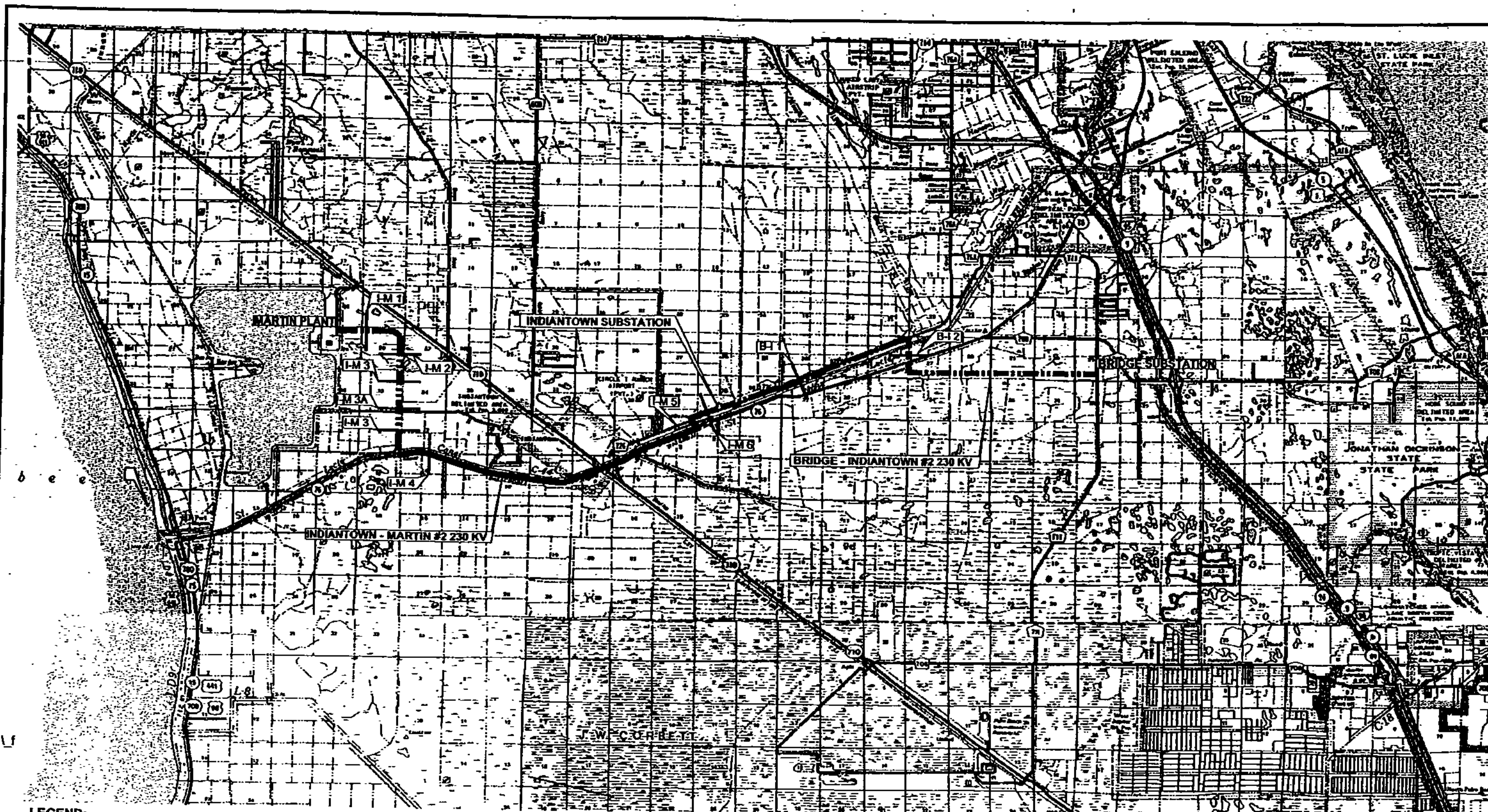
4. Transmission Interconnection

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

Existing transmission circuits will be upgraded to accommodate the output from Martin Unit 8. All new or upgraded circuits will be within existing transmission right-of-way, with the exception of 8.5 miles of the Martin-Indiantown #2 and Indiantown-Bridge #2, 230 kV Lines, as shown in Figure III.A.5.1. This includes significant associated transmission facilities, which are depicted in Figure III.A.5.1, and constitute part of the transmission integration of the project.

FIGURE III.A.5.1
DEPICTION OF MARTIN UNIT 8 TRANSMISSION FACILITIES



LEGEND:

- PROJECT CORRIDOR (TO BE CERTIFIED)
- CROSS SECTION #
- NEW 230 kv LINE ALONG EXISTING ROW (NOT TO BE CERTIFIED)

RESOURCES:

GENERAL HIGHWAY MAP, MARTIN COUNTY, FLORIDA, U.S. DEPARTMENT OF TRANSPORTATION, FEDERAL HIGHWAY ADMINISTRATION, AUGUST 1985.

GENERAL HIGHWAY MAP, PALM BEACH COUNTY, FLORIDA, U.S. DEPARTMENT OF TRANSPORTATION, FEDERAL HIGHWAY ADMINISTRATION, AUGUST 1975 (SHEETS 1 & 2).

Golder Associates, Tampa, Florida	SCALE 1:126720	TITLE	PROJECT CORRIDOR LOCATION
	DATE 1/27/02		
	DESIGN RAZ		
	CADD DM		
FILE No. 0137609A012 FIG 6_1_2	CHECK		
PROJECT No. 0137609-1502 REV. 0	REVIEW		MARTIN UNIT 8

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

	Begin	End
Initiate sequence of HRSG orders (LNTP x 4)	Jul 02	Sep 02
Initiate sequence of combustion turbine orders (LNTP x 2)	Aug 02	Oct 02
Issue LNTP for steam turbine		Sep 02
Receive approvals necessary to begin construction		May 03
Site Prep & Foundations	Jun 03	Jan 04
Balance of Plant	Aug 03	Dec 04
Erect HRSGs	Feb 04	
Erect CTs	Apr 04	
Erect steam turbine	Apr 04	
Startup	Jan 05	May 05
Commercial operation		Jun 05

7. Estimated Capital Cost

The estimated total installed cost for the Martin Unit 8 is $473 million (2005 dollars). This cost estimate was used in FPL's comparative economic analysis, and it includes $374 million for the power block, $7 million for the transmission interconnection, $30 million for transmission integration and $62 million in allowance for funds used during construction (AFUDC). The components of this total project cost are shown in Table III.A.7.1.[9]

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

Plant	$374
Transmission Interconnect	$7
Transmission Integration	$30
AFUDC	$62
Total Cost	$473

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 – 815 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 generating capability of approximately 1,625 MW. The site includes a 4000-acre cooling pond that serves Units 1 and 2.

[9] These costs are based on attributing a new transmission line that is needed for the Martin and Manatee expansion projects to Martin Unit 8 for purposes of this Need Study. Because the line is only needed if *both* projects are built its costs could be attributed to either project.

