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July 16, 2002

-VIA HAND DELIVERY-

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

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

Dear Ms. Bayó:

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

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

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

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

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

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

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

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

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

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

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

(2) Need Study Appendices A - D

(3) Need Study Appendices E - J

(4) Need Study Appendices K - O

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

(6) Direct Testimony of C. Dennis Brandt

(7) Direct Testimony of Moray P. Dewhurst

(8) Direct Testimony of Leonardo E. Green

(9) Direct Testimony of Rene Silva

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

(11) Direct Testimony of Donald R. Stillwagon

(12) Direct Testimony of Alan S. Taylor

(13) Direct Testimony of William L. Yeager

(14) Direct Testimony of Gerard Yupp

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

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

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

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

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

Respectfully submitted,

Charles A. Guyton

R. Wade Litchfield
Charles A. Guyton

Attorneys for Florida Power
& Light Company

CAG/gc
Enclosures

cc: Counsel for Parties of Record

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FPL

Need Study For Electrical Power Plant 2005 – 2006

APPENDICES E - J

Ten Year Power Plant Site Plan

2002 - 2011

FPL

FPL

Ten Year Power Plant Site Plan

2002-2011

Submitted To:

Florida Public Service Commission

Miami, Florida
April, 2002

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Overview of The Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten - Year Power Plant Site Plan. This plan includes an estimate of the utility's electric power generating needs, a projection of how those needs will be met, and a disclosure of information pertaining to the utility's preferred and potential power plant sites. This information is compiled and presented in accordance with rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (FAC).

This Ten - Year Power Plant Site Plan (Site Plan) document is based on Florida Power & Light Company's (FPL) 2001 planning analyses and the forecasted information presented in this plan addresses the 2002 – 2011 time frame.

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains tentative information, especially for the latter years of the ten - year time horizon, and is subject to change at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings.

This document is organized in the following manner:

Chapter I – Description of Existing Resources
This chapter provides an overview of FPL's current generating facilities. Also included is data on other FPL resources, including its transmission system.

Chapter II – Forecast of Electric Power Demand
FPL's load forecasting methodology, and its forecast of seasonal peaks and annual energy usage, is presented in Chapter II.

Chapter III – Projection of Incremental Resource Additions
This chapter discusses FPL's integrated resource planning (IRP) process and outlines FPL's projected resource additions, especially new power plants, as determined in FPL's 2001 IRP work.

Chapter IV – Environmental and Land Use Information
This chapter discusses various environmental information as well as preferred and potential site locations for additional electric generation facilities.

Chapter V – Other Planning Assumptions and Information
This chapter addresses twelve "discussion items" which pertain to additional specific information which is to be included in a Site Plan filing.

Chapter VI – Summary of Required Schedules

This chapter contains Schedules 1 thru 10. It also contains FPL's Ten Year Site Plan Fact Summary.

FPL
List of Abbreviations
Used in FPL Forms

Reference	Abbreviation	Definition
Unit Type	IC	Internal Combustion
	NP	Nuclear Power
	ST	Steam Unit
	CT	Combustion Turbine
	CC	Combined Cycle
	BIT	Bituminous Coal
Fuel Type	UR	Uranium
	NG	Natural Gas
	FO6	#4,#5,#6 Oil (Heavy)
	FO2	#1, #2 or Kerosene Oil (Distillate)
	BIT	Bituminous Coal
	No	None
Fuel Transportation	TK	Truck
	RR	Railroad
	PL	Pipeline
	WA	Water
	No	None
Unit/Site Status	A	Generation Unit Capability Increased (Rerated or Relicensed)
	P	Planned Unit
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete

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Executive Summary

Florida Power & Light Company's (FPL) 2002 Ten - Year Power Plant Site Plan (Site Plan) addresses FPL's plans to increase its electric generation capability as part of its efforts to meet its projected incremental resource needs for the 2002 – 2011 time period.

FPL's total generation capability will significantly increase during the 2002 – 2011 time period as is shown in Table ES.1. This table also shows the resulting Summer and Winter reserve margins for FPL over this ten-year time horizon.

Table ES.1 reflects FPL's efforts to repower existing units at its Fort Myers and Sanford sites, planned changes to existing generation units (due to unit overhauls, etc.), and scheduled changes in the delivered amounts of purchased power. The table also reflects the planned additions of new generating units. Although not specifically shown in this table, FPL's approved DSM goals are assumed to be implemented on schedule.

The number of these new generating units that will be added is driven in part by the outcome of the Florida Public Service Commission docket No. 981890-EU. This docket ended with a stipulated agreement that resulted in FPL, along with Tampa Electric Company and Florida Power Corporation, switching from a minimum reserve margin planning criterion of 15% to one of 20% beginning with the Summer of 2004. As a consequence, FPL is now planning to add significantly more new generation capacity than was shown in its Site Plans filed prior to this agreement.

As shown in Table ES.1, FPL plans to add two new combustion turbines (CT's) at FPL's existing Fort Myers plant site in 2003. Also during the 2002 – 2003 time period, FPL will be completing its work to repower its two existing steam units at its Fort Myers site and two (unit Nos. 4 & 5) of its existing three steam units at its Sanford site.

FPL has also secured capacity for the time period from 2002 through early 2007 through a number of firm capacity, short-term purchases from utilities and other entities. (Please see Chapter III for a further discussion of these purchases.)

In 2005, FPL will be adding a large (1,107 Summer MW) new combined cycle (CC) unit at its existing Manatee plant site. Also in 2005, the two combustion turbines (CT's) that were added at FPL's existing Martin plant site in mid - 2001 will be converted into a 1,107 Summer MW CC unit by the addition of two additional CT's, heat recovery steam generators, and associated equipment. This conversion will add another 789 Summer MW of capability above the present capability of the existing two CT's. The additions for 2005 were selected as the best options among other FPL construction alternatives and numerous outside proposals received in response to a Request for Proposals FPL issued in August 2001.

In the 2007 through 2011 time frame, FPL tentatively plans to add 4 more CC units each with a projected Summer capability of 1,107 MW.[4] One unit will be added in each of the following years: 2007, 2009, 2010, and 2011 to meet projected load growth and to account for the scheduled end in 2010 of FPL's UPS contract with Southern Company. Sites for these four additional CC units have not yet been selected.

These planned increases in electric generation capability will allow FPL to continue to maintain system reliability and integrity at a reasonable cost.

[4] FPL's current planning studies have identified new combined cycle units as the generally preferred option to meet future load growth. However, repowering of existing FPL sites remains an alternative to new construction, and FPL will continue to examine this option.

Projected Capacity Changes and Reserve Margins for FPL [1]					
		Net Capacity Changes (MW)		FPL Reserve Margin (%)	
		Winter [2]	Summer [3]	Winter	Summer
2002	Fort Myers Repowering:Second Phase [4]	(1)	35	18%	19%
	Sanford Repowering # 5: Initial Phase [5]	(390)	---		
	Sanford Repowering # 5: Second Phase [5]	---	567		
	Sanford Repowering # 4: Initial Phase [5]	---	(390)		
	Changes to existing units	10	30		
	New purchases [6]	593	897		
	Changes to existing QF's	---	(9)		
2003	Fort Myers Repowering:Second Phase	531	---	31%	23%
	Sanford Repowering # 5: Second Phase	1,065	---		
	Sanford Repowering # 4: Second Phase [7]	675	957		
	Combustion Turbines (2) Fort Myers [8]	---	318		
	Changes to existing QF's	(9)	---		
	Changes to existing units	20	---		
	New purchases [6]	724	71		
2004	Combustion Turbines (2) Fort Myers	362	---	31%	21%
	New purchases [6]	39	---		
2005	Changes to existing QF's	(10)	(10)	28%	24%
	New purchases [6]	(50)	(717)		
	Manatee Combined Cycle	---	1,107		
	Conversion of MR CT's to CC	---	789		
2006	Manatee Combined Cycle	1,197		31%	21%
	Conversion of MR CT's to CC	835	---		
	New purchases [6]	(763)	---		
	Changes to existing QF's	(133)	(133)		
2007	New purchases [6]	---	(447)	29%	22%
	Unsited Combined Cycle #1 [9]		1,107		
2008	New purchases [6]	(543)		30%	21%
	Unsited Combined Cycle #1 [9]	1,197	---		
2009	Unsited Combined Cycle #2 [9]	---	1,107	28%	24%
	Changes to existing QF's	(51)	(51)		
2010	Changes to existing purchases [10]	---	(975)	31%	23%
	Unsited Combined Cycle #2 [9]	1,197	---		
	Unsited Combined Cycle #3 [9]	---	1,107		
2011	Unsited Combined Cycle #3 [9]	1,197	---	30%	25%
	Unsited Combined Cycle #4 [9]	---	1,107		
	TOTALS =	***7,692***	***6,467***		

Table ES.1

Projected Capacity Changes and Reserve Margins for FPL
(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document. (2) Winter values are values for January of year shown. (3) Summer values are values for August of year shown. (4) The initial phase of the Fort Myers repowering project consists of the introduction of operational combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and steam turbines. (5) The initial phase of the Sanford repowering project consists solely of taking existing steam units # 4 and # 5 out-of-service; combustion turbine operation is not introduced at this time. The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines. (6) These are firm capacity, shorter - term purchases. See Section I.D and III.A. for more details. (7) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work. That schedule has recently changed. Please refer to Section III.A, "Step 1" for more information. The only reserve margin effect will be to lower FPL's Winter 2003 reserve margin from 31% to 29%. (8) The two CT's at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CT's are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin included in the calculations for Summer and Winter. (9) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years. (10) FPL will be determining at a later date whether to extend or replace the UPS purchases (928 MW) from Southern Company. However, for purposes of this Site Plan, FPL has assumed that the 2010 needs would be met through the addition of unsited combined cycles.

CHAPTER I

Description of Existing Resources

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I. Description of Existing Resources

FPL's service area contains approximately 27,650 square miles and has a population of approximately 7.7 million people. FPL served an average of 3,935,281 customer accounts in thirty-five counties during 2001. These customers were served from a variety of resources including: FPL-owned fossil and nuclear generating units, non-utility-owned generation, demand side management, and interchange/purchased power.

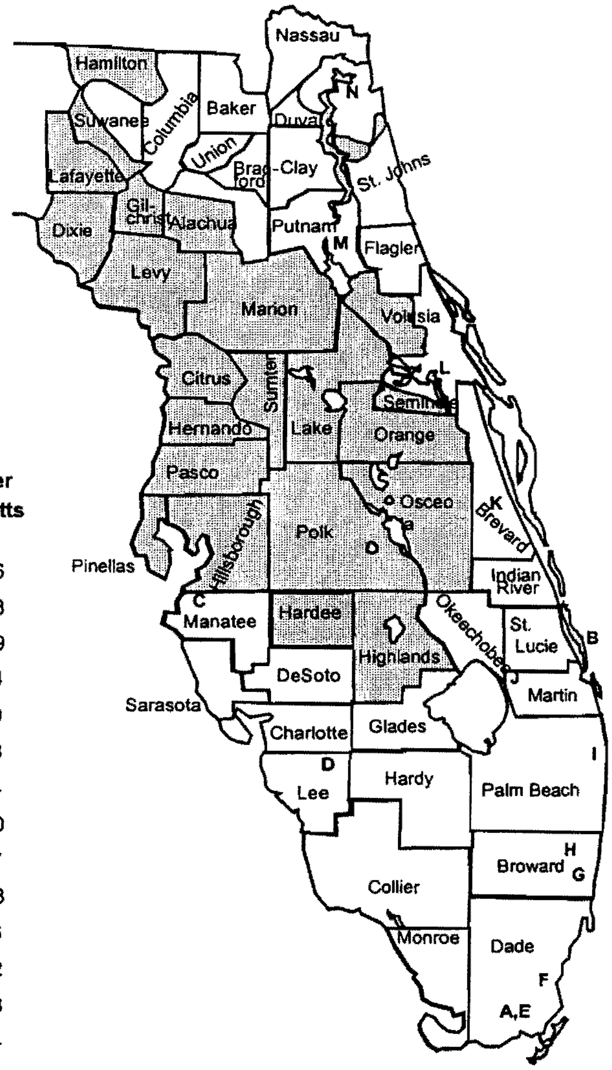
I.A. FPL- Owned Resources

The existing FPL 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 combined cycle units, twenty-one fossil steam units, fifty-six combustion gas turbines, and five diesel units. (Six of these fifty-six turbines are at Fort Myers and will be utilized later this year for the repowering project and another two of these fifty-six are at Martin and are planned to be used in a CT-to-CC conversion in 2005.) The location of these units is shown on Figure I.A.1.

The bulk transmission system is composed of 1,107 circuit miles of 500 Kilovolt (KV) lines (including 75 miles of 500 KV lines [two 37-1/2 mile lines] between Duval Substation and the Florida-Georgia state line, which are jointly owned with Jacksonville Electric Authority) and 2,644 circuit miles of 230 KV lines. The underlying 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.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2. In addition, Figure I.A.3. shows FPL's interconnection ties with other utilities.

Capacity Resources
(as of December 31, 2001)



Non-FPL Territory

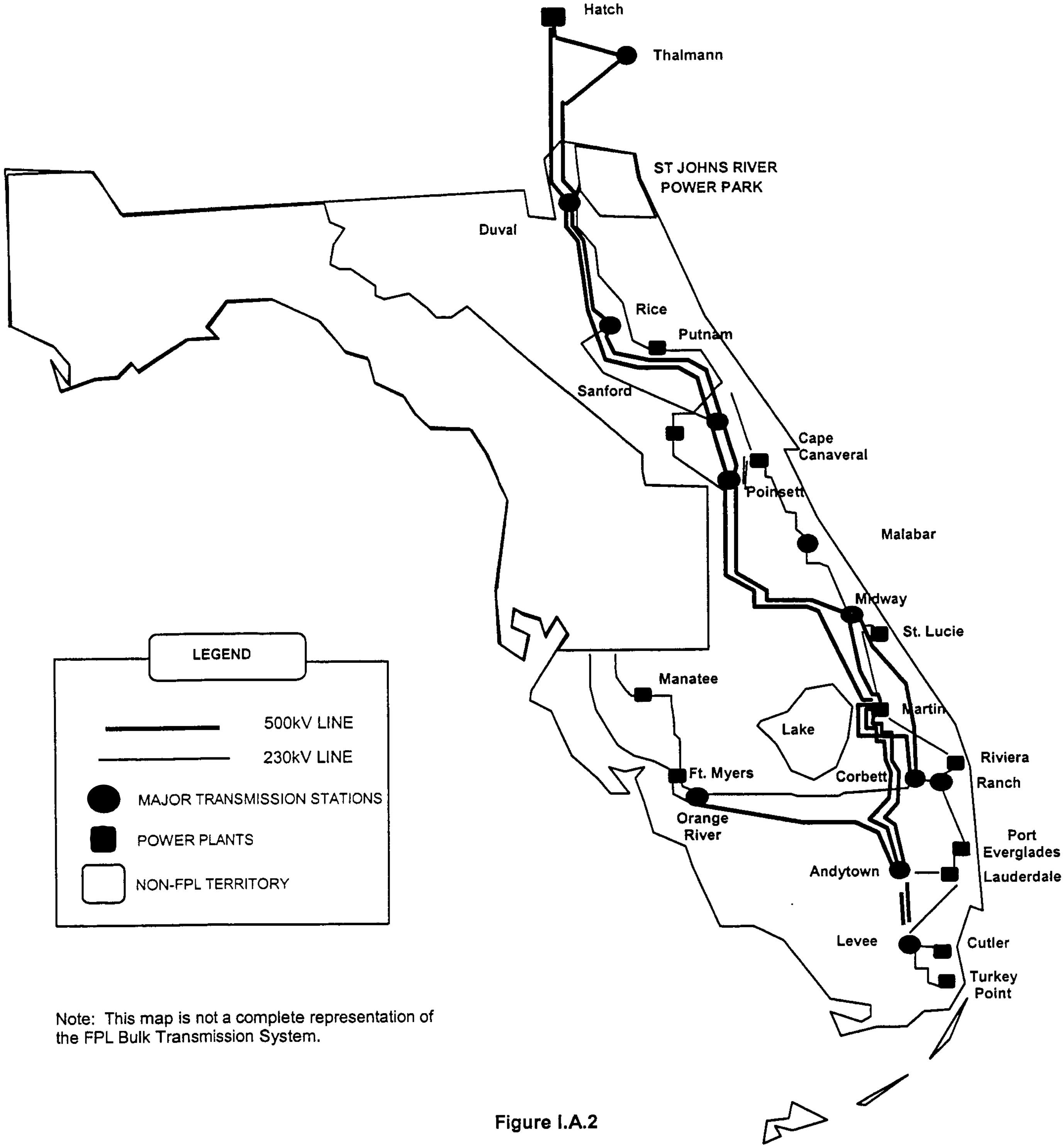
	Unit Name	Unit	Fuel Type	Summer Megawatts
A	Turkey Point	2	Nuclear	1,386
B.	St. Lucie *	2	Nuclear	1,553
C.	Manatee	2	Oil	1,619
D.	Ft. Myers	2	Oil	894
E.	Turkey Point	2	Oil/Gas	800
F.	Cutler	2	Gas	213
G.	Lauderdale	2	Oil/Gas	854
H.	Port Everglades	4	Oil/Gas	1,240
I.	Riviera	2	Oil/Gas	567
J.	Martin	4	Gas/Oil	2,548
K.	Cape Canaveral	2	Oil/Gas	806
L.	Sanford	3	Oil/Gas	532
M.	Putnam	2	Oil/Gas	498
N.	St. Johns River *	2	Coal	254
Scherer **		1	Coal	658
Peaking Units				2,206
FPL Generation				**16,628**

** 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.*

Figure I.A.1

FPL Substation and Transmission System Configuration



Note: This map is not a complete representation of the FPL Bulk Transmission System.

Figure I.A.2

FPL Interconnection Diagram
(115 to 500KV)

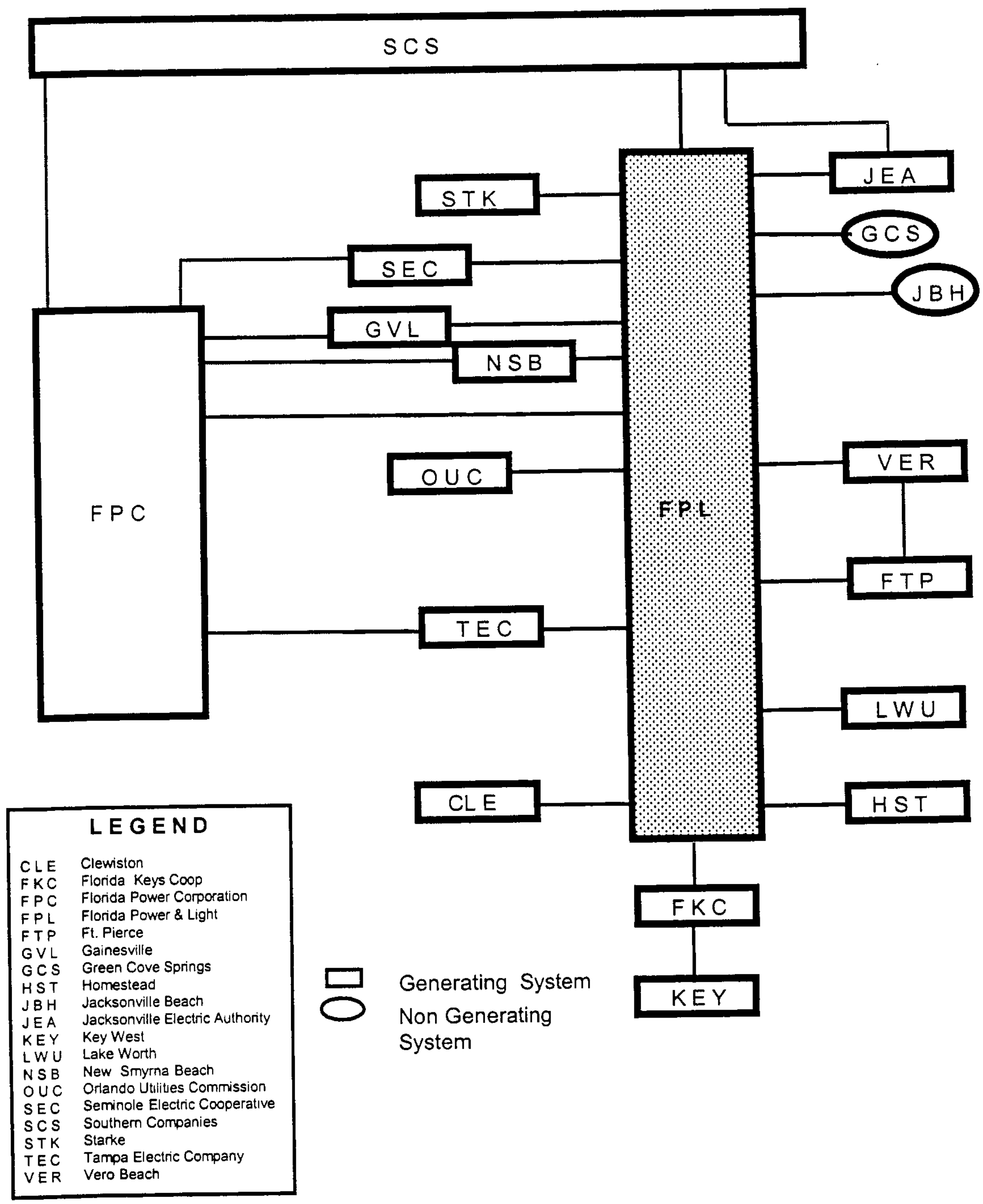


Figure I.A.3

I.B Non-Utility Generation

Non-utility generation is an important part of FPL's resource mix. FPL currently has contracts with eight cogeneration/small power production facilities to purchase firm capacity and energy. A listing of these facilities appears in Table I.B.1. In addition, FPL purchases as-available (non-firm) energy from several cogeneration facilities and small power production facilities as shown in Table I.B.2.

A cogeneration facility is one which simultaneously produces electrical and thermal energy, with the thermal energy (e.g., steam) being used for industrial, commercial, or cooling and heating purposes. A small power production facility is one which does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses as its primary energy source (at least 50%) solar, wind, waste, geothermal, or other renewable resources.

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

Table I.B.1

As-Available Energy Purchases From Non-Utility Generators in 2001				
Project	***County***	***Fuel***	***In-Service Date***	***Energy (MWH) Delivered to FPL in 2001***
US Sugar-Bryant	Palm Beach	Bagasse	2/80	4,473
Tropicana	Manatee	Natural Gas	2/90	5,686
Okeelanta	Palm Beach	Bagasse/Wood	11/95	179,116
Tomoka Farms	Volusia	Landfill Gas	7/98	21,246
Georgia Pacific	Putnam	Paper By- Product	2/94	9,452

Table I.B.2

I.C. Demand Side Management (DSM)

FPL's DSM activities continue what has been FPL's practice since 1978 of encouraging cost-effective conservation and load management. FPL's DSM efforts through 2001 have resulted in a cumulative Summer peak reduction of approximately 3,076 MW at the meter and an estimated cumulative energy saving of 19,713 GWH at the meter.

FPL's current DSM Plan was approved by the Florida Public Service Commission in late 1999 and reflects FPL's new DSM Goals for the 2000 – 2009 time frame. FPL's 2001 resource plan and the schedule for new generation additions presented in this document, are based on these approved DSM levels.

I.D. Purchased Power

Purchased power remains an important part of FPL's resource mix. FPL has a unit power sales (UPS) contract to purchase 928 MW, with a minimum of 380 MW, of coal-fired generation from the Southern Company. In addition, FPL has contracts with the Jacksonville Electric Authority (JEA) for the purchase of 382 MW (Summer) and 389 MW (Winter) of coal-fired generation from the St. John's River Power Park (SJRPP) Unit Nos. 1 and 2 (FPL also has an ownership interest in these units; that ownership amount is reflected in FPL's installed capacity shown on Schedule 1).

Finally, FPL has new firm capacity purchase contracts for the 2002 to early 2007 time period. These firm capacity purchase contracts are with a variety of suppliers. Table I.D.1 presents the Summer and Winter MW resulting from all firm purchased power contracts through the year 2011.

	FPL's Purchased Power MW (1)							
	UPS		*SJRPP*		*New Firm Capacity Purchases* (3)		*Total*	
Year	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*	*Winter*	*Summer*
2001 (2)	928	928	389	382	0	196	1317	1506
2002	928	928	389	382	593	1093	1910	2403
2003	928	928	389	382	1317	1164	2634	2474
2004	928	928	389	382	1356	1164	2673	2474
2005	928	928	389	382	1306	447	2623	1757
2006	928	928	389	382	543	447	1860	1757
2007	928	928	389	382	542	0	1859	1310
2008	928	928	389	382	0	0	1317	1310
2009	928	928	389	382	0	0	1317	1310
2010	928	0	389	382	0	0	1317	382
2011	0	0	389	382	0	0	389	382

Note:

(1) Total reflects total resource entitlements resulting from existing agreements between FPL, Southern Companies, JEA, and from new firm purchase agreements.

(2) Values for 2001 are actual.

(3) A discussion of these new firm capacity purchases can also be found in Section III.A.

Table I.D.1

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport. Pri.	(8) Fuel Transport. Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Turkey Point		Dade County 27/57S/40E									2,338,100	2,198	2,253
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	400	404
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	400	403
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	693	717
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	693	717
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Dade County 27/55S/40E									236,500	213	216
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	71	71
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	142	145
Lauderdale		Broward County 30/50S/42E									1,863,972	1,694	1,804
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	521,250	425	443
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	521,250	429	447
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	420	457
	13-24		CT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	420	457
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,660	1,701
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	221	222
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	221	222
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	390	392
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	408	408
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	420	457
Riviera		City of Riviera Beach 33/42S/43E									620,840	567	569
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	283
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	284	286

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Martin		Martin County 29/29S/38E									3,312,000	2,846	2,979
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	814	826
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	799	812
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	467	489
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	468	490
	8 A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	362,000	298	362
St. Lucie		St. Lucie County 16/36S/41E									1,553,000	1,553	1,579
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	839	853
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	714	726
Cape Canaveral		Brevard County 19/24S/36F									804,100	806	812
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	406
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	403	406
Sanford		Volusia County 16/19S/30E									1,022,450	532	528
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	144
	4		ST	FO6	NG	WA	PL	Unknown	Jul-72	Unknown	436,100	390	384
	5	3/	ST	FO6	No	WA	No	Unknown	Jul-73	Unknown	436,100	0	0
Putnam		Putnam County 16/10S/27E									580,000	498	520
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	249	260
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	249	260

1/ These ratings are peak capability.
2/ Total capability is 839/853 MW. Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.
3/ This unit was removed from service as part of the repowering project.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
						Fuel		Alt. Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW
Fort Myers		Lee County 35/43S/25E									2,388,250	1,530	1,668
	1	4/	ST	FO6	No	WA	No	Unknown	Nov-58	Unknown	156,250	0	0
	2	4/	ST	FO6	No	WA	No	Unknown	Jul-69	Unknown	402,000	0	0
	1-12		CT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	636	690
	Repowering CT A		CT	NG	FO2	PL	PL	Unknown	Oct-00	Unknown	181,000	149	163
	Repowering CT B		CT	NG	FO2	PL	PL	Unknown	Nov-00	Unknown	181,000	149	163
	Repowering CT C		CT	NG	FO2	PL	PL	Unknown	Dec-00	Unknown	181,000	149	163
	Repowering CT D		CT	NG	FO2	PL	PL	Unknown	Apr-01	Unknown	181,000	149	163
	Repowering CT E		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
	Repowering CT F		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
Manatee		Manatee County 18/33S/20E									1,726,600	1,619	1,633
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	809	816
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	810	817
St. Johns River Power Park 2/		Duval County 12/15/28E (RPC4)									250,000	254	260
	1		BIT	BIT	No	RR	No	Unknown	Mar-87	Unknown	125,000	127	130
	2		BIT	BIT	No	RR	No	Unknown	May-88	Unknown	125,000	127	130
Scherer 3/		Monroe, GA									891,000	658	666
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	658	666
								Total System as of December 31, 2001 =				16,628	17,188

1/ These ratings are peak capability.
2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.; SJRPP receives coal by water (WA) in addition to rail.
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
4/ These units were removed from service as part of the repowering project.

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

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.

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 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.

Forecasts for electric usage in the residential and commercial classes include end-use information such as appliance saturation studies, efficiencies, and intensity of energy use. In addition to these inputs, residential forecasts also make use of household characteristics such as ages of members in household, number of members in households, and income distributions.

The projections for the National and Florida economy are obtained from DRI-WEFA. Population projections for the counties served by FPL are obtained from the Bureau of Economic and Business Research (BEBR) of the University of Florida. In addition, FPL actively participates with local development councils and universities to obtain their assessments of the local economy, specifically in the area of expansion of new businesses and retention of the current business base. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity.

Weather is a key factor that affects the company's sales and peak demand. Weather variables are used in the forecasting models for energy sales and peak demand. There are two sets of weather variables developed and used in forecasting models:

1. Cooling and Heating Degree Days are used to forecast energy sales.
2. Temperature data is used to forecast Summer and Winter peaks.

The Cooling & Heating Degree Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric heaters. A composite temperature is derived using hourly temperatures across FPL's service territory (Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained) weighted by regional energy sales. This composite temperature is used to derive Cooling and Heating Degree Days which are based on starting point temperatures of 72°F and 66°F, respectively. Similarly, the maximum and minimum of the composite temperature is used for the Summer and Winter peak models.

II.A. Long-Term Sales Forecasts

Long-term forecasts of electricity sales were developed for each revenue class for the forecasting period of 2001 – 2020 and are adjusted to match the NEL forecast. The results of these sales forecasts for the years 2002 – 2011 are presented in Schedules 2.1 – 2.3 which appear at the end of this chapter. Econometric models are developed for each revenue class using the statistical tool Metrix ND. The methodologies used to develop sales forecasts for each jurisdictional revenue class are outlined below.

The first five years of the forecasts were developed using monthly models for Net Energy For Load, Residential, Commercial and Industrial Sales. For the subsequent years the growth rates from the annual models are applied for Net Energy for Load and energy sales by class.

1. Residential Sales

Residential energy sales are forecast by multiplying the residential use per customer forecast by the number of residential customers forecasted. 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. The price of electricity plays a role in explaining electric usage since electricity, like all other goods and services, will be purchased in greater or lesser quantities depending upon its price. The Cooling & Heating Degree Days are used to capture the changes in the electric usage of weather-sensitive appliances such as air conditioners and electric heaters. The Cooling Degree Days variable is multiplied by the level of air conditioning saturations and the Heating Degree Days variable is multiplied by the level of electric heating saturations. To capture economic conditions the model includes Florida's per capita income. The degree of economic prosperity can, and does, affect residential electricity sales. For the short-term period (first five years) a similar econometric model is developed using monthly data. The monthly model is a function of the same variables such as Cooling Degree Days, Heating Degree Days, price of electricity, Florida's total personal income and a dummy variable for the months of April, May and June along with an autoregressive term.

2. Commercial Sales

The commercial sales forecast is also developed 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. Florida's commercial employment is used to capture the economic activity in FPL's service territory. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. Cooling Degree Days are used to capture weather-sensitive load in the commercial sector. The first five years of the forecast are developed from a monthly model using the same explanatory variables, and for the following years, growth rates from the annual model are applied.

3. Industrial Sales

Industrial sales were forecasted through a linear multiple regression model using Florida manufacturing employment, the price of electricity and an autoregressive term as explanatory variables. Energy sales in this revenue class are primarily due to manufacturers; therefore, employment in this sector is a key variable in capturing the economic activity. The price of electricity is also included as an explanatory variable in the model because it has an impact on customer usage. The first five years of the forecast are developed from a monthly model using the same explanatory variables, and for the following years, growth rates from the annual model are applied.

4. Other Public Authority Sales

At present this class consists of sports fields and one government account. The forecast for this class is based on historical knowledge of its characteristics.

5. Street & Highway Sales and Railroad & Railways Sales

The forecast of Street & Highway sales are was developed using a constant use per customer, which is multiplied by the number of customers projected.

The growth in sales for Railroads & Railways are held constant since there are no plans for expansion.

6. Resales Sales

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.

Contract Rate

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. Sales to the Florida Keys are forecasted using a regression model. Forecasted sales to the City of Key West are based on assumptions regarding their contract demand and expected load factor. Metro-Dade County sells 60 MW to Florida Power Corporation. Line losses are billed to Metro-Dade under a wholesale contract. The forecast is calculated based on assumptions about the magnitude of line losses, the sales monthly capacity factor, and the number of hours in a particular month. FMPA has contracted for delivery of 75 MW for the period of June 2002 through October 2007.

Total Sales

Sales forecasts by revenue class 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 Net Energy for Load (NEL).

II.B. Net Energy for Load

An annual econometric model is developed to produce a Net Energy for Load (NEL) forecast. The key inputs to the model are: the price of electricity, Heating & Cooling Degree Days, and Florida Non-Agricultural Employment. The Cooling Degree Days are multiplied by cooling saturation; similarly the Heating Degree Days are multiplied by heating saturation. The monthly model is similar except the economic variable utilized is Florida's per capita income, since the model is estimated on a per customer basis. Like the sales forecasts, the first five years are obtained from the short-term model and forecasts for subsequent years are generated using the growth rates from the annual model.

Once an annual NEL forecast is obtained using the above-mentioned methodology, the results are then compared for reasonableness to the NEL forecast generated using the total sales forecast. The sales by class are then adjusted to match the NEL from the annual NEL model.

The forecasted NEL values for 2002 – 2011 are presented in Schedule 3.3 which appears at the end of this chapter. (While the forecasted value for 2001 was used during the 2001 IRP process, the form reflects the actual value for 2001.)

II.C. System Peak Forecasts

The rate of absolute growth in FPL system load has been a function of 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. FPL developed the Peak Forecast models to capture these behavioral relationships.

The forecasting methodology of Summer, Winter, and monthly system peaks is discussed below. The forecasted values for Summer and Winter peak loads for the years 2002 - 2011 are presented in Schedules 3.1 and 3.2, as well as in Schedules 7.1 and 7.2. (While the forecasted value for 2001 was used during the 2001 IRP process, the form reflects the actual value for 2001.)

System Summer Peak

The Summer peak forecast is developed using an econometric model. The model is a per customer model that includes: the total number off FPL Summer customers, the price of electricity, real Florida income as an economic driver, and the maximum temperature as a weather variable. The model is estimated using an autoregressive term.

System Winter Peak

Like the system Summer peak model, the Winter peak model is also an econometric model. The Winter peak model is a per customer model which consists of three weather-related variables: (1) the minimum temperature on the peak day, (2) a weather term which is a product of heating saturation and minimum Winter day temperature, and (3) Heating Degree Hours for the prior day until 9:00 a.m. of the peak day. In addition, the model also has an economic term, Real Florida Income. A dummy variable, which is used to capture the effects of larger homes, is multiplied by the minimum temperature.

Monthly Peak Forecasts

Monthly peaks for the 2001 - 2020 period are forecasted to provide information for the scheduling of maintenance for power plants and fuel budgeting. The forecasting process is basically the same as for the monthly NEL forecast; and consists of the following actions:

a. Develop the historical seasonal factor for each month by using ratios of historical monthly peaks to seasonal peak (Summer = April-October, Winter = November-March).

b. Apply the monthly ratios to their respective seasonal peak forecast to derive the peak forecast by month. This process assumes that the seasonal factors remain unchanged over the forecasting period.

II.D The Hourly Load Forecast

Forecasted values for system hourly load for the period 2001 - 2020 are produced using a System Load Forecasting "shaper" program. This model uses sixteen years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. These daily load shapes are ranked and used with forecasted monthly peaks, NEL, and calendars in developing an hourly forecast. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Year	Population*	Members per Household	GWH	Average** No. of Customers	Average KWH Consumption Per Customer	GWH	Average** No. of Customers	Average KWH Consumption Per Customer
1992	6,375,204	2.19	34,198	2,911,807	11,745	26,991	350,269	77,058
1993	6,486,127	2.18	36,360	2,975,479	12,220	28,508	358,679	79,481
1994	6,660,137	2.19	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,806,337	2.20	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,948,942	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,582	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,617	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,734	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,543	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,749,031	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,891,055	2.22	49,065	3,552,211	13,813	38,360	433,999	88,387
2003	8,029,615	2.22	51,340	3,616,387	14,196	39,745	444,604	89,395
2004	8,164,713	2.22	53,568	3,676,476	14,570	40,913	456,688	89,587
2005	8,296,344	2.22	55,902	3,739,451	14,949	42,018	468,420	89,702
2006	8,433,429	2.22	58,241	3,801,791	15,319	43,210	479,587	90,098
2007	8,570,515	2.22	59,857	3,858,417	15,513	44,317	488,478	90,724
2008	8,709,688	2.23	61,401	3,912,926	15,692	45,391	497,099	91,313
2009	8,850,948	2.23	62,961	3,966,369	15,874	46,461	505,533	91,905
2010	8,992,209	2.24	64,628	4,018,926	16,081	47,571	513,718	92,602
2011	9,134,785	2.24	66,282	4,070,702	16,283	48,478	521,756	92,913

* Population represents only the area served by FPL.
** Average No. of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Other Sales to	Total** Sales to
		Average*	Average KWH	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWH	Customers	Per Customer	GWH	GWH	GWH	GWH
1992	4,054	14,788	274,135	77	353	721	66,393
1993	3,889	14,866	261,602	79	330	665	69,830
1994	3,845	15,588	246,658	85	353	664	73,608
1995	3,883	15,140	256,481	84	358	648	76,248
1996	3,792	14,783	256,515	83	368	577	77,334
1997	3,894	14,761	263,830	85	383	702	79,855
1998	3,951	15,126	261,233	81	373	625	85,131
1999	3,948	16,040	246,112	79	473	465	84,676
2000	3,768	16,410	229,592	81	408	381	87,959
2001	4,091	15,445	264,872	86	419	67	90,212
2002	3,947	15,147	260,552	81	417	61	91,930
2003	3,960	15,176	260,942	81	428	60	95,615
2004	3,969	15,143	262,106	82	438	60	99,030
2005	3,971	15,105	262,875	82	446	60	102,479
2006	3,977	15,077	263,746	83	455	60	106,024
2007	3,974	15,122	262,795	83	461	60	108,752
2008	3,956	15,168	260,821	83	468	60	111,360
2009	3,933	15,213	258,530	84	474	60	113,973
2010	3,912	15,259	256,386	84	481	60	116,736
2011	3,891	15,305	254,215	85	487	60	119,282

*Average No.of Customers is the annual average of the twelve month values.
**GWH=Column 4 + Column 7 + Column 10 + Column 13 + Column 14 + Column 15.