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; 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

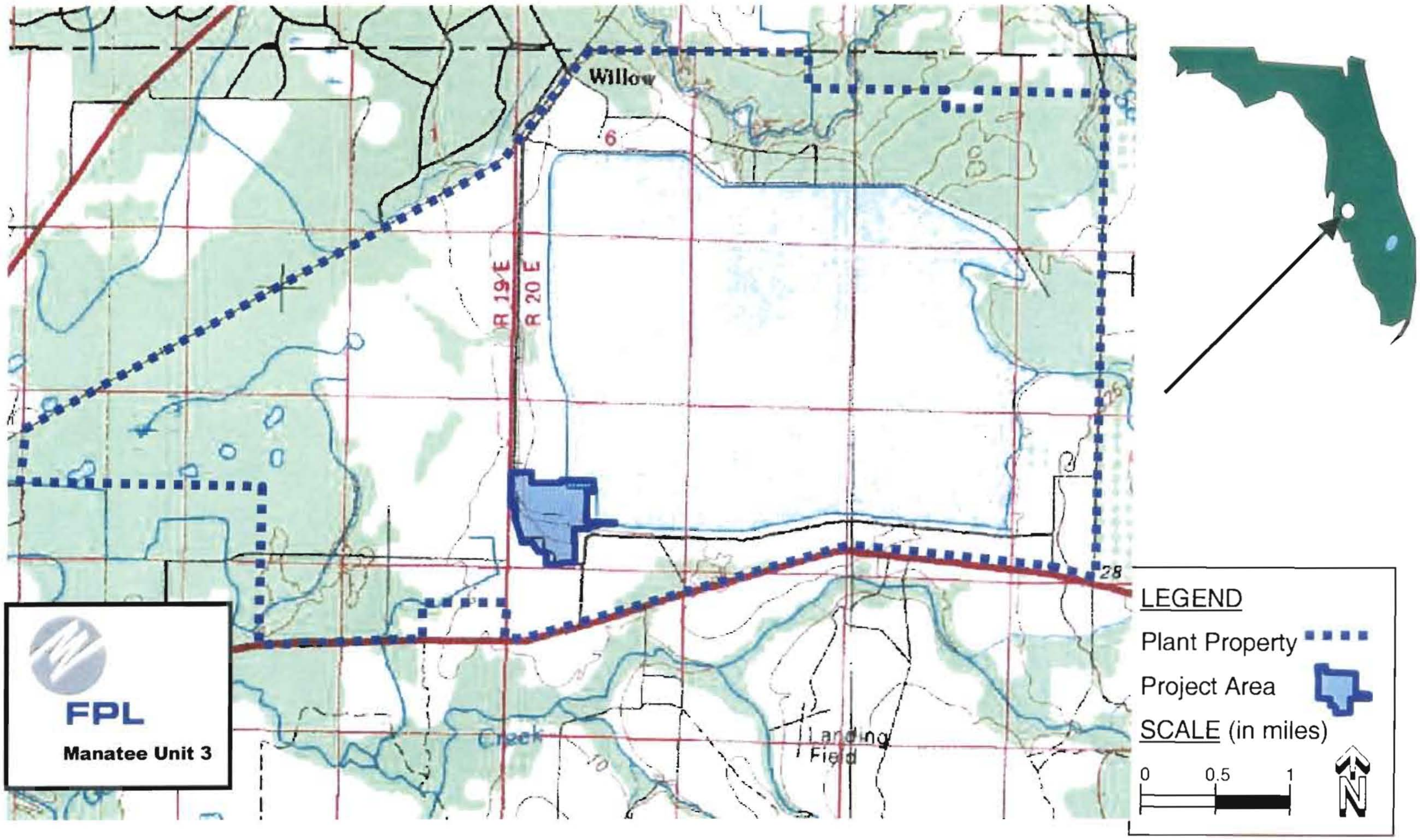
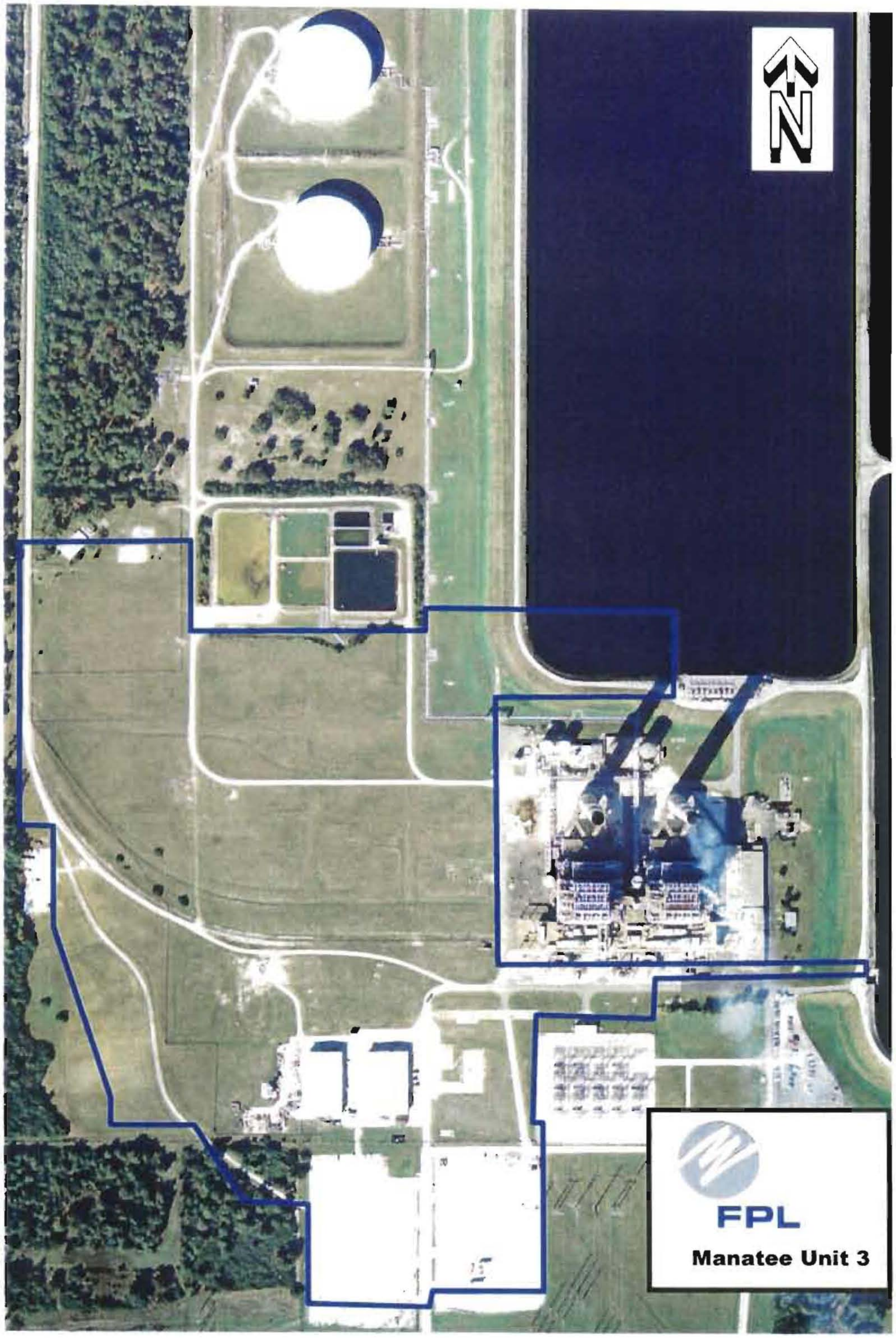
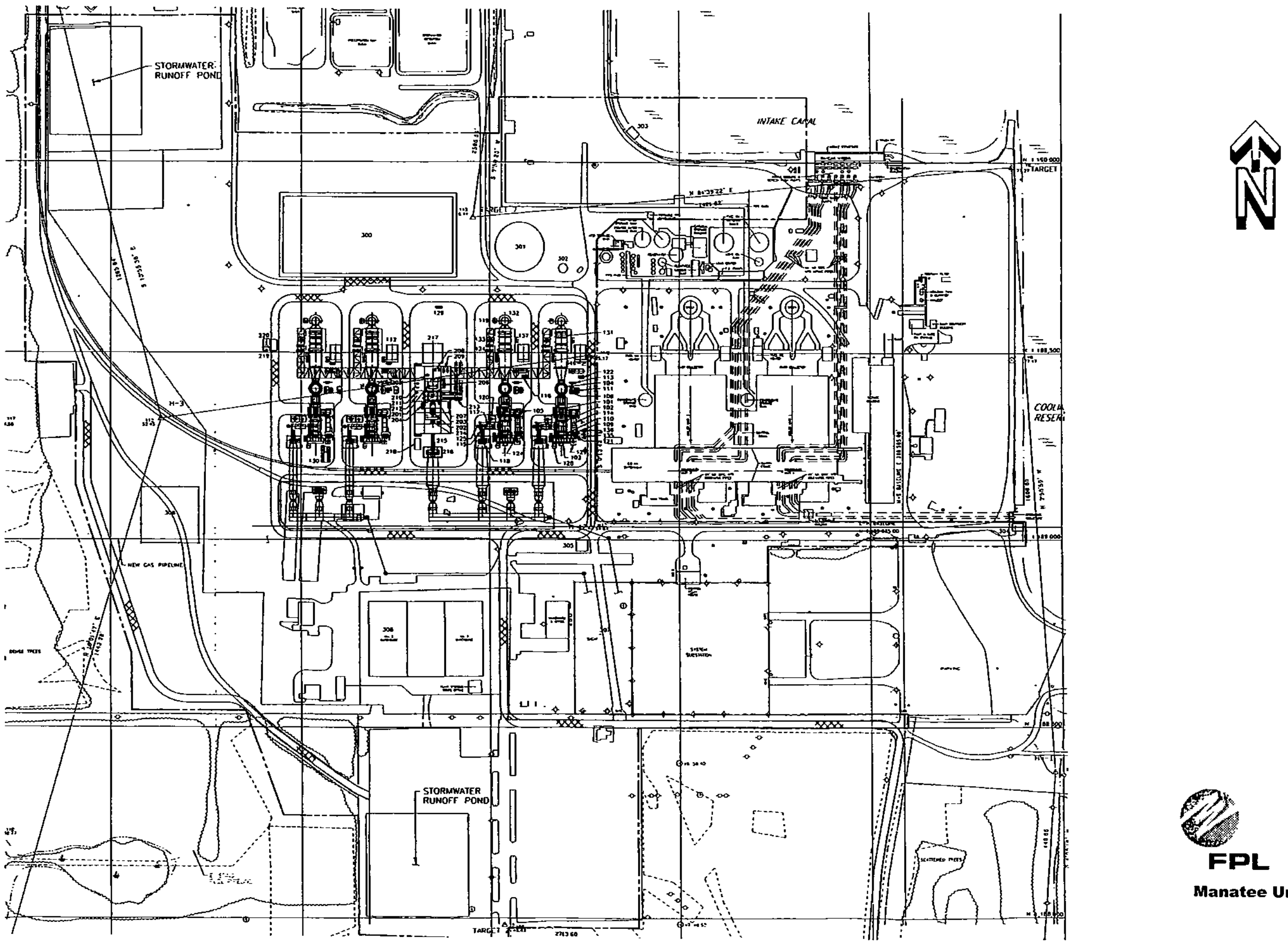


FIGURE III.B.1.2
AERIAL PHOTOGRAPH OF MANATEE PLANT DEPICTING THE PROJECT BOUNDARY



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 "F" Class advanced CTs, with dry low 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. 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).

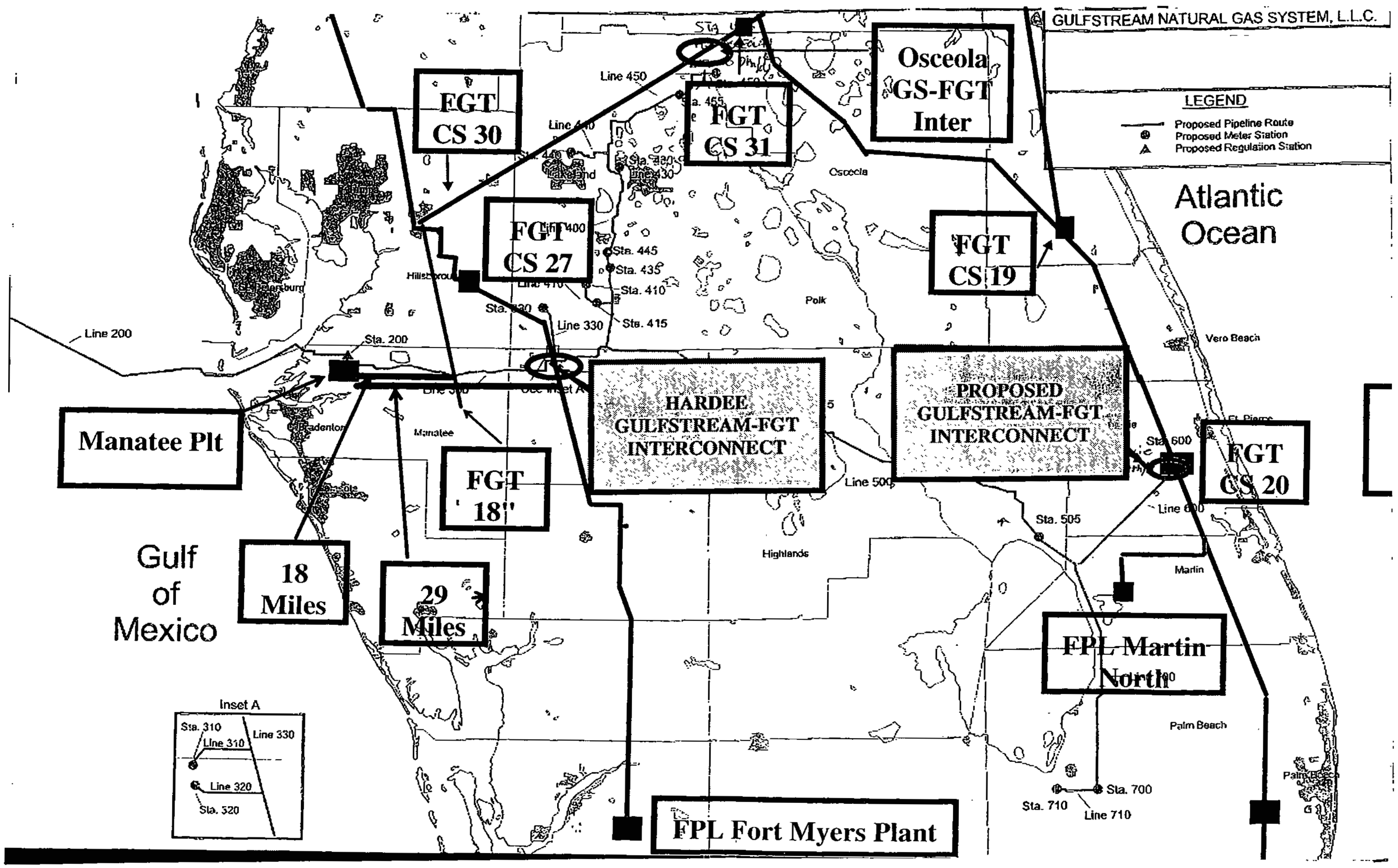
An additional 27 MW can also be achieved by raising the fuel flow to the CT for "peak firing mode" operation. Peak firing reduces the heat rate of the entire unit and the expected incremental heat rate for peak firing is 5,600 Btu/kWh (95°F). However, peak firing will shorten the normal replacement period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

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. By June of 2002, Gulfstream will 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.F

DIAGRAM OF PIPELINE SERVICE TO MANA'



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 SO_2 and emissions, and combustion controls will minimize NO_x, CO and VOC emission. Also, like the Martin unit, the Manatee Unit 3 HRSGs will have a SCR system for control of NO_x emissions.