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net* Energy For Load GWH	Average ** No. of Other Customers	Total Average*** Number of Customers
1992	702	6,002	73,097	4,374	3,281,238
1993	958	4,988	75,776	3,086	3,352,110
1994	1,400	5,367	80,376	2,560	3,422,187
1995	1,437	6,276	83,961	2,460	3,488,796
1996	1,353	5,984	84,671	2,480	3,550,748
1997	1,228	5,770	86,853	2,520	3,615,485
1998	1,326	6,205	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,207	7,021	100,158	2,805	4,004,161
2003	1,425	7,373	104,414	2,872	4,079,038
2004	1,446	7,567	108,042	2,931	4,151,237
2005	1,463	7,831	111,772	2,985	4,225,960
2006	1,482	8,097	115,602	3,036	4,299,491
2007	1,415	7,990	118,157	3,077	4,365,095
2008	1,081	8,108	120,549	3,116	4,428,309
2009	1,081	7,869	122,922	3,155	4,490,271
2010	1,081	7,631	125,448	3,193	4,551,096
2011	1,081	7,149	127,512	3,231	4,610,993

* GWH = Column 16 + Column 17 + Column 18

** Average Number of Customers is the annual average of the twelve month values.

*** Total = Column 5 + Column 8 + Column 11 + Column 20

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1992	14,661	223	14,438	0	234	151	248	51	14,179
1993	15,266	397	14,869	0	311	182	320	79	14,635
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,754	169	18,585	0	798	673	483	463	17,473
2002	19,131	146	18,985	0	805	83	487	39	17,717
2003	19,765	223	19,542	0	810	125	497	59	18,274
2004	20,226	225	20,002	0	817	167	507	79	18,656
2005	20,719	227	20,493	0	824	211	517	99	19,068
2006	21,186	227	20,959	0	829	255	525	120	19,457
2007	21,556	227	21,329	0	834	300	533	140	19,749
2008	21,870	152	21,718	0	839	347	541	159	19,984
2009	22,271	152	22,119	0	842	394	547	179	20,309
2010	22,687	152	22,535	0	844	410	548	185	20,700
2011	23,106	152	22,954	0	844	410	548	185	21,119

Historical Values (1992 - 2001):

Cols. (2) - (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD-LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002 - 2011):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1) Year	(2) Total	(3) Firm Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
1992/93	12,964	102	12,862	0	242	195	275	48	12,447
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,199	150	18,049	0	972	493	448	201	16,779
2001/02	17,597	145	17,452	0	1,081	534	489	242	16,028
2002/03	19,551	121	19,430	0	1,085	78	458	22	17,908
2003/04	19,976	198	19,779	0	1,093	104	464	30	18,285
2004/05	20,418	199	20,218	0	1,102	128	470	38	18,680
2005/06	20,854	199	20,654	0	1,109	153	476	48	19,068
2006/07	21,204	199	21,005	0	1,116	177	481	57	19,373
2007/08	21,538	124	21,414	0	1,123	200	486	66	19,663
2008/09	21,966	124	21,841	0	1,129	223	491	75	20,048
2009/10	22,366	124	22,242	0	1,134	245	494	82	20,411
2010/11	22,785	124	22,661	0	1,134	245	494	82	20,830

Historical Values (1992/93 - 2001/02):

Cols. (2) - (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD - LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002/03 - 2010/11):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) Net Energy For Load	(9) Load Factor(%)
1992	73,778	460	221	73,076	702	6,002	73,097	56.8%
1993	76,632	553	303	75,674	958	4,988	75,776	56.7%
1994	81,493	661	456	80,093	1,400	5,367	80,376	60.4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59.3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60.0%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59.7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	59.1%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	59.3%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	61.5%
2001	101,736	1,789	1,542	100,765	970	7,222	98,404	59.9%
2002	100,158	58	15	98,951	1,207	7,021	100,085	59.8%
2003	104,414	156	47	102,988	1,425	7,373	104,211	60.3%
2004	108,042	256	80	106,597	1,446	7,567	107,706	61.0%
2005	111,772	358	115	110,310	1,463	7,831	111,299	61.6%
2006	115,602	462	150	114,121	1,482	8,097	114,990	62.3%
2007	118,157	568	184	116,743	1,415	7,990	117,405	62.6%
2008	120,549	675	216	119,468	1,081	8,108	119,658	62.9%
2009	122,922	785	247	121,842	1,081	7,869	121,890	63.0%
2010	125,448	830	262	124,367	1,081	7,631	124,356	63.1%
2011	127,512	830	262	126,432	1,081	7,149	126,420	63.0%

Historical Values (1992 - 2001):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula: (2) =(3) + (4) + (8).
Cols. (3) & (4) are DSM values starting in January, 1988 through 2001 which contributed to the values in Cols. (5) - (9).
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .
Col. (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1. (9) = ((8)*1000) / ((2) * 8760)

Projected Values (2002 - 2011):

Col. (2) represents Net Energy for Load w/o DSM values. The values are calculated using the formula: (2) =(3) + (4) + (8).
Cols. (3) - (4) are forecasted values of the reduction on sales from incremental conservation.
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) , into Wholesale and Retail .
Col. (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. (9) = ((8)*1000) / ((2) * 8760)

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2001 ACTUAL		2002 * FORECAST		2003 * FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	18,199	8,074	18,968	7,375	19,551	7,708
FEB	13,268	6,541	16,070	6,859	16,563	7,190
MAR	14,611	7,442	14,353	7,368	14,793	7,703
APR	15,831	7,797	15,645	7,683	16,163	8,020
MAY	16,280	7,722	17,373	8,442	17,948	8,810
JUN	18,342	9,476	18,218	9,299	18,821	9,690
JUL	17,803	9,120	18,727	9,710	19,347	10,110
AUG	18,754	10,086	19,131	9,881	19,765	10,263
SEP	18,707	9,413	18,494	9,608	19,107	9,982
OCT	15,971	8,185	17,266	8,578	17,837	8,927
NOV	13,781	7,217	15,721	7,737	16,204	8,068
DEC	14,590	7,331	16,317	7,618	16,818	7,942
TOTALS		98,404		100,158		104,414

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation.

CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A FPL's Resource Planning:

FPL developed an integrated resource planning (IRP) process in the early 1990's and has since utilized the process to determine when new resources are needed, what the magnitude of the needed resources are, and what type of resources should be added. The timing and type of potential new power plants, the primary subjects of this document, are determined as part of the IRP process work. This section discusses how FPL applied this process in its 2001 planning work.

Four Fundamental Steps of FPL's Resource Planning:

There are 4 fundamental "steps" to FPL's resource planning. These steps can be described as follows:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

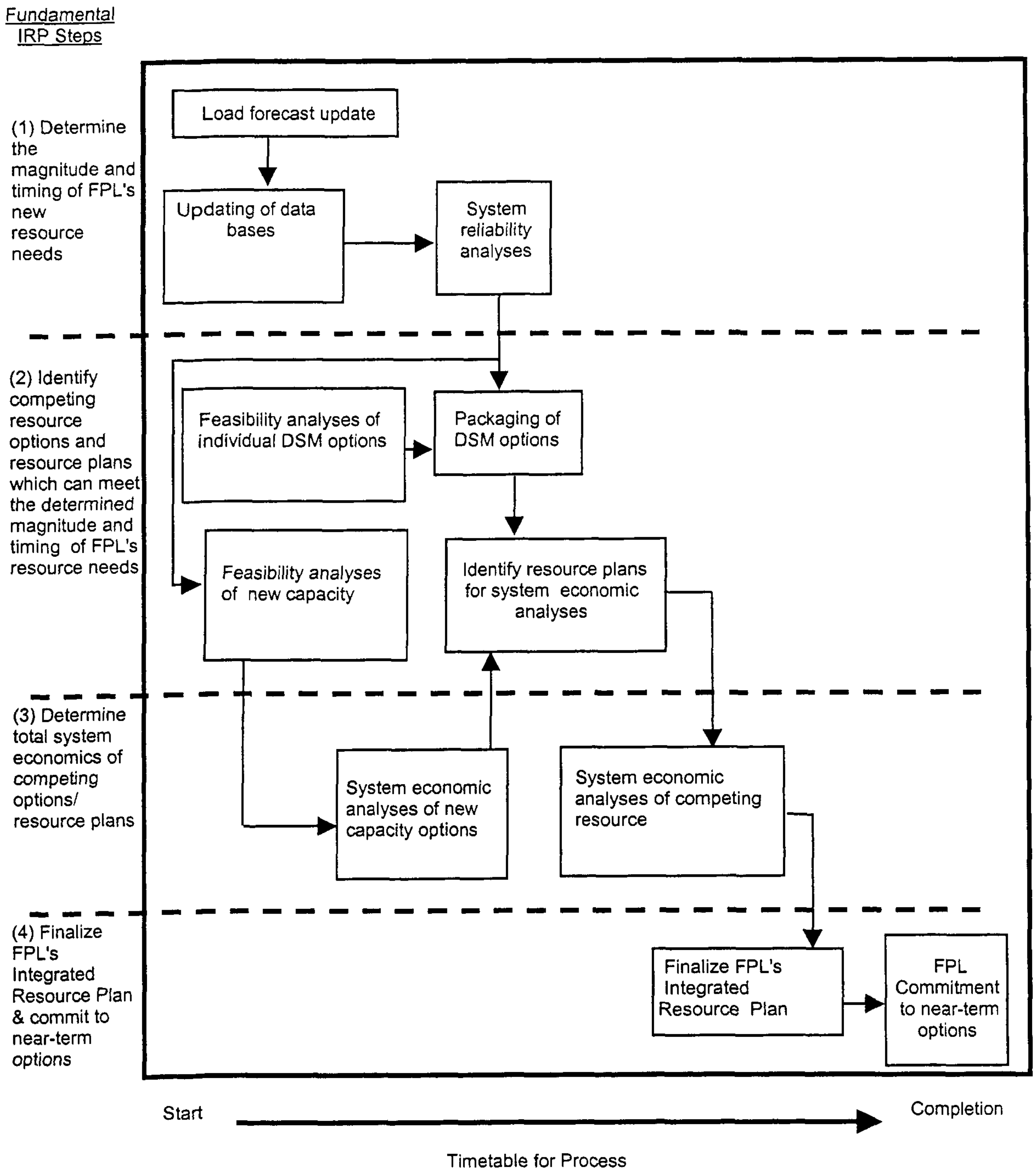
Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of FPL's resource needs (i.e., identify competing options and resource plans;

Step 3: Determine the economics for the total utility system with each of the competing options and resource plans; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of FPL's IRP Process



(Normal time period: approx. 6-7 months)

Figure III.A.1

Step 1: **Determine the Magnitude and Timing of FPL's New Resource Needs:**

The first of these four resource planning steps – determining the magnitude and timing of FPL's resource needs – is essentially a determination of how many megawatts (MW) of load reduction, new capacity, or a combination of both load reduction and new capacity options are needed. Also determined in this step is when the MW are needed to meet FPL's planning criteria. This step is often referred to as a reliability assessment for the utility system.

Step 1 starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information which is used in many of the fundamental steps in resource planning. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, and power plant capability and reliability assumptions. Three assumptions made by FPL during its 2001 IRP work involved near-term construction capacity additions, near-term firm capacity purchase additions, and long-term DSM implementation.

The first of these assumptions included FPL's announced plans to add near-term capacity through various construction projects. These construction projects include the repowering of several existing units and the addition of several new CT's. FPL committed 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. The repowered Fort Myers capacity is scheduled to come in-service by the Summer, 2002. CT's, which are components of the repowering effort, began coming in-service at Fort Myers in late 2000 and through their initial operation in a stand-alone mode have already increased FPL's system capacity. A somewhat different schedule is planned for the two Sanford units which will be repowered. Both of these units will be repowered without the combustion turbine components coming in-service during the process. Sanford Unit # 5 came out-of-service in the Fall, 2001, and will return fully repowered by Summer, 2002. Sanford Unit # 4 was projected to come out-of-service in the Spring, 2002, and was assumed to return fully repowered at the end of 2002. As a result of this commitment, FPL assumed that these capacity additions resulting from the Fort Myers and Sanford repowerings were a "given" in its 2001 resource planning work.

Another part of FPL's construction capacity addition assumption was its previously announced (in last year's Site Plan) decision to add two new CT's 2003 at FPL's existing Fort Myers site. FPL's 2001 resource planning work assumed that these new CT construction capacity additions would also be a "given".

The second of these assumptions involved a decision which was made during FPL's 2000 resource planning work to secure an amount of capacity for the next few years through firm capacity, short-term purchases. These firm capacity purchases are from a combination of utility and independent power producers. These capacity purchases were not finalized at the time FPL filed last year's (2001) Site Plan, but were finalized later in 2001. The total capacity and duration of these purchase totals are both greater than projected in last year's Site Plan. The annual total capacity values for these purchases are presented in Table I.D.1. These purchase amounts are also assumed as a "given" in FPL's 2001 resource planning work.

The third of these assumptions involved DSM. Since 1994, FPL's resource planning work has used the DSM MW called for in FPL's approved DSM goals as a "given" in its analyses. This was again the case in FPL's 2001 planning work as its recently approved new DSM goals through the year 2009 were taken as a given.

The first place in which these assumptions and much of the other updated information and assumptions are used is the first fundamental step: the determination of the magnitude and the timing of FPL's resource needs. This determination is accomplished by system reliability analyses which are typically based on a dual planning criteria of a minimum peak period reserve margin of 15% (FPL applies this to both Summer and Winter peaks) and a maximum loss-of-load probability (LOLP) of 0.1 days/year criteria. Both of these criteria are commonly used throughout the utility industry. The reserve margin criterion increases from 15% to 20% starting in mid - 2004 due to a voluntary agreement reached among FPL, FPC, and TECO, and accepted by the FPSC in the FPSC's Docket No. 981890-EU.

Historically, two types of methodologies, deterministic and probabilistic, have been employed in system reliability analyses. The calculation of excess firm capacity at the annual system peaks (reserve margin) is the most common method, and 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, deterministic methods do not take into account probabilistic-related elements such as: unit reliability; unit numbers and sizes (i.e., two 50 MW units which can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit which can also be counted on to run 90% of the time); and the value of being part of an interconnected system.

Therefore, probabilistic methodologies have been used to provide additional information on the reliability of a generating system. There are a number of probabilistic methods that are being used to perform system reliability analyses. Of these, the most widely used is loss-of-load probability or LOLP. 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 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. The standard for LOLP accepted throughout the industry is a maximum of 0.1 day per year. This analysis requires a more complicated calculation methodology than does reserve margin analysis. Reserve margin analyses are typically carried out on a spreadsheet. The more complicated LOLP analyses are carried out using the Tie Line Assistance and Generation Reliability (TIGER) model.

The end result of the first fundamental step of resource planning is a projection of how many MW are needed to maintain system reliability and of when the MW are needed. This information is used in the second fundamental step: identifying resource options and resource plans which can meet the determined magnitude and timing of FPL's resource needs.

Step 2: Identify Resource Options and Plans Which Can Meet the Determined Magnitude and Timing of FPL's Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, feasibility analyses of new capacity options are carried out to determine which new capacity options appear to be the most competitive on FPL's system. These analyses also establish capacity size (MW) values, projected construction / permitting schedules, and operating parameters and costs.

The individual new capacity options are then "packaged" into different resource plans which are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of FPL's new resource needs are met. The creation of these competing resource plans is typically carried out using dynamic programming techniques.

In recent years, FPL's analysis of new capacity options in its annual resource planning work has included only FPL construction options. The earliest date new capacity options were projected to be needed was in 2005. Prior to the 2001 planning cycle, the 2005 date was distant enough so that no actual construction/purchase decision was needed. However, in 2001, that was no longer the case. Furthermore, the type of new units FPL had been projecting for construction (combined cycle units) are among those addressed in the Florida Public Service Commission's "Bidding Rule" and thus require the issuance of a Request for Proposals (RFP) for meeting this capacity need.

FPL issued a Capacity RFP in mid – August of 2001. The RFP sought 1,150 MW of additional capacity by mid – 2005 and another 600 MW of additional capacity by mid – 2006. Fifteen (15) developers submitted one or more proposals in response to the RFP. In all, 81 proposals from these developers were evaluated along with 13 FPL construction options. Consequently, a much larger than usual number of generation options were evaluated in FPL's 2001 planning work.

At the conclusion of the second fundamental resource planning step in 2001, a number of different combinations of new resource options (i.e., resource plans) of a magnitude and timing necessary to meet FPL's resource needs were identified. These resource plans were then compared on an economic basis.

Step 3: **Determining the Total System Economics:**

At the completion of fundamental Steps 1 & 2, the most viable new resource options have been identified, and these resource options have been combined into a number of resource plans which meet the magnitude and timing of FPL's resource needs. The stage is set for comparing the system economics of these resource plans. FPL combines the resource options into resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone & Webster Management Consultants, Inc. The EGEAS model is also used to perform the basic economic analyses of the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of the competing resource plans is the competing resource plans' impact on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM methodology). However, in cases such as existed for FPL's 2001 planning work in which the DSM contribution was taken as a "given" and the only competing options were new generating units or purchases, comparisons of competing resource plans' impacts on electricity rates and on system revenue requirements are equivalent. Consequently, for FPL's 2001 resource planning work, the competing options and plans were evaluated on a present value system revenue requirement basis.

The basic economics analyses carried out with the EGEAS model focus on the capital and operating costs of new capacity options plus the impact these new capacity options have on FPL's system fuel costs. In FPL's 2001 analyses, three other costs were also evaluated. These three additional costs were: generator startup costs, transmission integration costs, and equity penalty costs. Once these three costs were calculated for the competing resource plans, they were added to the EGEAs costs to derive total costs.

In addition to FPL's own work that was carried out with the EGEAS model, an independent evaluator, Sedway Consulting, performed its own analyses of the outside proposals and FPL construction options. Sedway Consulting utilized its won Response Surface Model (RSM) to perform its basic economic analyses, then added in the generator startup costs, transmission integration costs, and equity penalty costs utilized by FPL. Finally Sedway Consulting used its RSM-derived estimate of residual benefits for FPL's construction options to derive its own total cost projections for the competing resource plans. Sedway Consulting's analyses came to the same conclusion as FPL analyses: FPL's Martin Conversion project and Manatee CC unit were the most cost-effective alternatives.

At the conclusion of the analyses carried out in Step 3, a determination of FPL's preferred resource plan was made.

Step 4: Finalizing FPL's 2001 Resource Plan

The results of the previous three fundamental steps' activities were evaluated by FPL management and a decision was made as to what FPL's 2001 resource plan would be. This plan is presented in the following section.

This evaluation focused both on the economics of the competing resource plans and on various non – price factors that essentially address risks associated with these plans. Both the economics and risk considerations favored the construction of the Manatee and Martin units.

III.B Incremental Resource Additions

FPL's projected incremental generation capacity additions/changes for 2002 through 2011 are depicted in Table III.B.1. (The planned DSM additions are shown separately in Table III.C.1.) These capacity additions/changes will result from a variety of actions including: changes to existing units (which are typically achieved as a result of plant component replacements during major overhauls), changes in the amounts of purchased power being delivered under existing contracts as per the contract schedules or by entering into new purchase contracts, repowering of existing units, projected construction of new units, and conversion of CT's into CC's.

As shown in Table III.B.1, the bulk of the capacity additions are made up of the following items: the repowering of both existing steam units at FPL's Fort Myers site by Summer, 2002; a similar repowering of FPL's Sanford Unit # 5 and # 4 projected by the Summer, 2002, and the end of 2002, respectively; the construction of two new CT's by mid – 2003, the conversion of two CT's into a larger CC unit in 2005 at FPL's Martin site; the addition of a new CC unit also in 2005 at FPL's Manatee site, new firm capacity, shorter-term purchases through early 2007; and the construction of four additional unsited CC units in the 2007 through 2011 time frame.[1] (Note that during FPL's 2001 resource planning work the projected schedule for repowering Sanford Unit # 4 was for the unit to come off-line in March, 2002 and return to service in December, 2002. These dates have recently been changed to August, 2002 and June, 2003, respectively. This schedule change has no effect on the 2002 Summer reserve margin shown in this document, but will lower FPL's Winter 2003 reserve margin from approximately 28% to 26%.)

The number of CC units which are projected to be built in FPL's 2002 Site Plan has decreased compared to the number of CC units shown in the 2001 Site Plan. This is due to the fact that the projected capacity of the new CC units has approximately doubled (i.e., approximately 1,100 MW from 550 MW) from last year's projections due to a preferred new design approach that utilizes 4 CT's instead of 2 CT's for each CC unit.

As first presented in last year's site plan, this site plan also shows capacity additions needed in 2010 to replace approximately 930 MW of firm capacity purchases from the Southern Company that are scheduled to end in 2010. The end of these purchases requires FPL to replace this capacity, as well as to meet projected load growth for 2010, in a way which meets a minimum 20% reserve margin requirement. While FPL has not yet determined whether it would extend or replace these purchases, or build new capacity to meet its needs, for purposes of this Site Plan it was assumed that the 2010 needs would be met through the addition of unsited CC units.

[1] FPL's current planning studies have identified new combined cycle units as the generally preferred option to meet future load growth. However, repowering of existing FPL sites remains an alternative to new construction, and FPL will continue to examine this option.

Projected Capacity Changes for FPL [1]			
		Net Capacity Changes (MW)	
		Winter [2]	***Summer*** [3]
2002	Fort Myers Repowering:Second Phase [4]	(1)	35
	Sanford Repowering # 5: Initial Phase [5]	(390)	---
	Sanford Repowering # 5: Second Phase [5]	---	567
	Sanford Repowering # 4: Initial Phase [5]	---	(390)
	Changes to existing units	10	30
	New purchases [6]	593	897
	Changes to existing QF's	---	(9)
2003	Fort Myers Repowering:Second Phase	531	---
	Sanford Repowering # 5: Second Phase	1,065	---
	Sanford Repowering # 4: Second Phase [7]	675	957
	Combustion Turbines (2) Fort Myers [8]	---	318
	Changes to existing QF's	(9)	---
	Changes to existing units	20	---
	New purchases [6]	724	71
2004	Combustion Turbines (2) Fort Myers	362	---
	New purchases [6]	39	---
2005	Changes to existing QF's	(10)	(10)
	New purchases [6]	(50)	(717)
	Manatee Combined Cycle	---	1,107
	Conversion of MR CT's to CC	---	789
2006	Manatee Combined Cycle	1,197	
	Conversion of MR CT's to CC	835	---
	New purchases [6]	(763)	---
	Changes to existing QF's	(133)	(133)
2007	New purchases [6]	---	(447)
	Unsited Combined Cycle #1 [9]		1,107
2008	New purchases [6]	(543)	
	Unsited Combined Cycle #1 [9]	1,197	---
2009	Unsited Combined Cycle #2 [9]	---	1,107
	Changes to existing QF's	(51)	(51)
2010	Changes to existing purchases [10]	---	(975)
	Unsited Combined Cycle #2 [9]	1,197	---
	Unsited Combined Cycle #3 [9]	---	1,107
2011	Unsited Combined Cycle #3 [9]	1,197	---
	Unsited Combined Cycle #4 [9]	---	1,107
	TOTALS =	***7,692***	***6,467***

Table III.B.1

Projected Capacity Changes for FPL

Note:

(1) Additional information about these capacity changes and resulting reserve margins is found in Chapter III of this document.

(2) Winter values are values for January of year shown.

(3) Summer values are values for August of year shown.

(4) The initial phase of the Fort Myers repowering project consists of the introduction of operational combustion turbines followed by taking existing steam units out-of-service. The second phase of repowering consists of completing the integration of the combustion turbines, heat recovery steam generators, and steam turbines.

(5) The initial phase of the Sanford repowering project consists solely of taking existing steam units # 4 and # 5 out-of-service; combustion turbine operation is not introduced at this time. The second phase of the repowering consists of integrating the combustion turbines, heat recovery steam generators, and steam turbines.

(6) These are firm capacity, short - term purchases. See Section I.D and III.A. for more details.

(7) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work. That schedule has recently changed. Please refer to Section III.A, "Step 1" for more information. The only reserve margin effect will be to lower FPL's Winter 2003 reserve margin from 31% to 29%.

(8) The two CTs at Fort Myers are scheduled to be in-service in the Spring of 2003. Therefore, the CTs are included in the 2003 Summer reserve margin calculation and are included in the 2004 - on reserve margin included in the calculations for Summer and Winter.

(9) All new combined cycle units are scheduled to be in-service in June of the year shown. Consequently, they are included in the Summer reserve margin calculation for the in-service year and in both the Summer and Winter reserve margin calculations for subsequent years.

(10) FPL will be determining at a later date whether to extend or replace the UPS purchases (928 MW) from Southern Company. However, for purposes of this Site Plan, FPL has assumed that the 2010 needs would be met through the addition of unsited combined cycles.

III.C Demand Side Management (DSM)

1. FPL's Current DSM Programs

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program which is designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation in residential dwellings that utilize whole-house electric air-conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of those leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On Call): This program offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial and industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilating, and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program (which started in 2001) is similar to the Commercial/Industrial Load Control mentioned above by continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Commercial/Industrial Building Envelope: This program encourages the installation of energy-efficient building envelope measures such as window treatments and roof/ceiling insulation for commercial/industrial facilities.

Business On Call: This program offers load control of central air conditioning units to both small, non-demand-billed and medium, demand - billed commercial/industrial customers in exchange for monthly electric bill credits.

2. Research and Development

FPL's DSM Plan continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies which build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies and from that research has been able to develop new programs such as Residential New Construction, Commercial/Industrial Building Envelope, and Business On Call.

Low Income Weatherization Retrofit Project

This R&D project is investigating cost-effective methods of increasing the energy efficiency of FPL's low - income customers. The research project addresses the needs of low - income housing retrofits by providing monetary incentives to various housing authorities including weatherization agency providers (WAPS), and non-weatherization agency providers (non-WAPS). These incentives are used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting. FPL either conducts a home energy survey, trains housing authority employees to perform FPL home energy surveys, accepts the National Energy Audit (NEAT) (as supplemented to capture water heating recommendations not included in the NEAT audit), or approves similar FPL - approved audits conducted by weatherization providers to determine the need for energy efficient retrofit measures for each home. FPL has designed the project so as to minimize extra work for the retrofit housing authorities.

Photovoltaic Research, Development and Education Project

Photovoltaic (PV) roof-tile systems are a relatively new technology which directly replaces existing roofing materials such as shingles and standing-rib roofing with PV materials. These PV materials have the same water - proofing characteristics as conventional roofing materials. This project is consistent with the Federal Government's Million Solar Roofs initiative. However, based on FPL's research to - date, a primary hurdle to the physical installation of PV systems, whether roofing materials or flat plate modules, is the lack of awareness, understanding, and acceptance by local building officials. For the most part, these officials are unclear about how these systems work and how to address these systems as part of the building, permitting, and inspection process. This creates barriers toward the use of this technology.

Green Energy Project

FPL finished an R&D project addressing customer acceptance of green energy where donations were used as the funding mechanism for the purchase and installation of utility - grid connected PV systems. This project raised in excess of $89,500 and a 10.1 kW (dc) PV system has been constructed at FPL's Martin power plant site.

FPL is now investigating potential customer acceptance of green pricing rates in its Green Energy Project. Under this project, FPL is examining the feasibility of purchasing electric energy generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy, and/or other renewable resources. Participating customers would then be charged higher "green" electric rates for utilizing electric energy derived from these sources.

FPL's Request for Proposals (RFP) solicitation previously mentioned in Section III.A. also included a separate request for proposals that would supply energy only (MWH) from new, renewable energy sources. Several proposals were received in response to the RFP and the proposals are now being evaluated. This evaluation will determine whether the proposals are suitable for providing renewable energy that could be offered in a Green Energy program. A decision on this is expected by mid – 2002.

Real-Time Pricing

Although not part of FPL's approved DSM Plan, FPL continues to research new conservation/efficiency options such as Real-Time Pricing. This option is an experimental service offering for large C/I customers designed to evaluate customer load response to hourly, marginal cost-based energy prices provided on a day-ahead basis.

3. FPL's DSM MW Goals

FPL's DSM implementation plan is designed to meet currently approved DSM Goals for 2000 – 2009. The combined total residential and commercial/industrial Summer MW reduction values from FPL's DSM Goals for 2000 – 2009 are presented in Table III.C.1. FPL has already implemented approximately 2,790 MW at the meter of DSM through 2001.

FPL's Summer MW Reduction Goals for DSM
(At the Meter)

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

Table III.C.1

III.D Independent Power Producers Generation Additions

As previously mentioned in Section III.A, FPL has entered into a number of new firm capacity, shorter - term purchases that extend through early 2007. The capacity supplied by these purchases are summarized in Table I.D.1. All but 50 MW of these purchases are from independent power producers.

Tables I.B.1 and I.B.2 present the previously contracted cogeneration/small power production facilities which are addressed in FPL's resource planning.

III.E Transmission Plan

The 2002 - 2011 transmission plan will allow for the reliable delivery of the required capacity and energy for FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV and 500 kV bulk transmission lines.

List of Proposed Power Lines
2002 – 2011

OWNER	LINE TERMINAL (FROM)	LINE TERMINAL (TO)	NET NEW CIRCUIT MILES	COMMERCIAL IN-SERVICE DATE (Mo/YR)	NOMINAL OPERATING VOLTAGE (KV)
FPL	Fort Myers GT's	Orange River	2.56	Mar-02	230
FPL	Greynolds (Aventura)	Laudania	6.70	Mar-02	230
FPL	Brevard	Malabar #2	25.79	Jun-02	230
FPL	Brevard	Malabar #3	25.79	Jun-02	230
FPL	Broward-Corbett	Marymount-Yamato	0.25	Jun-03	230
FPL	Broward-Corbett	Rainberry-Yamato	10.50	Jun-03	230
FPL	Broward-Goolsby	Yamato	2.50	Jun-03	230
FPL	Cortez	Johnson	11.00	Jun-03	230
FPL	Delmar	Yamato	2.00	Jun-03	230
FPL	Duval-Kingsland	Yulee-Oneil	6.50	Jun-03	230
FPL	Midway	Turnpike	2.00	Jun-03	230
FPL	Charlotte-Laurelwood	Coast-Peachland	6.70	Dec-03	230
FPL	Andytown	Pennsuco	2.00	Jun-04	230
FPL	Dade	Overtown	11.00	Jun-04	230
FPL	Indiantown	Martin #2	11.80	Jun-05	230
FPL	Conservation	OaklandPark	13.00	Jun-07	230
FPL	Conservation	Levee	36.00	Jun-08	500

Table III.E.1

In addition, there will be transmission facilities needed to connect FPL's projected capacity additions to the system transmission grid. These transmission facilities for the projected capacity additions at FPL's existing Fort Myers, Sanford, Martin, and Manatee sites are described below. Since the projected capacity additions for 2007 through 2011 are as-yet unsited, no transmission facilities information is provided. This information will be provided in future Site Plan documents once a site is selected.

III.E.1 Transmission Facilities at Fort Myers

The transmission work required for the repowering capacity addition at Fort Myers is as follows:

I. Substation:

1. Substation work is complete.

II. Transmission:

1. Transmission work is complete.

III.E.2 Transmission Facilities at Sanford

The transmission work required for the repowering capacity additions at Sanford is as follows:

I. Substation:

1. Substation work is complete.

II. Transmission:

1. Upgrade the Volusia #2 transmission line to 1475 Amps.

III.E.3 Transmission Facilities at Fort Myers

The transmission work required for the two new CT units at Fort Myers is projected to be as follows:

I. Substation:

1. Build one collector bus with 2 breakers each to connect 2 CT's on each one. Add another breaker to the collector bus to connect the start-up transformer.
2. Add the two main step-up transformers (200MVA/each), one for each CT.
3. Add the start-up transformer.
4. Disconnect the existing Fort Myers GT collector bus from the Fort Myers 230kV switchyard.
5. Add two breakers at Orange River 230 kV substation to connect the new line from the Fort Myers GT collector bus.
6. Connect the new Fort Myers collector bus to the Fort Myers 230kV switchyard.
7. Connect the Fort Myers collector bus to the Fort Myers 230kV switchyard.
8. Replace 4 breakers at the existing Fort Myers 230 kV switchyard.
9. Add relay and other protective equipment at Fort Myers and Orange River substations.

II. Transmission:

1. Build a new 230 kV line from the Fort Myers GT collector bus to Orange River (approximately 2.57 miles) similar to the existing circuits which are bundle 2-1431 ACSR 2580 Amps (1028 MVA) each.
2. Add protection and control equipment for the new line.

III.E.4 Transmission Facilities at Manatee

The transmission work required for the new combined cycle unit at Manatee is projected to be as follows:

II. Substation:

1. Build new collector yard containing two collector busses with 7 breakers to connect the four CT's, one ST, and the two start-up transformers.
2. Construct two string busses to connect the collectors and main switchyard.
3. Add five main step-up transformers (4-200MVA, 450MVA) one for each CT, and one for the ST.
4. Add the start-up transformers.
5. Add two breakers in bay # 6 to connect the collector bus at the Manatee switchyard.
6. Add three breakers in bay # 5 at the Manatee switchyard to connect the other collector bus and a new transmission line to Johnson # 2.
7. Add relays and other protective equipment.
8. Upgrade 230kV circuit breakers to 2 cycle Independent Pole breakers at Manatee switchyard.
9. Add a new line terminal at Johnson.

II. Transmission:

1. Construct 230kV Manatee-Johnson # 2 transmission line.
2. Add protection and control equipment for the new lines.
3. Upgrade the Johnson- JohnsonTap 138kV transmission line to 656 Amps.
4. Upgrade the Charlotte- Fort Myers 230kV transmission line to 1081 Amps.

III.E.5 Transmission Facilities at Martin

The transmission work required for the Martin Conversion project (convert the existing two CT's to a new four -on- one combined cycle unit) is projected to be as follows:

I. Substation:

1. Build new collector yard containing one collector buss with 4 breakers each to connect the two CT's, one ST, and the start-up transformer.
2. Add three main step-up transformers (2-200 MVA, 450MVA) one for each CT, and one for the ST.
3. Add the start-up transformer.
4. Add two breakers in bay #3 to connect the collector bus in the main switchyard.
5. Add relays and other protective equipment.
6. Install phase reactors and string buss in main switchyard to limit fault current.
7. Add breaker in bay #7 (7WE) for new Indiantown #2 transmission line. Tap existing 69kV auto-transformer off east 230kV operating buss.
8. Add breaker in Bay #3 (3WS) at Indiantown Substation for Martin line.
9. Create new bay 1a. Add breakers 1aWM, 1aWS for Indiantown-Bridge#2 line at Indiantown Substation.
10. Create new bay#1 at Bridge Substation with breakers 1WW and 1WM. Add breakers 2WW and 2WE to convert station configuration from ring buss.
11. Construct one string bus to connect the collector and main switchyard.

II. Transmission:

1. Construct 230kV Martin-Indiantown #2 transmission line.
2. Construct 230kV Indiantown – Bridge #2 transmission line.
3. Various OHGW replacements due to increased fault current.
4. Upgrade the Ranch - Marlin(2005) 230kV transmission line to 2052 Amps.
5. Upgrade the Cedar - Marlin (2005) 230kV transmission line to 1965 Amps. (Note that this line is necessary only if both Manatee & Martin are constructed and it is presented here for ease of presentation.)

III.F. Renewable Resources

FPL has been the leading Florida utility in examining ways to utilize renewable energy technologies to meet its customers' current and future needs. FPL has been involved since 1976 in renewable energy research and development and in facilitating the implementation of various technologies.

FPL assisted the Florida Solar Energy Center (FSEC) in the late 1970's in demonstrating the first residential solar photovoltaic (PV) system east of the Mississippi. This PV installation at FSEC's Brevard County location was in operation for over 15 years and provided valuable information about PV performance capabilities on both a daily and annual basis in Florida. FPL later installed a second PV system at the FPL Flagami substation in Miami. This 10 kilowatt (KW) system was placed into operation in 1984. The testing of this PV installation was completed, and the system was removed in 1990 to make room for substation expansion.

For a number of years, FPL maintained a thin-film PV test facility located at the FPL Martin Plant site. The FPL PV test facility was used to test new thin-film PV technologies and to identify design, equipment, or procedure changes necessary to accommodate direct current electricity from PV facilities into the FPL system. Although this testing has ended, the site is now the home for PV capacity which was installed as a result of FPL's recent Green Pricing effort (which is discussed on the following page).

In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first and only utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers choosing solar water heaters. Before the program was ended (due to the fact that it was not cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980's, FPL introduced another renewable energy program. FPL's Passive Home Program was created in order to broadly disseminate information about passive solar building design techniques which are most applicable in Florida's climate. Complete designs and construction blueprints for 6 passive homes were created by 3 Florida architectural firms with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, this program was popular and received a U.S. Department of Energy award for innovation. The program was eventually phased out due to a revision of the Florida Model Energy Building code. This revision was brought about in part by FPL's Passive Home Program. The revision incorporated into the Code one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

In early 1991, FPL received approval from the Florida Public Service Commission to conduct a research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. This research project was completed with mixed results. Some of the performance problems identified in the test may be solvable, particularly when new pools are constructed. However, the high cost of PV, the significant percentage of sites with unacceptable shading, as well as customer satisfaction issues remain as significant barriers to wide acceptance and use of this particular solar application.

More recently, FPL has analyzed the feasibility of encouraging utilization of PV in another, potentially much larger way. FPL's basic approach does not require all of its customers to bear PV's high cost, but allows customers who are interested in facilitating the use of renewable energy the means to do so. FPL's initial effort to implement this approach allowed customers to make voluntary contributions into a separate fund, which FPL used to make PV purchases in bulk quantities. PV modules were then installed and delivered PV-generated electricity directly into the FPL grid. Thus, when sunlight is available at this site(s), the PV-generated electricity displaces an equivalent amount of fossil fuel-generated electricity.

FPL's basic approach, which has been termed Green Pricing, was initially discussed with the FPSC in 1994. FPL's initial efforts to implement this approach were then formally presented to the FPSC as part of FPL's DSM Plan in 1995 and FPL received approval from the FPSC in 1997 to proceed. FPL initiated the effort in 1998 and received approximately $89,000 in contributions which significantly exceeded the goal of $70,000. FPL has purchased the PV modules and installed them at FPL's Martin plant site.