Primary water uses for Manatee Unit 3 will be for condenser cooling, CT inlet foggers, steam cycles 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 makeup 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

Existing transmission circuits will be upgraded to accommodate the output from Manatee Unit 3. All new or upgraded circuits will be within existing transmission right-of-way. The total transmission integration cost for Manatee Unit 3 is estimated to be $13 million (2005 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 combustion turbine orders (LNTP x 4)</td><td>Jul 02</td><td>Sep 02</td></tr>
<tr><td>Initiate sequence of HRSG orders (LNTP x 4)</td><td>Aug 02</td><td>Oct 02</td></tr>
<tr><td>Issue LNTP for steam turbine</td><td></td><td>Sep 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 $566 million (2005 dollars). This cost estimate was used in FPL's comparative economic analysis, and it includes $466 million for the power block, $10 million for the transmission interconnection, $13 million for transmission integration and $77 million in AFUDC. The components of this total project cost are shown in Table III.B.7.1.

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

Plant	$466
Transmission Interconnect	$10
Transmission Integration	$13
AFUDC	$77
Total Cost	$566

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. Figure III.C.1 is a "fact sheet" summarizing various aspects of Martin Unit 8. Figure III.C.2 is a similar "fact sheet" summarizing various aspects of Manatee Unit 3.

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)	1,107 MW
Annual Average (75°F)	1,149 MW
Winter (35°F)	1,197 MW

Projected Unit Performance Data:

Forced Outage Rate (EFOR)	1%
Scheduled Maintenance Outages	1 wk/yr (2% POF)
Equivalent Availability Factor (EAF)	97%
Base Average Net Operating Heat Rate @ 75°F	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	6,857,880 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}	11 lb/hr	36.9 lb/hr
SO_2	9.8 lb/hr	98.6 lb/hr

Water Balance:

- Total site consumptive water use will be within current SFWMD annual allocation
- Annual average consumptive use for Martin Unit 8 is approximately 4 MGD
- Process wastewater recycled to cooling pond

Linear Facilities:

- 8.5 miles of new 230 kV transmission ROW
- Two (2) FGT gas laterals currently supply Martin site; possibility of contracting with another supplier
- 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)	1,107 MW
Annual Average (75°F)	1,149 MW
Winter (35°F)	1,197 MW

Projected Unit Performance Data:

Forced Outage Rate (EFOR)	1%
Scheduled Maintenance Outages	1 wk/yr (2% POF)
Equivalent Availability Factor (EAF)	97%
Base Average Net Operating Heat Rate @ 75°F	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	6,857,880 scf/hr

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

NO_x (@ 15% O_2)	2.5 ppmvd
CO	9 ppmvd
PM_{10}	11 lb/hr
SO_2	9.8 lb/hr

Water Balance:

- Annual average consumptive use for Manatee Unit 3 is approximately 8.9 MGD
- Process wastewater recycled to cooling pond

Linear Facilities:

- No new transmission ROW required
- 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 meets 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 was scheduled to come in-service by 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 June 2002. 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 the 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% through mid-2004 and 20% thereafter) and a maximum of 0.1 days/year Loss-of-Load-Probability (LOLP).[10]

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

[10] 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, TECO and 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.

This determination is consistent with the reliability assessment results of FPL's 2000 IRP, in which FPL determined that a minimum total addition of 1,708 MW were needed for 2005 and 2006.[11] In 2001 this projection was revised slightly to 1,722 MW. The slight difference in the 2000 and 2001 IRP results is primarily due to two updated inputs in the later analysis.

The first of these updates was a change in the MW to be received from a series of short-term power purchase agreements that FPL had not yet finalized when the 2000 IRP was completed. (The 2000 IRP work is reported in the 2001 Site Plan that was filed in April 2001.) Consequently, the 2000 IRP used an estimate of the amount of purchased MW from those agreements. The agreements were all finalized in mid-2001, and the final agreements showed that FPL would receive more MW than had been assumed in the 2000 IRP work. By itself, this change in the short-term purchased MW would have lowered FPL's capacity needs for 2005 and 2006. However, FPL's load forecast increased in the 2001 IRP and therefore offset the effect of larger-than-projected power purchases.

When the two changes were combined, they largely cancelled each other out, with the 2001 projection of the total capacity needs for the years 2005 and 2006 rising slightly to 1,722 MW.

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[11] This value was rounded up to 1,750 MW for purposes of FPL's RFP solicitation.

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 three-on-one CC unit at FPL's Martin site (547 MW); and,
- Construction of a new three-on-one CC unit at FPL's Midway site (547 MW).

For 2006:

- Construction of another new three-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 under the Commission's "Bidding Rule" (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. A copy of the RFP is attached as Appendix E.

While FPL awaited the receipt of proposals submitted in response to the RFP, it updated its planning assumptions and forecasts so that they would be in place when the proposals were received. These assumptions and forecasts included peak load and annual energy forecasts, fuel price and availability forecasts, financial and economic data, and power plant capability and reliability values.

FPL ultimately received 81 RFP proposals from 15 entities. The evaluation process used to analyze 80 of these proposals and FPL's 13 construction options is discussed in more detail in a later section.[12] 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 portfolio 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. The RFP bidders and the Commission were informed of FPL's decision, and efforts were accelerated to prepare the necessary licensing applications.

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 the financial and economic data assumptions. This section discusses these major forecasts and assumptions that serve as inputs to the resource planning process.

[12] One proposal was deemed ineligible since it proposed a natural gas tolling arrangement that was specifically prohibited in the RFP.

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. In the area of demographics, population trends by county, plus housing characteristics such as housing starts, housing size, and vintage of homes, are assessed.

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), Metro-Dade County, and FMPA.

(ii) Net Energy for Load (NEL)

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.

A separate annual econometric model is also developed to produce a NEL forecast.[13] 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, varying weather conditions, continued 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.

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

(A) **Summer Peak** demand is developed using an econometric regression model developed on a per-customer basis. The key variables included in the summer 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 RFP analyses are presented in Appendix F. Also presented in Appendix F are the output from the models used to develop FPL's peak load forecast and the 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, and different availabilities, 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 and availability 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 a 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 Results

The detailed fuel price and availability forecasts for these fuels are presented in tabular form in Appendix G.

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 the Florida Gas Transmission Pipeline System or the Gulfstream Natural Gas Pipeline System. For the Manatee site, FPL will have the capability to utilize both systems due to nearby 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.

(ii) Oil

The alternate fuel for Martin Unit 8 is light oil, which would be trucked from local markets to the plant 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 RFP proposals and FPL construction options are presented in Appendix H.

C. FPL's Request for Proposals (RFP)

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. Since CC units fall under the Commission's Bidding Rule, it was apparent that FPL would need to issue a RFP. Consequently, in 2001 FPL 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.

The RFP was announced in an August 13, 2001 advertisement in the Wall Street Journal and in a press release that was carried in numerous Florida newspapers and trade publications. A copy of the Wall Street Journal advertisement is presented in Appendix I. FPL filed a copy of the RFP with the Commission as well.