As previously discussed, FPL initiated two new renewable efforts in 2000. FPL's first new initiative in 2000 was the Green Energy Project which is a second, different attempt to implement the basic Green Pricing approach. Under this project FPL would purchase electric energy generated from new renewable resources. The project would offer to supply to FPL's electrical grid the equivalent of all, or part of, a customer's monthly Kwh usage with electricity generated from new renewable resources, with the remaining portion of that load being served by the Company's conventional generating facilities. Participants would be residential (and possibly commercial) customers who would pay higher ("green" rates) for electricity provided from these renewable sources. As discussed in Section III.1, FPL issued a Request for Proposals (RFP) in 2001 to solicit proposals to supply energy only (MWH) from new renewable sources. Proposals have been received and are now being evaluated. Program feasibility is also being assessed.

The second effort initiated in 2000 is FPL's Photovoltaic Research, Development and Education Project. This demonstration project's objectives are to increase the public awareness of roof tile PV technologies, provide data to determine the durability of this technology and its impact on FPL's electric system, collect demand and energy data to better understand the coincidence between PV roof tile system output and FPL's system peaks as well as the energy capabilities of roof tile PV systems, and assess the homeowner's financial benefits and costs of PV roof tile systems for our customers.

Finally, FPL has also facilitated renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.). Firm capacity and energy, and as-available energy, have been purchased by FPL from these developers. (Please refer to Tables I.B.1 and I.B.2).

III.G FPL's Fuel Mix and Fuel Price Forecasts

1. FPL's Fuel Mix

Until the mid-1980's, FPL relied primarily on a combination of oil, natural gas, and nuclear energy to generate electricity. In 1986, coal was first added to the fuel mix, allowing FPL to meet its customers' energy needs with a more diversified mix of energy sources. Additional coal resources have been added with the partial acquisition (76%) of Scherer Unit # 4. In 1997, petroleum coke was added to the fuel mix as a blend stock with coal at the St. Johns River Power Park.

2. Fuel Price Forecasts

FPL's long-term oil price forecast assumes that worldwide demand for petroleum products will grow moderately throughout the planning horizon. Non-OPEC crude oil supply is projected to increase as new and improved drilling technology and seismic information will reduce the cost of producing crude oil and increase both recovery from existing fields and new discoveries. However, the rate of increase in non-OPEC supply is projected to be slower than that of petroleum demand, resulting in an increase in OPEC's market share throughout the planning horizon. As OPEC gains market share, prices for petroleum products are projected to increase.

FPL's natural gas price forecast assumes that domestic demand for natural gas will grow throughout the planning horizon, primarily due to increased requirements for electric generation. Domestic natural gas production will increase as new and improved drilling technology and seismic information will reduce the cost of finding, developing, and producing natural gas fields. The rate of increase in domestic natural gas production is assumed to be slower than that of demand, with the balance being supplied by increased Canadian and liquefied natural gas (LNG) imports. As demand for natural gas in Florida grows, it is anticipated that based on natural gas users' commitments, the Florida Gas Transmission (FGT) pipeline system will be augmented/expanded. This anticipated expansion of FGT's pipeline, combined with the new Gulfstream pipeline, should result in sufficient gas for FPL's continued needs.

Schedule 5
Fuel Requirements [1/]

	Fuel Requirements	Units	Actual [2/] 2000	2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear	Trillion BTU	268	263	263	258	258	263	258	257	264	258	257	263
(2)	Coal	1,000 TON	4,170	3,078	3,460	3,584	3,416	3,396	3,479	3,194	3,513	3,110	3,113	3,281
(4)	Residual (FO6)- Total	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(5)	Steam	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(6)	Distillate (FO2)- Total	1,000 BBL	461	381	538	2,750	4,114	799	792	537	612	20	9	5
(7)	CC	1,000 BBL	1	75	124	2,220	3,404	683	677	486	549	10	3	3
(8)	CT	1,000 BBL	446	306	415	529	711	116	115	51	63	11	6	2
(9)	Steam	1,000 BBL	14	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	1,000 MCF	203,234	212,956	297,272	303,963	308,493	362,745	406,236	434,737	445,987	495,736	555,295	594,673
(11)	Steam	1,000 MCF	80,967	79,157	80,432	17,368	20,648	16,698	17,897	15,280	17,064	10,769	7,970	6,199
(12)	CC	1,000 MCF	117,684	109,778	196,898	274,488	277,953	337,081	384,738	414,787	424,908	482,040	546,027	587,265
(13)	CT	1,000 MCF	4,583	24,022	19,942	12,107	9,891	8,966	3,601	4,670	4,015	2,927	1,298	1,209

1/ Reflects fuel requirements for FPL only.
2/ Source: A Schedules.

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 2000	2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Energy Interchange 2/	GWH	7,443	7,701	8,061	7,912	7,973	7,832	7,645	7,573	7,605	7,371	2,873	0
(2)	Nuclear	GWH	24,584	24,070	24,284	23,873	23,845	24,284	23,873	23,776	24,344	23,857	23,776	24,274
(3)	Coal	GWH	6,977	6,267	6,503	6,674	6,396	6,396	6,514	6,071	6,577	5,901	5,900	6,187
(4)	Residual(FO6) -Total	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(5)	Steam	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(6)	Distillate(FO2) -Total	GWH	193	163	278	1,979	2,979	592	581	408	461	13	5	3
(7)	CC	GWH	1	41	101	1,681	2,588	536	529	387	433	8	2	2
(8)	CT	GWH	183	122	177	298	391	55	52	22	28	5	3	1
(9)	Steam	GWH	9	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	GWH	24,217	24,496	40,313	41,995	41,809	49,873	56,309	60,446	62,208	69,722	78,684	84,556
(11)	Steam	GWH	7,840	7,588	11,524	2,340	1,881	1,527	1,643	1,402	1,577	996	734	569
(12)	CC	GWH	16,064	14,849	26,923	38,510	38,989	47,498	54,339	58,611	60,259	68,450	77,830	83,874
(13)	CT	GWH	313	2,060	1,866	1,144	940	848	327	433	372	275	120	113
(14)	Other 3/	GWH	9,345	9,905	10,858	10,101	10,155	9,852	8,867	8,961	8,901	8,710	8,101	7,446
	Net Energy For Load 4/	GWH	95,989	98,404	100,158	104,414	108,042	111,772	115,602	118,157	120,549	122,922	125,448	127,512

1/ Source: A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

4/ Net Energy For Load is Column 2 on Schedule 3.3 and Column 1 on EIA411 Form 11C.

Schedule 6.2
Energy % by Fuel Type

	Energy Source	Units	Actual 2000	Actual 2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Energy Interchange 2/	%	7.8	8.0	8.0	7.6	7.4	7.0	6.6	6.4	6.3	6.0	2.3	0.0
(2)	Nuclear	%	25.6	24.5	24.2	22.9	22.1	21.7	20.7	20.1	20.2	19.4	19.0	19.0
(3)	Coal	%	7.3	6.4	6.5	6.4	5.9	5.7	5.6	5.1	5.5	4.8	4.7	4.9
(4)	Residual (FO6) -Total	%	24.2	26.2	9.8	11.4	13.8	11.6	10.2	9.2	8.7	6.0	4.9	4.0
(5)	Steam	%	24.2	26.2	9.8	11.4	13.8	11.6	10.2	9.2	8.7	6.0	4.9	4.0
(6)	Distillate (FO2) -Total	%	0.2	0.2	0.3	1.9	2.8	0.5	0.5	0.3	0.4	0.0	0.0	0.0
(7)	CC	%	0.0	0.0	0.1	1.6	2.4	0.5	0.5	0.3	0.4	0.0	0.0	0.0
(8)	CT	%	0.2	0.1	0.2	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	25.2	24.9	40.2	40.2	38.7	44.6	48.7	51.2	51.6	56.7	62.7	66.3
(11)	Steam	%	8.2	7.7	11.5	2.2	1.7	1.4	1.4	1.2	1.3	0.8	0.6	0.4
(12)	CC	%	16.7	15.1	26.9	36.9	36.1	42.5	47.0	49.6	50.0	55.7	62.0	65.8
(13)	CT	%	0.3	2.1	1.9	1.1	0.9	0.8	0.3	0.4	0.3	0.2	0.1	0.1
(14)	Other 3/	%	9.7	10.1	10.8	9.7	9.4	8.8	7.7	7.6	7.4	7.1	6.5	5.8
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	% of Peak
2002	17,860	2,403	0	877	21,140	19,131	1,414	17,717	3,423	19.3	0	3,423	19.3
2003	19,135	2,474	0	877	22,486	19,765	1,491	18,274	4,212	23.0	0	4,212	23.0
2004	19,135	2,474	0	877	22,486	20,226	1,570	18,656	3,830	20.5	0	3,830	20.5
2005	21,031	1,758	0	867	23,656	20,719	1,651	19,068	4,588	24.1	0	4,588	24.1
2006	21,031	1,757	0	734	23,522	21,186	1,729	19,457	4,065	20.9	0	4,065	20.9
2007	22,138	1,310	0	734	24,182	21,556	1,807	19,749	4,433	22.4	0	4,433	22.4
2008	22,138	1,310	0	734	24,182	21,870	1,886	19,984	4,198	21.0	0	4,198	21.0
2009	23,245	1,310	0	683	25,238	22,271	1,962	20,309	4,929	24.3	0	4,929	24.3
2010	24,352	382	0	639	25,373	22,687	1,987	20,700	4,673	22.6	0	4,673	22.6
2011	25,459	382	0	594	26,435	23,106	1,987	21,119	5,316	25.2	0	5,316	25.2

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.

2/ Total Capacity Available=Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation from 1/99 - on. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance =Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2001/02	17,730	1,910	0	886	20,526	18,968	1,589	17,379	3,147	18.1	0	3,147	18.1
2002/03	20,007	2,634	0	877	23,518	19,551	1,643	17,908	5,610	31.3	0	5,610	31.3
2003/04	20,369	2,673	0	877	23,919	19,976	1,691	18,285	5,634	30.8	0	5,634	30.8
2004/05	20,369	2,623	0	867	23,859	20,418	1,738	18,680	5,179	27.7	0	5,179	27.7
2005/06	22,402	1,860	0	734	24,996	20,854	1,786	19,068	5,928	31.1	0	5,928	31.1
2006/07	22,402	1,860	0	734	24,996	21,204	1,831	19,373	5,623	29.0	0	5,623	29.0
2007/08	23,598	1,317	0	734	25,649	21,538	1,875	19,663	5,986	30.4	0	5,986	30.4
2008/09	23,598	1,317	0	734	25,649	21,966	1,918	20,048	5,601	27.9	0	5,601	27.9
2009/10	24,795	1,317	0	683	26,795	22,366	1,955	20,411	6,384	31.3	0	6,384	31.3
2010/11	25,992	389	0	595	26,976	22,785	1,955	20,830	6,146	29.5	0	6,146	29.5

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS														
2002														
---		---	---	---	---	---	---	---	---	---	---	---	---	---
2003														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	Apr-03	Unknown	190,000	---	159	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	---	159	P
2004														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	181	---	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	May-03	Unknown	190,000	181	---	P
2005														
Manatee Combined Cycle Unit	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	---	1,107	P
2006														
Manatee Combined Cycle Unit	3	*Manatee County* 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	1,197	---	P
2007														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	---	1,107	P
2008														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	1,197	---	P
2009														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	---	1,107	P
2010														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	1,197	---	P
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-10	Unknown	470,000	---	1,107	P
2011														
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-10	Unknown	470,000	1,197	---	P
Unsited Combined Cycle Unit #4	4	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-11	Unknown	470,000	---	1,107	P

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter [1,2] MW	Summer [1,2] MW	Status
CHANGES/UPGRADES														
2002														
Sanford Repowering: Initial Phase [3]	4	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Mar-02	----	Unknown	106,600	0	(390) [4]	RP
Sanford Repowering: Initial Phase	5	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Oct-01	----	Unknown	106,600	(390) [4]	0	RP
Sanford Repowering: Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	May-02	Jul-02	Unknown	106,600	0	567	RP
Ft. Myers Repowering: Second Phase	1&2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-01	Jan-02	Unknown	161,700	(1)	35	RP,U
Riviera	4	City of Riviera Beach 33/42S/43E	ST	FO6	NG	WA	PL	Nov-01	Jan-02	Unknown	310,420	10	10	P
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	---	10	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	---	10	P
											2002 Total:	**(381)**	**242**	
2003														
Sanford Repowering: Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	675	957	RP
Sanford Repowering: Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	1,065	0	RP
Ft. Myers Repowering: Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-02	Jan-03	Unknown	161,700	531	0	RP,U
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	---	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	---	P
											2003 Total:	**2,291**	**957**	
2004														
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											2004 Total:	**0**	**0**	
2005														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	---	394.5	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	---	394.5	P
											2005 Total:	**0**	**789**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by July. All other MW will be picked up in the following year. This is done for reserve margin calculation.

2) All MW differences are calculated based on using IRP 2001 Submittal (for the year 2001) as the base for all other years.

3) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work. That schedule has recently changed. Please refer to Section III.A, "Step 1" for more information.

4) Negative values for Sanford and Ft. Myers reflect the existing steam units being temporarily out of service during that seasonal period for repowering efforts.

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1]	Summer [1]	
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt	Mo./Yr.	Mo./Yr.	Mo./Yr.	KW	MW	MW	Status
CHANGES/UPGRADES														
2006														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417.5	---	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417.5	---	P
											2006 Total:	835	0	
2007														
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											2007 Total:	0	0	
2008														
----------		----------	---	---	---	---	---	---	---	---	---	---	---	---
											2008 Total:	0	0	
2009														
----------		----------	---	---	---	---	---	---	---	---	---	---	---	---
											2009 Total:	0	0	
2010														
----------		----------	---	---	---	---	---	---	---	---	---	---	---	---
											2010 Total:	0	0	
2011														
----------		----------	---	---	---	---	---	---	---	---	---	---	---	---
											2011 Total:	0	0	

1)The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by July. All other MW will be picked up in the following year. This is done for reserve margin calculation.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Repowering	
(2)	**Capacity**			
	a. Summer	929	MW Incremental (1473 MW Total After Repowering)	
	b. Winter	1,073	MW Incremental (1617 MW Total After Repowering)	
(3)	**Technology Type:**		Combined Cycle	
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	1999		
	b. Commercial In-service date:	2002		
(5)	**Fuel**			
	a. Primary Fuel		Natural Gas	
	b. Alternate Fuel		None	
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors	
(7)	**Cooling Method:**		Once-through Cooling w/ Helper Cooling Tower	
(8)	**Total Site Area:**	460	Acres	
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)	
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)	
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)	
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):		3%	
	Forced Outage Factor (FOF):		1%	
	Equivalent Availability Factor (EAF):		96%	
	Resulting Capacity Factor (%):		Approx. 90%	(First Year)
	Average Net Operating Heat Rate (ANOHR):		6,830	Btu/kWh
(13)	**Projected Unit Financial Data, *,**,*****			
	Book Life (Years):		25	years
	Total Installed Cost (In-Service Year $/kW):		559	
	Direct Construction Cost ($/kW):			
	AFUDC Amount ($/kW):			
	Escalation ($/kW):			
	Fixed O&M ($/kW -Yr.): (2001$/kW-Yr)		13.45	
	Variable O&M ($/MWH): (2001 $/MWH)		0.37	
	K Factor:		1.5395	

* $/kW values are based on incremental Summer capacity.

** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.

*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 4 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	U	(Under Construction ≤ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction ≤ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction ≤ 50% Complete)

(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	3%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	96%	
	Resulting Capacity Factor (%):	Approx. 96%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	6,918	Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	656	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	14.41	
	Variable O&M ($/MWH): (2001 $/MWH)	0.374	
	K Factor:	1.4637	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: *Total installed cost already includes escalation and AFUDC.*

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 5 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		3%
	Forced Outage Factor (FOF):		1%
	Equivalent Availability Factor (EAF):		96%
	Resulting Capacity Factor (%):		Approx. 96% (First Year)
	Average Net Operating Heat Rate (ANOHR):		6,918 Btu/kWh
(13)	**Projected Unit Financial Data *,**,*****		
	Book Life (Years):		25 years
	Total Installed Cost (In-Service Year $/kW):		656
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)		14.41
	Variable O&M ($/MWH): (2001 $/MWH)		0.374
	K Factor:		1.5395

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Combustion Turbines No. 13 and No. 14 *
(2)	**Capacity**		
	a. Summer	159	MW each for a total of 318 MW
	b. Winter	181	MW each for a total of 362 MW
(3)	**Technology Type:**		Combustion Turbine
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2001	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NOx Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Air Coolers
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	U	(Under Construction ≤ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction ≤ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction ≤ 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 25%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	414	per Combustion Turbine
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	0.69	
	Variable O&M ($/MWH): (2001 $/MWH)	0.87	
	K Factor:	1.5394	

* Values shown are per unit values for the two units being added.
** $/kW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Martin Combustion Turbine Conversion to Combined Cycle
(2)	**Capacity**		
	a. Summer	789	MW Incremental (1107 MW Total)
	b. Winter	835	MW Incremental (1197 MW Total)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond/Tower
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)
(12)	**Projected Unit Performance Data •**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 80%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	599	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	9.07	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

• Values represent an operational combined cycle unit after the conversion is completed.
** $/kW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Manatee Combined Cycle	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	9,500	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 71%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	511	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	12.96	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

* *$/kW values are based on Summer capacity.*
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle No. 1

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,197 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2005
b. Commercial In-service date: 2007

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 65%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	568	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5399	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle No. 2

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,197 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 60%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	587	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5399	

* $/kW values are based on Summer capacity.
** *Fixed O&M cost includes capital replacement.*

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 3		
(2)	**Capacity**			
	a. Summer	1,107 MW		
	b. Winter	1,197 MW		
(3)	**Technology Type:**	Combined Cycle		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2008		
	b. Commercial In-service date:	2010		
(5)	**Fuel**			
	a. Primary Fuel		Natural Gas	
	b. Alternate Fuel		Distillate	
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate	
(7)	**Cooling Method:**	Unknown		
(8)	**Total Site Area:**	Unknown	Acres	
(9)	**Construction Status:**	P	(Planned)	
(10)	**Certification Status:**	P	(Planned)	
(11)	**Status with Federal Agencies:**	P	(Planned)	
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):		2%	
	Forced Outage Factor (FOF):		1%	
	Equivalent Availability Factor (EAF):		97%	
	Resulting Capacity Factor (%):		Approx. 60%	(First Year)
	Average Net Operating Heat Rate (ANOHR):		7,021	Btu/kWh
(13)	**Projected Unit Financial Data *,****			
	Book Life (Years):		25	years
	Total Installed Cost (In-Service Year $/kW):		597	
	Direct Construction Cost ($/kW):			
	AFUDC Amount ($/kW):			
	Escalation ($/kW):			
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)		15.47	
	Variable O&M ($/MWH): (2001 $/MWH)		0.037	
	K Factor:		1.5400	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle No. 4

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,197 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 52%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	607	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5400	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fort Myers Repowering

The transmission line work for this project has been completed

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sanford Repowering

The transmission line work for this project has been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Ft. Myers: 2 CT's

(1)	Point of Origin and Termination:	From Ft. Myers GT Collector bus – To Orange River
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	2.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: January 1, 2003 End date: May 1, 2003
(7)	Anticipated Capital Investment:	$1,050,000
(8)	Substations:	Orange River and Ft. Myers GT collector bus
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee CC Unit

(1)	Point of Origin and Termination:	Manatee – Johnson
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: June 1, 2004 End date: June 1, 2005
(7)	Anticipated Capital Investment:	$12,700,000
(8)	Substations:	Manatee and Johnson
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Martin CT – to - CC Conversion

(1)	Point of Origin and Termination:	Martin – Indiantown #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	12.9 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$9,400,000
(8)	Substations:	Martin 230kV and Indiantown
(9)	Participation with Other Utilities:	None

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(1)	Point of Origin and Termination:	Indiantown – Bridge
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	10.0 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$10,300,000
(8)	Substations:	Indiantown and Bridge
(9)	Participation with Other Utilities:	None

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A Protection of the Environment

FPL operates in a sensitive, temperate/sub-tropical environment containing a number of distinct ecosystems with many endangered plant and animal species. Population growth in our service area is continuing, which heightens competition for air, land, and water resources which are necessary to meet the increased demand for generation, transmission, and distribution of electricity. At the same time, residents and tourists want unspoiled natural amenities, and the general public has an expectation that large corporations such as FPL will conduct their business in an environmentally responsible manner.

FPL has been recognized for many years as one of the leaders among electric utilities for our commitment to the environment. Our environmental leadership has been heralded by many outside organizations. For example, FPL was recently ranked first out of 30 major electric utilities surveyed in an environmental assessment conducted by Innovest, an independent advisory group. In 2001, FPL was awarded the 2001 Waste Reduction and Pollution Prevention Award from the Solid Waste Association of North America. We also received the 2001 Program Champion Award from the Environmental Protection Agency's Wastewise Program. The Florida Department of Environmental Protection named FPL a "Partner for Ecosystem Protection" for our emission-reducing "repowering" projects at our Fort Myers and Sanford plants. In addition, FPL has been recognized by numerous federal and state agencies for our innovative endangered species programs which include such species as manatees, crocodiles and sea turtles.

IV.B FPL's Environmental Statement

To reaffirm its commitment to conduct business in an environmentally responsible manner, FPL developed an Environmental Statement in 1992 to clearly define the Company's position. This statement reflects how FPL incorporates environmental values into all aspects of the Company's activities and serves as a framework for new environmental initiatives throughout the Company. The FPL environmental statement further establishes a long-term direction of environmental responsibility for the Company. FPL's Environmental Statement is:

> It is the Company's intent to continue to conduct its business in an environmentally responsible manner. Accordingly, Florida Power & Light Company will:

- Comply with the spirit and intent, as well as the letter of, environmental laws, regulations, and standards.
- Incorporate environmental protection and stewardship as an integral part of the design, construction, operation, and maintenance of our facilities.
- Encourage the wise use of energy to minimize the impact on the environment.
- Communicate effectively on environmental issues.
- Conduct periodic self-evaluations, report performance, and take appropriate actions.

IV.C Environmental Management

In order to implement the Environmental Statement, FPL established an environmental management system to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program which is discussed below. Other components include: written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident/emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.D Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities which are designed to: evaluate environmental performance, verify compliance with Company policy as well as with legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is the environmental audit. An environmental audit may be defined as a management tool comprising a systematic, documented, periodic, and objective evaluation of the performance of the organization and of the specific management systems and equipment designed to protect the environment. The environmental audit's primary objectives are to: 1) facilitate management control of environmental practices; and, 2) assess compliance with existing environmental regulatory requirements and Company policies.

IV.E Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental protection through the facilitation of environmental awareness and public education. Some of FPL's 2001 environmental outreach activities are noted in Table IV.E.1.

2001 FPL Environmental Outreach Activities *

Site	Activity	# of Participants (approx.)
St. Lucie Plant	Turtle Beach Nature Trail Visitation	2,000
Riviera Plant & Fort Myers Plant	Manatee Awareness Activities	155,000
St. Lucie Plant	Turtle Walk Participation	802
St. Lucie Plant	FPL Energy Encounter	28,000
Not applicable	Inquiries - 800 enviromental information line and e-mails	3,800
Martin Plant	Barley Barber Swamp Visitation	2,200

Table IV.E.1

* A reduction in attendance at some of these facilities was observed due to changes in operation as a result of the events of September 11, 2001.

IV.F Preferred And Potential Sites

Based upon its projection of future resource needs, FPL has identified preferred and potential sites for future generation additions. These preferred and potential sites are discussed in separate sections below.

IV.F.1 Preferred Sites

FPL has identified four preferred sites: the existing Fort Myers plant site, the existing Sanford plant site, the existing Martin plant site, and the existing Manatee plant site. These four sites are currently the expected known locations for capacity additions that FPL projects to make during the 2002 – 2005 period. (Other capacity additions, in the form of new combined cycle units, are projected to be made in the 2007 through 2011 time period. Selection of sites for these later capacity additions is not yet needed and has not been made. Please see Table III.B.1).

The four preferred sites are discussed below. FPL has committed to repower existing units at both its Fort Myers and Sanford sites, to add new combustion turbine (CT) capacity at the Fort Myers site, to convert existing CT capacity into combined cycle (CC) capacity at the Martin site, and to add new CC capacity at the Manatee site.

Preferred Site # 1: Fort Myers Plant, Lee County

The site is located on the 460-acre Fort Myers property. Current facilities on the site include two steam electric generating units, nominally 150 MW and 400 MW respectively (which have recently been decommissioned as part of the repowering work), six CT's (that along with heat recovery steam generating (HRSG) units and the existing steam turbines will comprise the repowered facility); and a bank of 12 simple-cycle combustion turbine peaking units. The site has direct access to a four-lane highway, State Road (SR) 80, and barge access is available. The nearest town is Tice, which is approximately 4 miles west of the site. The City of Fort Myers is approximately 8 miles west of the site. The Fort Myers site has been listed as a potential or preferred site in previous FPL Site Plans.

Beyond the current repowering effort, FPL is planning to add two CT's at the site. The CT's are expected to be in service in the Spring of 2003 and will add 318 MW (Summer) and 362 MW (Winter) to FPL's system.

The repowering project currently underway at the site will add approximately 929 MW during Summer conditions and approximately 1,073 MW during Winter conditions. This project is expected to be completed in mid-2002.

The output capability of the existing bank of 12 CT's at the site will be unaffected by the repowering project and the addition of the two new CT's.

a. and b. U.S. geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Fort Myers plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter. It is pertinent to note that several designations on the current South Florida Water Management District Florida Land Use, Cover, and Forms Classification System (FLUCCS) appear to be in error, or to require some clarification. For example, the freshwater marsh identified toward the western boundary of the site is actually FPL's 50-acre evaporation/percolation pond. Similarly, while there are scattered mangroves along the shore, the "Central Mangrove" area shown is not mangrove but is the FPL switchyard for that site. The "Improved Pasture" shown towards the east of the site is currently the location of a tree nursery.

d. Existing Land Uses of Site and Adjacent Areas

The land on the site is primarily dedicated to industrial use with surrounding grassy and landscaped areas. There is the previously mentioned 50-acre evaporation/percolation pond on the site. Much of the site is currently being used for either direct construction activities or in support of the repowering project.

FPL has recently donated an 18-acre island, located north of the plant in the Caloosahatchee River, to the United States Fish & Wildlife Service (USFWS) for the purpose of wildlife conservation. This island has been owned by FPL since the 1950's, but has never been developed. The USFWS plans to incorporate the island into the Caloosahatchee National Wildlife Refuge.

Lee County operates Manatee Park (approximately 5 acres) with a manatee viewing area on FPL property to the east side of the discharge canal where it adjoins the Orange River south of SR 80. This manatee viewing area provides public viewing and education about the species. FPL leases the property to the county for a nominal amount.

The adjacent land uses are light commercial and retail to the south of the property and some residential areas located toward the west. Mixed scrub with some hardwoods and wetlands, plus agriculture land, can be found to the east and further to the south. The Caloosahatchee National Wildlife Refuge is located across the Caloosahatchee River, northwest of the power plant.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

The site is adjacent to the south bank of the Caloosahatchee River near the confluence of the Orange River and the Caloosahatchee. Much of the site is no longer in its original natural condition. However, a scattering of mangroves can be found along the river shoreline. Some mixed scrub with some hardwoods and wetlands can be found to the east and further to the south. Other than the occasional congregation of manatees noted below, FPL is not aware of any significant environmental features on the site or in the vicinity.

2. Listed Species

Construction and operation of the repowered facility, plus the new CT's at the site, are not expected to affect any rare, endangered, or threatened species. The only known listed species associated with the site are the West Indian Manatees (Trichechus manatus: Federal - and - State listed as Endangered) which are attracted to the warmed waters in the vicinity of the site discharge and can be found congregating in the area during cool weather.

The Florida Natural Areas Inventory (FNAI) reports the presence of the Eastern Indigo Snake (Drymarchons corais couperi: Federal - and - State listed as Threatened) and Tricolored Heron (Egretta tricolor: State - listed as a Species of Special Concern) within a two-mile radius of the site.

3. Natural Resources of Regional Significance Status

No Natural Resource of Regional Significance is identified on the plant site in the Southwest Florida Regional Strategic Policy Plan.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design options currently being pursued for the Fort Myers site are the repowering of the two existing oil-fired boilers with natural gas-fired CT's and HRSG's, plus the installation of two stand-alone CT's. All of this new generation equipment will be installed on the existing facility property and will make effective use of existing transmission facilities and infrastructure although some transmission line upgrades will be required. Steam developed in the new HRSG's will be directed to the existing steam turbines. FPL has contracted with Florida Gas Transmission (FGT) for a firm natural gas supply to the plant.

Mitigation options being planned for the capacity additions at Fort Myers include: the capture and reuse of plant process water, the use of combustion technology that is inherently low in air pollutant emissions, the reduction of oil barge traffic on the Caloosahatchee River, plumbing the sanitation system to Lee County's system and closing the on-site septic tanks, and closing the on-site ash basins.

g. Local Government Future Land Use Designations

The Local Government Future Land Use Plan designates the major portion of the site as Public Facilities and a small area as Resource Protection. Since there are no significant environmental resources on the site, and the "Resource Protection" designated area appears to be the location of a current tree nursery, FPL believes that this designation is in error.

h. Site Selection Criteria and Process

For the past several years, many of FPL's existing power plant sites have been considered potentially suitable sites for new, expanded, or repowered generation. The Fort Myers plant has been selected as a preferred site due to consideration of various factors including electrical transmission, system load, and economics. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i. Water Resources

The available surface water source is the Caloosahatchee River and the available groundwater source is the shallow aquifer.

j. Geological Features of Site and Adjacent Areas

The geology underlying the Fort Myers Plant consists of Quaternary Holocene and Pleistocene undifferentiated materials. The upper part of these undifferentiated materials consists of fine-to-medium-grained quartz sand with varying percentages of shell and clay. Hardpan frequently occurs at the base of the quartz sands. The lower section consists of shell beds with interbedded limestones. Underlying the undifferentiated materials are the Pliocene Tamiami formations, the Miocene Hawthorn formation, Oligocene Suwanee Limestone, the Eocene Crystal River and Williston formations, the Avon Park Limestone, and the Lake City Limestone.

Several stratigraphic units can be differentiated based upon shallow borings drilled on the plant property. Sand with some heterogeneous fill material related to past site construction activity covers most of the surface. It is underlain by layers of clayey sand and clay to a depth of approximately 23 feet. These units mantle a thicker clay unit with numerous shell fragments that occurs from 15 feet to about 55 feet below the surface. A silty sand with a trace of clay was encountered at 55 feet near the termination depth of one deep boring on the site.

The water table at the site occurs at levels from just under the surface to about 5 feet below grade. Locally, the surficial aquifer and surface water will generally flow toward the Caloosahatchee River. However, at the site, the intake and discharge canal will affect groundwater near the power block area. A drainage canal that borders the plant property on the west will affect groundwater flow along the western portion of the waste treatment area.

k. Projected Water Quantities For Various Uses

It is estimated that 150 gallons per minute (gpm) will be needed for industrial processing water for uses such as boiler makeup and service water. For industrial cooling (once-through cooling water), no significant increase is projected in the current 451,000 gpm usage rate. Other facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 5 gpm.

l. Water Supply Sources By Type

For industrial processing, FPL anticipates that groundwater will be available. For cooling water, for the repowered unit, FPL plans to continue to use its existing allocation from the Caloosahatchee River in a once-through cooling mode. The new CT's will be air-cooled.

m. Water Conservation Strategies Under Consideration

A plan to treat and recycle equipment wash water, boiler blowdown, and equipment area runoff for use as service water would reduce ground water consumption. FPL would anticipate this site being designed and classified as a wastewater zero-discharge site following the completion of the repowering work.

n. Water Discharges and Pollution Control

Heated water discharge will be dissipated using both the existing once-through cooling water system and a multi-cell cooling tower. Treating and recycling equipment wash water, boiler blowdown, and equipment area runoff will minimize industrial discharges. Storm water runoff will be collected and used to recharge the surficial aquifer via a stormwater management system. Design elements will be included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which will provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

A combustion turbine-based repowering project, plus the addition of the new CT's, requires a natural gas pipeline to be installed. Florida Gas Transmission has initiated permitting to install and operate such a facility. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired facility would generally have air pollutant emissions, that are substantially lower than emissions from the current oil-fired boilers. While several technologies are available for nitrogen oxide (NO_x) emissions control, FPL is using a dry-low-NO_x combustion turbine design. In these devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. FPL has proposed NO_x emission limits for this facility that will be among the lowest in the state once the facility is constructed. Sulfur dioxide and particulate emissions are intrinsically low due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion rather than through the use of add-on control devices. Carbon dioxide emission rates associated with burning natural gas are well below those of other liquid or solid fuels. While the Fort Myers plant site is located within 100 kilometers of a Class I area (Everglades National Park), the reduction in emissions associated with repowering is expected to improve the air quality in the area as compared to current levels. CC and CT facilities have been permitted at several locations throughout the state of Florida including near Class I areas. Dry-low-NO_x combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NO_x emissions for this technology pursuant to the requirements of the Clean Air Act.

q. <u>Noise Emissions and Control systems</u>

Lee County has a noise ordinance which limits noise at the receiving property line to 75 decibels. Noise emissions from the Fort Myers project are not anticipated to approach this level based upon demonstrated noise control at similar natural gas-fired facilities (the Lauderdale plant in Broward County and the Martin plant in Martin County) and computer modeling of the anticipated noise emissions from the Fort Myers repowered plant. FPL will undertake studies to assure that noise level associated with the new CT's comply with Lee County noise standard.

r. <u>Status of Applications</u>

FPL has received all the permits necessary to construct and start up the repowered plant and the two new CT units.

<u>Preferred Site # 2:</u> Sanford Plant, Volusia County

The site is located on the 1,718–acre FPL Sanford property just west of Lake Monroe on the north bank of St. Johns River in Volusia County. Current facilities on the site include three steam electric generating units (one with a nominal rating of 150 MW and two with nominal ratings of 400 MW). The site is within the city limits of Debary and the community of Debary is located approximately 2 miles to the northwest. The town of Deland is approximately 4 miles west of the site. The site has direct access to a four-lane highway, State Road (SR) 17-92, and barge access is available. The Sanford site has been listed as a potential or preferred site in previous FPL Site Plans.

FPL is currently in the process of adding new capacity at the Sanford site by replacing two existing oil-and gas-fired units (i.e., existing units # 4 and # 5) with advanced natural gas-fired combustion turbines (CT's) and heat recovery steam generators (HRSG's). This type of steam generation replacement is commonly called "repowering".

This repowering will enable FPL to produce significantly more electrical output with nearly the same environmental impact. The repowering of units # 4 and # 5 will each produce approximately 567 additional MW during Summer conditions, and approximately 671 additional MW of generation during Winter conditions, beyond the current capabilities of these units. The two repowered units # 5 and # 4 were projected to be in-service by mid-2002 and late-2002, respectively. The existing 150 MW unit # 3 at Sanford will be unaffected by the repowering of units # 5 and # 4.

a. and b. U.S. Geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Sanford plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A large part of the property is covered by the 1,100-acre closed-cycle-cooling pond which occupies almost all of the northern portion of the site. The remainder of the site is primarily rangeland and the power plant facilities.

The surrounding land use is largely crop land and pasture. To the east of the plant there is a small residential area and some commercial/industrial land use. There are some residential areas mixed in with the agricultural areas located between the site and the St. John's River to the west. To the south is the St. Johns River and residential homes and commercial/industrial businesses are located along the south side of the river.

e. General Environmental Features On and In the Site Vicinity

1. Natural Environment

Small, scattered wooded areas can be found on the site. There are two small areas of wetland marsh on the site and a few acres of wetland forest along the riverbank. There are some wooded areas on the site, primarily upland coniferous forest. Forested and non-forested wetlands can be found to the west, adjacent to the river. Rover and wetland areas towards the northwest are designated as part of the Wekiwa River Aquatic Preserve and Wekiwa River State Preserve.

2. Listed Species

One inactive bald eagle (Haliaeetus leucocephalus: Federal - and - State listed as Threatened) nest has been found on the site. Bald eagles have also nested in the Lake Monroe area. There are a number of other eagle nests in the vicinity of the site, primarily along the St. Johns river. The Florida Natural Areas Inventory (FNAI) reports several Scrub Jay populations (Aphelocoma coerulescens: Federal - and - State listed as Threatened) located in scrub vegetation to the northwest of the site. West Indian Manatees (Trichechus manatus: Federal - and - State listed as Endangered) have also been found in this area.

3. Natural Resources of Regional Significance Status

The Wekiwa River Aquatic Preserve extends along the St. John's River in the vicinity of the plant.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design option for the Sanford site is the repowering of two existing oil-and gas-fired boilers with natural gas-fired combustion turbines (CT's) and heat recovery steam generators (HRSG's). Advanced CT's can be installed on the existing facility property to make effective use of existing transmission facilities and infrastructure although some transmission line upgrades will be required. Steam produced in the new HRSG's will be directed to two of the existing steam turbines. Natural gas-fired facilities represent one of the cleanest, most efficient technologies currently available for capacity additions to FPL's system.

Mitigation options being considered in the repowering project at Sanford include the reduction in the use of ground water, the use of combustion technology that is inherently low in air pollutant emissions, reduction in the amount of solid waste generated, plumbing the sanitary waste system into the Volusia county system, and the significant reduction of oil barge traffic on the St. Johns River.

g. Local Governmental Future Land Use Designations

The site is designated as "Industrial Utilities" in the Local Government land use plan. The city is currently updating its Land Use Plan. It is expected that the name, but not the expected use designation, may change. Land use designation of the surrounding area is primarily Agricultural. There is an area of "Public Institution" around Lake Monroe to the southeast and a small area of "Mixed Use" to the west along Barwick Road.

h. Site Selection Criteria and Process

The Sanford plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All are considered permittable.

i. Water Resources

For surface water supply, the available water resource is the St. John's River and / or the on-site cooling pond, which is periodically refilled from the St. John's River. For groundwater supply, the available resources are the shallow aquifer or the Floridan Aquifer.

j. Geological Features of Site and Adjacent Areas

The near-surface geology of Volusia County, like that of most of north central Florida, is represented by late Tertiary and Quaternary geologic units. Soils in the vicinity of the plant include unconsolidated Pleistocene to Recent sands, with intervening beds of shells and clay. These deposits form the reservoir for the surficial aquifer in the county. Deposits of Pliocene or Miocene clay with some sand underlie the aquifer. These low-permeability units serve to confine groundwater under pressure in the underlying porous limestone formations of Eocene age. These formations are part of the principal hydrologic unit referred to as the Floridian Aquifer. This aquifer, the top of which generally occurs through the region at or below 100 feet, is the major source of potable groundwater in Volusia County. Two faults, one trending north-to-south, the other trending east-to west, intersect a number of miles north of the site. Downward displacement of the fault is hypothesized as being approximately 60 to 100 feet.

k. Projected Water Quantities for Various Uses

FPL has estimated that 150 gallons per minute (gpm) would be required for industrial processing purposes (boiler makeup, service water, etc.). Note that Units # 5 and # 4 both currently take their cooling water directly from an on-site FPL cooling pond and are expected to continue to do so once the units are repowered. The cooling water needs for the repowered facilities are expected to increase over what is currently used, due primarily to the increased heat loading to the cooling pond that will result from operating the larger repowered units more than they have been operated in the past, and corresponding evaporative losses. Therefore, greater quantities of water may be used. Existing Unit # 3 will use water from the St. John's River in a once-through cooling mode.

FPL also evaluated alternative sources of water to meet the expected needs of the site. It is anticipated that the existing off-site wells and the existing once-through cooling water system and cooling pond would continue to be used after the repowering project is completed, albeit the use of groundwater is expected to decrease significantly from past usage.

l. Water Supply Sources by Type

The available surface water supply source is the St. Johns River. The Floridan Aquifer is an available groundwater source for service water and boiler water.

m. Water Conservation Strategies Under Consideration

In 2000 FPL obtained a revised Consumptive Use permit from the St. Johns Water Management District. This permit reduced the quantity of water that FPL has historically been permitted to withdraw from the ground, in favor of additional use of surface water (preferred).

n. Water Discharges and Pollution Control

Heated water discharge will be dissipated using the existing once-through cooling water system. Non-point source discharges are not anticipated to be an issue because surface water runoff is planned to be collected and reused. Treating and recycling equipment wash water, boiler blowdown, and equipment area runoff will minimize industrial discharges. Storm water runoff will be collected and used to recharge the surficial aquifer via a stormwater management system. Design elements will be included to capture suspended sediments. Various facility permits mandate various sampling and testing activities, which will provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The repowered facilities at the Sanford site would require a larger natural gas pipeline to be installed. FPL has contracted with Florida Gas Transmission Company (FGT) to permit, install, and operate such a facility. Virtually no waste is associated with natural gas firing.

p. Air Emissions and Control Systems

A natural gas-fired facility would generally have air pollutant emissions which are substantially lower than emissions from the current oil-fired boilers. While several technologies are available for nitrogen oxide (NO_x) emissions control, the most appropriate candidate for the Sanford site is a dry-low-NO_x combustion turbine design type. In these types of devices, combustion is staged in order to reduce the formation of combustion-derived oxides of nitrogen. Sulfur dioxide and particulate emissions are intrinsically low, due to the lack of sulfur and solids in natural gas fuel. Carbon monoxide and volatile organic compound emissions can each be controlled via the use of efficient combustion, rather than through the use of add-on control devices. CC and CT facilities have been permitted at several locations throughout the state of Florida. Dry-low-NO_x combustor systems have been repeatedly demonstrated to be the Best Available Control Technology (BACT) for the control of NO_x emissions for this technology pursuant to the requirements of the Clean Air Act.

q. Noise Emissions and Control Systems

Noise emissions from the project are not anticipated to be significantly different from current levels at the existing plant. FPL will install appropriate sound attenuation devices such as insulation on high-energy piping systems in order to ensure that sound levels do not exceed allowable levels. Similar natural gas-fired facilities (the Lauderdale plant in Broward County and the Martin plant in Martin County) have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

FPL has now acquired all permits needed to commence construction. Modifications to operating permits will continue to be pursued as necessary through 2002.

Preferred Site # 3: Manatee Plant, Manatee County

The site is located in unincorporated north-central Manatee County approximately 2.5 miles south of The Hillsborough-Manatee County line. It is 5 miles east of Parrish, Florida and is approximately 5 miles east of U.S. Hwy. 301 and 9.5 miles east of Interstate 75 (I-75). State Road 62 (S.R.62) is about 0.5 miles south of the site. Safford Road marks the eastern boundary of the site.

FPL's Manatee Plant occupies a portion of the approximately 9,500 acre Manatee Site, which is owned wholly by FPL. The site includes a 4,000 acre cooling pond including the dike area. The existing approx.1,625 MW (net summer) of generating capacity is made up of two steam units (Units # 1 and # 2) which have been in service since 1976 (Unit # 1) and 1977 (Unit # 2). These units currently burn fuel oil (residual) with a maximum sulfur content of 1 percent. A recent agreement between FPL and Gulfstream Natural Gas Systems will provide an alternative fuel source (natural gas) for these units.

Additional generating capacity will be added to the site to meet projected energy needs for 2005 and 2006. Four new combustion turbines (CT's), four new heat recovery steam generators (HRSG's), and a new steam turbine generator are scheduled for in-service operation beginning in June, 2005. The four new CT's, HRSGs and steam turbine will ultimately be operating in combined cycle (CC) configuration. This new CC unit will add 1,107 MW (Net Summer) and 1,197 MW (Net Winter) capability to the site. This new CC Unit will be designated as "Manatee Unit # 3".

Unit # 3 will be located west of the existing generating Units # 1 and # 2. The location of the new combined cycle Unit # 3 at the Manatee Plant site and the selection of the highly efficient combined cycle technology (firing clean natural gas) will maximize the beneficial use of the site while minimizing environmental, and land use impacts otherwise associated with the development of a new generating plant of this capacity.

a.and b. Map of the Manatee Plant Site and Land use

A map indicating the Manatee plant site showing the general layout of the facilities and a map indicating the land use of the site are found at the end of this chapter.

c. Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d. Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 4,000 acre cooling pond. Manatee Units # 1 and # 2 will not be affected by the addition of Unit # 3. The area for Unit # 3 is expected to comprise approximately 73 acres. The site and surrounding land uses are almost exclusively agricultural with the exception of the Willow Shores residential area located northwest of the Manatee Plant site. Individual homes are located in the larger of two outparcels within the Manatee Plant site, along SR 62 at the northeast corner of the site. The vast majority of the Manatee Plant site is located in the Agricultural/Rural land use category. Other portions of the site are designated as Major Public/Semi Public (1) (P/SP). Electric generating plants are specifically allowed in the Agricultural/R and P/SP category in accordance with the Manatee County Local

Government Comprehensive Plan and Land Development Regulation Act, Chapter 163, Part II, Florida Statues (FS).

e. General Environment Features On and In the Site Vicinity

1. Natural Environment

There are no incorporated areas within 5 miles of the Manatee Plant site. Unincorporated communities in the area include Willow, located about 2 miles north of the Manatee Plant; Parrish, located about 5 miles southwest of the plant; and in Hillsborough County, Sundance, located 3 miles northwest of the plant, Sun City Center, located 7 miles north of the plant; and Wimauma, located 8 miles northeast of the plant.

The Manatee Plant site includes areas of improved pasture with forested land southeast of the Project area. This forested area is comprised of flatwoods and oak habitat. The western side of the Manatee Plant site is currently used for row crops (tomato farm). There are also wetlands to the southeast of the Project area containing wet pine flatwoods mixed with dry pine flatwoods. There will not be any disturbance of existing wetlands associated with this project.

2. Listed Species

Construction and operation of the new Unit # 3 at the site is not expected to affect any rare, endangered, or threatened species. The majority of the site is cleared, grassed and periodically mowed. The project area has been significantly altered by the construction and operation of the existing plant facilities, as a result wildlife utilization of this area is expected to be minimal. Common wading birds utilizing the plant site outside of the project area, include the great blue heron, little blue heron, great egret, snowy egret and the white ibis. Typical mammals found in the habitats surrounding the project area are common bobcat, raccoon, deer, feral hog, opossum, armadillo, skunk and gray squirrel. Avian species observed in the vicinity of the project include a variety of songbirds, red-shouldered hawk and marsh hawk.

3. Natural Resources of Regional Significance Status

There are no County, State or Federally designated areas located within 1 mile of the plant site. The construction and operation of Manatee Unit # 3 is not expected to have any adverse impacts on parks, recreation areas or environmentally sensitive lands that are associated with the Little Manatee River within a 5 mile radius of the project site. These lands include: Little Manatee River State Recreation Area, Little Manatee River State Canoe Trail, Florida Gulf Coast Railroad Museum, Cockroach Bay Aquatic Preserve, Critical Manatee Habitat, South Hillsborough Wildlife Corridor, Hillsborough County ELAPP Parcels and SOR-Little Manatee River.

4. Other Significant Features

FPL is not aware of any other significant features of the site.

f. Design Features and Mitigation Options

The design for Manatee Unit # 3 is the addition of four new CT's, with four new HRSGs and one new steam turbine generator in combined cycle configuration (creating a 4X1 configuration). Manatee Unit # 3 will begin operation in mid – 2005. Natural gas, delivered via pipeline, will be the sole fuel for this unit. Natural gas fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation options being planned for Manatee Unit # 3 include the capture and reuse of plant process water and rainwater. In addition, other mitigating options include the use of combustion technology that is very efficient and low in air pollutant emissions, combined with pollution control technology (dry-low NO_x burners and selected catalytic reduction equipment).

g. Local government Future Land Use Designations

As mentioned above the Local Government Future Land Use Plan is consistent with the existing Designated uses of the Manatee Plant Site as major portions of the site are Agriculture/R and the remainder is designated as Major Public/Semi Public (1) – P/PS. Electric generating plants are specifically allowed in these land use categories .

h. Site Selection Criteria and Process

For the past several years, many of FPL's existing power plant sites have been considered potentially suitable sites for new, expanded, or repowered generation. The Manatee site has been selected as a preferred site due to consideration of various factors including system load and economics. The projected availability of a natural gas pipeline that will be available to Unit # 3 as well as Units # 1 and # 2 in the near future was also a major factor in the selection of the Manatee site for the new 4x1 CC unit. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential sites exhibit significant environmental sensitivity or other environmental issues. All of these site are considered permittable.

i. Water Resources

The available surface water source is the Little Manatee River. Make up water for the 4,000 acre cooling pond will continue to be provided from the Little Manatee River. Plant process and service water requirements are currently supplied by the cooling pond, there are three wells in the Floridan aquifer that are reserved for standby purposes.

j. Geological Features of Site and Adjacent Areas

The Geology underlying the Manatee Plant consist of unconsolidated sediments comprised of sand, clay silt, marl shell, limestone and phosphorite (terrace deposits) from the Pleistocene age to Recent. Undifferentiated Deposits comprised of sand and clay with Pliocene age and includes the Bone Valley Formation which is generally described to be less than 25 feet thick. Underlying the undifferentiated materials are the Miocene Hawthorn Formation, the Tampa Member, the Suwannee Limestone of the Oligocene age, the Ocala Limestone of the Eocene Age, the Avon Park Formation, the Oldsmar Formation of the Eocene age and the Cedar Key Formation of the Paleocene age.

k. Projected Water Quantities For Various Uses

The estimated additional quantity of water for industrial processing is estimated to be 150 gpm (gallons per minute) plant process and service water. FPL operates on-site water treatment systems for each of these uses. Water quantities for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l. Water Supply Sources by Type

Manatee Unit # 3 will utilize the existing on-site cooling pond as its source of cooling water. The cooling pond operates as a "closed cycle" system, any makeup water is provided from the Little Manatee River to replace net evaporation and seepage loses from the pond. These makeup needs are within the existing agreement between FPL and the Southwest Florida Water Management District (SWFWMD). There are three wells, currently on Reserve (standby) that are in the Floridan Aquifer.

FPL is currently evaluating alternative water sources for use at the Manatee Plant site.

m. Water Conservation Strategies Under Consideration

Available water including non-contact storm water, treated industrial wastewater, treated sanitary wastewater, and recovered service water are captured and returned to the cooling pond. Storm water from the equipment areas is also treated and returned to the cooling pond.

n. Water Discharges and Pollution Control

The Manatee Plant employs a Best Management Practices (BMP) plan, a Spill Prevention, Control and Countermeasure (SPCC) plan to assist in the control of inadvertent release of pollutants. Stormwater runoff will be collected and routed to detention ponds. Construction activities will be managed so that equipment maintenance and fueling are designated areas to conduct these activities so that in the event of a spill or release of any contaminant, impacts to any surface water or the cooling pond are minimized.

o. Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by fuel delivery services and facilities for residual, low sulfur (1 percent) fuel oil. FPL has an agreement with Gulfstream Natural Gas Systems to install a natural gas lateral to the Manatee Plant that will provide the availability of natural gas for existing Units # 1 and # 2. The addition of Unit # 3, that will be solely fueled by natural gas, will require further negotiations or agreements with Gulfstream or some other supplier.

p. Air Emissions and Control Systems

The use of clean fuels and combustion controls will minimize air emissions from Unit # 3 and ensure compliance with applicable emission limiting standards. Using clean fuels minimizes emissions of sulfur dioxide (SO2), particulate matter, and other fuel-bound contaminates. 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. NO_x emissions will be controlled using dry-low NO_x combustion technology and selective catalytic reduction (SCR). 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 Manatee Unit # 3 will incorporate features that will make it one of the most efficient and cleanest power plants in the State of Florida.

q. Noise Emissions and Control Systems

Noise emissions from the project are not anticipated to be significantly different from the current levels at the existing plant. Similar natural gas-fired facilities in Broward and Martin Counties have been constructed and operated without exceeding allowable noise levels.

r. Status of Applications

FPL filed the Site Certification Application (SCA) for the Manatee Plant Unit # 3 with the Florida Department of Environmental Protection (FDEP) on February 20, 2002.

Preferred Site # 4: Martin Plant, Martin County

The Martin site is located approximately 40 miles northwest of West Palm Beach, 5 miles east of Lake Okeechobee, and 7 miles northwest of Indiantown in Martin County, Florida. The site is bounded on the west by the Florida East Coast Railway (FEC) and the adjacent South Florida Water Management District (SFWMD) L-65 Canal, on the south by the St. Lucie Canal (C-44 or Okeechobee Waterway), and on the northeast by SR 710 and the adjacent CSX Railroad.

The Martin site was identified in 1987 as a preferred location for development of coal gasification/combined cycle electric generation facilities and subsequent FPL Site Plans have continued to identify this site as a preferred site.

The existing 2,906 MW (net Summer) of generating capacity at FPL's Martin site occupies a portion of the approximately 11,300 acres that are wholly owned by FPL. The generating capacity is made up of two steam units (Units # 1 and # 2), plus two combined cycle units (Units # 3 and # 4), and two combustion turbine units (Units # 8a and # 8b). The site includes a 6,800-acre cooling pond (6,500 acres of water surface and 300 acres of dike area) and approximately 300 acres for the existing power plant units and related facilities.

Additional generating capacity will be added to the site. The existing two CT's at the site will be converted into a four on one (4X1) combined cycle (CC) unit with the addition of two new CTs and four new HRSGs and a new steam turbine generator in mid - 2005. The two existing CT's total capabilities are 318 MW (Summer) and 362 MW (Winter). The later conversion of these two CT's to a (4X1) CC will add approximately 789 MW (Summer) and 835 MW (Winter) of capacity. The new CC unit will be designated as Unit # 8.

a) and b) U.S. Geological Survey (USGS) Map and Proposed Facilities Layout Map

A USGS map of the Martin plant site, plus a map of the general layout of the proposed generating facilities at the site, are found at the end of this chapter.

c) Map of Site and Adjacent Areas

An overview map of the site and adjacent areas is also found at the end of this chapter.

d) Existing Land Uses of Site and Adjacent Areas

A major portion of the site consists of a 6,800-acre cooling pond. The existing power plant facilities are located on approximately 300 acres. To the east of the power plant there is an area of mixed pine flatwood with a scattering of small wetlands. To the north of the reservoir there is a 1,200-acre area which has been set aside as a mitigation area. There is peninsula of wetland forest on the west side of the reservoir which is named the Barley Barber Swamp. The Barley Barber Swamp encompasses

400 acres and is preserved as a natural area. There is also a 10 kilowatt (KW) photovoltaic energy facility at the south end of this site.

e) General Environment Features On and In The Site Vicinity

1) Natural Environment

As noted above, the Barley Barber Swamp is located on the site. There is also a 1,200-acre mitigation area in the northern area of the site where wetlands and uplands have been restored. Along the south and west sides of the cooling pond is an area where the vegetation has been allowed to return to its natural state in order to serve as a wildlife corridor. FPL has preserved a Florida Panther corridor along the west side of the cooling pond. There are pine flatwoods and small scattered wetlands to the east of the plant.

2) Listed Species

Construction and operation of new units at the site are not expected to affect any rare, endangered, or threatened species. There are two active Bald Eagle (Haliaeetus leucocephalus: Federal - and - State listed as Threatened) nests that have been on the site for many years. The Florida Natural Areas Inventory (FNAI) database notes a record of Eastern Indigo Snakes (Drymachon coralis coupert which are Federal - and - State listed as Threatened) in the Barley Barber Swamp. A number of other Bald Eagle nests and sightings of Eastern Indigo Snakes are reported by the FNAI database within a two-mile radius of the site. Infrequent sightings of Florida Panther have been made in the site area.

3) Natural Resources of Regional Significance Status

The Treasure Coast Regional Planning Council lists the "FPL Preserve", including the Barley Barber Swamp, as a Significant Regional Facility. Natural communities such as uplands and wetlands are also generically listed as Resources of Regional Significance.

4) Other significant features

FPL is not aware of any other significant features of the site.

f) Design Features and Mitigation Options

The design options are to add two new CT's and four new HRSG's and a new steam turbine that, together with the two existing CT's, will comprise Martin Unit # 8. This unit is scheduled to be in service in mid-2005. Natural gas delivered via pipeline is envisioned as the fuel type for this unit (with light oil serving as a backup fuel). Natural gas-fired facilities are among the cleanest, most efficient technologies currently available.

Mitigation options being considered include the capture and reuse of plant process water and rainwater. The facility already encompasses several preserved areas where wildlife is abundant.

g) Local Government Future Land Use Designations

Local government future land use designation for the site is "Public Utilities". Designations for the surrounding area are primarily "Agricultural". There are also limited areas of "Agricultural Ranchette", "Industrial", and a small "Commercial" area designation. To the southeast of the property, fronting on the St. Lucie Canal, there is an area designated for "Public Conservation".

h) Site Selection Criteria and Process

For the past several years, a number of FPL's existing power plant sites have been considered as potentially suitable sites for new or repowered generation. The Martin plant has been selected as a preferred site due to consideration of various factors including system load and economics. Environmental issues were not a deciding factor in FPL's site evaluation since none of the existing preferred and potential site exhibit significant environmental sensitivity or other environmental issues. All of these sites are considered permittable.

i) Water Resources

Surface water resources currently used at the Martin facility include the cooling pond, which takes its water from the St. Lucie canal. The available groundwater resource is the shallow aquifer which is used as a source of potable water and for service water for Units # 1 and # 2. Both of these sources are available for use with the site expansion.

j) Geological Features of Site and Adjacent Areas

FPL's Martin site is underlain by approximately 13,000 feet of sedimentary rock strata. The basement complex in this area consists of Paleozoic igneous and metamorphic rocks about which little is known due to their great depth.

Overlying the basement complex to the ground surface are sedimentary rocks and deposits that are primarily marine in origin. Below a depth of about 400 feet these rocks are predominantly limestone and dolomite. Above 400 feet the deposits are largely composed of sand, silt, or clay. The deepest formation in Martin County on which significant published data are available is the Eocene Age Avon Park. Limited information is available from wells penetrating the underlying Lake City formation. The published information on the sediments comprising the formations below the Avon Park Limestone in western Martin County is based on projections from deep wells in Okeechobee, St. Lucie, and Palm Beach counties.

k) Projected Water Quantities for Various Uses

The estimated additional quantity of water required for industrial processing is 130 gallons per minute (gpm) for uses such as boiler water and service water. FPL operates on-site water treatment systems for each of these uses. Cooling water for new Unit # 8, will be supplied from the on-site 6,800-acre cooling pond. Makeup water for the pond is taken from the St. Lucie canal. The current makeup water quantity to the cooling pond (approximately 4,800 gpm) is expected to be adequate for the proposed expansion. Water quantities needed for other uses such as irrigation and potable water are estimated to be approximately 5 gpm.

l) Water Supply Sources by Type

All additional capacity at the site will utilize the existing on-site cooling pond as the source of cooling water and as a heat sink for the dissipation of cooling water heat. The cooling pond operates as a "closed cycle" system in which heated water from the generating units loses its heat as it is circulated within the pond and back around to the plant intake. A cooling tower may also be utilized. Makeup water to the pond is withdrawn from the St. Lucie Canal as needed to replace net evaporation and seepage losses from the pond. Such needs will comply with the existing agreement between FPL and the South Florida Water Management District (SFWMD) regarding allocation of cooling water to the pond and with SFWMD's regulations for consumptive water use.

The existing water treatment system at the plant, which provides treated water for use in the Unit # 1 and # 2 boilers, as well as the HRSG's associated with Units # 3 and # 4, will be expanded to provide treated water for new Unit # 8. FPL will discuss Unit # 8 requirements with SFWMD as the project moves forward in the licensing process.

m) Water Conservation Strategies Under Consideration

Impacts on the surficial aquifer will be reduced by changing the source of plant process water to the Floridan aquifer, upon completion of Unit # 8. In addition, the facility captures and reuses process water whenever feasible, and manages stormwater in such a manner so as to recharge the surficial aquifer.

n) Water Discharges and Pollution Control

Heated water discharges will be dissipated in the cooling pond. Non-point source discharges are not an issue since there are none at this facility. Industrial discharges will be minimized by treating and recycling equipment wash water, boiler blowdown water, and equipment area runoff. Storm water runoff is collected and used to recharge the surficial aquifer via a stormwater management system. Design elements have been included to capture suspended sediments. Facility permits mandate various sampling and testing activities, which provide indication of any pollutant discharges. The facility employs a Best Management Practices (BMP) plan and Spill Prevention, Control and Countermeasure (SPCC) plan to control the inadvertent release of pollutants.

o) Fuel Delivery, Storage, Waste Disposal, and Pollution Control

The site is already serviced by multiple fuel delivery facilities. There are currently two pipelines with the capability of supplying of natural gas into the facility. The additional capacity due to the conversion of the CT's into a CC unit will require an enlargement of an existing pipeline(s), the installation of a new pipeline, or the addition of another natural gas pipeline compressor station.

p) Air Emissions and Control Systems

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 (SO2), particulate matter and other fuel-bound contaminates. 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 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.

q) Noise Emissions and Control Systems

A field survey and impact assessment of noise expected to be caused by unit construction at the site indicated that construction noise will be below current noise levels for the residents nearest the site. Noise from the operation of the new units will also be within allowable levels.

r) Status of Applications

A Site Certification application was filed in December, 1989, for the construction and operation of the Martin Coal Gasification/Combined Cycle project under the Florida Electrical Power Plant Siting Act.

On June 15, 1990, the Public Service Commission issued a Determination of Need Order for proposed Martin Units # 3 and # 4. This determination of need applies only to the first phase of the Project, or 832 MW of combined cycle generation. The Siting Board issued a Land Use Order on June 27, 1990. The Certification Hearing was held on November 5-7, 1990. As mentioned earlier, on February 12, 1991, the Governor and Cabinet, serving as the Siting Board, approved the construction and operation of natural gas-fired combined cycle Units # 3 and # 4 and determined that the Martin Site has capacity to accommodate additional combined cycle units fueled by natural gas, fuel oil, or coal-derived gas produced at the site.

Since the initial certification in 1991, the Site Certification has been modified five times to provide authorization for items such as CT testing, increasing the cooling pond elevation, incorporating changes from other permits, and incorporating a custom fuel monitoring program. For the addition of the two CT's, FPL obtained a sixth modification to the existing Site Certification in August 2000.

In order to convert these two CT's from simple cycle to CC configuration, a seventh modification to the Site Certification will be required. FPL filed the Site Certification Application on February 1, 2002 with the FDEP.

IV.F.2. Potential Sites

Four FPL-owned sites are identified as the next most likely potential sites for future generation after the four preferred sites just discussed. These four sites are considered the next most likely potential sites due to considerations of location to FPL load centers, space, infrastructure, and/or accessibility to fuel and transmission facilities. These sites are located in Brevard, Palm Beach, Broward, and St. Lucie Counties. These sites are suitable for different capacity levels and technologies, and they will remain as potential sites pending future decisions on how best to meet the timing and magnitude of FPL's future capacity needs.[2]

Each of these potential sites offers advantages and disadvantages relative to engineering considerations and/or costs associated with the construction and operation of feasible technologies. In addition, each potential site has different characteristics, which could require further definition and attention. For purposes of estimating water usage amounts, it

[2] As has been described in previous FPL Plant Site Plans, FPL also considers a number of other sites as possible sites for future generation additions. These include the remainder of FPL's existing generation sites.

is assumed that a natural gas-fired CC unit would be the technology of choice for any capacity additions at the sites.

Permits are presently considered to be obtainable for all four sites, assuming measures can be taken to mitigate any particular site-specific environmental concerns. None of the sites exhibit any significant environmental constraints. The potential sites are briefly discussed below. (Note: The order in which the sites are discussed below does not reflect a relative ranking of these sites in regard to how likely it is for FPL to add capacity at the site.)

Potential Site # 1: Cape Canaveral Plant, Brevard County

The site is located on the FPL Cape Canaveral property in unincorporated Brevard County. The city of Port St. Johns is located less than a mile away. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The existing facility consists of two 400 MW (nominal) steam boiler type generating units.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Cape Canaveral plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

This site is located on the Indian River. The land is primarily dedicated to industrial use with surrounding grassy areas and a few acres of remnant pine forest. The land adjacent to the site is dedicated to light commercial and residential use. There are no significant environmental features on the site.

d) and e) Water Quantities and Supply Sources

FPL projects that an increase of up to 260 gallons per minute (gpm) would be required for industrial processing use (boiler makeup, service water, etc.) It is expected that industrial cooling water needs could be met using the current 550,000 gpm once-through cooling water quantity. For industrial processing, FPL would use existing on-site wells. For industrial cooling, the Indian River would continue to be utilized.

Potential Site # 2: Riviera Plant, Palm Beach County

This site is located on the FPL Riviera Plant property in Riviera Beach, Palm Beach County. The site has direct access to a four-lane highway, US 1, and barge access is available. A rail line is located near the plant. The facility currently houses two operational 300 MW (nominal) steam boiler generating units and one retired 50 MW generating unit.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Riviera plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is primarily covered by the existing generation facilities with some open maintained grass areas. There is a small manatee viewing area on the site which is operated seasonally by FPL. Adjacent land uses include port facilities and associated industrial activities, as well as light commercial and residential development. The site is located on the Intracoastal Waterway near the Lake Worth Inlet.

d) and e) Water Quantities and Supply Sources

Additional industrial processing water needs are estimated to be up to 40 gallons per minute (gpm). Industrial cooling water needs are estimated to be up to 54,000 gpm using the existing once-through cooling water system. The existing municipal water supply would be used for industrial processing water if additional generating capacity is placed at Riviera. For once-through cooling water, FPL would continue to use Lake Worth as a source of water.

Potential Site # 3: Port Everglades Plant, Broward County

This site is located on the 94-acre FPL Port Everglades plant site in Port Everglades, Broward County. The site has convenient access to State Road (SR) 84 and Interstate 595. A rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (nominal) and two 400 MW (nominal) sized units.

a) U.S. Geological Survey (USGS) Map

A USGS map of the Port Everglades plant site is found at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

d) and e) Water Quantities and Supply Sources

FPL estimates that up to 130 gallons per minute (gpm) of industrial processing water would be required for uses such as boiler makeup, fogger usage, and service water. FPL would expect to use the existing municipal water supply for industrial process water. For cooling water, FPL would anticipate that the existing 320,000 gpm once-through cooling seawater source would continue to be used.

Potential Site # 4: Midway Substation Property, St. Lucie County

The site is located on the 122-acre Midway Substation property. Current facilities on the site include an electric substation. The site has direct access to a two-lane highway, State Road 712 (SR 712). The nearest town is White City, which is approximately 5 miles east of the site. The City of Fort Pierce is approximately 9 miles northeast of the site. The Midway site was previously listed as a preferred site in the FPL 2001-2010 Ten Year Power Plant Site Plan.

a) U.S. Geological Survey (USGS) Map
A map is provided of the Midway Site area and a land use map is provided at the end of this chapter.

b) and c) Land Uses and Environmental Features

The land on the site is currently dedicated to industrial and agricultural use. Much of the site is currently not being used. Developed portions of the adjacent properties are primarily agricultural (orange groves and cattle grazing). Undeveloped portions include mixed scrub with some hardwoods and wetlands.

d) and e) Water Quantities and Supply Sources

No surface water source is available at this site. The groundwater source would either be the shallow aquifer or a local source of gray water. It is estimated that 150 gallons per minute (gpm) will be needed for industrial processing water for uses such as inlet air-cooling, NO_x control during light oil firing and for service water. Other facility water uses may include irrigation, potable use, etc. The total volume of these uses is estimated to be about 5 gpm.

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Environmental and Land Use Information: Supplemental Information

Preferred Site: Fort Myers Plant

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FT. MYERS PLANT SITE
SHOWING LANDUSE
0 400 Feet
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GIS
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of any and all loss. All Boundaries are
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Figure IV.F.1

Figure IV.F.2

LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

Residential Low Density
Residential Medium Density
Residential High Density
Commercial and Services
Industrial
Extractive
Institutional
Recreational
Open Land
Cropland and Pastureland
Tree Crops
Feeding Operations
Nurseries and Vineyards
Specialty Farms
Other Open Lands <Rural>
Herbaceous
Shrub and Brushland
Mixed Rangeland
Upland Coniferous Forests
Upland Hardwood Forests
Tree Plantations

Streams and Waterways
Lakes
Reservoirs
Bays and Estuaries
Major Springs
Slough Waters
Oceans Seas and Gulfs
Wetland Hardwood Forests
Wetland Coniferous Forests
Wetland Forested Mixed
Vegetated Non-Forested Wetlands
Non-Vegetated
Wetland Shrub
Beaches OtherThan Swimming Beaches
Sand Other Than Beaches
Exposed Rock
Disturbed Lands
Riverine Sandbars
Transportation
Communications
Utilities
Vegetation-Sea Grass

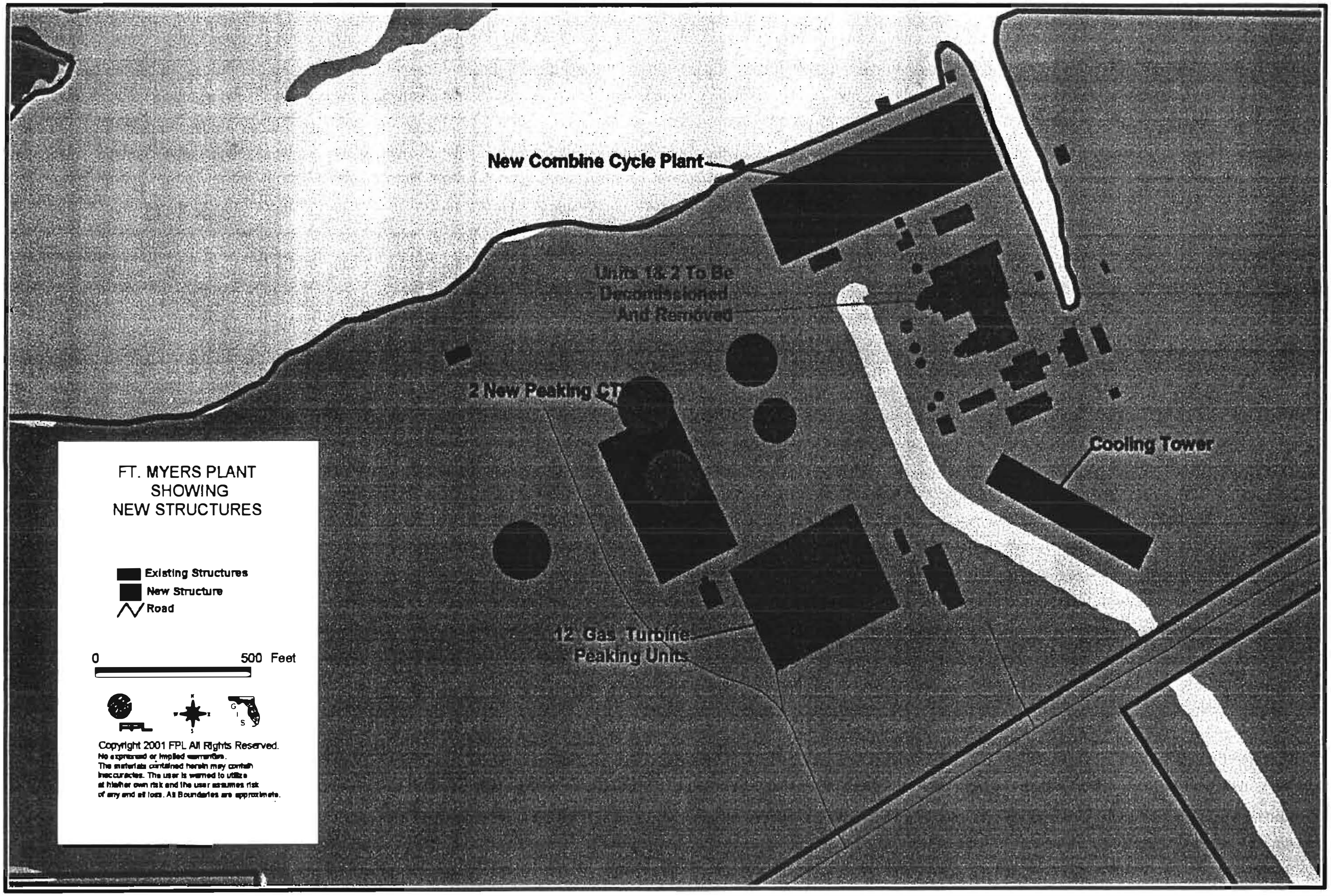
New Combine Cycle Plant
Units 1& 2 To Be Decommissioned And Removed
2 New Peaking CT
Cooling Tower
12 Gas Turbine Peaking Units
FT. MYERS PLANT
SHOWING
NEW STRUCTURES
Existing Structures
New Structure
Road
0
500 Feet
FPL
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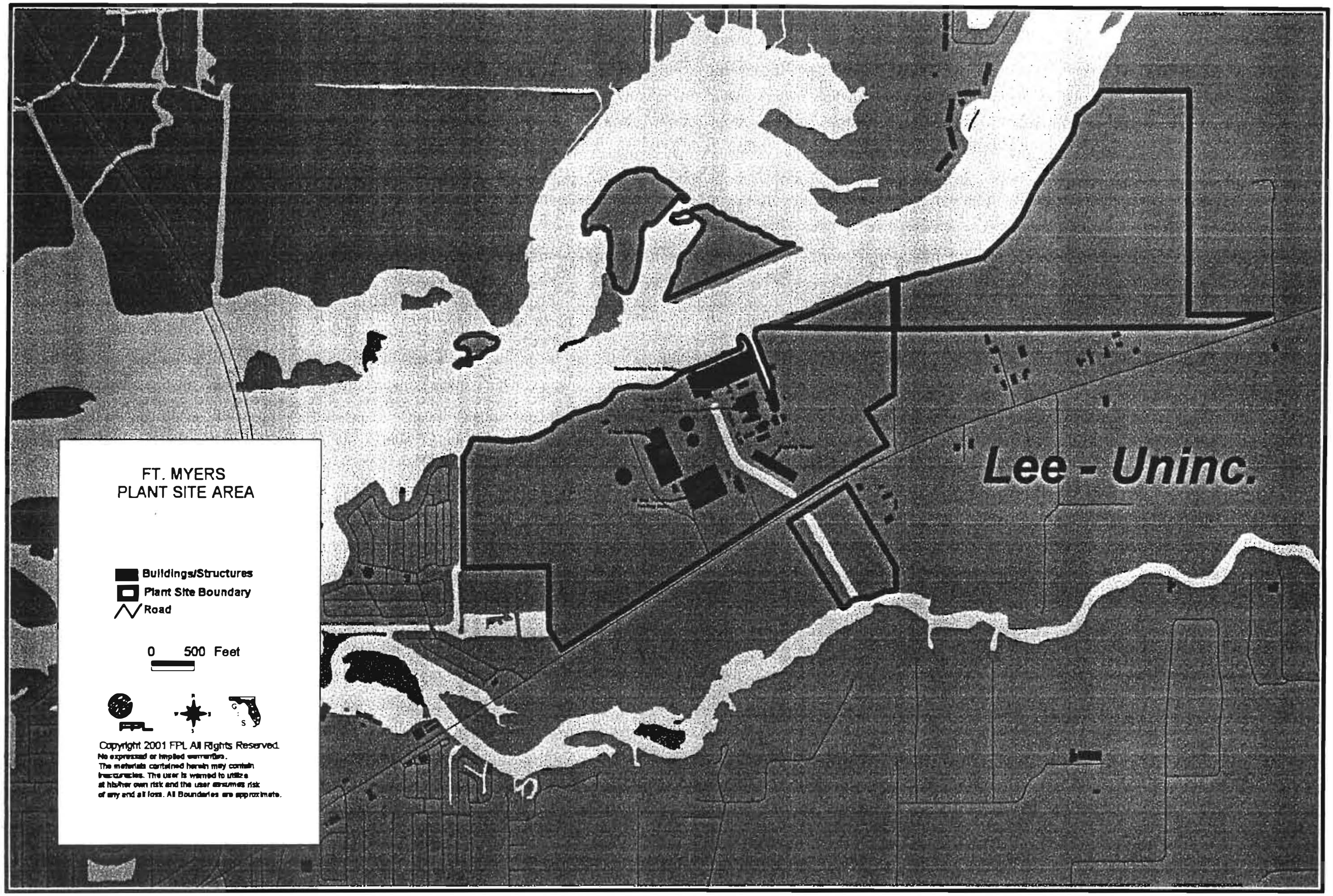
Figure IV.F.3


FT. MYERS
PLANT SITE AREA
Buildings/Structures
Plant Site Boundary
Road
0 500 Feet
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Lee - Uninc.