The notice of the RFP stated that interested parties needed to submit a RFP registration fee of $500 along with their request for the RFP document. This registration fee also allowed interested parties to attend a Pre-Bid Workshop in Miami on August 24, 2001. Individuals representing 31 organizations, including the Commission Staff, attended the workshop.[14]

At the Pre-Bid Workshop, FPL provided a detailed explanation of the RFP, the schedule to be followed, and the RFP forms to be completed. Following its presentation, FPL accepted and orally answered written questions from the audience. FPL also announced that all of these questions, plus any additional questions that potential Bidders wished to later submit via e-mail, would be placed on a special FPL website along with the answers. This website, which was available only to RFP-registered parties, was maintained by FPL through the Due Date for the proposals. A copy of the final list of the questions and answers as they appeared on this website is shown in Appendix J.

[14] This number includes organizations interested in renewable energy proposals that were also requested in the RFP but which are unrelated to these proceedings.

As a result of inquiries from potential bidders, FPL modified its RFP in two ways. First, it extended the Due Date for proposals from September 14, 2001 to September 28, 2001 to give potential bidders more time to prepare proposals. Second, it modified the "regulatory out" clause language in the RFP. Both of these changes were subsequently filed with the Commission.

The next step in the RFP process was the submittal of a Notice of Intent to Respond to the Solicitation form and an accompanying check for a second $500. This was required of all parties who wished to subsequently submit a bid. The Notice of Intent to Respond to the Solicitation form and check were due on August 31, 2001. FPL received submittals of forms and checks from 19 organizations for firm capacity projects totaling approximately 20,000 MW.

The final step was the submittal of the actual proposals. On the revised Due Date of September 28, 2001, FPL received firm capacity proposals from 15 organizations that consisted of 3 electric utilities and 12 non-utilities. The total amount of capacity offered in these proposals exceeded 14,500 MW.

A number of these bidders submitted more than one proposal. Furthermore, in the course of e-mail and telephone conversations with these bidders to clarify the information contained in their proposals, the number of proposals to be evaluated increased. This occurred as some bidders decided they wanted their proposals evaluated for both 2005 and 2006, while other bidders wanted one or more variations of their proposal evaluated as well. Ultimately, 81 proposals were offered to FPL in response to the RFP. The vast majority of these were power purchase offerings from as yet non-existent generating units, primarily natural gas-fired CC units.

A lengthy period of clarifying information in the proposals, lasting more than a month, delayed the start of FPL's analyses. This delay in starting, plus the sheer volume of proposals to be evaluated, stretched out the analyses that followed and caused FPL's announcement of the results of its analyses to slip from November to mid-January.

D. FPL Construction Options

The identification of the Martin and Manatee sites as preferred candidates for the construction of new CC units are 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. Since 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 should also 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.

However, even development at an existing power generation-site needs to take steps to minimize the impacts on surrounding communities. With this consideration, five FPL power plant sites were selected for site-specific screening analysis, which resulted in the thirteen options shown on Table V.D.1:

Table V.D.1
Candidate Self-build Capacity Additions

Location	Technology	Primary Fuel	Level of Duct Firing	Incremental Net Summer Peak Capability*
Fort Myers	(1) - 2x1 CC	Natural gas	Moderate	237 MW
Port Everglades	(2) – 4x1 CC repowering	Natural Gas	Light	1258 MW
Manatee	(1) – 3x1 CC	Natural Gas	Moderate	833 MW
	(1) – 4x1 CC	Natural Gas	Moderate	1107 MW
Martin	(2) – 300 MW pulverized coal boiler	Petroleum coke	N/A	600 MW
	(1) – 3x1 CC	Natural Gas	Light	763 MW
	(1) – 3x1 CC	Natural Gas	Moderate	833 MW
	(1) – 3x1 CC expansion of Units 8A&B	Natural Gas	Moderate	515 MW
	(1) – 3x1 CC	Natural Gas	Heavy	881 MW
	(1) – 4x1 CC	Natural Gas	Moderate	1110 MW
	(1) – 4x1 CC expansion of Units 8A&B	Natural Gas	Moderate	789 MW
Sanford	(1) – 1x0 simple cycle w/ HRSG to provide power augmentation for new CT and existing Unit 4 CTs	Natural Gas	None	214 MW
	(1) – 1x0 simple cycle w/ HRSG to provide power augmentation for new CT and existing Unit 5 CTs	Natural Gas	None	214 MW

* The capacity values shown for each option reflect FPL's final analysis of the option.

Each of the thirteen options were evaluated by developing site-specific capital cost estimates for construction that included consideration of fuel supply, cooling system design, transmission interconnection, and site development. The capital cost estimates were prepared on a consistent basis using conceptual engineering costs and FPL's knowledge base of power plant construction costs. FPL's capital cost estimating tools are based on FPL's first-hand knowledge of the cost of constructing safe and reliable CC power plants in Florida (Putnam 1&2, Lauderdale 4&5, Martin 3&4, Fort Myers 1, Sanford 4&5). A more detailed list of the 13 FPL self-build construction options analyzed by FPL is presented in Appendix K.

E. Economic Evaluation of the Options

FPL ultimately performed economic evaluations of 80 outside proposals and 13 self-build FPL construction options. (One outside proposal was deemed to be ineligible since it was based on a natural gas "tolling" arrangement that was not allowed in the RFP. The evaluation fee for this proposal was returned to the bidder.) In addition, an independent evaluator, Sedway Consulting, Inc. ("Sedway"), was retained to evaluate the outside proposals and FPL construction options.

1. FPL's Analysis

FPL conducted a "blind" evaluation of the outside proposals. In other words, the persons performing the analyses were unaware of the identity of each organization that submitted a proposal and were unaware of the location of each project. To ensure this, a unique code number was assigned to each of the outside proposals by an FPL planner who was not responsible for conducting the evaluations. Only this person and the RFP contact person knew the code-number associated with each bidder. (The RFP contact person for the bidders needed this code information since it was necessary to contact bidders when questions arose regarding their proposals.) The code numbered information was given both to the FPL analysts conducting the evaluation and to the independent evaluator.

FPL's analysis first developed individual rankings of all outside proposals. Separate individual rankings for the FPL construction options were then developed. (These individual ranking analyses were carried out a number of times as information about the options was clarified and/or assumptions changed.) Ultimately, based on the results of these individual ranking analyses, a determination was made of which outside proposals and which FPL construction options to carry forward for additional analyses.

These additional analyses consisted of developing generation expansion plans that addressed FPL's capacity needs through the year 2020. In these expansion plans, FPL's capacity needs for 2005 and 2006 were met with either outside proposals alone, FPL construction options alone, or a combination of outside proposals and FPL construction options.

The capacity needs for 2007-on were met in these expansion plans with essentially generic CC or CT "filler" units that could be selected by FPL's computer model. This approach allowed the analyses to fairly compare 3-year options versus 25-year options by creating a comparable stream of revenue requirements for meaningful comparison and recognizing that any short-term option would have to be replaced by another resource when its term ended.

FPL conducted most of its economic analyses using the EGEAS model designed by Stone & Webster for the Electric Power Research Institute. FPL has used the model in its annual resource planning work for a number of years.

The EGEAS model is well suited to the type of analysis carried out in this evaluation. It is a sophisticated tool for analyzing utility resource options. It is an optimization model that can examine a number of resource options for meeting a utility's future resource needs by utilizing the resource options in question to create a number of resource expansion plans that meet a utility's reliability criteria over many years. The capital and operating costs of these resource options are calculated and added to the production costs of the other generating units in the utility system. In this way, there is an accounting for the impacts of each resource option on the operation of the existing generating units. Then the resulting resource expansion plans are compared to determine the economics of each plan.