Figure IV.F.4

Environmental and Land Use Information: Supplemental Information

Preferred Site: Sanford Plant

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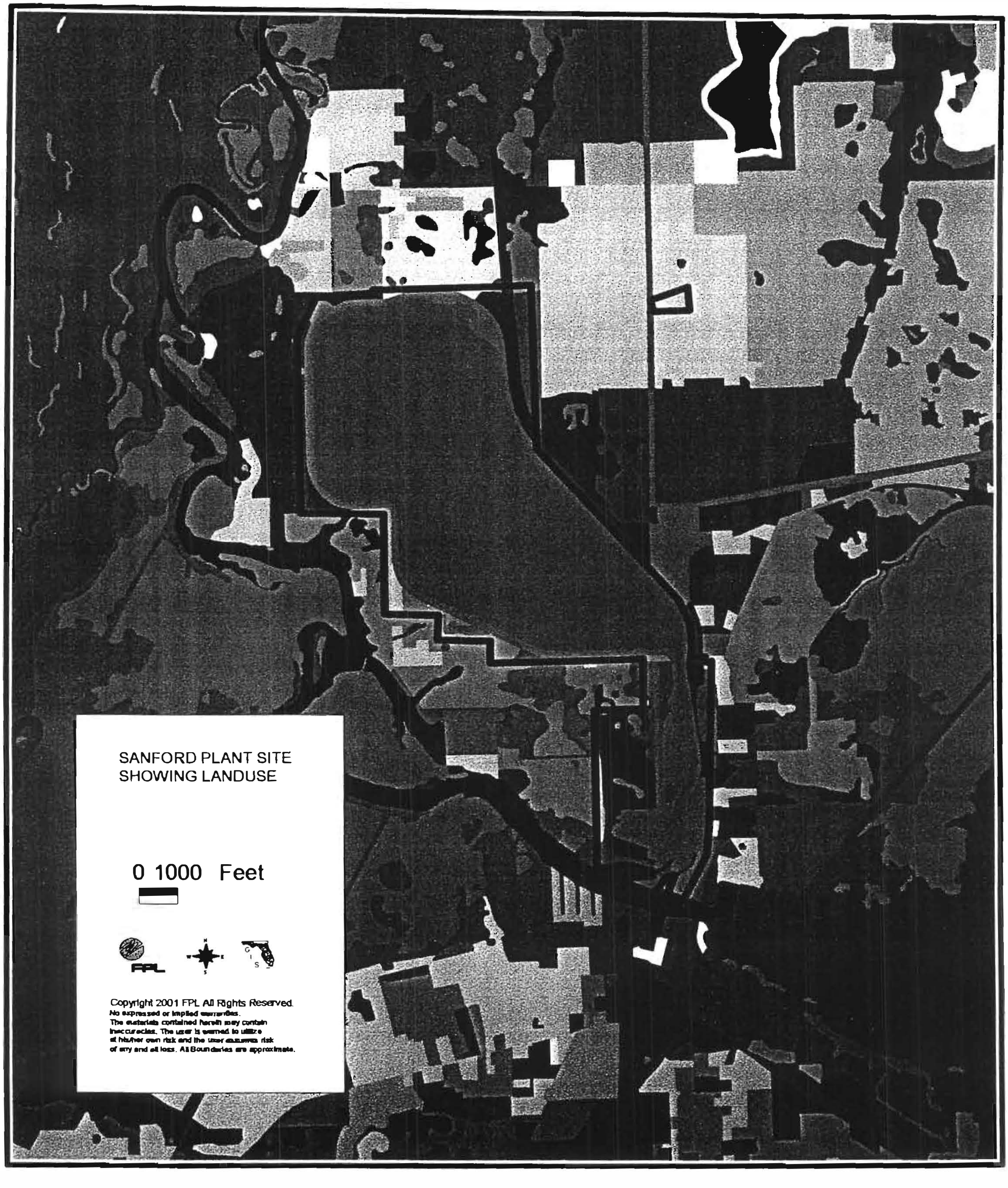
Figure IV.F.5



E-144

Figure IV.F.6

LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass

FPL

G I S

Figure IV.F.7

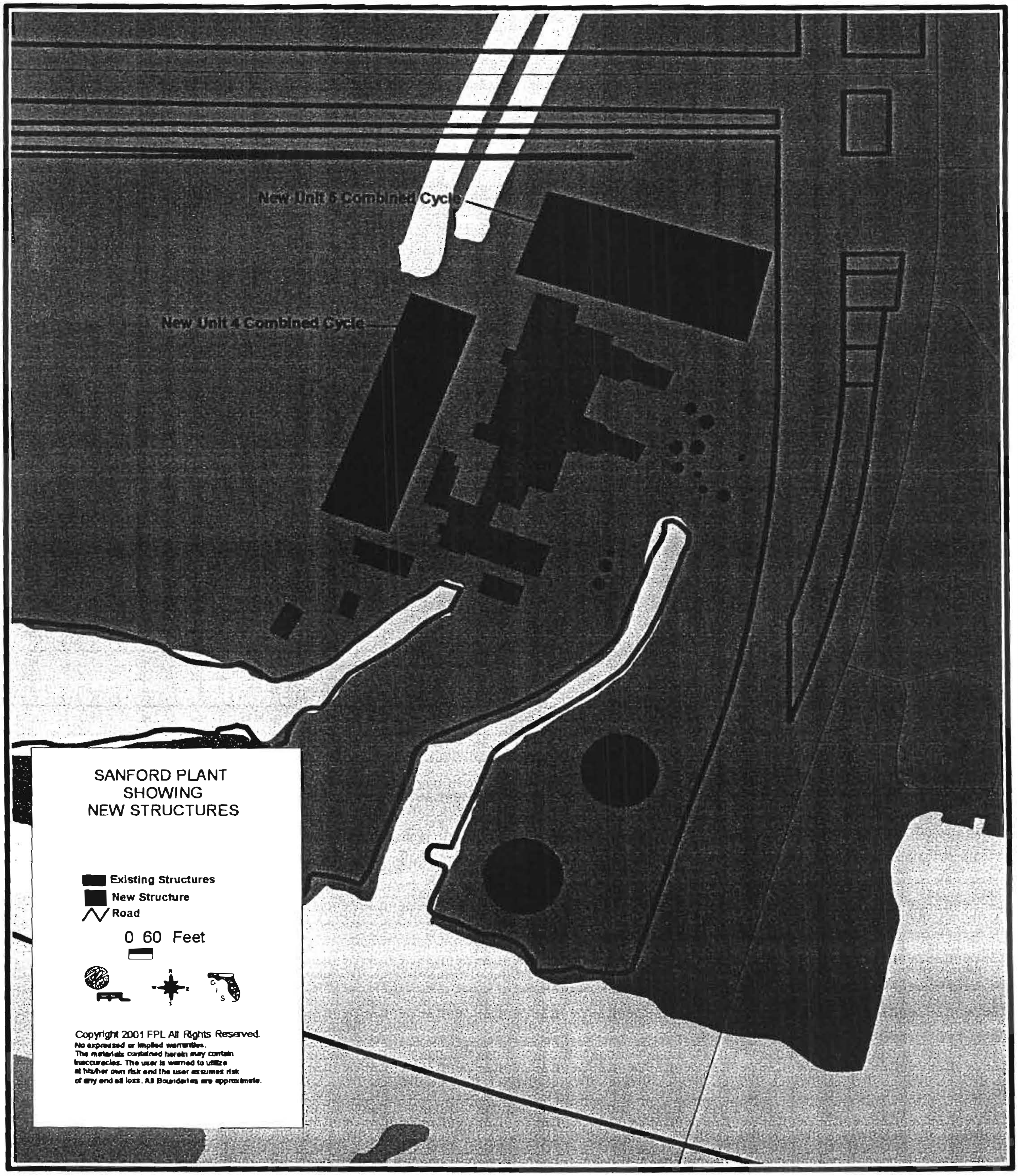


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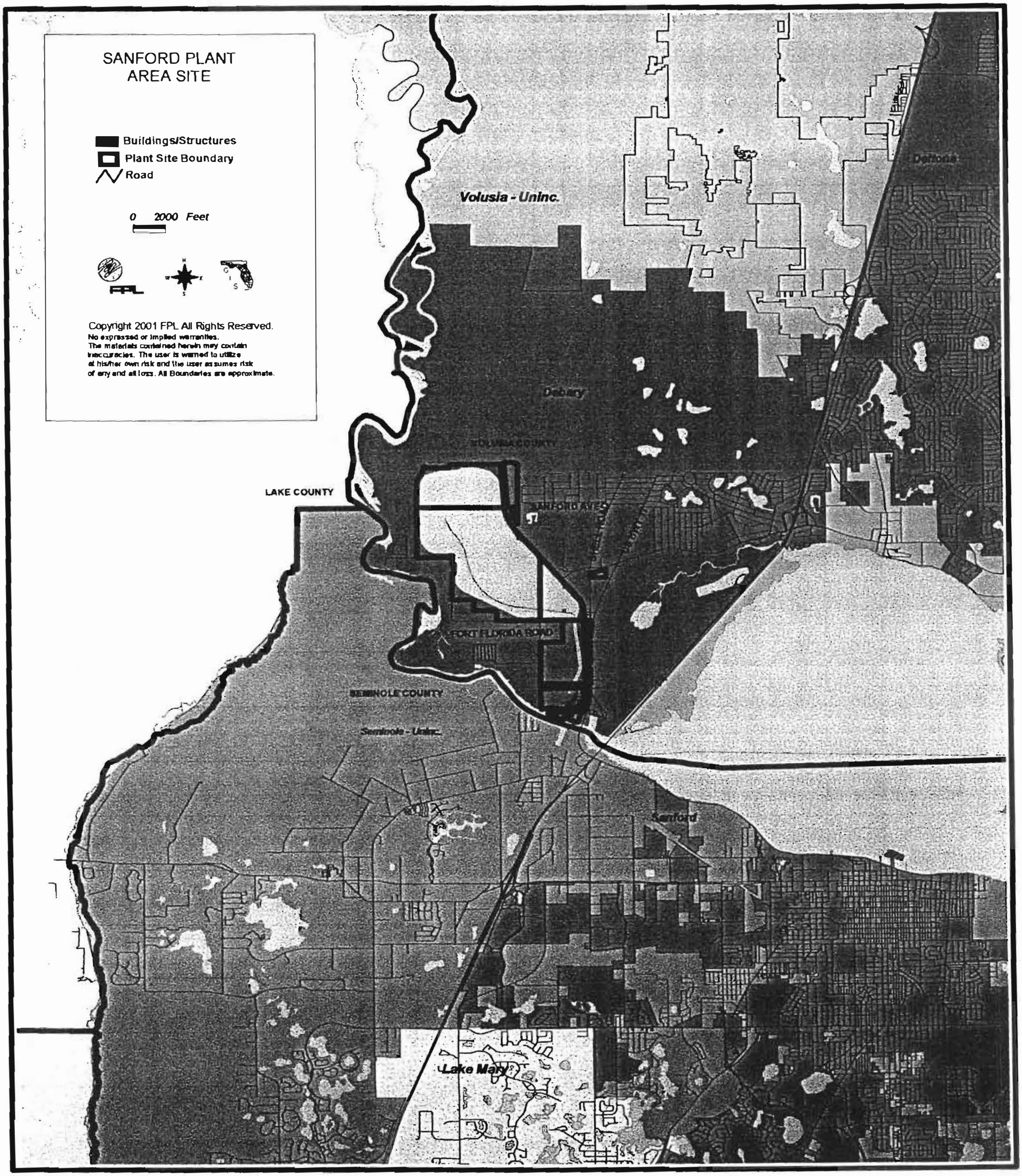
Figure IV.F.8



SANFORD PLANT
AREA SITE
Buildings/Structures
Plant Site Boundary
Road
0 2000 Feet
FPL
G I S
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Volusia - Uninc.
Deltona
Debary
LAKE COUNTY
FORT FLORIDA ROAD
SEMINOLE COUNTY
Seminole - Uninc.
Sanford
Lake Mary

Environmental and Land Use Information:

Supplemental Information

Preferred Site: Manatee Plant

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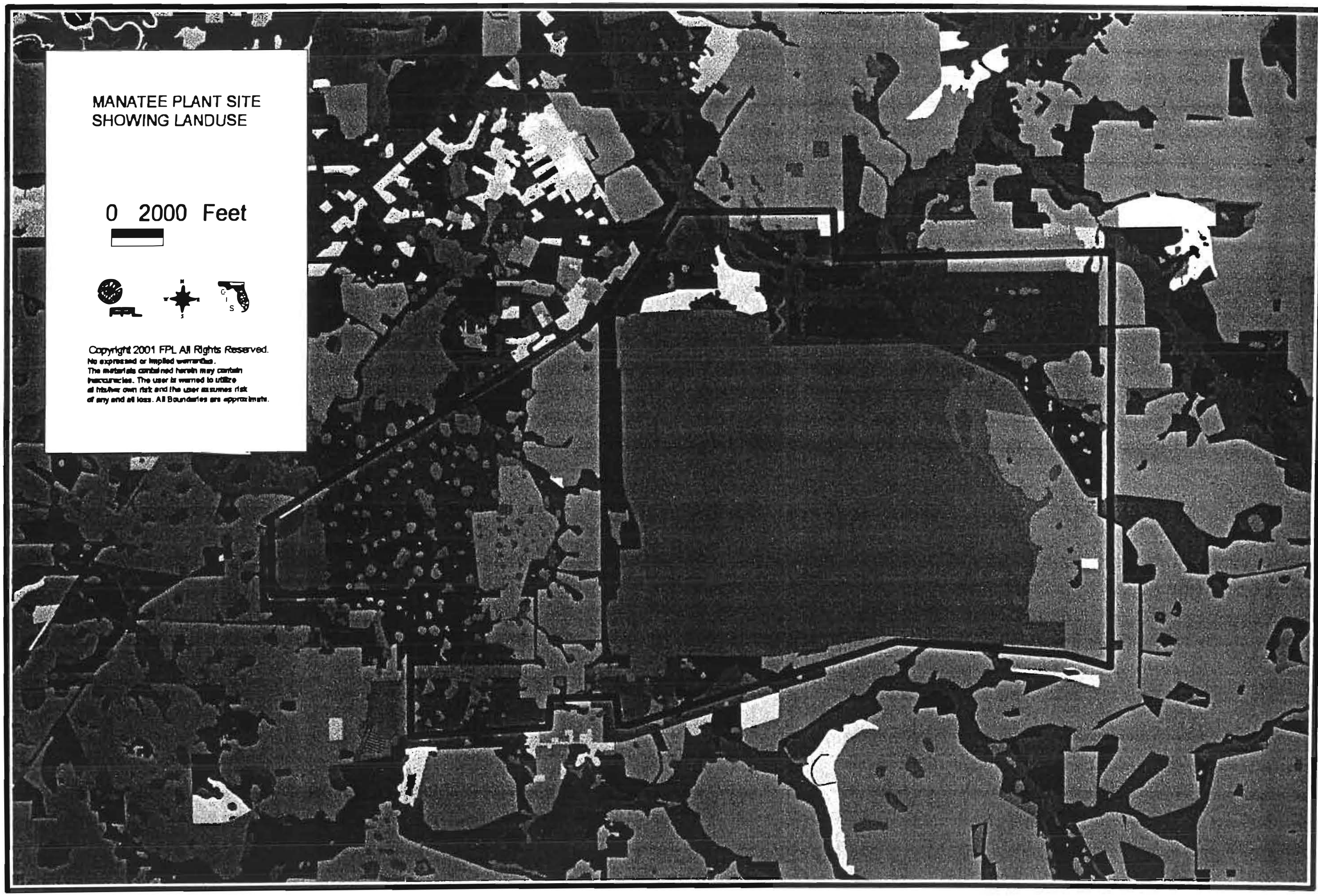
MANATEE PLANT SITE
SHOWING LANDUSE
0 2000 Feet
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Figure IV.F.9

Figure IV.F.10

LEGEND FOR LANDUSE MAPS

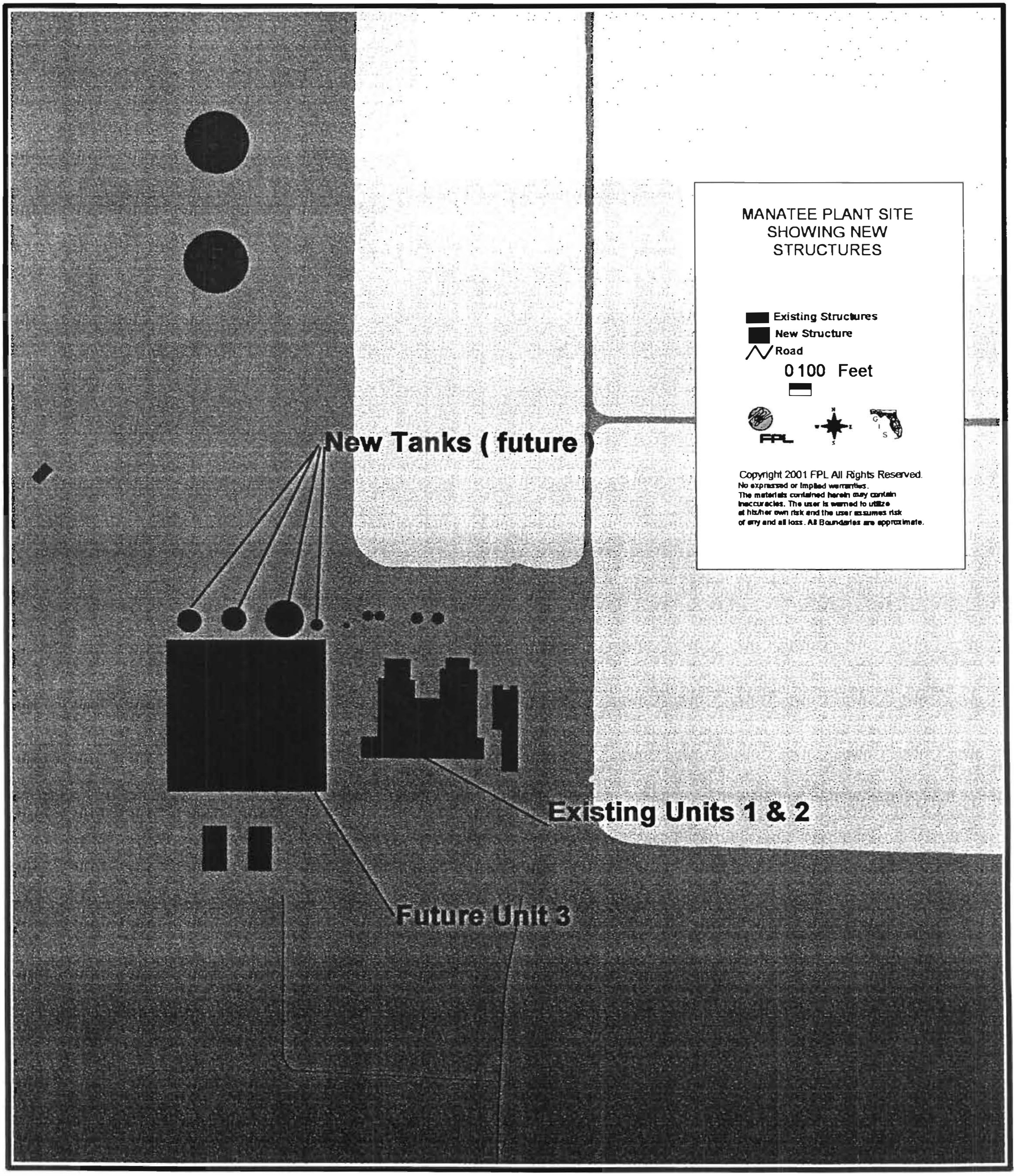
Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
- Exposed Rock
- Disturbed Lands
- Riverine Sandbars
- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass

FPL

Figure IV.F.11



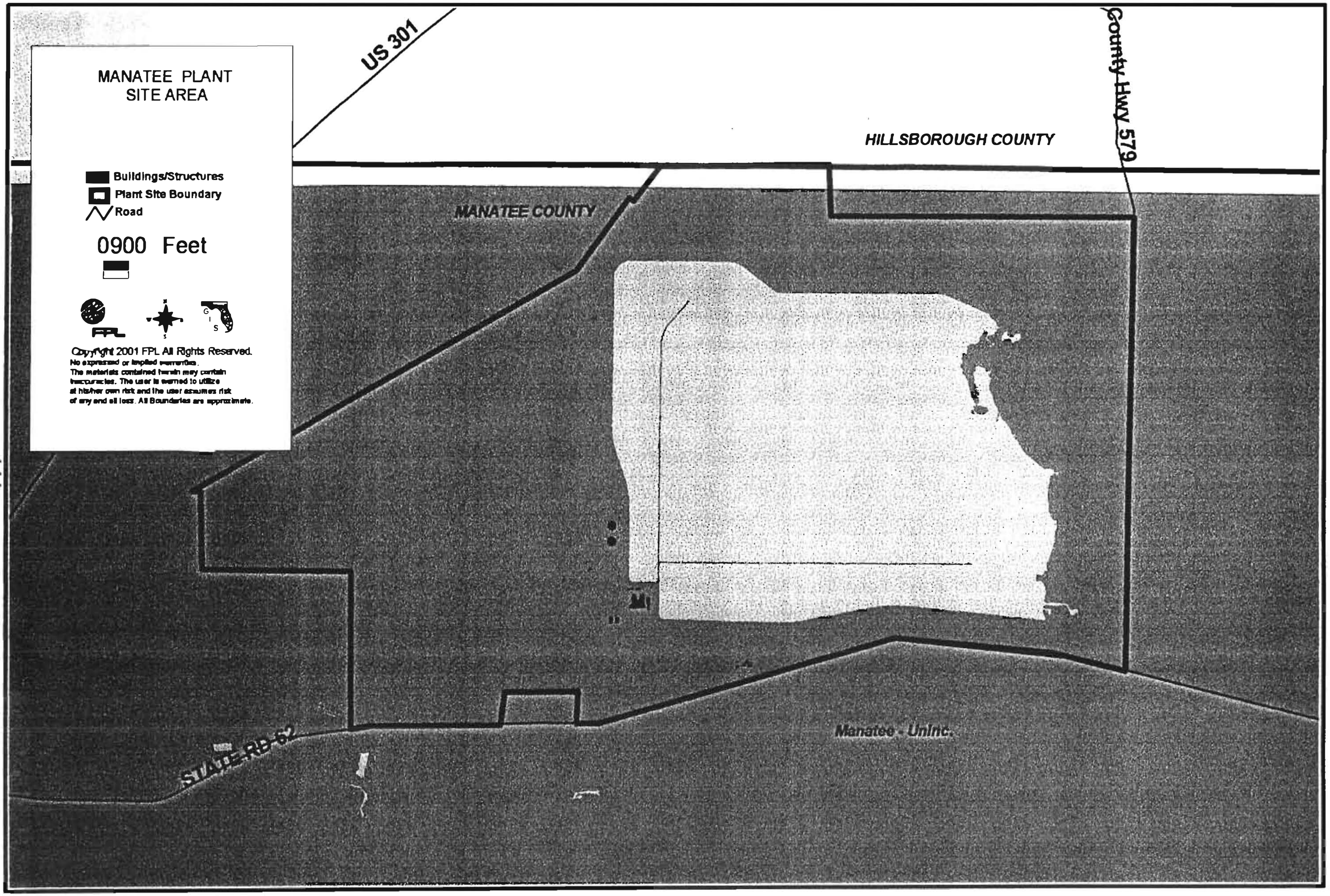


Figure IV.F.12

Environmental and Land Use Information: Supplemental Information

Preferred Site: Martin Plant

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Figure IV.F.13

Figure IV.F.14

LEGEND FOR LANDUSE MAPS

Plant Site Boundary

Level 3 Landuse Categories 1995

- Residential Low Density
- Residential Medium Density
- Residential High Density
- Commercial and Services
- Industrial
- Extractive
- Institutional
- Recreational
- Open Land
- Cropland and Pastureland
- Tree Crops
- Feeding Operations
- Nurseries and Vineyards
- Specialty Farms
- Other Open Lands <Rural>
- Herbaceous
- Shrub and Brushland
- Mixed Rangeland
- Upland Coniferous Forests
- Upland Hardwood Forests
- Tree Plantations
- Streams and Waterways
- Lakes
- Reservoirs
- Bays and Estuaries
- Major Springs
- Slough Waters
- Oceans Seas and Gulfs
- Wetland Hardwood Forests
- Wetland Coniferous Forests
- Wetland Forested Mixed
- Vegetated Non-Forested Wetlands
- Non-Vegetated
- Wetland Shrub
- Beaches OtherThan Swimming Beaches
- Sand Other Than Beaches
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- Transportation
- Communications
- Utilities
- Vegetation-Sea Grass

Figure IV.F.15

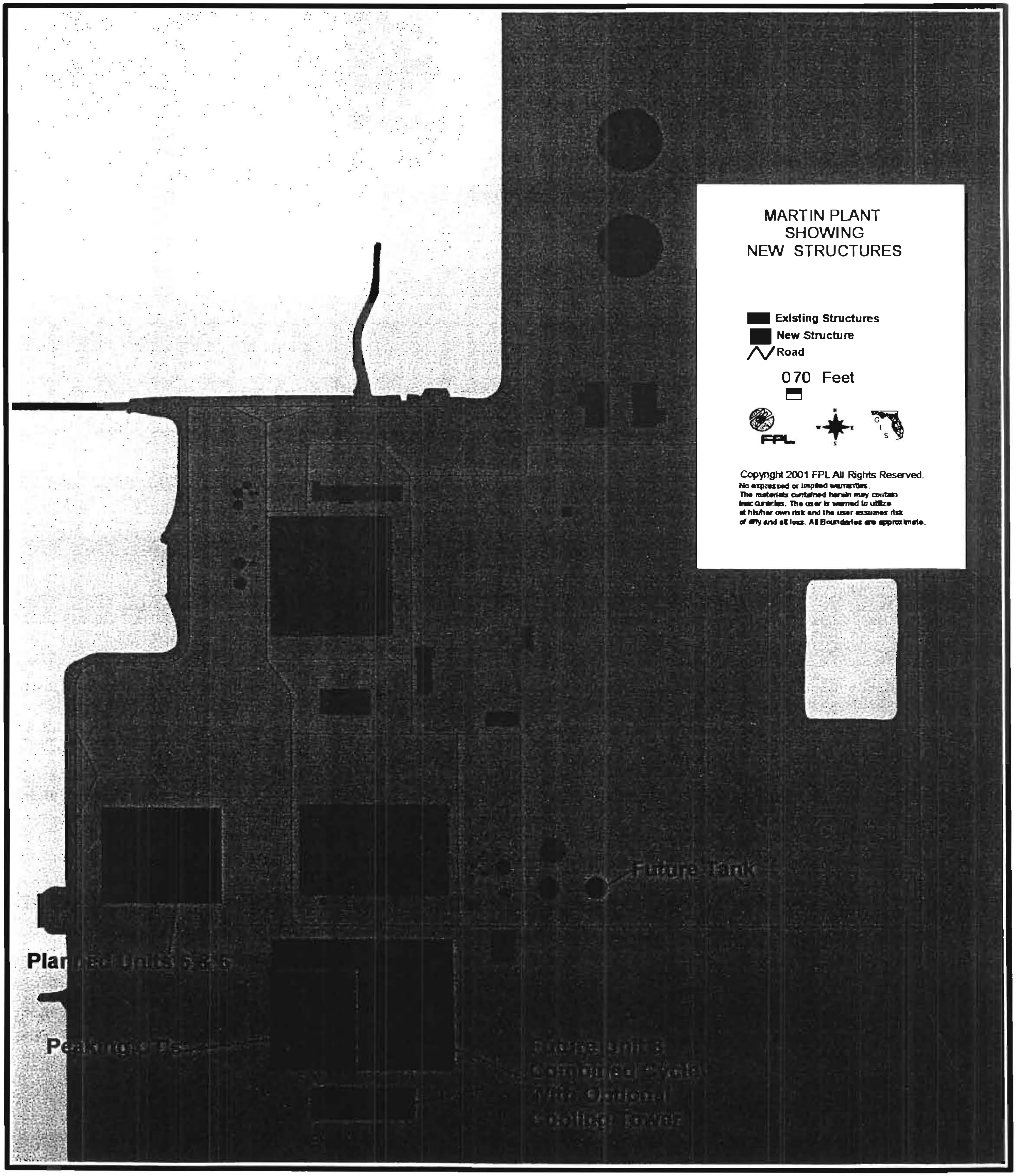

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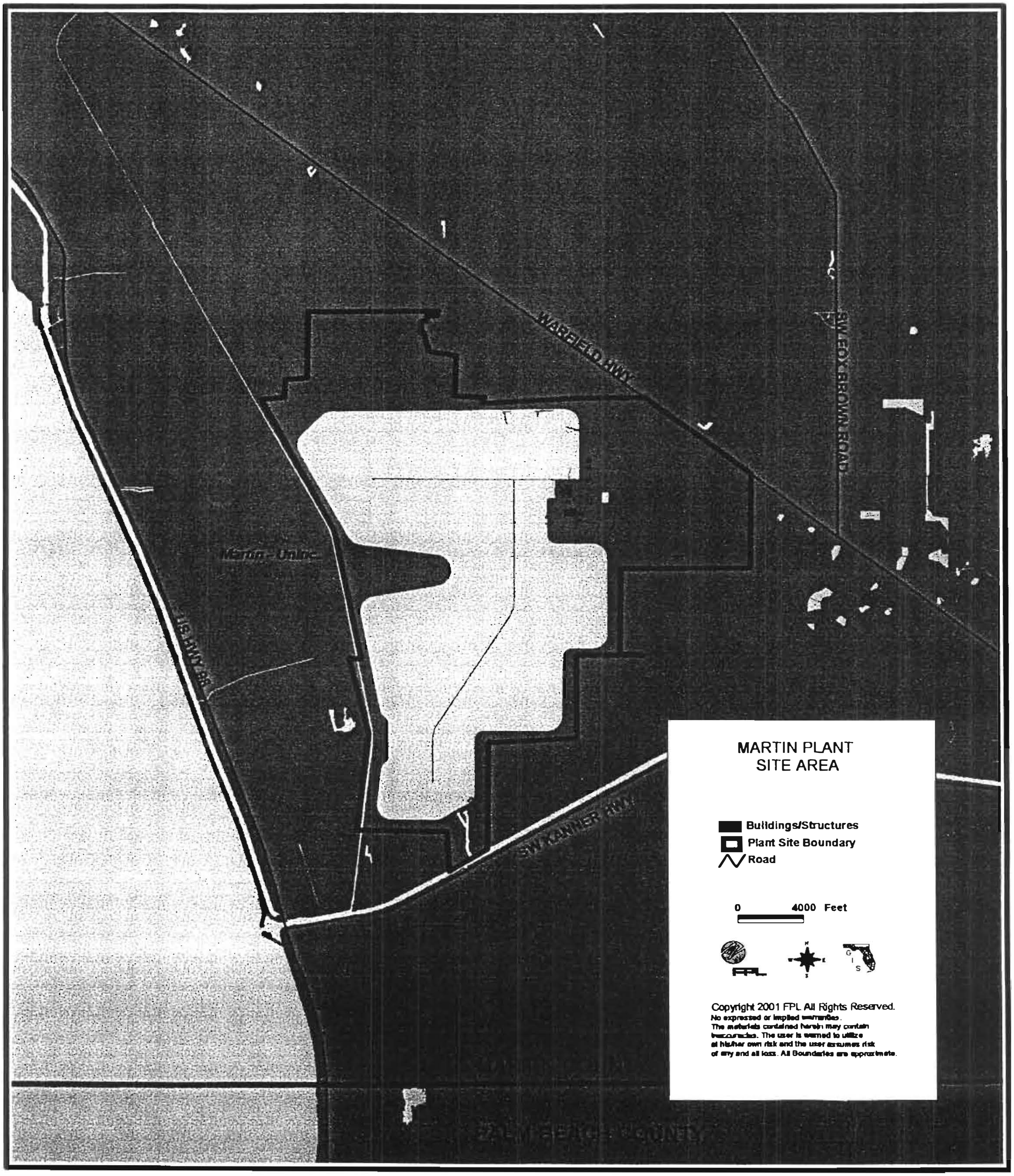
Figure IV.F.16



Environmental and Land Use Information: Supplemental Information

Potential Sites

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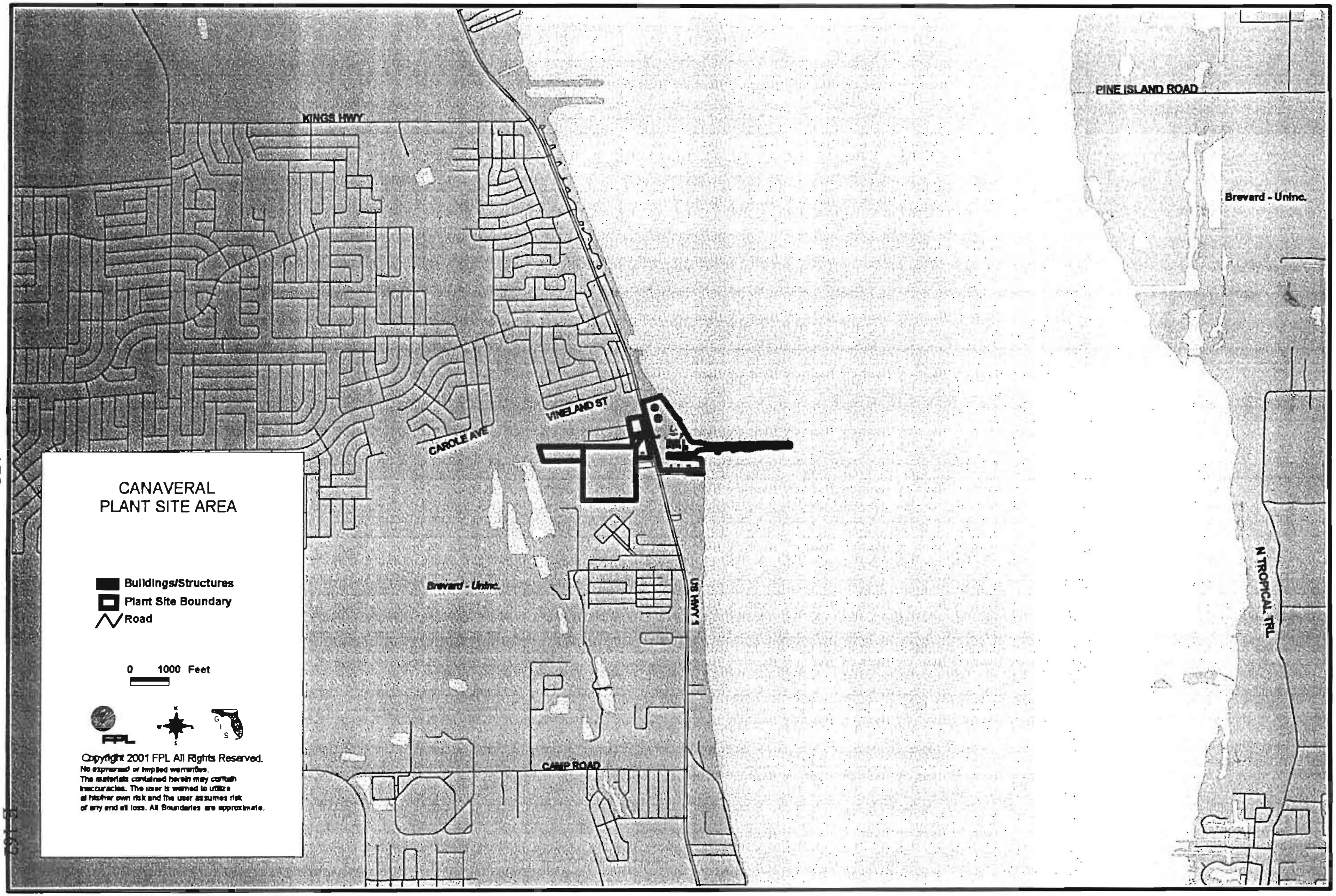

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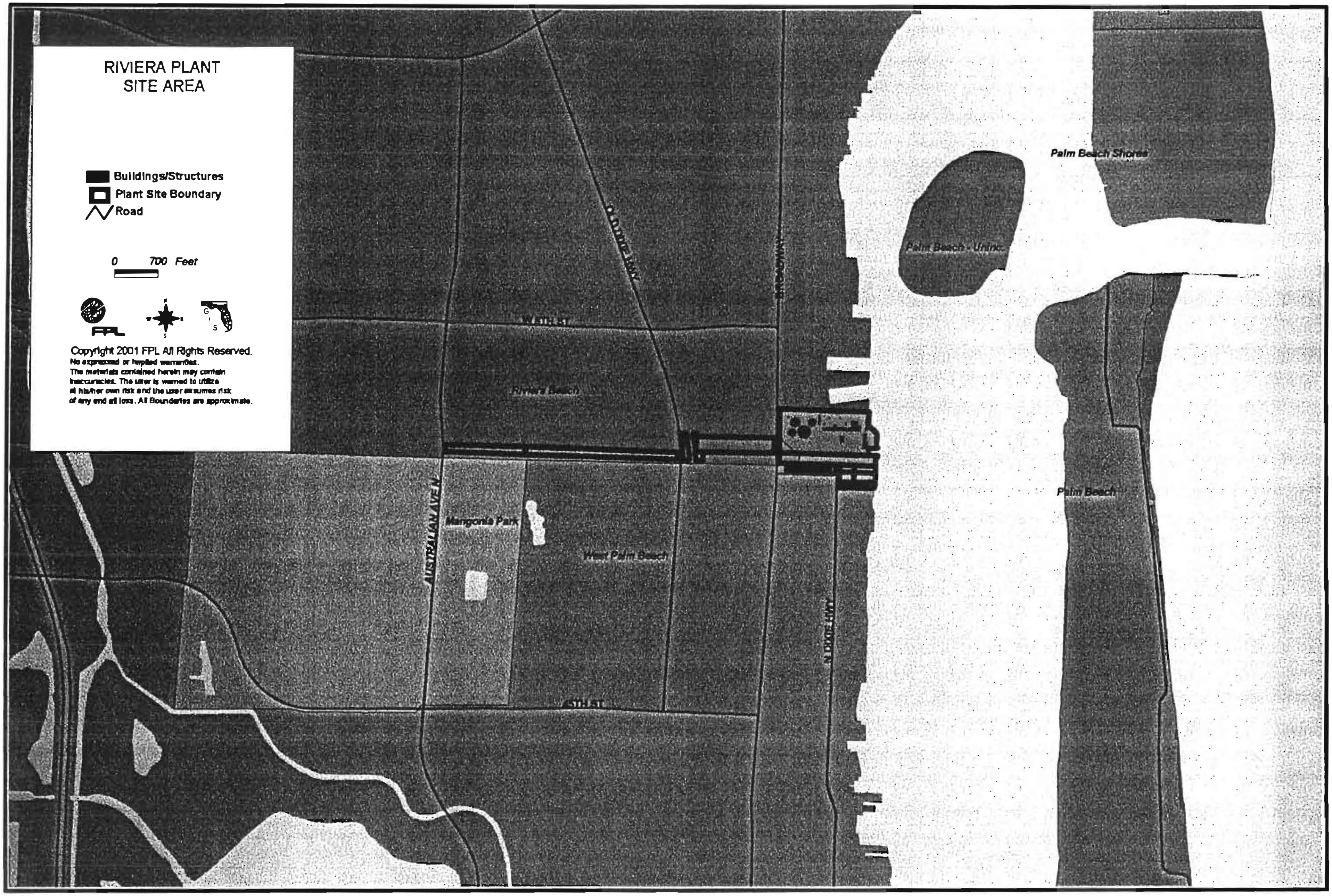