However, the EGEAS model has a direct limitation in the number of options it can evaluate in one run. This is further limited by the time it takes to complete an evaluation. The more options there are to evaluate and/or the longer the time period addressed in the analysis, the longer the computing time. The direct limitation on the number of options EGEAS can evaluate in one run is 50. Therefore, it was impossible to evaluate all 80 outside proposals in one optimization run and they had to be broken down into groups of a more manageable size.

As noted, a major factor is deciding the size of these groups is EGEAS's run time. This indirect limitation is primarily dictated by the number of options being evaluated. In addition, many of the options, both outside proposals and FPL construction options, had a duct-firing or power augmentation feature. To properly model these options, FPL treated each of those features as a separate "unit" that is "linked" to the generating unit's base operation mode (also modeled as a separate unit). In other words, if the EGEAS model selects the base operation "unit," it must also select the associated duct-firing or power augmentation "unit" as well. This means that one generating unit proposal can take up to two available slots in an EGEAS run if the proposal has two operational modes.

FPL ultimately decided, largely based on the run time of the model, that the optimum number of slots to include in an optimization run was approximately 20.

Much of FPL's evaluation took place from November of 2001 through early January of 2002. Prior to November there was a period of about a month (from the proposal Due Date of September 28, 2001 to early November) that was used to clarify information in many of the proposals and perform "shake down" initial computer runs of some of the outside proposals. The "shake down" runs during this period served primarily to help identify data in the outside proposals that needed clarification.

Analyses determining the relative economics of the outside proposals and FPL construction options began in early November of 2001. The basic analytic approach was to first perform individual rankings of the outside proposals alone and of the FPL construction options alone. Then, based primarily on the results of these individual rankings, the top outside proposals and/or FPL construction options would be utilized in analyses designed to determine three types of groupings:

1) the best "All Outside" group of outside proposals that could meet FPL's 2005 and 2006 capacity needs;

2) the best "All FPL" group of FPL construction options that could meet FPL's 2005 and 2006 capacity needs; and,

3) the best "Combination" group of a mixture of outside proposals and FPL construction options that could meet FPL's 2005 and 2006 capacity needs.

In both the individual ranking and grouping (i.e., full expansion plan) analyses, FPL utilized the EGEAS model. The individual rankings (and the expansion plan runs that followed) were performed several times over the evaluation period as assumptions about the outside proposals, FPL construction options, and/or other inputs changed.

Once the initial analyses were performed to develop the most economical All Outside expansion plans, the most economical All FPL expansion plans, and the most economical Combination plans, one preliminary conclusion was reached. The best All Outside plans did not appear to be able to compete with either the best Combination plans or the best All FPL plans. Therefore, the focus of the EGEAS analyses became to evaluate the most economical Combination plans relative to the best All FPL plans.

FPL completed most of its EGEAS analyses in early January. These analyses focused on the five best Combination plans EGEAS identified and the best All FPL plan. These plans were composed of the following options:

<u>All FPL Plan</u>: Martin Expansion (conversion of 2 CTs into a 4x1 CC unit)
New Manatee CC (a 4x1 CC unit)

Combination Plan 1: Martin Expansion (conversion of 2 CTs into a 4x1 CC unit)
FC 3 (25 year, 465 MW purchase from CTs)
FC 58 (3 year, 526 MW purchase from CC)

Combination Plan 2: Martin Expansion (conversion of 2 CTs into a 4x1 CC unit)
FC 3 (25 year, 465 MW purchase from CTs)
FC 71 (3 year, 300 MW purchase from CC system)
FC 72 (10 year, 300 MW purchase from CC system)

Combination Plan 3: Martin Expansion (conversion of 2 CTs into a 4x1 CC unit)
FC 65 (25 year, 465 MW purchase from CTs)
FC 19 (3 year, 526 MW purchase from CC)

Combination Plan 4: Martin Expansion (conversion of 2 CTs into a 4x1 CC unit)
FC 38 (3 year, 150 MW purchase from utility system)
FC 39 (10 year, 300 MW purchase from CC system)
FC 65 (25 year, 465 MW purchase from CTs)
FC 71 (3 year, 300 MW purchase from CC system)

Combination Plan 5: Martin Expansion (conversion of 2 CTs into a 4x1 CC unit)
FC 3 (25 year, 465 MW purchase from CTs)
FC 19 (3 year, 526 MW purchase from CC)
FC 38 (3 year, 150 MW purchase from utility system)

Table V.E.1 shows the EGEAS results of the analyses of these plans in terms of the cumulative present value of revenue requirements (CPVRR) in millions of dollars.

Table V.E.1
Final EGEAS Results for the Best All FPL Plan and the 5 Best Combination Plans

	All FPL Plan	Combination Plan 1	Combination Plan 2	Combination Plan 3	Combination Plan 4	Combination Plan 5
2005 Additions:	Martin Conversion, Manatee CC	Martin Conversion, FC 3	Martin Conversion, FC 3	Martin Conversion, FC 19	Martin Conversion, FC 38, FC 39	FC 3, FC 19, FC 38
2006 Additions:	----	FC 58	FC 71, FC 72	FC 65	FC 65, FC 71	Martin Conversion
EGEAS Costs(CPVRR, millions, 2001$) =	40,970	40,966	40,995	41,001	41,003	41,010

Table V.E.1 shows that the All FPL plan and Combination Plan 1 had total CPVRR costs of $40,970 million and $40,966 million, respectively. The next best Combination Plan was at least $25 million higher in cost.

At this point, FPL's evaluation moved beyond the EGEAS analyses to include other costs not included in the EGEAS work. There were three such costs: generator startup costs, transmission integration costs, and equity penalty costs.

Startup costs refer to the costs incurred when a generating unit is started up, and are detailed in Appendix L. Each outside proposal supplied payment levels for these costs, and FPL estimated these costs for its construction options. FPL then used that information to calculate cumulative present value startup costs for each of the best Combination expansion plans and the best All FPL expansion plan. These costs were then added to the EGEAS costs.

The other two non-EGEAS costs, transmission integration and equity penalty, were not supplied for either RFP proposals or FPL construction options. FPL therefore developed estimates of these costs.

There are two basic transmission-related costs for a new generating unit. The first are the transmission interconnection costs. These costs refer to the expenditures needed to connect or attach a generating unit to a transmission grid. These transmission interconnection costs were included in the outside proposal prices, and in the FPL construction option costs.

The second are the integration costs, which represent the expenditures needed for the transmission system to enable it to move the generating unit's output throughout the electrical grid to the customers. An assessment of transmission integration costs was performed for each of the best Combination expansion plans and the best All FPL expansion plan. Load flow analyses were performed to identify any facilities that would be overloaded as a result of the operation of the units in each of the leading portfolios. A determination was first made of the facilities that would have to be built or upgraded to meet transmission requirements. Then an estimate of the cost of the necessary construction and upgrades was developed. The total integration construction cost for the group of 2005 and 2006 projects in each expansion plan was then converted into revenue requirements. The CPVRR value for each expansion plan's transmission integration costs was then added to the previously calculated EGEAS and startup costs. The integration cost estimates for each of the portfolios examined are included in Appendix M.

Equity penalty costs reflect the equivalent financial impact of FPL acquiring more debt through the signing of additional power purchases. Such contracts are treated as debt by the financial community and can adversely affect a utility's financial ratings. The equity penalty costs are applicable only to outside power purchase proposals, not to FPL construction options or outside proposal turnkey projects.

FPL, after consulting with Standard & Poors, performed an equity penalty cost calculation for each outside power purchase proposal that appeared in the best Combination expansion plans mentioned above.[15] The CPVRR equity penalty costs for each outside proposal were calculated and summed for the groups of outside proposals making up each of the Combination expansion plans. The calculation of these equity penalty costs are shown on Appendix N. These equity penalty costs were then added to the EGEAS, startup, and transmission integration costs described above to derive a total CPVRR cost estimate for the Combination expansion plans and the All FPL expansion plan.

The combined totals of these four CPVRR costs (EGEAS, startup, transmission integration, and equity penalty) for the All FPL plan and the best Combination plans identified at this point in the analysis are presented in Table V.E.2.

[15] The All FPL expansion plan does not have an equity penalty cost since such costs result from rating agency treatment of purchased power contracts as additional debt.

Table V.E.2
Results for the Best Combination Plans and the Best All FPL Plan
(January, 2002)

	All FPL Plan	Combination Plan 1	Combination Plan 2	Combination Plan 3	Combination Plan 4	Combination Plan 5
2005 Additions:	Martin Conversion, Manatee CC	Martin Conversion, FC 3	Martin Conversion, FC 3	Martin Conversion, FC 19	Martin Conversion, FC 38, FC 39	FC 3, FC 19, FC 38
2006 Additions:	----	FC 58	FC 71, FC 72	FC 65	FC 65, FC 71	Martin Conversion
Costs (CPVRR, millions, 2001$)						
EGEAS Costs =	40,970	40,966	40,995	41,001	41,003	41,010
Startup Costs =	14	13	13	13	13	13
Transmission Integration Costs =	58	128	127	128	128	128
Equity Penalty Costs =	0	59	73	56	72	60
Total Cost =	**41,042**	**41,166**	**41,208**	**41,198**	**41,216**	**41,211**
Cost Difference from All FPL Plan =	**----**	**124**	**166**	**156**	**174**	**169**

The total cost results presented in Table V.E.2 show that, as of January 2002, the "All FPL" plan consisting of Martin Unit 8 and Manatee Unit 3 was the most economic way for FPL to meet its 2005 and 2006 capacity needs. When all costs (EGEAS, startup, transmission integration, and equity penalty costs) were summed, the All FPL plan emerged as the lowest cost plan by $124 million compared to the best Combination plan (Combination Plan 1).[16]

2. The Independent Evaluation

Sedway, the independent evaluator, developed its own economic assessment of the 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.

[16] The All FPL plan's cost advantage over the remaining Combination plans was even larger.

Using the RSM model Sedway first developed rankings of individual outside proposals and individual FPL construction options. Then, Sedway combined selected individual projects into All Outside, All FPL, and Combination groupings (similar in concept to EGEAS's expansion plans) that met FPL's 2005 and 2006 capacity needs. The RSM model-calculated costs for these groupings were then compared. Finally, Sedway utilized the FPL calculations of startup costs, 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 groupings.

The independent evaluator's January economic analyses also showed the Martin Conversion and Manatee CC expansion plan to be the most cost-effective alternative to meet FPL's 2005 and 2006 capacity needs. This analysis showed even larger cost savings than FPL computed. Sedway showed the Martin Conversion/Manatee CC plan to range from $201 to $291 million more cost-effective than what was then perceived as the five next lowest cost plans, all of which were combination plans that included the Martin Conversion along with outside proposals.

3. The February Combination Plan

Based on the economic analyses, the portfolio comprising of Martin Unit 8 and Manatee Unit 3 appeared to be the most cost-effective way to meet FPL's 2005 and 2006 capacity needs by considerable margin.

At this point, FPL publicly announced that it would meet its 2005 and 2006 capacity needs by proceeding with the Martin Unit 8 and Manatee Unit 3 expansion plan. Although some review work and potential adjustments remained to be done, the magnitude of the economic advantage of the All FPL plan in the analysis results to that point, the non-price attributes of the All FPL Plan and the need to begin the unit permitting process, prompted FPL to announce its decision.

FPL's subsequent review of the analysis inputs and outputs showed that a computational "quirk" in the EGEAS model analyses had prevented a full evaluation of an expansion plan that exactly met the 1,722 MW total capacity need.[17] This plan consisted of the Manatee Unit 3 and two outside proposals.

[17] The computational quirk that led to a separate evaluation of the February Combination Plan, and FPL's subsequent analyses, are fully described on pages 61 to 69 of the testimony of Steven R. Sim.

FPL adjusted the model's parameters so that this expansion plan could be fully evaluated by EGEAS. The EGEAS costs calculated for this plan showed that this new "February Combination Plan" was competitive with both the All FPL plan and Combination Plan 1. Therefore, startup costs, transmission integration costs, and equity penalty costs for the February Combination Plan were also calculated and added to the EGEAS costs.

Several other adjustments to the costs of the All FPL plan, Combination Plan 1, and the new February Combination Plan were then made. These adjustments primarily related to AFUDC cost calculations, including (1) the number of years over which AFUDC was calculated, (2) the AFUDC rate used in the calculation, the annual/monthly spending curves used in the analyses, and (3) the escalation rate used to calculate transmission integration AFUDC and non AFUDC costs.

FPL made these AFUDC adjustments and calculated the total additional AFUDC costs that would apply to the All FPL plan, Combination Plan 1, and the February Combination Plan. These additional AFUDC costs were then added as a separate line item cost to the total EGEAS, startup, transmission integration, and equity penalty costs that had previously been calculated.

The results of these new calculations are presented in Table V.E.3.

TABLE V.E.3

Final Results for the Best Combination and All FPL Expansion Plans (February)

	All FPL Plan	Combination Plan 1	February Combination Plan
2005 Additions:	Martin Conversion, Manatee CC	Martin Conversion, FC 3	Manatee CC, FC 11
2006 Additions:	----	FC 58	FC 65
Costs (CPVRR, millions, 2001$)			
EGEAS Costs =	40,970	40,966	40,974
Startup Costs =	14	13	10
Transmission Integration Costs =	58	128	19
Equity Penalty Costs =	0	59	55
AFUDC additional costs =	12	6	8
Total Cost =	**41,054**	**41,172**	**41,066**
Cost Difference from All FPL Plan =	**----**	**118**	**12**

As shown in Table V.E.3, the new February Combination Plan is significantly less expensive than the previous best Combination plan, Combination Plan 1. This is due to its much lower transmission integration costs that, in turn, are due to the fact that the February Combination Plan does not have the majority of its capacity located in the vicinity of the Martin plant site.

However, even though the February Combination Plan now becomes the least expensive Combination expansion plan, its costs are still higher by $12 million (CPVRR) than the costs of the All FPL plan. Consequently, the All FPL plan remains as the most economical plan and its components, Martin Unit 8 and Manatee Unit 3, are the most cost-effective options with which FPL can meet its 2005 and 2006 capacity needs.

Sedway's evaluation of the February Combination portfolio concluded that the portfolio was $36 million more expensive than the All-FPL plan. Also, Sedway noted that the February Combination portfolio (and many of the other top-ranked Combination portfolios) included a proposal whose costs had been estimated rather conservatively (i.e., on the low side) by both Sedway and the FPL evaluation team. Sedway concluded that the cost savings associated with the All-FPL portfolio relative to the Combination portfolios that included this proposal may be significantly underestimated.

In addition, there are non-price attributes that further support the Martin Unit 8 and Manatee Unit 3 expansion plan as the superior portfolio.

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, must also be considered.

The non-price factors FPL considers when choosing among its own options or between outside proposals and FPL options include: (1) fuel diversity; (2) technology risk; and (3) environmental risk.

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.

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.

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.