Figure IV.F.18

Figure IV.F.19

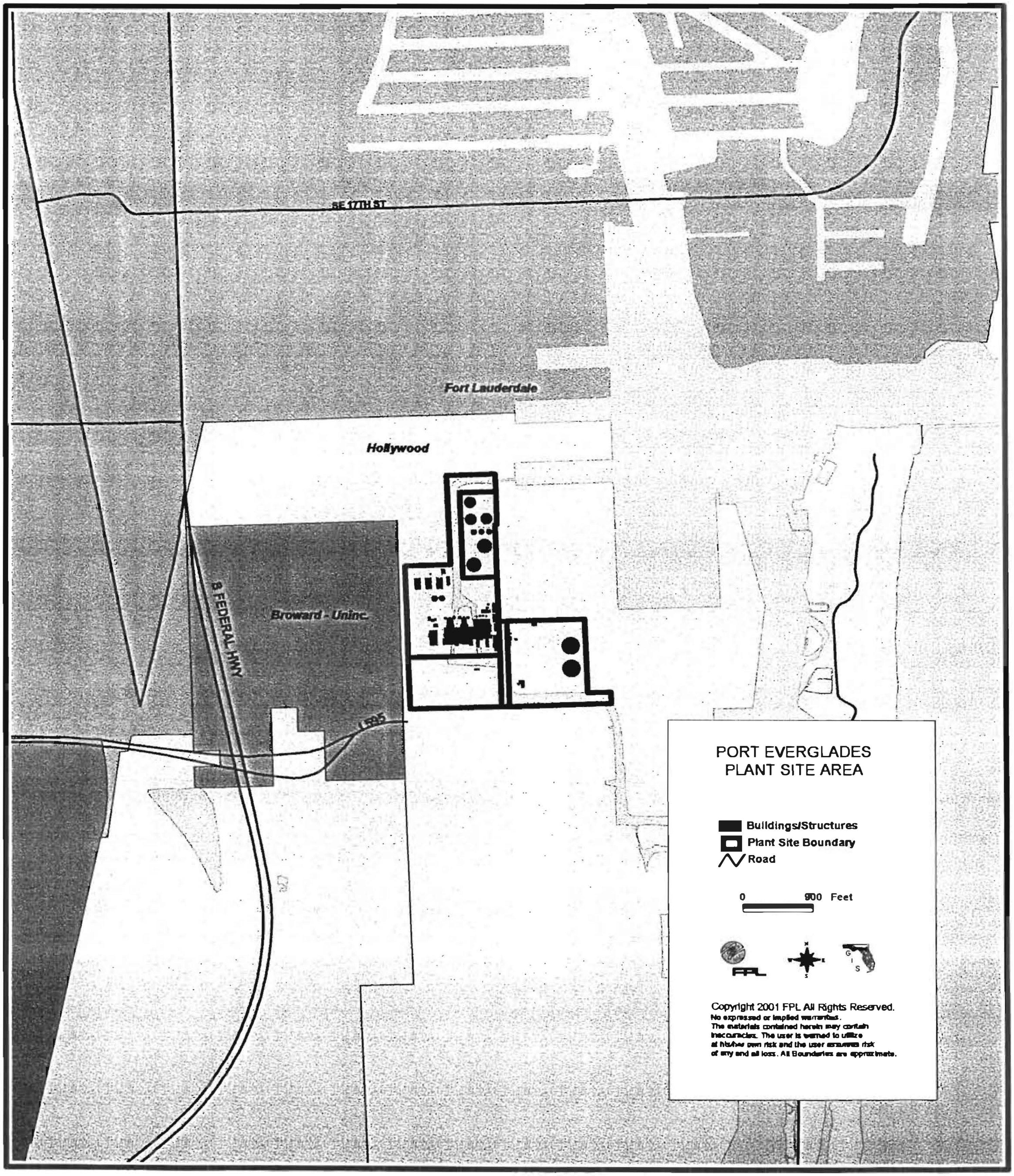
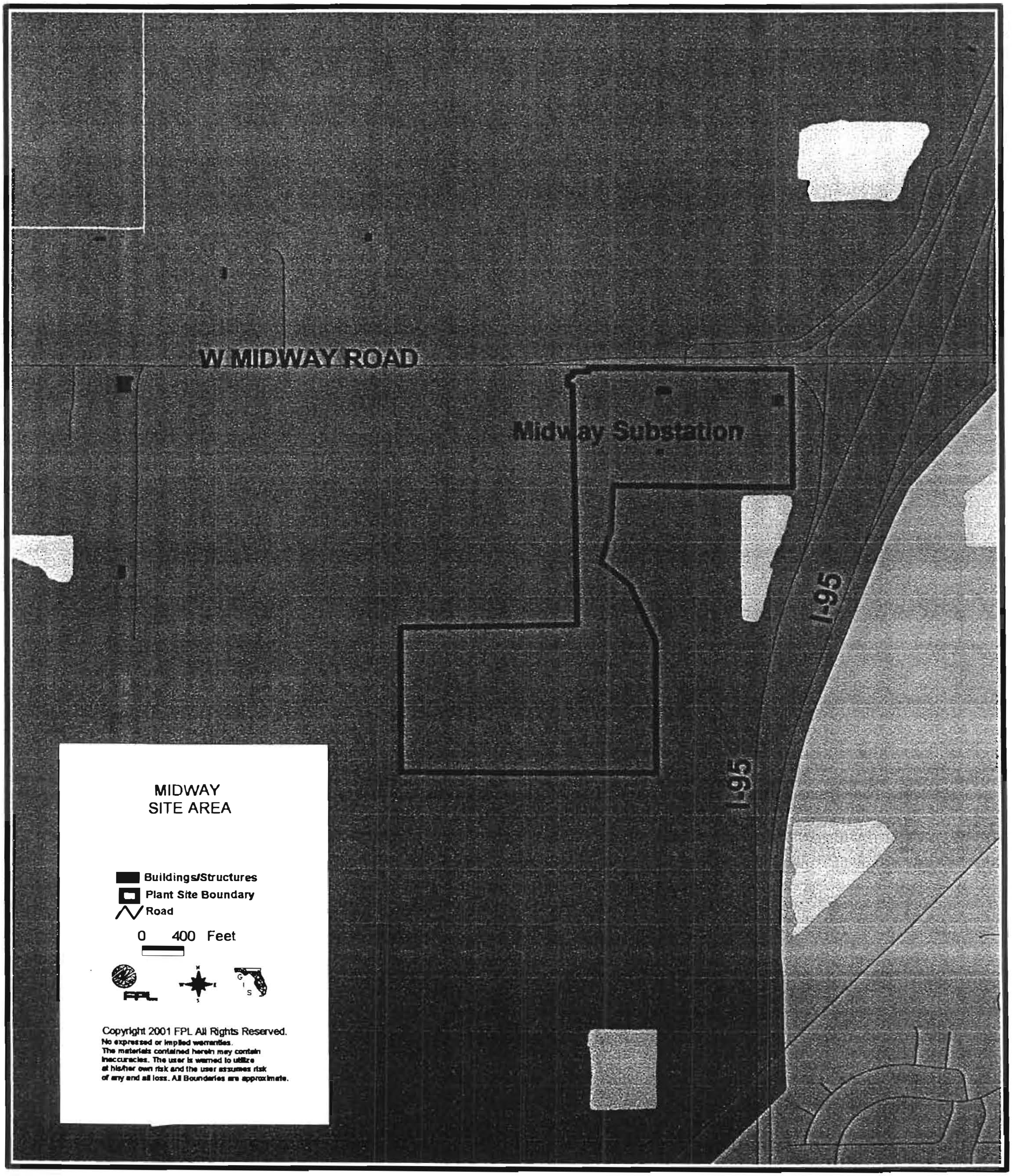


Figure IV.F.20



CHAPTER V

Other Planning Assumptions & Information

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Introduction

The Florida Public Service Commission (FPSC), in Docket No. 960111-EU, specified certain information that was to be included in an electric utility's Ten Year Power Plant Site Plan filing. Among this specified information was a group of 12 items listed under a heading entitled "Other Planning Assumptions and Information". These 12 items basically concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission constraints. External constraints deal with FPL's ties to its neighboring systems. Internal constraints deal with the flow of electricity within the FPL system. The projected effects of these constraints are modeled in FPL's resource planning work.

The external constraints are important since they affect the development of assumptions for the amount of external assistance which is available and the amount and price of economy energy purchases. Therefore, these external constraints are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance which is assumed to be available is based on the projected transfer capability to FPL from outside its system as well as historical levels of available assistance. In its reliability analyses, FPL models this amount of external assistance as an additional generator within FPL's system which provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission constraints or limitations are addressed in developing the costs for siting new units at different locations. Site-specific transmission costs are developed for each different unit/unit location option or groups of options.

FPL's annual transmission planning work determines transmission additions needed to address constraints and to maintain/enhance system reliability. FPL's transmission plans are presented in Section III.E.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

As discussed in Chapter III of this document, FPL typically performs economic analyses of competing resource plans using the EGEAS (Electric Generation Expansion Analysis System) computer model from the Electric Power Research Institute (EPRI) and Stone and Webster Management Consultants, Inc. The resource plan reflected in this document emerged as the resource plan with the least impact on FPL's levelized system average electric rates (i.e., a Rate Impact Measure or RIM approach) and on the present value of revenue requirements for the FPL system.[3]

As part of its 2001 resource planning work, FPL issued a Request for Proposals (RFP) for firm capacity offerings designed to address FPL 2005 and 2006 capacity needs. FPL received 81 proposals in response to the RFP. These outside proposals, and 13 FPL construction options, were subsequently evaluated by FPL using the EGEAS model. Following the EGEAS calculations, three other calculations designed to determine generator startup costs, transmission integration costs, and equity penalty costs were made. These other costs were then added to the EGEAS costs to develop total costs (in terms of the cumulative present value of revenue requirements) for the competing options. A similar analysis of the outside proposals and FPL construction options was performed independently by an outside consultant.

No sensitivity case analyses based on different load forecasts were carried out during 2001. This is due to the fact that the vast majority of the options studied, including the two most economical options (the Martin Conversion project and the new Manatee unit), are combined cycle (CC) units. If higher – than – projected loads begin to appear, the combustion turbine components of any of the CC options could be placed in service early in simple cycle mode. FPL believed that this fact qualitatively enabled it to be able to address higher – than – projected loads. A quantitative analysis of this occurrence was not possible since the proposals did not include costs for such a scenario.

[3] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis, the lowest rate basis and the lowest system revenue requirements basis are identical. In such cases (as in FPL's 2001 resource planning work), FPL evaluates options on the simpler – to – calculate (but equivalent) lowest system revenue requirements basis.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenario. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

The basic assumptions FPL used in deriving its base case or "Most Likely" fuel price forecast are discussed in Chapter III of this document.

In its 2001 planning work, FPL did not test the sensitivity of its resource plan to a "Low Price" fuel forecast in conjunction with a "High Load" forecast. The reason given in response to Discussion Item # 2 explains why FPL felt that a high load forecast scenario was not needed. Similarly, since the vast majority of the options considered in the RFP analysis were gas-fired units, any change in the fuel costs projections would have affected these proposals in essentially the same way. Consequently, FPL did not believe that a fuel price sensitivity case was needed.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

For the same reason given in response to Discussion Item #3, FPL did not conduct a "constant fuel differential" sensitivity analysis in its 2001 planning work.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units on FPL's system was modeled using current projections for scheduled outages, unplanned outages, and capacity output ratings and heat rate information. Schedule 1 and Schedule 8 present the current and projected capacity output ratings of FPL's existing units. The values used for outages and heat rates are consistent with the values FPL has used in planning studies in recent years.

In regard to new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating & maintenance costs, capital replacement costs, construction schedules, heat rates, and capacity ratings for all construction options which were considered in the resource planning work. A summary of this information for the new capacity options FPL projects to add over the planing horizon is presented on Schedule 9.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The key financial assumptions used in FPL's 2001 resource planning work were 45% debt and 55% equity FPL capital structure, projected debt cost of 7.4%, and an equity return of 11.7%. These assumptions resulted in a weighted average cost of capital of 9.8% and an after-tax discount rate of 8.5%. In its 2001 planning work, FPL did not test the sensitivity of its resource plan to varying financial assumptions. The reason for this is that in recent years FPL's planning work has focused on FPL construction options only. Results between higher capital cost options and lower capital cost options could have changed as financial (primarily capital cost) assumptions changed.

However, in its 2001 planning work, outside proposals were analyzed versus the FPL construction options. While FPL could have examined the effect of different financial assumptions on its options, there simply is no practical way to request, receive and reanalyze new cost information for the outside proposals based on a common set of new financial assumptions (such as higher debt rates). The complexity and length of time inherent in an RFP-based process precludes this analysis.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's integrated resource planning (IRP) process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on FPL's electricity rate levels with the intent of minimizing FPL's levelized system average rate (i.e., a Rate Impact Measure or RIM approach). However, in its 2001 planning work FPL utilized a net present value of system revenue requirements as the basis for comparing options and plans. (As discussed in response to Discussion Item # 2, both the electricity rate basis and the system revenue requirement basis are identical when DSM levels are unchanged between competing plans. Such was the case in FPL's 2001 planning work.)

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL uses two generation reliability criteria in its resource planning work. One of these is a minimum 15% Summer and Winter reserve margin for years up to mid – 2004 that changes to a minimum 20% Summer and Winter reserve margin for the mid – 2004 – on time period. The other reliability criterion is a maximum of 0.1 days per year loss-of-load-probability (LOLP). These reliability criteria are discussed in Chapter III of this document.

In regard to transmission reliability, FPL has adopted transmission planning criteria that are consistent with the planning criteria established by the Florida Reliability Coordinating Council (FRCC). The FRCC has adopted transmission planning criteria that are consistent with the planning criteria established by the North American Electric Reliability Council (NERC) in its *Planning Standards*. FPL has applied these planning criteria in a manner consistent with prudent utility practice. The *NERC Planning Standards* are available on the internet (http://www.nerc.com/~filez/pss-psg.html).

In addition, FPL has developed a Facility Connection Requirements (FCR) document as well as a Facility Rating Methodology document that are also available on the internet (http://www.enx.com/FPL/fpl_home.html).

Thermal ratings for specific transmission lines or transformers are found in the load flow cases that are available on the internet (http://www.enx.com/FPL/fpl_home.html). The normal voltage criteria for FPL stations is given below:

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138, 500	0.95	1.05
230	0.95	1.06

There may have been isolated cases for which FPL may have determined it prudent to deviate from the general criteria stated above. The overall potential impact on customers, the probability of an outage actually occurring, as well as other factors may have influenced the decision in such cases.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

The impact of FPL's DSM Programs on demand and energy consumption are revised periodically. Engineering models, calibrated with field-metered data, are updated when significant efficiency changes occur in the marketplace. Participation trends are tracked for all the FPL programs in order to adjust impacts each year for changes in the mix of efficiency measure being installed by program participants.

Survey data is collected from non-participants in order to establish the baseline efficiency. Participant data is compared against non-participant data to establish the demand and energy saving benefits of the utility program versus what would be installed in the absence of the program. Finally, FPL is careful to only claim program savings for the average life of the installed efficiency measure. For these DSM measures which involve the utilization of load management, FPL conducts periodic tests of the load control equipment to ensure that it is functioning correctly.

Discussion Item # 10: **Discuss how strategic concerns are incorporated in the planning process.**

The strategic or non-price factors FPL considers when choosing between resource 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 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 an FPL self-build option and buying power, the strategic or 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 not "fully committed" to serving retail load might fact 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. 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' 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 construct capacity or to purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As has been discussed, the near - term elements of FPL's capacity additions are the repowering of its Fort Myers and Sanford plants, the addition of new combustion turbines (CT's) at Fort Myers, and a number of firm capacity, short-term purchases. The incremental capacity from the two repowering projects comes from the addition of new CT's and heat recovery steam generators (HRSG's). FPL acquired the repowering-related CT's, plus the other CT's for Fort Myers, and the HRSG's through a bid process which combined cost and performance considerations. The firm capacity short-term purchases were acquired through negotiations.

The 2005 capacity addition decision was arrived at after evaluating 81 bids received in response to a capacity Request for Proposals (RFP) issued by FPL in mid-2001. (Please see Section III for a further discussion of the RFP effort.)

The later (2007 – on) capacity additions projected in FPL's Site Plan document will likely be carried out following the issuance of a similar capacity solicitation to potential suppliers at an appropriate time, if that approach represents the best vehicle to offer the lowest cost new generating capacity.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL's plans do not include any new or upgraded transmission lines during the 2002 – 2011 time period which would need to be certified under the Transmission Line Siting Act (403.52 – 403.536, F.S.)

CHAPTER VI

Summary of Required Schedules

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Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt					
						Fuel		Fuel	Commercial	Expected	Gen Max	Net Capability 1/	
	Unit		Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Use	Month/Year	Month/Year	KW	MW	MW
Turkey Point		Dade County 27/57S/40E									2,338,100	2,198	2,253
	1		ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	400	404
	2		ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	400	403
	3		NP	UR	No	TK	No	Unknown	Nov-72	Unknown	760,000	693	717
	4		NP	UR	No	TK	No	Unknown	Jun-73	Unknown	760,000	693	717
	1-5		IC	FO2	No	TK	No	Unknown	Dec-67	Unknown	14,000	12	12
Cutler		Dade County 27/55S/40E									236,500	213	216
	5		ST	NG	No	PL	No	Unknown	Nov-54	Unknown	74,500	71	71
	6		ST	NG	No	PL	No	Unknown	Jul-55	Unknown	162,000	142	145
Lauderdale		Broward County 30/50S/42E									1,863,972	1,694	1,804
	4		CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	521,250	425	443
	5		CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	521,250	429	447
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,736	420	457
	13-24		CT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,736	420	457
Port Everglades		City of Hollywood 23/50S/42E									1,665,086	1,660	1,701
	1		ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	221	222
	2		ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,000	221	222
	3		ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	390	392
	4		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	408	408
	1-12		CT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,736	420	457
Riviera		City of Riviera Beach 33/42S/43E									620,840	567	569
	3		ST	FO6	NG	WA	PL	Unknown	Jun-62	Unknown	310,420	283	283
	4		ST	FO6	NG	WA	PL	Unknown	Mar-63	Unknown	310,420	284	286

1/ These ratings are peak capability.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Martin		Martin County 29/29S/38E									3,312,000	2,846	2,979
	1		ST	NG	FO6	PL	PL	Unknown	Dec-80	Unknown	863,000	814	826
	2		ST	NG	FO6	PL	PL	Unknown	Jun-81	Unknown	863,000	799	812
	3		CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	467	489
	4		CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	468	490
	8 A & B		CT	NG	FO2	PL	PL	Unknown	Jun-01	Unknown	362,000	298	362
St Lucie		St Lucie County 16/36S/41E									1,553,000	1,553	1,579
	1		NP	UR	No	TK	No	Unknown	May-76	Unknown	839,000	839	853
	2	2/	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	714,000	714	726
Cape Canaveral		Brevard County 19/24S/36F									804,100	806	812
	1		ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	403	406
	2		ST	FO6	NG	WA	PL	Unknown	May-69	Unknown	402,050	403	406
Sanford		Volusia County 16/19S/30E									1,022,450	532	528
	3		ST	FO6	NG	WA	PL	Unknown	May-59	Unknown	150,250	142	144
	4		ST	FO6	NG	WA	PL	Unknown	Jul-72	Unknown	436,100	390	384
	5	3/	ST	FO6	No	WA	No	Unknown	Jul-73	Unknown	436,100	0	0
Putnam		Putnam County 16/10S/27E									580,000	498	520
	1		CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,000	249	260
	2		CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,000	249	260

1/ These ratings are peak capability.
2/ Total capability is 839/853 MW. Capabilities shown represent the company's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of 14.89551%.
3/ This unit was removed from service as part of the repowering project.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1) Plant Name	(2) Unit No	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen.Max Nameplate KW	(13) Net Capability 1/ Summer MW	(14) Net Capability 1/ Winter MW
Fort Myers		Lee County 35/43S/25E									2,388,250	1,530	1,668
	1	4/	ST	FO6	No	WA	No	Unknown	Nov-58	Unknown	156,250	0	0
	2	4/	ST	FO6	No	WA	No	Unknown	Jul-69	Unknown	402,000	0	0
	1-12		CT	FO2	No	WA	No	Unknown	May-74	Unknown	744,000	636	690
	Repowering CT A		CT	NG	FO2	PL	PL	Unknown	Oct-00	Unknown	181,000	149	163
	Repowering CT B		CT	NG	FO2	PL	PL	Unknown	Nov-00	Unknown	181,000	149	163
	Repowering CT C		CT	NG	FO2	PL	PL	Unknown	Dec-00	Unknown	181,000	149	163
	Repowering CT D		CT	NG	FO2	PL	PL	Unknown	Apr-01	Unknown	181,000	149	163
	Repowering CT E		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
	Repowering CT F		CT	NG	FO2	PL	PL	Unknown	May-01	Unknown	181,000	149	163
Manatee		Manatee County 18/33S/20E									1,726,600	1,619	1,633
	1		ST	FO6	No	WA	No	Unknown	Oct-76	Unknown	863,300	809	816
	2		ST	FO6	No	WA	No	Unknown	Dec-77	Unknown	863,300	810	817
St. Johns River Power Park 2/		Duval County 12/15/28E (RPC4)									250,000	254	260
	1		BIT	BIT	No	RR	No	Unknown	Mar-87	Unknown	125,000	127	130
	2		BIT	BIT	No	RR	No	Unknown	May-88	Unknown	125,000	127	130
Scherer 3/		Monroe, GA									891,000	658	666
	4		BIT	BIT	No	RR	No	Unknown	Jul-89	Unknown	891,000	658	666
									Total System as of December 31, 2001 =			16,628	17,188

1/ These ratings are peak capability
2/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80% ; SJRPP receives coal by water (WA) in addition to rail.
3/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.
4/ These units were removed from service as part of the repowering project.

Schedule 2.1
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Year	Population*	Members per Household	GWH	Average** No. of Customers	Average KWH Consumption Per Customer	GWH	Average** No. of Customers	Average KWH Consumption Per Customer
1992	6,375,204	2.19	34,198	2,911,807	11,745	26,991	350,269	77,058
1993	6,486,127	2.18	36,360	2,975,479	12,220	28,508	358,679	79,481
1994	6,660,137	2.19	38,716	3,037,629	12,745	29,946	366,409	81,729
1995	6,806,337	2.20	40,556	3,097,192	13,094	30,719	374,005	82,135
1996	6,948,942	2.20	41,302	3,152,625	13,101	31,211	380,860	81,949
1997	7,105,582	2.21	41,849	3,209,298	13,040	32,942	388,906	84,703
1998	7,249,617	2.22	45,482	3,266,011	13,926	34,618	396,749	87,255
1999	7,412,734	2.22	44,187	3,332,422	13,260	35,524	404,942	87,725
2000	7,603,543	2.23	46,320	3,414,002	13,568	37,001	415,295	89,096
2001	7,749,031	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,891,055	2.22	49,065	3,552,211	13,813	38,360	433,999	88,387
2003	8,029,615	2.22	51,340	3,616,387	14,196	39,745	444,604	89,395
2004	8,164,713	2.22	53,568	3,676,476	14,570	40,913	456,688	89,587
2005	8,296,344	2.22	55,902	3,739,451	14,949	42,018	468,420	89,702
2006	8,433,429	2.22	58,241	3,801,791	15,319	43,210	479,587	90,098
2007	8,570,515	2.22	59,857	3,858,417	15,513	44,317	488,478	90,724
2008	8,709,688	2.23	61,401	3,912,926	15,692	45,391	497,099	91,313
2009	8,850,948	2.23	62,961	3,966,369	15,874	46,461	505,533	91,905
2010	8,992,209	2.24	64,628	4,018,926	16,081	47,571	513,718	92,602
2011	9,134,785	2.24	66,282	4,070,702	16,283	48,478	521,756	92,913

* Population represents only the area served by FPL

** Average No of Customers is the annual average of the twelve month values.

Schedule 2.2
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial						
Year	GWH	Average* No of Customers	Average KWH Consumption Per Customer	Railroads & Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total** Sales to Ultimate Consumers GWH
1992	4,054	14,788	274,135	77	353	721	66,393
1993	3,889	14,866	261,602	79	330	665	69,830
1994	3,845	15,588	246,658	85	353	664	73,608
1995	3,883	15,140	256,481	84	358	648	76,248
1996	3,792	14,783	256,515	83	368	577	77,334
1997	3,894	14,761	263,830	85	383	702	79,855
1998	3,951	15,126	261,233	81	373	625	85,131
1999	3,948	16,040	246,112	79	473	465	84,676
2000	3,768	16,410	229,592	81	408	381	87,959
2001	4,091	15,445	264,872	86	419	67	90,212
2002	3,947	15,147	260,552	81	417	61	91,930
2003	3,960	15,176	260,942	81	428	60	95,615
2004	3,969	15,143	262,106	82	438	60	99,030
2005	3,971	15,105	262,875	82	446	60	102,479
2006	3,977	15,077	263,746	83	455	60	106,024
2007	3,974	15,122	262,795	83	461	60	108,752
2008	3,956	15,168	260,821	83	468	60	111,360
2009	3,933	15,213	258,530	84	474	60	113,973
2010	3,912	15,259	256,386	84	481	60	116,736
2011	3,891	15,305	254,215	85	487	60	119,282

*Average No.of Customers is the annual average of the twelve month values.
**GWH=Column 4 + Column 7 + Column 10 + Column 13 + Column 14 + Column 15.

Schedule 2.3
History and Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net* Energy For Load GWH	Average ** No. of Other Customers	Total Average*** Number of Customers
1992	702	6,002	73,097	4,374	3,281,238
1993	958	4,988	75,776	3,086	3,352,110
1994	1,400	5,367	80,376	2,560	3,422,187
1995	1,437	6,276	83,961	2,460	3,488,796
1996	1,353	5,984	84,671	2,480	3,550,748
1997	1,228	5,770	86,853	2,520	3,615,485
1998	1,326	6,205	92,662	2,584	3,680,470
1999	953	5,829	91,458	2,605	3,756,009
2000	970	7,059	95,989	2,694	3,848,401
2001	970	7,222	98,404	2,722	3,935,281
2002	1,207	7,021	100,158	2,805	4,004,161
2003	1,425	7,373	104,414	2,872	4,079,038
2004	1,446	7,567	108,042	2,931	4,151,237
2005	1,463	7,831	111,772	2,985	4,225,960
2006	1,482	8,097	115,602	3,036	4,299,491
2007	1,415	7,990	118,157	3,077	4,365,095
2008	1,081	8,108	120,549	3,116	4,428,309
2009	1,081	7,869	122,922	3,155	4,490,271
2010	1,081	7,631	125,448	3,193	4,551,096
2011	1,081	7,149	127,512	3,231	4,610,993

* GWH = Column 16 + Column 17 + Column 18

** Average Number of Customers is the annual average of the twelve month values.

*** Total = Column 5 + Column 8 + Column 11 + Column 20

Schedule 3.1
History and Forecast of Summer Peak Demand: Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1992	14,661	223	14,438	0	234	151	248	51	14,179
1993	15,266	397	14,869	0	311	182	320	79	14,635
1994	15,179	409	14,770	0	392	220	354	125	14,433
1995	16,172	435	15,737	0	466	259	391	193	15,315
1996	16,064	364	15,700	0	531	339	414	296	15,119
1997	16,613	380	16,233	0	615	440	432	341	15,566
1998	17,897	426	17,471	0	656	480	441	359	16,800
1999	17,615	169	17,446	0	722	565	450	397	16,443
2000	17,808	161	17,647	0	767	626	456	432	16,585
2001	18,754	169	18,585	0	798	673	483	463	17,473
2002	19,131	146	18,985	0	805	83	487	39	17,717
2003	19,765	223	19,542	0	810	125	497	59	18,274
2004	20,226	225	20,002	0	817	167	507	79	18,656
2005	20,719	227	20,493	0	824	211	517	99	19,068
2006	21,186	227	20,959	0	829	255	525	120	19,457
2007	21,556	227	21,329	0	834	300	533	140	19,749
2008	21,870	152	21,718	0	839	347	541	159	19,984
2009	22,271	152	22,119	0	842	394	547	179	20,309
2010	22,687	152	22,535	0	844	410	548	185	20,700
2011	23,106	152	22,954	0	844	410	548	185	21,119

Historical Values (1992 - 2001):

Cols. (2) - (4) are actual values for historical summer peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD-LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002 - 2011):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col (10) is derived by using the formula: (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 3.2
History and Forecast of Winter Peak Demand:Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
1992/93	12,964	102	12,862	0	242	195	275	48	12,447
1993/94	12,594	278	12,316	0	317	231	342	67	11,935
1994/95	16,563	635	15,928	0	393	265	360	93	15,810
1995/96	18,096	698	17,398	0	459	310	406	143	17,231
1996/97	16,490	626	15,864	0	731	368	418	154	15,341
1997/98	13,060	239	12,821	0	823	403	429	168	11,807
1998/99	16,802	149	16,653	0	1,218	438	417	182	15,167
1999/00	17,057	142	16,915	0	1,296	469	441	193	15,320
2000/01	18,199	150	18,049	0	972	493	448	201	16,779
2001/02	17,597	145	17,452	0	1,081	534	489	242	16,028
2002/03	19,551	121	19,430	0	1,085	78	458	22	17,908
2003/04	19,976	198	19,779	0	1,093	104	464	30	18,285
2004/05	20,418	199	20,218	0	1,102	128	470	38	18,680
2005/06	20,854	199	20,654	0	1,109	153	476	48	19,068
2006/07	21,204	199	21,005	0	1,116	177	481	57	19,373
2007/08	21,538	124	21,414	0	1,123	200	486	66	19,663
2008/09	21,966	124	21,841	0	1,129	223	491	75	20,048
2009/10	22,366	124	22,242	0	1,134	245	494	82	20,411
2010/11	22,785	124	22,661	0	1,134	245	494	82	20,830

Historical Values (1992/93 - 2001/02):

Cols. (2) - (4) are actual values for historical winter peaks. As such, they incorporate the effects of conservation (Cols. (7&9)), and may incorporate the effects of load control if load control was operated on these peak days Therefore, Col. (2) represents the actual Net Firm Demand.
Cols. (5) - (9) represent actual DSM capabilities starting from January 1988.
Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes GS-LC, CDR and GSD - LC.
Col. (10) represents a HYPOTHETICAL "Net Firm Demand" if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: (10) = (2) -(6) -(8).

Projected Values (2002/03 - 2010/11):

Cols. (2) - (4) represent FPL's forecasted peak w/o incremental conservation or cumulative load control. The effects of conservation implemented prior to 2001 are incorporated into the forecast.
Cols. (5) - (9) represent all incremental conservation and cumulative load control. These values are projected August values and are based on projections with a 1/2001 starting point.
Col (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula. (10) = (2) - (5) - (6) - (7) - (8) - (9).

Schedule 3.3
History and Forecast of Annual Net Energy for Load - GWH: Base Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C/I Conservation	(5) Retail	(6) Sales for Resale GWH	(7) Utility Use & Losses	(8) Net Energy For Load	(9) Load Factor(%)
1992	73,778	460	221	73,076	702	6,002	73,097	56.8%
1993	76,632	553	303	75,674	958	4,988	75,776	56.7%
1994	81,493	661	456	80,093	1,400	5,367	80,376	60.4%
1995	85,415	777	677	83,978	1,437	6,276	83,961	59 3%
1996	86,708	971	1,039	85,355	1,353	5,984	84,698	60.0%
1997	89,240	1,213	1,174	88,012	1,228	5,770	86,853	59.7%
1998	95,316	1,374	1,279	93,990	1,326	6,205	92,663	59.1%
1999	94,361	1,542	1,362	93,408	953	5,829	91,458	59.3%
2000	99,094	1,674	1,431	98,123	970	7,059	95,989	61.5%
2001	101,736	1,789	1,542	100,765	970	7,222	98,404	59.9%
2002	100,158	58	15	98,951	1,207	7,021	100,085	59.8%
2003	104,414	156	47	102,988	1,425	7,373	104,211	60.3%
2004	108,042	256	80	106,597	1,446	7,567	107,706	61.0%
2005	111,772	358	115	110,310	1,463	7,831	111,299	61.6%
2006	115,602	462	150	114,121	1,482	8,097	114,990	62.3%
2007	118,157	568	184	116,743	1,415	7,990	117,405	62.6%
2008	120,549	675	216	119,468	1,081	8,108	119,658	62.9%
2009	122,922	785	247	121,842	1,081	7,869	121,890	63.0%
2010	125,448	830	262	124,367	1,081	7,631	124,356	63.1%
2011	127,512	830	262	126,432	1,081	7,149	126,420	63.0%

Historical Values (1992 - 2001):

Col. (2) represents derived "Total Net Energy For Load w/o DSM". The values are calculated using the formula· (2) =(3) + (4) + (8).
Cols. (3) & (4) are DSM values starting in January, 1988 through 2001 which contributed to the values in Cols. (5) - (9).
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) into Retail and Wholesale .
Col (9) is calculated using Col. (8) from this page and Col. (2), "Total", from Schedule 3.1. (9) = ((8)*1000) / ((2) * 8760)

Projected Values (2002 - 2011):

Col. (2) represents Net Energy for Load w/o DSM values. The values are calculated using the formula: (2) =(3) + (4) + (8)
Cols. (3) - (4) are forecasted values of the reduction on sales from incremental conservation.
Cols. (5) & (6) are a breakdown of Net Energy For Load in Col (2) , into Wholesale and Retail .
Col (9) is calculated using Col. (2) from this page and Col. (2), "Total", from Schedule 3.1. (9) = ((8)*1000) / ((2) * 8760)

Schedule 4
Previous Year Actual and Two-Year Forecast of
Retail Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2001 ACTUAL		2002 * FORECAST		2003 * FORECAST	
Month	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH	Total Peak Demand MW	NEL GWH
JAN	18,199	8,074	18,968	7,375	19,551	7,708
FEB	13,268	6,541	16,070	6,859	16,563	7,190
MAR	14,611	7,442	14,353	7,368	14,793	7,703
APR	15,831	7,797	15,645	7,683	16,163	8,020
MAY	16,280	7,722	17,373	8,442	17,948	8,810
JUN	18,342	9,476	18,218	9,299	18,821	9,690
JUL	17,803	9,120	18,727	9,710	19,347	10,110
AUG	18,754	10,086	19,131	9,881	19,765	10,263
SEP	18,707	9,413	18,494	9,608	19,107	9,982
OCT	15,971	8,185	17,266	8,578	17,837	8,927
NOV	13,781	7,217	15,721	7,737	16,204	8,068
DEC	14,590	7,331	16,317	7,618	16,818	7,942
TOTALS		98,404		100,158		104,414

* Forecasted Peaks & NEL do not include the impacts of cumulative load management and incremental conservation.

Schedule 5
Fuel Requirements [1/]

	Fuel Requirements	Units	Actual [2/] 2000	2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear	Trillion BTU	268	263	263	258	258	263	258	257	264	258	257	263
(2)	Coal	1,000 TON	4,170	3,078	3,460	3,584	3,416	3,396	3,479	3,194	3,513	3,110	3,113	3,281
(4)	Residual (FO6)- Total	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(5)	Steam	1,000 BBL	36,859	40,995	57,569	26,714	23,538	20,417	18,661	17,222	16,514	11,535	9,609	7,905
(6)	Distillate (FO2)- Total	1,000 BBL	461	381	538	2,750	4,114	799	792	537	612	20	9	5
(7)	CC	1,000 BBL	1	75	124	2,220	3,404	683	677	486	549	10	3	3
(8)	CT	1,000 BBL	446	306	415	529	711	116	115	51	63	11	6	2
(9)	Steam	1,000 BBL	14	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	1,000 MCF	203,234	212,956	297,272	303,963	308,493	362,745	406,236	434,737	445,987	495,736	555,295	594,673
(11)	Steam	1,000 MCF	80,967	79,157	80,432	17,368	20,648	16,698	17,897	15,280	17,064	10,769	7,970	6,199
(12)	CC	1,000 MCF	117,684	109,778	196,898	274,488	277,953	337,081	384,738	414,787	424,908	482,040	546,027	587,265
(13)	CT	1,000 MCF	4,583	24,022	19,942	12,107	9,891	8,966	3,601	4,670	4,015	2,927	1,298	1,209

1/ Reflects fuel requirements for FPL only

2/ Source A Schedules

Schedule 6.1
Energy Sources

	Energy Sources	Units	Actual 2000	Actual 2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Energy Interchange 2/	GWH	7,443	7,701	8,061	7,912	7,973	7,832	7,645	7,573	7,605	7,371	2,873	0
(2)	Nuclear	GWH	24,584	24,070	24,284	23,873	23,845	24,284	23,873	23,776	24,344	23,857	23,776	24,274
(3)	Coal	GWH	6,977	6,267	6,503	6,674	6,396	6,396	6,514	6,071	6,577	5,901	5,900	6,187
(4)	Residual(FO6) -Total	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(5)	Steam	GWH	23,230	25,802	9,861	11,881	14,885	12,943	11,813	10,922	10,453	7,349	6,109	5,045
(6)	Distillate(FO2) -Total	GWH	193	163	278	1,979	2,979	592	581	408	461	13	5	3
(7)	CC	GWH	1	41	101	1,681	2,588	536	529	387	433	8	2	2
(8)	CT	GWH	183	122	177	298	391	55	52	22	28	5	3	1
(9)	Steam	GWH	9	0	0	0	0	0	0	0	0	0	0	0
(10)	Natural Gas -Total	GWH	24,217	24,496	40,313	41,995	41,809	49,873	56,309	60,446	62,208	69,722	78,684	84,556
(11)	Steam	GWH	7,840	7,588	11,524	2,340	1,881	1,527	1,643	1,402	1,577	996	734	569
(12)	CC	GWH	16,064	14,849	26,923	38,510	38,989	47,498	54,339	58,611	60,259	68,450	77,830	83,874
(13)	CT	GWH	313	2,060	1,866	1,144	940	848	327	433	372	275	120	113
(14)	Other 3/	GWH	9,345	9,905	10,858	10,101	10,155	9,852	8,867	8,961	8,901	8,710	8,101	7,446
	Net Energy For Load 4/	GWH	95,989	98,404	100,158	104,414	108,042	111,772	115,602	118,157	120,549	122,922	125,448	127,512

1/ Source: A Schedules.

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

4/ Net Energy For Load is Column 2 on Schedule 3.3 and Column 1 on EIA411 Form 11C.

Schedule 6.2
Energy % by Fuel Type

	Energy Source	Units	Actual 2000	Actual 2001	Forecasted 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Energy Interchange 2/	%	7.8	8.0	8.0	7.6	7.4	7.0	6 6	6 4	6 3	6.0	2.3	0 0
(2)	Nuclear	%	25.6	24.5	24.2	22 9	22.1	21.7	20 7	20 1	20.2	19.4	19.0	19 0
(3)	Coal	%	7 3	6 4	6.5	6.4	5.9	5.7	5.6	5.1	5.5	4.8	4.7	4.9
(4)	Residual (FO6) -Total	%	24.2	26.2	9.8	11.4	13.8	11.6	10.2	9.2	8.7	6.0	4.9	4.0
(5)	Steam	%	24.2	26.2	9.8	11.4	13.8	11.6	10 2	9.2	8.7	6 0	4.9	4.0
(6)	Distillate (FO2) -Total	%	0.2	0.2	0.3	1.9	2.8	0.5	0.5	0.3	0.4	0.0	0.0	0.0
(7)	CC	%	0 0	0.0	0.1	1.6	2.4	0.5	0.5	0.3	0.4	0.0	0.0	0.0
(8)	CT	%	0.2	0.1	0.2	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Steam	%	0 0	0.0	0 0	0.0	0.0	0.0	0 0	0 0	0 0	0.0	0.0	0.0
(10)	Natural Gas -Total	%	25.2	24.9	40.2	40.2	38.7	44.6	48.7	51.2	51.6	56.7	62.7	66.3
(11)	Steam	%	8.2	7.7	11.5	2.2	1.7	1.4	1.4	1.2	1.3	0.8	0.6	0.4
(12)	CC	%	16 7	15.1	26.9	36.9	36.1	42.5	47.0	49.6	50.0	55.7	62.0	65.8
(13)	CT	%	0.3	2.1	1.9	1.1	0.9	0.8	0.3	0.4	0.3	0.2	0.1	0.1
(14)	Other 3/	%	9.7	10.1	10.8	9.7	9.4	8.8	7.7	7.6	7.4	7.1	6.5	5.8
			100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules

2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies.

3/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2002	17,860	2,403	0	877	21,140	19,131	1,414	17,717	3,423	19.3	0	3,423	19.3
2003	19,135	2,474	0	877	22,486	19,765	1,491	18,274	4,212	23.0	0	4,212	23.0
2004	19,135	2,474	0	877	22,486	20,226	1,570	18,656	3,830	20.5	0	3,830	20.5
2005	21,031	1,758	0	867	23,656	20,719	1,651	19,068	4,588	24.1	0	4,588	24.1
2006	21,031	1,757	0	734	23,522	21,186	1,729	19,457	4,065	20.9	0	4,065	20.9
2007	22,138	1,310	0	734	24,182	21,556	1,807	19,749	4,433	22.4	0	4,433	22.4
2008	22,138	1,310	0	734	24,182	21,870	1,886	19,984	4,198	21.0	0	4,198	21.0
2009	23,245	1,310	0	683	25,238	22,271	1,962	20,309	4,929	24.3	0	4,929	24.3
2010	24,352	382	0	639	25,373	22,687	1,987	20,700	4,673	22.6	0	4,673	22.6
2011	25,459	382	0	594	26,435	23,106	1,987	21,119	5,316	25.2	0	5,316	25.2

1/ Capacity additions and changes projected to be in-service by June 1st are considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. All values are Summer net MW.

2/ Total Capacity Available=Col (2) + Col (3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation from 1/99 - on. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based.

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance =Col.(13) / Col.(9)

Schedule 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Year	Total Installed 1/ Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Capacity Available 2/ MW	Total Peak 3/ Demand MW	DSM 4/ MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance 5/ MW	Reserve Margin Before Maintenance 5/ % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance 6/ MW	Reserve Margin After Maintenance 6/ % of Peak
2001/02	17,730	1,910	0	886	20,526	18,968	1,589	17,379	3,147	18.1	0	3,147	18.1
2002/03	20,007	2,634	0	877	23,518	19,551	1,643	17,908	5,610	31.3	0	5,610	31.3
2003/04	20,369	2,673	0	877	23,919	19,976	1,691	18,285	5,634	30.8	0	5,634	30.8
2004/05	20,369	2,623	0	867	23,859	20,418	1,738	18,680	5,179	27.7	0	5,179	27.7
2005/06	22,402	1,860	0	734	24,996	20,854	1,786	19,068	5,928	31.1	0	5,928	31.1
2006/07	22,402	1,860	0	734	24,996	21,204	1,831	19,373	5,623	29.0	0	5,623	29.0
2007/08	23,598	1,317	0	734	25,649	21,538	1,875	19,663	5,986	30.4	0	5,986	30.4
2008/09	23,598	1,317	0	734	25,649	21,966	1,918	20,048	5,601	27.9	0	5,601	27.9
2009/10	24,795	1,317	0	683	26,795	22,366	1,955	20,411	6,384	31.3	0	6,384	31.3
2010/11	25,992	389	0	595	26,976	22,785	1,955	20,830	6,146	29.5	0	6,146	29.5

1/ Capacity additions and changes projected to be in-service by January 1st are considered to be available to meet Winter peak loads which are forecast to occur during January of the "second" year indicated. All values are Winter net MW.

2/ Total Capacity Available = Col.(2) + Col.(3) - Col.(4) + Col.(5).

3/ These forecasted values reflect the Most Likely forecast without DSM.

4/ The MW shown represent cumulative load management capability plus incremental conservation. They are not included in total additional resources but reduce the peak load upon which Reserve Margin calculations are based

5/ Margin (%) Before Maintenance = Col.(10) / Col.(9)

6/ Margin (%) After Maintenance = Col.(13) / Col.(9)

Schedule 8
Planned And Prospective Generating Facility Additions And Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter	Summer	
Plant Name	No	Location	Type	Pri.	Alt	Pri	Alt	Mo./Yr	Mo./Yr.	Mo./Yr	KW	MW	MW	Status
ADDITIONS														
2002														
—		—	—	—	—	—	—	—	—	—	—	—	—	—
2003														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	Apr-03	Unknown	190,000	—	159	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	May-03	Unknown	190,000	—	159	P
2004														
Fort Myers Combustion Turbines	13	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-02	Apr-03	Unknown	190,000	181	—	P
Fort Myers Combustion Turbines	14	Lee County 35/43S/25E	CT	NG	FO2	PL	PL	Apr-00	May-03	Unknown	190,000	181	—	P
2005														
Manatee Combined Cycle Unit	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	—	1,107	P
2006														
Manatee Combined Cycle Unit	3	Manatee County 18/33S/20E	CC	NG	FO2	PL	PL	Jun-02	Jun-05	Unknown	470,000	1,197	—	P
2007														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	—	1,107	P
2008														
Unsited Combined Cycle Unit #1	1	Unknown	CC	NG	FO2	PL	PL	Jan-04	Jun-07	Unknown	470,000	1,197	—	P
2009														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	—	1,107	P
2010														
Unsited Combined Cycle Unit #2	2	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-09	Unknown	470,000	1,197	—	P
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-10	Unknown	470,000	—	1,107	P
2011														
Unsited Combined Cycle Unit #3	3	Unknown	CC	NG	FO2	PL	PL	Jan-06	Jun-10	Unknown	470,000	1,197	—	P
Unsited Combined Cycle Unit #4	4	Unknown	CC	NG	FO2	PL	PL	Jan-07	Jun-11	Unknown	470,000	—	1,107	P

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm	Expected	Gen. Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter [1) 2)]	Summer [1), 2)]	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr.	Mo /Yr.	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2002														
Sanford Repowering Initial Phase [3)]	4	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Mar-02	----	Unknown	106,600	0	(390) [4)]	RP
Sanford Repowering Initial Phase	5	Volusia County 16/19S/30E	ST	FO6	NG	WA	PL	Oct-01	----	Unknown	106,600	(390) [4)]	0	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	May-02	Jul-02	Unknown	106,600	0	567	RP
Ft. Myers Repowering Second Phase	1&2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-01	Jan-02	Unknown	161,700	(1)	35	RP,U
Riviera	4	City of Riviera Beach 33/42S/43E	ST	FO6	NG	WA	PL	Nov-01	Jan-02	Unknown	310,420	10	10	P
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	—	10	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	—	10	P
											2002 Total:	**(381)**	**242**	
2003														
Sanford Repowering Second Phase	4	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	675	957	RP
Sanford Repowering Second Phase	5	Volusia County 16/19S/30E	CC	NG	No	PL	No	Sep-02	Dec-02	Unknown	106,600	1,065	0	RP
Ft. Myers Repowering Second Phase	1 & 2	Lee County 35/43S/25E	CC	NG	No	PL	No	Nov-02	Jan-03	Unknown	161,700	531	0	RP,U
Martin Combustion Turbines	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	—	P
Martin Combustion Turbines	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-02	Jun-02	Unknown	190,000	10	—	P
											2003 Total:	**2,291**	**957**	
2004														
----------		----------	—	—	—	—	—	—	—	—	—	—	—	—
											2004 Total:	**0**	**0**	
2005														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	—	394 5	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	—	394.5	P
											2005 Total:	**0**	**789**	

1)The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by July All other MW will be picked up in the following year This is done for reserve margin calculation

2) All MW differences are calculated based on using IRP 2001 Submittal (for the year 2001) as the base for all other years

3) The values shown reflect the schedule for the repowering of Sanford Unit # 4 that was used in FPL's 2001 resource planning work. That schedule has recently changed. Please refer to Section III A, "Step 1" for more information

4) Negative values for Sanford and Ft. Myers reflect the existing steam units being temporarily out of service during that seasonal period for repowering efforts

Schedule 8
Planned And Prospective Generating Facility Additions And Changes (Cont.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const	Comm	Expected	Gen Max	Net Capability		
	Unit		Unit					Start	In-Service	Retirement	Nameplate	Winter 1)	Summer 1)	
Plant Name	No	Location	Type	Pri	Alt	Pri	Alt	Mo /Yr	Mo /Yr	Mo /Yr	KW	MW	MW	Status
CHANGES/UPGRADES														
2006														
Martin Combustion Turbine Conversion	8A	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417.5	—	P
Martin Combustion Turbine Conversion	8B	Martin County 29/29S/38E	CT	NG	FO2	PL	PL	Apr-05	Jun-05	Unknown	190,000	417.5	—	P
											2006 Total:	835	0	
2007														
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
											2007 Total:	0	0	
2008														
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
											2008 Total:	0	0	
2009														
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
											2009 Total:	0	0	
2010														
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
											2010 Total:	0	0	
2011														
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
											2011 Total:	0	0	

1)The Winter Total MW value consists of all generation additions and changes achieved by January The Summer Total MW value consists of all generation additions and changes achieved by July. All other MW will be picked up in the following year This is done for reserve margin calculation.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Repowering
(2)	**Capacity**		
	a. Summer	929	MW Incremental (1473 MW Total After Repowering)
	b. Winter	1,073	MW Incremental (1617 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	1999	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Once-through Cooling w/ Helper Cooling Tower
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	Approx. 90%	(First Year)
Average Net Operating Heat Rate (ANOHR):	6,830	Btu/kWh

(13) **Projected Unit Financial Data, *,**,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	559	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001$/kW-Yr)	13.45	
Variable O&M ($/MWH): (2001 $/MWH)	0.37	
K Factor:	1.5395	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 4 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	U	(Under Construction ≤ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction ≤ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction ≤ 50% Complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	Approx. 96%	(First Year)
Average Net Operating Heat Rate (ANOHR):	6,918	Btu/kWh

(13) **Projected Unit Financial Data *,**,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	656	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	14.41	
Variable O&M ($/MWH): (2001 $/MWH)	0.374	
K Factor:	1.4637	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Sanford Unit 5 Repowering
(2)	**Capacity**		
	a. Summer	567	MW Incremental (957 MW Total After Repowering)
	b. Winter	671	MW Incremental (1065 MW Total After Repowering)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2000	
	b. Commercial In-service date:	2002	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	1,718	Acres
(9)	**Construction Status:**	V	(Under Construction > 50% Complete)
(10)	**Certification Status:**	V	(Under Construction > 50% Complete)
(11)	**Status with Federal Agencies:**	V	(Under Construction > 50% Complete)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	96%	
Resulting Capacity Factor (%):	Approx. 96%	(First Year)
Average Net Operating Heat Rate (ANOHR):	6,918	Btu/kWh

(13) **Projected Unit Financial Data *,**,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	656	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	14.41	
Variable O&M ($/MWH): (2001 $/MWH)	0.374	
K Factor:	1.5395	

* $/kW values are based on incremental Summer capacity.
** Note that cost values shown do not reflect the FPL system benefits which result from efficiency improvements to the existing steam capacity at the site.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Fort Myers Combustion Turbines No. 13 and No. 14 *
(2)	**Capacity**		
	a. Summer	159	MW each for a total of 318 MW
	b. Winter	181	MW each for a total of 362 MW
(3)	**Technology Type:**		Combustion Turbine
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2001	
	b. Commercial In-service date:	2003	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NOx Combustors, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Air Coolers
(8)	**Total Site Area:**	460	Acres
(9)	**Construction Status:**	U	(Under Construction ≤ 50% Complete)
(10)	**Certification Status:**	U	(Under Construction ≤ 50% Complete)
(11)	**Status with Federal Agencies:**	U	(Under Construction ≤ 50% Complete)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	1%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	98%	
	Resulting Capacity Factor (%):	Approx. 25%	(First Year)
	Average Net Operating Heat Rate (ANOHR):	10,430	Btu/kWh
(13)	**Projected Unit Financial Data **,*****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	414	per Combustion Turbine
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	0.69	
	Variable O&M ($/MWH): (2001 $/MWH)	0.87	
	K Factor:	1.5394	

* Values shown are per unit values for the two units being added.
** $/kW values are based on Summer capacity.
*** Fixed O&M includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Martin Combustion Turbine Conversion to Combined Cycle
(2)	**Capacity**		
	a. Summer	789	MW Incremental (1107 MW Total)
	b. Winter	835	MW Incremental (1197 MW Total)
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**		Cooling Pond/Tower
(8)	**Total Site Area:**	11,300	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)

(12) **Projected Unit Performance Data ***

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 80%	(First Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
Base Operation 75F	100%	

(13) **Projected Unit Financial Data **,*****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	599	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	9.07	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5397	

* Values represent an operational combined cycle unit after the conversion is completed.
** $/kW values are based on Summer incremental capacity.
*** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**		Manatee Combined Cycle
(2)	**Capacity**		
	a. Summer	1,107	MW
	b. Winter	1,197	MW
(3)	**Technology Type:**		Combined Cycle
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2003	
	b. Commercial In-service date:	2005	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		None
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR
(7)	**Cooling Method:**		Cooling Pond
(8)	**Total Site Area:**	9,500	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	L	(Regulatory Approval Pending)
(11)	**Status with Federal Agencies:**	L	(Regulatory Approval Pending)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	2%	
	Forced Outage Factor (FOF):	1%	
	Equivalent Availability Factor (EAF):	97%	
	Resulting Capacity Factor (%):	Approx. 71%	(First Year Base Operation)
	Average Net Operating Heat Rate (ANOHR):	6,850	Btu/kWh
	Base Operation 75F	100%	
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):	25	years
	Total Installed Cost (In-Service Year $/kW):	511	
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	12.96	
	Variable O&M ($/MWH): (2001 $/MWH)	0.037	
	K Factor:	1.5397	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 1	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2005	
	b. Commercial in-service date:	2007	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 65%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	568	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5399	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Combined Cycle No. 2

(2) **Capacity**
a. Summer 1,107 MW
b. Winter 1,197 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2007
b. Commercial In-service date: 2009

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Unknown

(8) **Total Site Area:** Unknown Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 60%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25	years
Total Installed Cost (In-Service Year $/kW):	587	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):		
Escalation ($/kW):		
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47	
Variable O&M ($/MWH): (2001 $/MWH)	0.037	
K Factor:	1.5399	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 3	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2008	
	b. Commercial In-service date:	2010	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):		2%
	Forced Outage Factor (FOF):		1%
	Equivalent Availability Factor (EAF):		97%
	Resulting Capacity Factor (%):		Approx. 60% (First Year)
	Average Net Operating Heat Rate (ANOHR):		7,021 Btu/kWh
(13)	**Projected Unit Financial Data *,****		
	Book Life (Years):		25 years
	Total Installed Cost (In-Service Year $/kW):		597
	Direct Construction Cost ($/kW):		
	AFUDC Amount ($/kW):		
	Escalation ($/kW):		
	Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)		15.47
	Variable O&M ($/MWH): (2001 $/MWH)		0.037
	K Factor:		1.5400

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Combined Cycle No. 4	
(2)	**Capacity**		
	a. Summer	1,107 MW	
	b. Winter	1,197 MW	
(3)	**Technology Type:**	Combined Cycle	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2009	
	b. Commercial In-service date:	2011	
(5)	**Fuel**		
	a. Primary Fuel		Natural Gas
	b. Alternate Fuel		Distillate
(6)	**Air Pollution and Control Strategy:**		Natural Gas, Dry Low NO_x Combustors, SCR, 0.05% S. Distillate, & Water Injection on Distillate
(7)	**Cooling Method:**	Unknown	
(8)	**Total Site Area:**	Unknown	Acres
(9)	**Construction Status:**	P	(Planned)
(10)	**Certification Status:**	P	(Planned)
(11)	**Status with Federal Agencies:**	P	(Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2%	
Forced Outage Factor (FOF):	1%	
Equivalent Availability Factor (EAF):	97%	
Resulting Capacity Factor (%):	Approx. 52%	(First Year)
Average Net Operating Heat Rate (ANOHR):	7,021	Btu/kWh

(13) **Projected Unit Financial Data *,****

Book Life (Years):	25 years
Total Installed Cost (In-Service Year $/kW):	607
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2001 $kW-Yr)	15.47
Variable O&M ($/MWH): (2001 $/MWH)	0.037
K Factor:	1.5400

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost already includes escalation and AFUDC.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fort Myers Repowering

The transmission line work for this project has been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sanford Repowering

The transmission line work for this project has been completed.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Ft. Myers: 2 CT's

(1)	Point of Origin and Termination:	From Ft. Myers GT Collector bus – To Orange River
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	2.5 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: January 1, 2003 End date: May 1, 2003
(7)	Anticipated Capital Investment:	$1,050,000
(8)	Substations:	Orange River and Ft. Myers GT collector bus
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Manatee CC Unit

(1)	Point of Origin and Termination:	Manatee – Johnson
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	18 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: June 1, 2004 End date: June 1, 2005
(7)	Anticipated Capital Investment:	$12,700,000
(8)	Substations:	Manatee and Johnson
(9)	Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Martin CT – to - CC Conversion

(1)	Point of Origin and Termination:	Martin – Indiantown #2
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned & New acquisitions
(4)	Line Length:	12.9 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$9,400,000
(8)	Substations:	Martin 230kV and Indiantown
(9)	Participation with Other Utilities:	None

(1)	Point of Origin and Termination:	Indiantown – Bridge
(2)	Number of Lines:	1
(3)	Right-of-way	FPL Owned
(4)	Line Length:	10.0 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: TBA End date: TBA
(7)	Anticipated Capital Investment:	$10,300,000
(8)	Substations:	Indiantown and Bridge
(9)	Participation with Other Utilities:	None

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TEN YEAR SITE PLAN FACT SUMMARY

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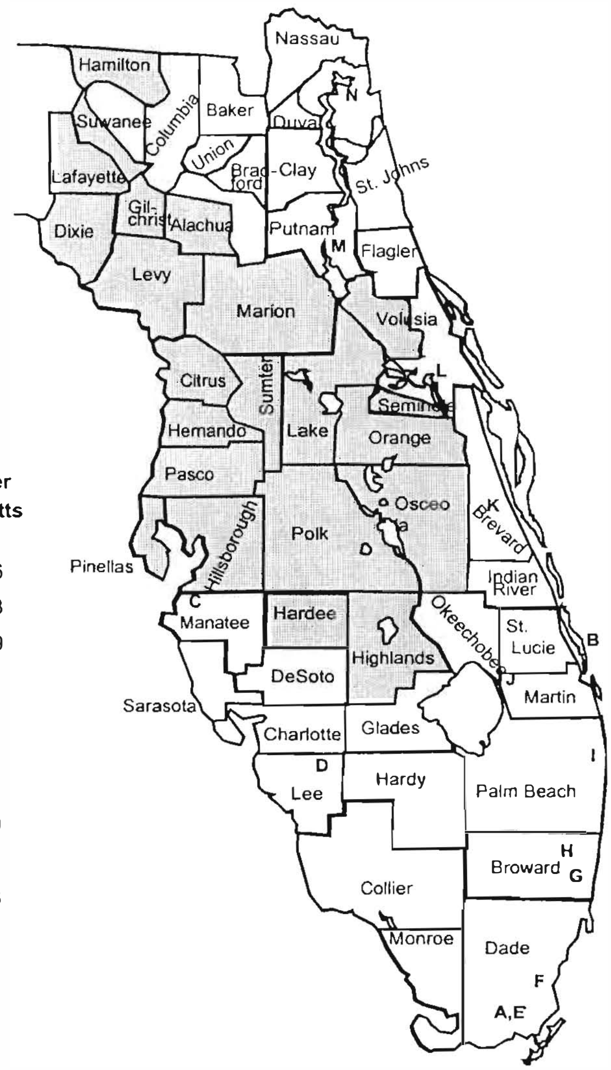
Capacity Resources
(as of December 31, 2001)

☐ Non-FPL Territory



Unit Name	Unit	Fuel Type	Summer Megawatts
A Turkey Point	2	Nuclear	1,386
B. St. Lucie *	2	Nuclear	1,553
C. Manatee	2	Oil	1,619
D. Ft. Myers	2	Oil	894
E. Turkey Point	2	Oil/Gas	800
F. Cutler	2	Gas	213
G. Lauderdale	2	Oil/Gas	854
H. Port Everglades	4	Oil/Gas	1,240
I. Riviera	2	Oil/Gas	567
J. Martin	4	Gas/Oil	2,548
K. Cape Canaveral	2	Oil/Gas	806
L. Sanford	3	Oil/Gas	532
M. Putnam	2	Oil/Gas	498
N. St. Johns River *	2	Coal	254
Scherer **	1	Coal	658
Peaking Units			2,206
FPL Generation			**16,628**

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

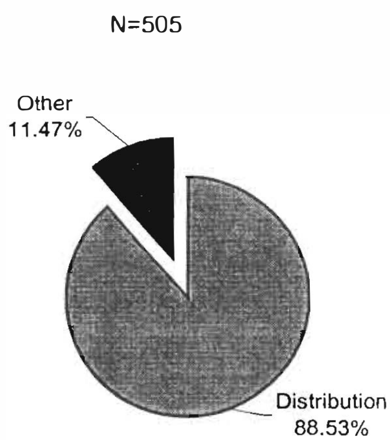
*** The Scherer unit is located in Georgia and is not shown on this map.*

Figure I.A.1

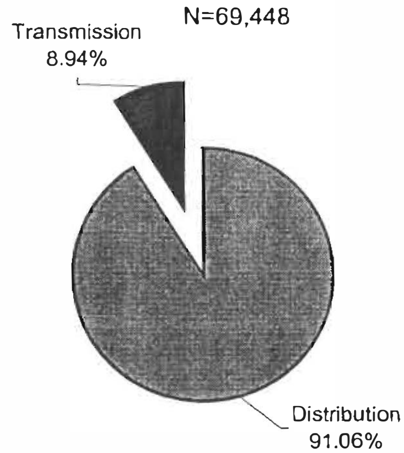
FPL OWNED RESOURCES

	2001 Actual	2002 Projection	2011 Projection
Average Number of Customers			Source: FPL Schedule 2
Residential	3,490,541	3,552,211	4,070,702
Commercial	426,573	433,999	521,756
Indusrial	15,445	15,147	15,305
Other	2,722	2,805	3,231
Total:	**3,935,281**	**4,004,162**	**4,610,994**
Peak Demand			Source: FPL Schedule 4
Winter	18,199	17,597	22,785
Summer	18,754	19,131	23,106
Installed Capability (MW)			Source: FPL Schedule 7.1 & 7.2
Winter	17,188	17,730	25,946
Summer	16,628	17,860	25,459

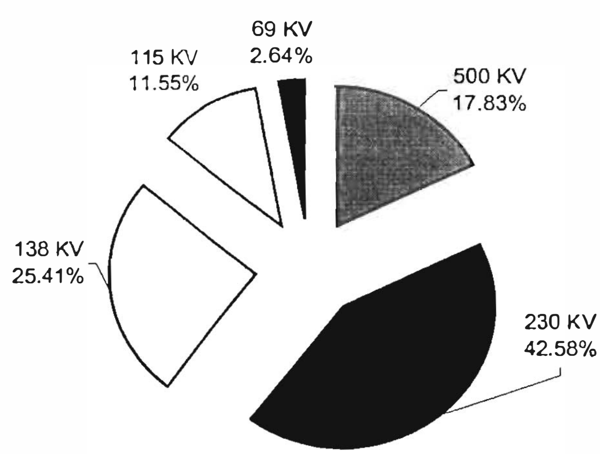
Number of Substations



Miles of Lines



Miles of Bulk Transmission Lines (By Voltage Level)

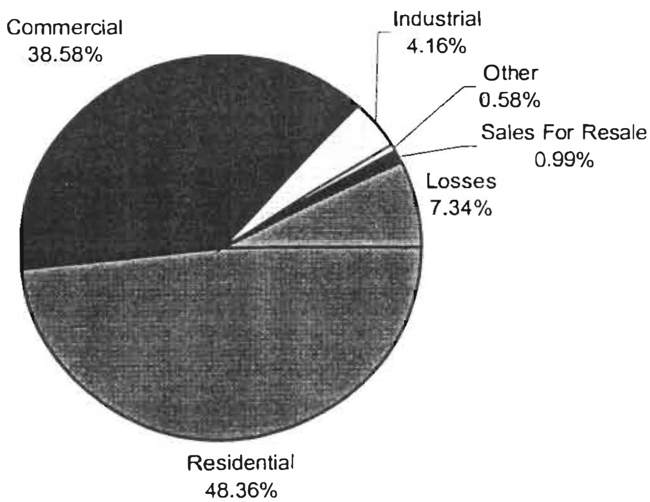


NET ENERGY FOR LOAD

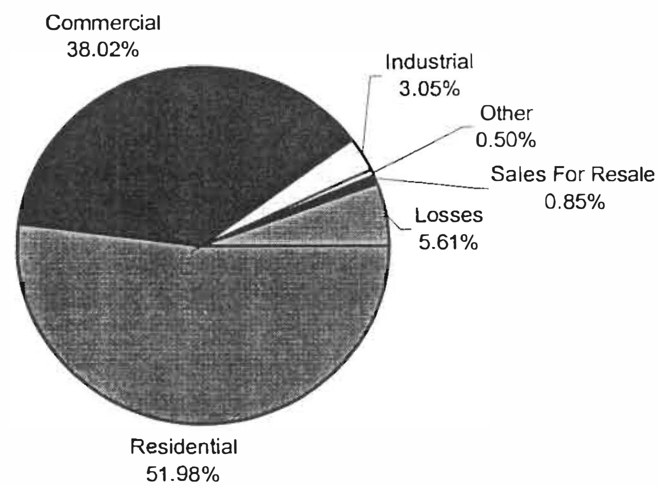
	2001 Actual	2002 Projection	2011 Projection
Consumption (GWH)			Source: FPL Schedule 2
Residential	47,588	49,065	66,282
Commercial	37,960	38,360	48,478
Industrial	4,091	3,947	3,891
Other	572	559	632
Sales For Resale	970	1,204	1,081
Losses	7,222	7,021	7,149
Total:	**98,403**	**100,156**	**127,513**

NET ENERGY FOR LOAD

2001



2011



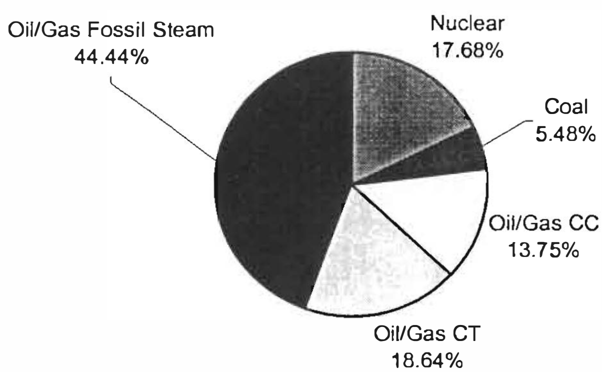
	Actual	Projection	Projection
Per Capita Consumption (KWH)			Source: FPL Schedule 2
Residential	13,633	13,813	16,283
Commercial	88,989	88,387	92,913
Indusrial	264,872	260,552	254,215

GENERATION RESOURCES

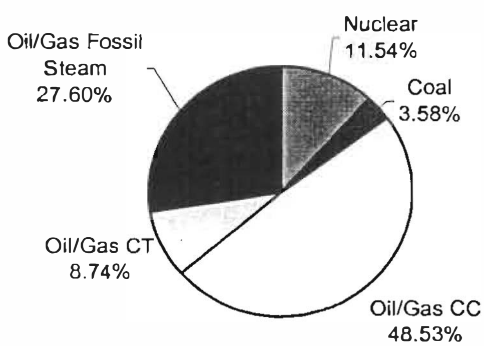
Facilities	2001 Actual	2002 Projection	2011 Projection
			Source: FPL Schedule 5
Coal 1,000 Ton	3,078	3,460	3,821
Oil 1,000 BBL	41,376	16,058	7,910
Gas 1,000 MCF	212,956	339,321	594,673
Nuclear Trillion BTU	263	263	263

INSTALLED GENERATION MW BY FUEL TYPE

2001

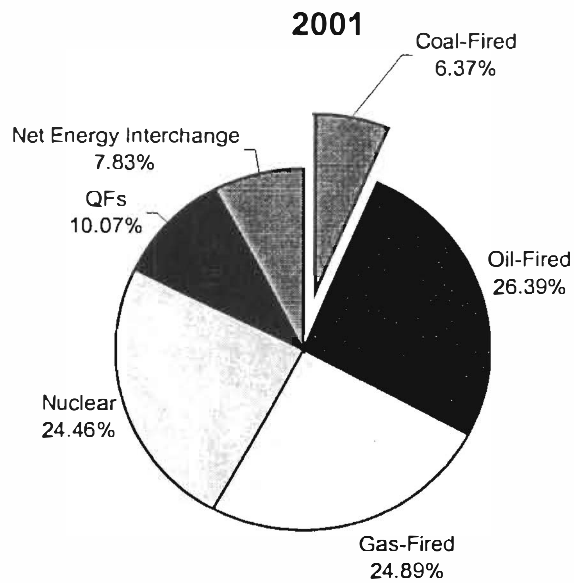


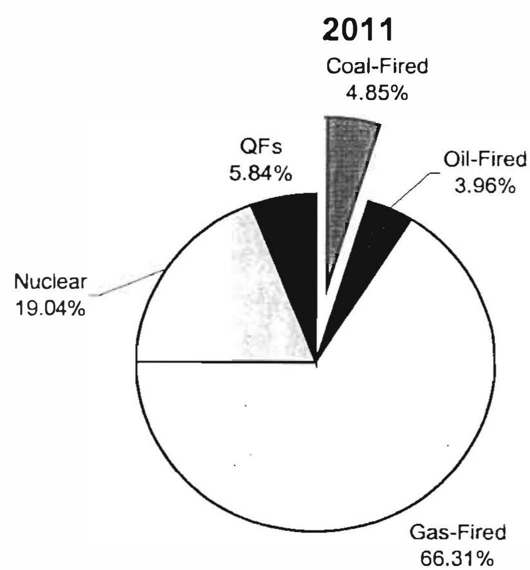
2011



ENERGY BY FUEL TYPE

	2001 Actual	2002 Projection	2011 Projection
Energy By Fuel Type (GWH)			Schedule
FPL Facilities			
Coal-Fired	6,267	6,503	6,187
Oil-Fired	25,965	10,139	5,048
Gas-Fired	24,496	40,313	84,556
Nuclear	24,070	24,284	24,274
QFs	9,905	10,858	7,446
Net Energy Interchange	7,701	8,061	0
Net Energy For Load (NEL)	98,404	100,158	127,511





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2002 Supplemental Request for Proposals (RFP)
Resource Needs For: 2005 - 2006

FPL

Florida Power & Light Company's

Supplemental Request for Proposals for Capacity

April 26, 2002

Florida Power & Light Company's

Supplemental RFP for Capacity

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Supplemental Request for Proposals

I. Introduction

A. Purpose of the Supplemental RFP

Florida Power & Light Company (FPL) issues this Supplemental Request for Proposals (RFP) for the purpose of identifying and potentially acquiring supply side projects that can deliver firm capacity and energy starting in the years 2005 and 2006.

Firm capacity and energy proposals will compete with FPL's power plant construction options. FPL invites proposals for firm capacity and energy that are based on any types of power plants or system resources including "turnkey" proposals.

For firm capacity and energy starting in the years 2005 and 2006, FPL seeks either power supply proposals for periods ranging from a minimum of three (3) years to as much as twenty-five (25) years or "turnkey" proposals. Proposals to provide firm capacity and energy must cover at least three (3) years beginning no later than either June 1, 2005 or June 1, 2006. Bidders may propose an earlier 2005 delivery date; indeed, FPL prefers a delivery date of January 1st for each of these years. Turnkey proposals may offer sale of a unit(s) on or before June 1, 2005 or June 1, 2006, or they may be made as hybrid proposals beginning as power supply arrangements for some period of time and then ending with the sale of the underlying unit(s) to FPL.

FPL seeks proposals that offer the greatest value to FPL and its customers. A successful bid will contain a number of favorable attributes including, but not limited to, price, flexibility in regard to operations and maintenance, and low risk. Low price alone will not necessarily result in a successful bid.

FPL is soliciting proposals both from Bidders which submitted proposals to FPL's August 13, 2001 RFP and from new Bidders. Bidders who submitted proposals in response to FPL's August 13, 2001 RFP may either resubmit their proposal or submit an entirely new proposal. FPL will not evaluate the proposals submitted in response to the August 13, 2001 RFP unless they are resubmitted. Any Bidder who submitted a proposal in response to FPL's August 13, 2001 RFP is entitled to submit an equivalent number of proposals in response to this RFP without incurring a new RFP fee. However, if a Bidder to the August 13, 2001 RFP submits more proposals in response to this RFP, each such additional proposal shall require an RFP fee. Bidders who did not submit a proposal in response to FPL's August 13, 2001 RFP may submit a proposal in response to this RFP. Each such proposal must be accompanied by an RFP fee.

FPL reserves the right to identify any number of short-listed Bidders to satisfy the needs identified herein in whole or in part with resources developed as a result of this RFP, to accept other than the lowest-priced proposal, to accept a combination of proposals, to waive any technical non-compliance in any proposal, to conduct negotiations with any short-listed Bidder, to reject any/all proposals, to modify or cancel the RFP, and to refine its cost estimates for FPL's resource options, up or down, based upon more recent data available when FPL performs its evaluation.

This RFP is not an offer to enter into a contract. It is a solicitation of firm offers from potential Bidders. Nothing in this RFP or any communication associated with this RFP shall be taken as constituting an offer or representation between FPL and any other party. Neither issuance of this RFP, nor the entry of FPL into negotiations with any Bidder, will be deemed to create any commitment or obligation on the part of FPL to enter into a binding agreement with any Bidder. Those who submit proposals do so without recourse against FPL or any of its affiliates for either rejection of their proposal(s) or for failure to execute a purchase agreement for any reason.

B. Projected Resource Needs

The proposals FPL is seeking are intended to address FPL's projection of needed firm capacity in 2005 and 2006. The approximate MW values needed to bring FPL to a 20 % Summer reserve margin for these two years are shown below.

Year of Need	Incremental Capacity Need (MW)	Cumulative Capacity Need (MW)
2005	1,122	1,122
2006	600	1,722

These MW values represent monthly firm capacity requirements starting no later than June 1st of each year shown. FPL may choose to acquire more or less capacity than shown above and may choose to exercise extension options in existing FPL purchase contracts or to build its own plants to provide a portion or all of the capacity needs shown above.

C. FPL's "Next Planned Generating Units"

Rule 25-22.082, Florida Administrative Code, requires that specific information about FPL's "next planned generating unit" be included in an RFP seeking firm capacity such as this RFP. That specific information is presented in Section VI of this document.

The "next planned generating units" described in Section VI are based on FPL's 2005 and 2006 projected capacity additions as presented in FPL's 2002 Site Plan, which was filed with the Florida Public Service Commission on April 1, 2002. These capacity additions are:

For 2005:

- conversion of 2 existing combustion turbines (CT's) at FPL's existing Martin site, plus the addition of 2 more CT's, into 1 combined cycle (CC) unit which adds 789 incremental MW (Summer);
- construction of a new four CT-based CC unit at FPL's existing Manatee site which adds 1,107 incremental MW (Summer);

For 2006:

- No additions

The Site Plan reports details and results of FPL's resource planning work during the year 2001. FPL periodically updates its planning data and will use the most current planning data to evaluate proposals and its self-build and contract extension options.

D. Eligible Proposals

All proposals for firm capacity and energy should satisfy all of the nine (9) Minimum Requirements listed below. Although FPL reserves the right to waive technical non-compliance with these Minimum Requirements, failure to comply with one or more of the Minimum Requirements can be grounds for determining a proposal ineligible.

Minimum Requirements for Proposals:

#1 Proposal Delivery Date & Time

Proposals must be received by the FPL Contact Person by 4:00 p.m. on May 24, 2002.

#2 **<u>Completeness of Proposal</u>**

All required forms, and the information requested on these forms, must be submitted. (FPL may, at its discretion, contact a Bidder to request that omitted information be provided.)

#3 **<u>Term</u>**

a) The proposed term must be for a minimum of three (3) years.

b) The firm capacity and energy delivery for 2005 must commence on or before June 1, 2005.The firm capacity and energy delivery for 2006 must commence on or before June 1, 2006.