When choosing between a self-build option and buying power, the non-price factors FPL considers also include: (1) the financial strength of the supplier; (2) the feasibility of licensing and construction requirements; (3) the delivery risk related to firmness of fuel supply and the experience of the seller; and (4) the degree of control offered, including dispatchability and rights to sell power.

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 in light of the collapse of Enron and the generally declining strength of independent power developers following that collapse. It is FPL's customers that ultimately bear the risk of nonperformance of a project resulting from the financial instability of a developer.

Feasibility of licensing and construction plans is an assessment of the reasonableness of the timing of a proposal, given 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.

Delivery risk related to firmness of fuel supply, the construction schedule, and the experience of the seller relate to an assessment of whether a 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 would obviously be less favored than one from a developer with a strong project management record.

The degree of control offered to FPL, including dispatchability and rights to sell power from a project, 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, 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 factors play a part in FPL's planning and decisions, including its decisions to purchase power. With regard to FPL's RFP analysis, certain of these factors are important in choosing the best expansion plan.

Fuel diversity and technology risk had no impact on FPL's RFP analysis. All self-build options, with the exception of a petroleum coke plant, were fueled by natural gas and based on commercially available gas turbine technology.[18] Regarding the diversity introduced by competing pipelines, most of the more economic alternatives were all supplied by the same natural gas pipeline, so no qualitative advantage was conferred on any given project.

The assessment of environmental risk 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 role in FPL's RFP Decision.

[18] The petroleum coke plant analysis was deferred in part due to concerns over licensing and construction lead times.

Concerning the factors to be considered in a build versus buy decision, there is more differentiation to be recognized. With regard to financial viability of potential suppliers, there is a heightened concern over the financial health of all independent power developers since the collapse of Enron, particularly those without an affiliate relationship to a strong parent. This concern reflects a general tightening of the financial markets since that time. Any threat to project financing increases the risk of delay and/or possible cancellation of the project, and financial guarantees, such as bonds or escrowing of funds, are inadequate where system reliability is threatened. Evaluation of the most competitive portfolios to FPL's self-build options shows that they include a project offered by a supplier that is known to be facing current financial difficulties. The degree of risk introduced by purchasing power from this provider would certainly be higher than risk associated with FPL's self-build approach. Thus, even if overall costs had been equal, FPL's self-build portfolio would have been preferred.

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

The next factors, firmness of fuel supply, and experience of the seller, also played a part in FPL's decision. All of the most competitive Combination Plans were at least in part based on a specific outside CT proposal. And, if this one proposal were to be excluded from consideration, all other portfolio would be at least $150 million (CPVRR) more expensive that FPL's self-build plan. This CT proposal included firm gas transportation (at $0 cost) from a Bahamian liquefied-natural-gas facility that plans to develop an undersea pipeline to the U.S. mainland. The transportation facilities do not presently exist and have not yet been permitted by the appropriate regulatory agencies. In addition, this proposal did not provide for backup fuel capability. If gas was not available no electricity would be produced. This introduces a high degree of risk to the proposal, and again, financial guarantees would not substitute for lack of reliability. FPL's self-build portfolio has access to firm gas from more than one pipeline thus offering a much higher level of reliability.

The final consideration, which is the degree of control offered by a project, is multifaceted and cannot be fully and specifically addressed 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 there is a natural and irresolvable 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 are three qualitative factors that provided additional support to FPL's decision to pursue construction of the Manatee and Martin projects:

- The financial viability of one project in the most competitive Combination Plans places those portfolios at greater risk than the self-build portfolio.
- The same proposal that presents greater financial risk also has a gas transportation risk, further increasing risk to system reliability.
- All other factors being equal, it is difficult to achieve the level of control offered by ownership through a contract, and administration of the contract increases litigation risks.

Given these quantitative considerations, FPL's Manatee and Martin projects offer the best combination of economics and non-price factors to FPL's customers.

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 1980's and 1990's. These programs have included both conservation and load management and have addressed the residential, commercial and industrial markets.

The portfolio 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 has also 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 of 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 only offering 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. There was no challenge to

FPL's DSM goals, and there is no basis to conclude it fails to capture FPL's reasonably achievable, cost-effective DSM potential.

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 and one-half years to mitigate the need for even the smaller projected unit, the Martin Expansion project and its 789 MW of incremental capacity. After accounting for a 20% reserve margin requirement and losses, 612 MW of additional, cost-effective DSM at the meter would be needed by summer of 2006 to avoid this capacity addition. The Commission previously determined there was only 765 MW of additional, achievable, cost-effective DSM for the ten-year period, 2000-2009. It would defy reality to conclude that FPL could achieve an additional 612 MW of cost-effective DSM in the next three and one-half 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 not previously found by

FPL or the Commission, not enough could be added in the time remaining to meet FPL's 2005 reliability needs.

Consequently, FPL's 2005 and 2006 capacity needs can only be met by acquiring new supply side resources. Additional, cost-effective DSM could not substantially lower the 2005 and 2006 resource needs that FPL sought to meet through the RFP process.

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 its 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 consequently FPL's system reliability.

A. Adverse Effects Upon FPL System Reliability

Both of the planned capacity additions, the Martin Expansion and the Manatee CC unit, 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 Expansion & Manatee CC are in-service by mid - 2005	24.0%	20.9%
2)	Martin Expansion only is delayed one year	19.9%	20.9%
3)	Manatee CC only is delayed one year.	18.2%	20.9%
4)	Both Martin Expansion & Manatee CC are delayed one year	14.1%	20.9%
5)	Both Martin Expansion & Manatee CC 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 be denied 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. 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 were 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.B.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.B.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	22Jul02	01May03	24 months	June 2005
Manatee CC Unit 3	22Feb02	15Aug02	01May03	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. In late September of 2001, FPL received proposals from 15 Bidders. A total of 81 proposals were received.

FPL and an independent evaluator separately analyzed these outside proposals and 13 FPL self-build construction options. First, these outside proposals were individually ranked as were the FPL construction options. Then, using the top-rated projects from each group, a number of All Outside expansion plans and All FPL expansion plans 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 top-rated outside proposals and FPL construction options were also mixed to create Combination expansion plans.

An early result was that FPL lessened its focus on creating All Outside expansion plans. This was based on the results of repeated analyses that showed both the All FPL and Combination plans were significantly more economical than All Outside plans. In January an evaluation including costs as calculated by FPL's EGEAS model, plus generator startup costs, transmission integration costs, and associated equity penalty costs was made. In that January evaluation, the All FPL plan emerged as the most economical plan by at least $124 million (CPVRR).

Although some review and potential adjustment work still remained to be done, FPL publicly announced in mid-January that it planned to meet its 2005 and 2006 capacity needs with its Martin Expansion and Manatee CC projects. This announcement was based on the All FPL plan's cost advantage shown in the January analyses, the non-price attributes of the Al FPL plan, and the need to begin the permitting process for the two units.

In the course of its subsequent work, FPL found that a computational "quirk" in the EGEAS analyses had resulted in a Combination expansion plan not being fully evaluated. FPL adjusted the EGEAS model parameters to allow this evaluation to occur, then added in startup costs, transmission integration costs, and equity penalty costs for this new Combination plan. In addition, several adjustments to the previous calculations of AFUDC costs were also made, and the resulting additional costs were added to the All FPL plan, Combination Plan 1, and the new February Combination Plan.

The results of these calculations and adjustments showed that the new February Combination Plan was significantly less expensive than Combination Plan 1, but still more expensive than the All FPL plan. Therefore, the All FPL plan emerged as the most cost-effective expansion plan with which FPL can meet its 2005 and 2006 capacity needs.

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

These two units are 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, deny them the cost-effective power that would be provided and adversely affect 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.