#4 **<u>Year-round/seasonal capacity</u>**

Proposals must offer year-round firm capacity. However, the monthly levels of the firm capacity (and the corresponding payments) may vary as discussed in Section I.H.

#5 **<u>Resource Block Size (MW)</u>**

Unless the Bid is based on a Qualifying Facility (QF), the minimum resource block size that FPL will consider in a proposal is 50 MW. Bids based on a QF may be less than 50 MW.

Recognizing that economies-of-scale may result in a more competitive proposal, FPL encourages developers and operators of "small" facilities (i.e., facilities which are 50 MW in size or slightly larger) to aggregate/pool their facilities in order to submit a more attractive proposal. FPL also encourages developers and operators of facilities less than 50 MW to aggregate/pool their facilities in order to submit a joint proposal whose combined total firm capacity meets or exceeds 50 MW.

#6 **<u>Pricing</u>**

A Bid's proposed prices must include any and all costs that FPL will be expected to pay to the bidder for delivered capacity and energy. Therefore, all costs for the offered capacity and energy, including all equipment, transmission interconnection, fuel delivery and commodity costs, and all costs of meeting current and future environmental regulations, must be covered in the Bid price. Proposals must include all costs of delivering capacity and energy to the FPL system over intervening transmission systems. Transmission integration costs within FPL's system will be evaluated for the most economic proposals/combination of proposals.

Bidder's proposal(s) must remain open for 120 days from the submittal date.

In addition, the proposed prices must be presented in the appropriate format specified in Section IV.F. and Section IV.G. Prices for firm capacity and energy purchases, or for projects that initially offer purchases prior to a turnkey sale to FPL, must be provided on Pricing Information Form # 5. Prices for the sale of turnkey facilities must also be provided on Pricing Information Form # 6.

#7 **Operational Flexibility**

The proposal must address, at a minimum, the following operational requirements:

- Coordination of planned and maintenance outages with FPL's System Control Center; and,
- Coordination of dispatch of capacity and energy with FPL's System Control Center.

8 **Completion Security**

The proposal must provide Completion Security to FPL to protect against capacity and energy not being available on the scheduled Capacity Delivery Date (CDD). The Completion Security shall, at a minimum, be a deposit or other form of security acceptable to FPL in an amount equal to Fifty Thousand Dollars ($50,000) per MW of the proposed Guaranteed Firm Capacity. Starting with the CDD, for each day the guaranteed firm capacity is not fully available to FPL, FPL shall be entitled to draw down the Completion Security at a rate of $330/MW per day. When the Completion Security is fully drawn down, FPL shall be entitled to terminate the contract.

9 <u>Identifiable Capacity Source</u>

The proposal's capacity and energy must be from a specific power plant(s) that is clearly identified in the proposal or from a system sale. If the capacity and energy are from a system sale, a clear explanation of how the MW are to be obtained and delivered must be given in the proposal.

E. Ineligible/Non-Responsive Proposals

A proposal may be deemed ineligible or non-responsive for a variety of reasons. A discussion of some of the reasons a proposal may be deemed ineligible or non-responsive appears in Section III.F. (1). Proposals deemed ineligible or non-responsive will not be evaluated further.

F. An Option to Buy

"Turnkey" proposals may also be submitted. These proposals may offer sale of the power plant beginning on or before June 1, 2005, on or before June 1, 2006, or after some period of a firm capacity sale to FPL. The purchase price will be set by a predetermined price to be submitted by the Bidder in the proposal on Pricing Information Form # 6.

Turnkey proposals must be made assuming that the new power plant will be built at a non-FPL site.

FPL reserves the right to review and to request modification of any and all environmental permit conditions and values in regard to the Licensing and Permitting process of the Power Plant Siting Act prior to the issuance of the permit. For new generating units which are the basis for turnkey proposals submitted in response to this RFP, and for which applications for environmental permits have not yet been submitted, FPL reserves the right to review and request modifications, if any, prior to the submittal of these permit applications. For turnkey proposals based on new generating units whose permit applications have already been submitted, FPL reserves the right to review and request modifications, if any, prior to final issuance of these permits.

G. Schedule

FPL envisions that the schedule for the solicitation of proposals and the evaluation of the resulting Bids will be as described below. FPL reserves the right to change the schedule at its sole discretion. If a schedule change occurs before the Proposal Due Date, parties that have received the Supplemental RFP will be notified of the change electronically or in writing.

Milestone	Date	Comments
• Release Supplemental RFP Document	April 26, 2002	The Supplemental RFP document will be issued to parties requesting a copy starting on 4/26/02.
• Proposals Due	May 24, 2002	Proposals, together with the applicable RFP fee, must be received by the RFP Contact Person by 4:00 p.m. on this date.
• Short List Announcement	June 18, 2002	All Bidders will be notified of their status; initial negotiations begin.
• End of Initial Negotiating Period	July 2, 2002	All Short List Bidders will be notified of their status and whether negotiations will continue. If FPL's options are determined to be the superior options, FPL will terminate negotiations at this point.
• Florida Public Service Commission Filing	July 16, 2002	If FPL's options are determined to be the superior options, FPL will resume its Need Determination proceedings.
• Contract Completion Date	August, 2002	FPL will complete contract negotiations with winning bidders.
• Need Hearing	October 2 - 4, 2002	Need Determination Hearing on FPL options, if necessary.
• Florida Public Service Commission Filing	September, 2002	Winning Bidder(s) and FPL file Need Determination and/or Cost Recovery filing with the FPSC as required.
• Need Hearing	December 2002	Need Hearing on Bidder unit(s).

H. Payment Structure

For each winning Bid, FPL expects to enter into a pay-for-performance type purchase power contract.

Payments to be made would be capped at the prices contained in the Bid and would have the following three (3) payment provisions:

#1 <u>Fixed Payment</u>

FPL shall make a capacity payment on a monthly basis for the contract capacity. The payment will be based on a formula that takes into account the Bid's proposed prices for capacity payments per operational mode of the generating unit(s) and an agreed-upon level of performance. A sliding scale formulaic approach will be used thereby establishing a relationship between the level of performance and the actual monthly capacity payments. Performance below a specified level may result in no monthly capacity payments being made for one or more months (and may lead to default). Extended poor performance and/or default may result in liquidated damages per terms to be negotiated. Proposals that establish a seasonal relationship between delivered capacity and the level of capacity payments will be considered (e.g., higher payments during the peak months than during other months). However, as FPL is counting on the contracted capacity throughout the year, minimum levels of performance will be required for all months.

#2 <u>Variable Payment</u>

FPL shall make monthly energy payments for the energy purchased on a monthly basis per operational mode of the generating unit(s). The Energy Payment shall be calculated in accordance with the following formula:

$$EP = [(NEO*GHR*FP) + (NEO*VOM)]$$

Where:

EP = the Energy Payment expressed in dollars for the Billing Period;

NEO = the Net Energy Output for the Billing Period;

GHR = Guaranteed Heat Rate(s) (as specified in the Bidder's proposal);

FP = Fuel (Commodity and Transportation) Price*; and,

VOM = Guaranteed Variable O&M Price(s) (as specified in the Bidder's proposal).

* Fuel Prices may be as guaranteed in the proposal or indexed to a mutually acceptable benchmark.

#3 Start Up Payment

FPL shall also pay separately the amounts specified in the Bidder's proposal for prices associated with successful starts of the Facility. Successful starts are limited to one per dispatch cycle.

II. Bidder Exceptions, Bidder Obligations, and Regulatory Provisions

A. Bidder Exceptions

A Bidder may pose exceptions to the terms and conditions set forth in this RFP, other than Minimum Requirements. FPL will consider Bids that propose exceptions to the conditions, terms, or other facets of the RFP other than the Minimum Requirements. If a Bidder proposes exceptions, the exceptions must be explained in writing as part of the Bidder's proposal using Form # 9 (which is discussed below in Section IV.J. and presented in Section V). For each exception, the Bidder must fully explain in writing the condition, requirement, or facet of the RFP to which the Bidder takes exception and provide the replacement language proposed by the Bidder. FPL prefers Bids that make the least amount of and least significant exceptions.

A Bidder's failure to state exceptions and pose alternative language shall constitute acceptance of the terms and conditions set forth in this RFP. Any attempt by a Bidder to disclaim generally the terms and conditions of this RFP without stating specific exceptions will be grounds for determining a bid to be ineligible.

B. Bidder Obligations

The Bidder is responsible for acquiring all licenses, permits, and other regulatory approvals (including environmental) that will be required by federal, state, or other local government laws, regulations, or ordinances for the Bidder's proposal. (For a winning proposal that requires new power plant construction falling under Florida's Power Plant Siting Act, FPL will be a co-applicant in a Determination of Need filing.) FPL will cooperate with the winning Bidder(s) to provide information or such other assistance as may reasonably be necessary for the Bidder(s) to satisfy licensing and regulatory requirements. The winning Bidder(s) shall fully support all of FPL's regulatory requirements associated with this potential capacity and/or energy arrangement.

The Bidder is responsible for the location, acquisition, and development of the plant site and other needed land which is needed for new generating units.

The Bidder will also be completely and solely responsible for ensuring that the implementation of any and all parts of the proposal is carried out in full compliance with any changes, modifications, or additions to laws, regulations, and ordinances (including environmental) that affect the proposal. FPL shall not bear any price or cost risk associated with any such changes, modifications, or additions, except in the case of turnkey proposals when, once FPL assumes ownership of the facility, FPL is responsible for such price or cost risks.

The Bidder is also completely responsible for securing, locating, or guaranteeing any emissions allowances or credits which may be required by the Title IV Clean Air Act Amendments or other federal, state, or local requirements to allow the construction and/or operation of the proposed facility. Turnkey proposal Bidders must secure the emission allowances or credits necessary to construct and operate the facility until ownership of the facility is transferred to FPL.

If a Bidder's proposal is based on a generating unit that is to be constructed, the Bidder is obligated to undertake reasonable public outreach activities with the local community. These outreach activities will be designed to enhance the likelihood that the new unit will receive all local permits and approvals necessary to build and operate the unit. (FPL, at its sole discretion, has the option to assist with these outreach activities.)

All Bidders are completely and solely responsible for all financing activities related to the project; engineering, design, procurement and construction of all aspects of the facility, including, but not limited to, the power block, environmental control systems, fuel delivery systems, electrical interconnections, etc.; the sourcing and contracting for a reliable fuel supply; and any other activity required for the reliable delivery of firm capacity and energy to FPL at the identified delivery or interconnection point.

The Bidder must secure with the appropriate transmission provider(s) all needed transmission facilities and arrangements required to bring the firm capacity and energy to FPL. FPL prefers proposals for facilities that are directly connected to FPL's transmission system, although any proposal with firm transmission shall be considered.

All costs associated with the design, construction, operation and maintenance of the transmission interconnection facilities associated with the delivery of firm capacity and energy to FPL will be the responsibility of the Bidder.

Winning Bidder(s) of firm capacity and energy proposals agree by the act of submitting their proposal to file, as needed, an application under the Florida Power Plant Siting Act and to support, as requested by FPL, any FPL regulatory proceeding(s) related to firm capacity purchases and/or turnkey projects emanating from this solicitation.

In compliance with Rule 25-22.082, Florida Administrative Code, each participant (Bidder of a firm capacity proposal) is required

> ...To publish a notice in a newspaper of general circulation in each county in which the participant's proposed generating facility would be located. The notice shall be at least one-quarter of a page and shall be published no later than 10 days after the date that proposals are due. The notice shall state that the participant has submitted a proposal to build an electrical power plant and shall include the name and address of the participant submitting the proposal, the name and address of the utility that solicited proposals, and a general description of the proposed power plant and its location.

The Bidder of a firm capacity proposal must provide FPL with a copy of the newspaper notice mentioned above within seven (7) days of the notice appearing in the paper. The copy of this notice should clearly indicate the name of the newspaper and the date on which the notice appeared in the newspaper. ***Failure to either meet the 10-day newspaper notice or the 7-day notification to FPL will be grounds for deeming the Bidder's proposal ineligible or non-responsive.***

C. Regulatory Provisions

1) Any negotiated contract for the purchase of capacity and energy between FPL and a Bidder will be conditioned upon approval or acceptance of such contract without substantial change by any and all regulatory authorities that have, or claim to have, jurisdiction over any or all of the subject matters of this RFP and/or resulting contracts, including, without limitation, the Florida Public Service Commission and the Federal Energy Regulatory Commission.

2) In the event that the Florida Public Service Commission fails to allow cost recovery of any of the costs incurred pursuant to the contract between FPL and the Bidder, FPL will reduce payments to the Bidder in amounts equivalent to the amounts disallowed.

III. Proposal Development and Evaluation

A. FPL's RFP Contact Person

All proposals submitted for this RFP, plus all inquiries or communication about the RFP, are to be directed to:

Steve Sim
RFP Contact Person
Florida Power & Light Company
Resource Assessment & Planning Department
9250 West Flagler Street
Miami, Florida 33174
e-mail: steve_r_sim@fpl.com
Telephone: (305) 552-2246
Fax: (305) 552-2716

B. Completion of the Proposal

Bidders should follow all instructions contained in this RFP and provide all information requested on the forms in Section V of this document. Bidders are also expected to provide supporting documentation, and answer any follow-up questions from FPL, as requested. Bidders are encouraged to contact FPL with questions prior to the bid due date (May 24,2002) to ensure complete and accurate submittals. FPL has no obligation to pursue incomplete or unclear proposals.

C. Submitting the Proposal

All proposals must be received by the RFP Contact Person by 4:00 p.m. on May 24, 2002. Bidders must submit two (2) bound hard copies, plus an electronic copy of the completed forms on a diskette (supplied with the RFP), by this date and time.

D. RFP Fee

In order for a firm capacity and energy proposal to be evaluated, a non-refundable (except for Bids deemed ineligible or otherwise non-responsive) check of $10,000 made out to "Florida Power & Light Company" must be submitted to the FPL RFP Contact Person at the same time and date (by 4:00 p.m. on May 24, 2002) as the proposal. If more than one proposal is submitted by a specific Bidder, then a separate, non-refundable $10,000 check must accompany each proposal.

Note: Bidders who previously submitted proposals in response to FPL's August 13, 2001 RFP may now submit one new proposal, or resubmit an earlier proposal, for each proposal submitted in the original solicitation without submitting a new fee (i.e., one-for-one). **Unless resubmitted, proposals submitted in response to FPL's August 13, 2001 RFP will not be evaluated.**

One proposal consists of one total capacity level, one length of service (for example, 10 years), and one location. However, one proposal is allowed pricing values for both a 2005 start date and a 2006 start date.

Bids with variations of price, total capacity level, term-of-service, location, etc. will constitute a separate proposal.

E. Proposal Confidentiality

Other than the information to be submitted on the Public Information Regarding Proposal Form (see Section IV.B.), FPL will take reasonable precautions and use reasonable efforts to protect proprietary and confidential information contained in a proposal, provided that such information is clearly identified by the Bidder as "Proprietary and Confidential" on the page(s) on which the information appears. FPL requests that this clear identification be done by highlighting/shading the sensitive information on the forms. (A blanket statement that an entire page or proposal is proprietary and confidential will not be considered clear identification.)

FPL will attempt to maintain the confidentiality of the clearly identified proprietary and confidential information in the proposals. **However, this information will have to be disclosed to the Florida Public Service Commission and/may have to be disclosed to third parties in regulatory and/or legal proceedings.**

FPL currently has pending determination of need proceedings for the two combined cycle units identified as the "next planned generating units" in this Supplemental RFP. FPL has asked that those proceedings be suspended so that FPL may conduct this Supplemental RFP. At the close of FPL's evaluation, FPL may choose to resume on or both of those need determination proceedings. In those proceedings there is pending before the Prehearing Officer a joint motion to approve a nondisclosure agreement which, if approved, would allow intervenors limited access to the proposals submitted in response to this RFP. Such access would be for the purpose of litigation in these proceedings. Several of the intervenors were Bidders in FPL's 2001 RFP and may be Bidders in this Supplemental RFP.

Bidders may request a copy of the nondisclosure agreement mentioned above by contacting FPL's RFP Contact Person.

F. Proposal Evaluation

In this RFP, FPL is requesting both price- and non-price information about each proposal. The forms described in Section IV and presented in Section V seek information about a number of attributes of each proposal including, but not limited to, the following:

- The costs of firm capacity and energy plus the timing/structure of these costs;
- whether the Bidder has a firm fuel supply for the duration of the proposed contract;
- the heat rate(s) of the generating unit(s) to be used to supply the firm capacity and energy by operational mode, i.e., base operation, duct firing, power augmentation, etc.
- the amount of capacity (MW) offered, availability of the resource, and length of time the capacity is offered;
- the financial viability and experience of the Bidder;
- the pollution control equipment/strategy to be utilized and the projected emission rates of the generating unit(s);
- the cooling method to be utilized;
- the dispatchability of the generating unit(s) to be used to supply the firm capacity and energy; and,
- the deliverability of the firm capacity and energy (in terms of construction schedules, transmission interconnection arrangements, etc.)

The actual evaluation of the individual proposals will involve a three (3) – step process:

1) <u>A "Pass/Fail" Screening</u>

In this initial step submittals that are ineligible or otherwise non-responsive to the RFP will be screened out. Submittals may be deemed ineligible or non-responsive for various reasons including, but not limited to, the following:

- One or more of the applicable Minimum Requirements for proposals were not met;

- the applicable RFP fee was not received by the due date;
- the delivery dates for the capacity and energy are not responsive to the delivery dates listed in the RFP;
- failure to publish the required newspaper notice or to timely inform FPL of this notice;
- the proposal's capacity and/or energy does not come solely from supply side resources; and,
- incomplete or unclear submittals

Submittals that are screened out in this initial step will be returned to the Bidder, along with an applicable RFP Fee, and will not be analyzed further.

2) **Economic Evaluation:**

In this step all remaining (after the initial screening) proposals will be evaluated to determine their economic impacts on the FPL system. Depending upon the capacity size (MW) offered in firm capacity and energy proposals and FPL's resource needs, a proposal may be evaluated by itself and/or in combination with other proposals.

The economic evaluation will seek to identify the firm capacity and energy proposal(s) which result in the lowest electric rates for the FPL system. Therefore, the evaluation will examine each proposal's impact on the entire FPL system, including the estimated impact on FPL's cost of capital associated with entering into a purchased power agreement. It is anticipated that the EGEAS model, plus various spreadsheet calculations, will be utilized in this evaluation and that the evaluation will be conducted by FPL's Resource Assessment & Planning Department. Costs associated with unit startups and transmission integration will also be evaluated at least for the superior alternatives.

3) **Other Considerations**

In this final step, the proposals which were deemed the best economic choices for FPL's system will be evaluated for various risk factors and other considerations in order to determine which proposal(s) would be the best overall choice(s) for FPL. Factors which may be considered include, but are not necessarily limited to, the following:

- experience/track record of the Bidder;
- financial viability of Bidder (refer to Section IV.D);
- number and type of exceptions taken to the terms, conditions, and other facets of this RFP;

- proposed performance criteria;
- reasonableness of construction schedule milestones;
- operating and permitting limitations;
- likelihood of being able to deliver the proposed capacity and energy to FPL's system through transmission systems;
- likelihood of success in receiving all permits and approvals necessary to build and operate a generating unit;
- security of fuel supply;
- water supply;
- facility location;
- dispatchability and maintenance considerations;
- commitment of guaranteed firm capacity to FPL; and,
- other value-added benefits (if any).

FPL seeks to identify the proposal(s) with the best combination of low economic impact, low risk, and other desirable attributes. FPL reserves the right to analyze proposals in detail, to reject any and all proposals in whole or in part, and to award a contract or contracts which FPL, in the exercise of reasonable discretion, believes to be in its best interest and the best interests of its customers.

G. Negotiations and FPL's Self-Build/Contract Extension Options

Once FPL has evaluated all of the proposals, FPL will enter into initial negotiations with certain Bidders. After an initial negotiating period, FPL will either continue negotiations with one or more of those Bidders, reject all bids and pursue self-build options and/or existing purchased power contract extensions, or pursue some combination of purchasing and building.

IV. Discussion of Bidder's Forms

A. Overview of the Required Ten (10) Forms

There are ten (10) forms that all Bidders must complete and return to FPL by 4:00 p.m. on May 24, 2002.

These completed forms and requested attachments to these forms will, collectively, comprise a Bidder's proposal. If a Bidder is submitting more than one proposal, a separate set of forms must be completed for each proposal. These ten forms are described in the remainder of this Section.

The Bidder must submit two (2) bound hard copies of the proposal that contains the forms and requested information, and an electronic copy of the completed forms on a diskette, along with the RFP fee (if applicable). A diskette containing electronic versions of the forms is attached to this RFP. The Bidder must complete the forms contained on the diskette and return the diskette, plus the two bound hard copies of the completed forms, plus the RFP fee (if applicable), by 4:00 p.m. on May 24, 2002.

As previously discussed in Section III. E., FPL intends to treat as confidential all information contained in proposals which is clearly identified as "Proprietary and Confidential" except for the information to be submitted on Form #1, Public Information Regarding Proposal. FPL requests that Bidders highlight/shade information on the forms that they want treated as "Proprietary and Confidential".

B. Discussion of Form #1: Public Information Regarding Proposal

In order to provide general information to the public about the proposals received in response to this RFP, FPL requires that all proposal submittals include a completed Public Information Regarding Proposal form and an attached list of projects undertaken (constructed and/or operated) by the Bidder that are similar to the project being proposed by the Bidder in response to FPL's Supplemental RFP. ***The information contained in this form will be treated as non-confidential and non-proprietary and may be released to the public at the sole discretion of FPL.***

C. Discussion of Form #2: Executive Summary of the Proposal

A one (1) page summary of the proposal and the Bidder is sought on this form. This executive summary should highlight any major value-added features of the proposal.

D. Discussion of Form #3: Financial Information

To mitigate risk, FPL will examine the Bidder's credit/corporate profile and financial guarantees. If a bidder or a parent/affiliate guarantor of the Bidder has a corporate bond or commercial paper rating, it should be either:

1) A corporate bond rating by at least two rating agencies, one of which should be either Moody's or Standard & Poor's, which is equivalent to or above a rating of BBB by Standard & Poor;

2) A commercial paper rating by at least two rating agencies, one of which should be either Moody's or Standard & Poor's, which is equivalent to or above 1 or 2.

If a Bidder or a parent or affiliate acting as a guarantor to the Bidder does not have a corporate bond or commercial paper rating, the Bidder must submit with its proposal sufficient, current financial information to demonstrate a financial position equivalent to a position that would be necessary to achieve a Standard & Poor's corporate bond rating of at least BBB or a commercial paper rating of 1 or 2.

This form requests the Bidder's and, if applicable, the parent/affiliate guarantor's corporate ratings for the two above-mentioned indices. If the Bidder or parent/affiliate guarantor does not have a corporate bond rating or commercial paper rating at the levels described above, then some form of additional security beyond that described in Section IV.H.(2) may be required by FPL in order to execute an agreement with the Bidder. Such a Bidder who does not show at least one financial rating for itself or its guarantor at the levels listed above must propose the type and amount of additional security they offer on Form # 3.

This security could be an irrevocable, unconditional letter of credit from a financial institution acceptable to FPL, a parent or affiliate guarantee (provided the parent or affiliate meets the credit requirements listed above) in form and substance acceptable to FPL, or an actual deposit of funds.

The type and amount of security required for any final agreement will depend upon the amount of firm capacity involved in the proposal and an assessment of the risk that FPL takes by entering into an agreement with the Bidder.

If a Bidder will be relying on any parent /affiliate guarantees, the Bidder shall also include a description of the corporate relationship between the Bidder and the guarantor and provide a description regarding the proposed guarantor's willingness to guarantee the Bidder's obligations and the terms of the guarantee.

E. Discussion of Form #4 : Operations & Engineering Information

Bidders submitting a proposal for firm capacity and energy must complete Form #4. Using this form, the Bidder must submit a detailed description of the performance of the generating facility or system facilities from which the firm capacity and energy sale will originate and describe various performance attributes. This description must be done in two parts.

Part 1 is basic information to be supplied on Form #4. Capacity (MW) and heat rate information is required regarding each "operational mode" (base operation, duct firing, power augmentation, etc.) of the generating unit(s) upon which the proposal is based. In addition, annual values for availability, forced outage rate, and planned outage hours are sought separately for a 2005 start date and a 2006 start date for each proposal. Part 2 is information describing the following seven (7) items which are to be developed by the Bidder and added to Form #4:

1. Net reactive capability (leading and lagging)

2. Host dependency (if facility is a cogenerator).

3. Regulated voltage range

4. Any start-up and shut down operating restrictions

5. Dispatchability

   FPL prefers to be able to dispatch the facility as if it were its own unit. This includes, but is not limited to, the following rights with respect to the facility/facilities:

   - the right to commit and decommit;
   - the right to control the real and reactive power output;
   - the right to request and receive a specific output level from the facility with or without regards to system economics (e.g., to regulate the system, to control voltage levels, to verify the facility's/facilities' claimed capability, or due to safety or reliability reasons; and ,
   - the right to make off-system sales from the unit.

   FPL expects to be able to exercise its rights in full or in part at any time and at its own discretion. FPL may, at its option, dispatch the facility/facilities through Automatic Generation Control (AGC) or manually by directions to the Seller.

   To better understand a proposal's dispatch potential, FPL may consider factors such as: ramp rates; incremental generating costs; incremental power purchase costs; incremental transmission losses; minimum and maximum range of operation (real and reactive power); hot and cold start-up times; minimum downtime; load following capability; and the ability to commit and decommit the facility (cycling) and any restriction on the total number of times or the frequency (e.g., once per day) of cycling the facility.

   Bidders shall provide sufficient information on the above factors to allow FPL to consider the proposal's capabilities and desirability in this area.

6. Reactive Control

   FPL currently operates an extensive high-voltage transmission system throughout the southwestern and eastern portions of Florida. In a variety of contingencies and operating scenarios, portions of this transmission system may be voltage-limited. As such, the reactive capability and control strategies of generating resources are very important. Units with greater power factor capability are preferred.

7. Facility Outages

   FPL expects that facility outages will be coordinated with, and acceptable to, FPL to meet its system needs. Bidder shall specify in the proposal a number of hours per calendar year to perform its facility maintenance/repair ("Planned Outage Hours" on Form #4). An example of FPL's desired terms follows: [By May 1st of the year preceding the Capacity Delivery Date, and by May 1st of the year preceding each succeeding calendar year of the Contract, the Seller shall submit to FPL its desired schedule of maintenance periods ("Scheduled Outages") for the following calendar year. Under no circumstances shall the Seller be permitted to request Scheduled Outages during the following months: January, February, June, July, August, September, and December. Following the Capacity Delivery Date, the Seller may request additional outages ("Maintenance Outages") for the purpose of performing work on specific components of the facility/facilities that would limit its output and which should not, in the reasonable opinion of the Seller, be postponed until the next Scheduled Outage. FPL will notify the Seller whether its requested outages (both Scheduled and Maintenance) are acceptable or whether they need to be rescheduled. The sum of Scheduled Outages and Maintenance Outages shall not exceed the Seller's total Planned Outage Hours included in the Bid. All other outages will be considered Forced Outages and may serve to reduce capacity payments through a performance adjustment mechanism as discussed in Section I.H. (Bids that do not provide assurance of scheduling flexibility and/or coordination in the scheduling of the facility's/facilities' maintenance may be rejected exclusively on that basis.)]

F. Discussion of Form #5: Pricing Information for Purchased Power or System Proposals

Pricing for firm capacity and energy proposals that offer power purchases or system sales only, or that initially offer power purchases prior to a turnkey facility sale to FPL, must be presented on Pricing Information Form #5. (Pricing for firm capacity and energy proposals that offer the sale of turnkey facilities to FPL must be presented on Pricing Information Form #6.)

Separate cost information is to be supplied for both a 2005 start date and a 2006 start date for each proposal unless the Bidder wishes only one start date for the proposal to be considered. (In such a case, the Bidder should enter "NA" in the cost information spaces for the "unwanted" start date.)

1) **Capacity Pricing**

The Bidder must provide guaranteed, fixed price capacity payment values for the term of the proposed contract. Capacity payment levels in terms of $/kW-month must be supplied for each operational mode (base operation, duct firing, power augmentation, etc.) of the generating unit(s) upon which the proposal is based. Proposals must include all costs of delivering capacity and energy to the FPL System over intervening transmission systems.

2) **Energy Pricing**

The Bidder may submit a guaranteed fuel commodity price ($/mmBTU) for the proposed term of the contract. If the Bidder does not wish to provide guaranteed fuel commodity and transportation prices, FPL will use its own fuel cost projections for the purposes of proposal evaluation.

For guaranteed fuel transportation cost, the Bidder must either designate "FGT" or "Gulfstream" as the gas supplier, or provide a firm gas transportation cost (in $/mmBTU).

In addition, the guaranteed annual variable O&M costs (in $/MWH) of the proposal for the term for both the base operational mode and for any other operational mode (duct firing, power augmentation, etc.) must be provided.

3) **Startup Pricing**

The Bidder's guaranteed startup prices in $/startup must also be provided. Successful starts are limited to one per dispatch cycle.

G. Discussion of Form #6: Pricing Information for Turnkey Project Sales

Pricing-related information required for the proposed sale of a turnkey facility is as follows:

- Date (month/day/year) of the proposed sale of the turnkey facility to FPL;
- Guaranteed sale price of the proposed facility on the Sale Date in total dollars* ;
- Projected average annual fixed O&M cost ($/guaranteed Summer kW) over a ten (10)-year period from the Sale Date assuming no escalation over time;
- Projected average annual variable O&M cost ($/mwh) over a ten (10)-year period from the Sale Date assuming no escalation over time; and,
- Projected average annual capital replacement cost (total dollars/year) over a ten (10)-year period from the Sale Date assuming no escalation over time.

* Turnkey proposal total sale pricing must cover all costs of delivering power to the FPL system over the intervening transmission systems.

H. Discussion of Form # 7: Key Milestones & Completion Security Agreement

1) <u>Key Milestones</u>

FPL's ability to maintain a certain level of system reliability for its customers and/or meet its customers needs will be dependent upon the Bidder's ability to meet the contracted Capacity Delivery Date(CDD). Since there is a possibility that the Bidder will not meet this date, FPL may have to make alternate arrangements to cover the capacity and energy shortfall. This will require FPL to monitor the Bidder's progress. Therefore, the Bidder must provide a list of key project milestones and their expected completion dates on part 1) of this form.

FPL intends in contract negotiations to seek terms beyond Completion Security to protect against any potential failure to meet key milestones. These terms will include, but not necessarily be limited to, the right to perform site inspections, the right to determine whether the project will be reliably available by the Capacity Delivery Date, and the right to terminate the contract.

2) Completion Security Agreement

The Capacity Delivery Date (CDD) listed on Form #7 will be the subject of a Completion Security provision in any purchased power contract entered into between FPL and a Bidder. At a minimum the Bidder must agree to the Completion Security arrangement set forth in Section I.D. #8. FPL prefers the following Completion Security provision.

> To protect FPL from the Bidder failing to achieve its scheduled Capacity Delivery Date (CDD) the Bidder will pay FPL a deposit or provide some other form of security acceptable to FPL in an amount equal to Fifty Thousand Dollars ($50,000) per MW of guaranteed firm capacity (Completion Security). For each day the Bidder fails to reliably deliver the guaranteed firm capacity, FPL shall be entitled to draw down the Completion Security by Three Hundred and Thirty Dollars ($330) per MW of guaranteed firm capacity. Upon FPL's draw down of the entire Completion Security, if the Bidder is not able to reliably deliver the guaranteed firm capacity, FPL may terminate the contract. The Parties acknowledge that the injury that FPL will suffer as a result of delayed availability of Firm Capacity of the Proposal and associated energy is difficult to ascertain and that FPL may have to accept the above deposit as liquidated damages or resort to any other remedies which may be available to it under law or in equity.

Successful bidders should be prepared to address these issues in contract negotiations. For instance, FPL will seek contract terms that would allow it to terminate if the seller or its parent/affiliate guarantor enters, voluntarily or involuntarily, bankruptcy proceedings, or if the seller or its parent/affiliate guarantor's financial position deteriorates below the standards presented in Section IV. D.

Part 2) of this form requests the Bidder to indicate agreement or disagreement with the Completion Security provision language above. If the Bidder indicates disagreement, the Bidder is instructed to present revised language concerning a Completion Security Agreement that is acceptable to the Bidder.

I. Discussion of Form # 8: Delivery Point(s) to FPL

This Form is intended to identify the location of the delivery point(s) of each proposed capacity and energy source(s). Listing of the nearest substations is requested.

J. Discussion of Form # 9: Bidder Exceptions

All Bidders must complete and return the Bidder Exceptions form as part of their proposal submittal. On this form, the Bidder must either indicate that they take no exceptions to any of the terms, conditions, or other facets of the RFP or must indicate that they do take exception(s). In the case in which one or more exceptions are taken, then for each term, condition, or other RFP facet to which an exception is taken, the revised language the Bidder proposes must be presented in writing.

FPL will consider the number and significance of exceptions in its evaluation of non-price factors. FPL will not consider proposed exceptions to the RFP's Minimum Requirements.

K. Discussion of Form # 10: Proposal Certification

All Bidders must complete and return the Proposal Certification form as part of their proposal submittal. An officer of the bidding company is to certify that all information contained in the Bidder's proposal is complete and accurate; that the terms, conditions, and other facets of the RFP are acceptable, except as specifically noted by the Bidder on Form # 9; the proposal has been submitted in the legal name of the entity which would be bound by any resulting contract; and that the offer is firm and will remain open for 120 days from May 24, 2002.

The copy of this form that is included in the two bound hard copies of the proposal must be signed by an officer of the bidding company.

V. Bidder's Forms

The blank forms that follow on the remaining pages of this Section are the required forms which must be completed by all Bidders for each project they wish to offer.

FPL Capacity RFP

Form # 1: Public Information Regarding Proposal

Facility Name: ______________________________

1) Name of Bidding Company: ______________________________

2) Type of Generating Technology: ______________________________

3) Type of Project (Check One):

Purchased Power ________
Turnkey ________
Other: (Specify:) ________

4) Location of Generating Facility (City/County): ____________________

5) Fuel:

Primary: ______________

Secondary: ______________

6) Bidder Classification (Check One):

Utility (retail serving): ________
Independent Power Producer: ________
Small Power Producer: ________
Cogenerator: ________
Other (explain): ________

7) Proposed Total Guaranteed Firm Capacity (Net MW) to FPL:

Summer: ________ Winter: ________

8) Proposed Capacity Delivery Start Date: ______________

9) Proposed Capacity Delivery End Date: ______________

FPL Capacity RFP

Form # 1: Public Information Regarding Proposal

Facility Name: ______________________________

10) Use the space below to list of all major projects undertaken (constructed and/or operated) by the Bidder or Bidder's affiliates/parent company during the last five (5) years which are similar to the project being proposed by the Bidder in response to FPL's RFP.

11) Bidder: Company Name: ______________________________

Contact Person: ______________________________

Position Title: ______________________________

Telephone: ______________________________

Fax: ______________________________

E-Mail: ______________________________

Form # 2: Executive Summary of the Proposal

Facility Name: ____________________________________

Please provide a one (1) page summary of the proposed project and the Bidder.

FPL Capacity RFP

Form # 3: Financial Information

Facility Name: ______________________________

1) Bidder's Legal Name: ______________________________

2) Physical Address: ______________________________
____
____

3) Financial/Credit Contact Person:

Name: ______________________________

Position Title: ______________________________

Telephone: ______________________________

Fax: ______________________________

E-Mail: ______________________________

4) Federal Tax Identification Number: ______________________________

5) Bidder is (check all that apply):

______ Corporation
______ Partnership
______ Joint Venture
______ Sole Proprietorship
______ Limited Liability Company
______ Limited Liability Partnership
______ Other (attached description)

6) State in which Bidder is incorporated or organized: ______________

7) Bidder Information:

a) Dunn & Bradstreet Identification Number: ______________

b) Corporate Bond Ratings: ______ Sources: ______________
______ ______________

c) Commercial Paper Ratings: ______ Sources: ______________
______ ______________

d) Dunn & Bradstreet Credit Appraisal Rating: ______________

FPL Capacity RFP

Form # 3: Financial Information

Facility Name: ____________________

8) (If applicable) Parent/Affiliate Guarantor Information:

a) Name of parent/affiliate guarantor: ____________________

b) Dunn & Bradstreet Identification Number: ____________________

c) Corporate Bond Ratings: __________ Sources: __________

__________ __________

d) Commercial Paper Ratings: __________ Sources: __________

__________ __________

e) Dunn & Bradstreet Credit Appraisal Rating: ____________

9) If Bidder is relying on any parent/affiliate guarantees, use the space below to describe the corporate relationship between the Bidder and the guarantor and to provide a statement regarding the proposed guarantor's willingness to guarantee the Bidder's obligation.

FPL Capacity RFP

Form # 4: Operations & Engineering Information

Facility Name: ______________________________

Part 1:

1) Type of Generating Unit (Combustion Turbine, etc.): ______________________________

2) Check One: New Unit __________ Existing Unit __________
System Sale __________

If "Existing Unit", Date of Commercial Operation: ______
If "New Unit", Manufacturer Name: ______
Model Number: ______
If "System Sale", use this space to provide details of the system sale: ______________________________

____

3) Guaranteed Firm Capacity (Net MW) and Heat Rates :

Operational Mode	Summer Capacity at 95 deg.F (MW)	Winter Capacity at 35 deg.F (MW)	Heat Rate at 75° F 100% Load, HHV (BTU/kwh)
Base Operation			

Additional Operational Mode *	Incremental Summer Capacity at 95 deg.F (MW)	Incremental Winter Capacity at 35 deg.F (MW)	Incremental Heat Rate at 95° F ** (BTU/kwh)
Duct Firing			
Power Augmentation			
Other (specify) ______			
Total Guaranteed Capacity * * * =			

* Provide incremental capacity provided by all operational modes of the generation upon which the proposal is based. Input zero MW if operational mode is not applicable.
* * Provide heat rate for only the incremental MW provided by each operational mode.
* * * Total Guaranteed Capacity value should equal the sum of the incremental capacities from all applicable operational modes.

4) Response (Ramp) Rates:
Under Manual Control : + __________ MW/Minute
Under Manual Control : - __________ MW/Minute
Under AGC: + __________ MW/Minute
Under AGC: - __________ MW/Minute
Turnaround rate: __________ MW/Minute

5) Minimum: Run Time: __________ Hours
Shut-down Time: __________ Hours

6) Start-up Time from Cold Conditions: __________ Hours
Start-up Time from Warm Conditions: __________ Hours

FPL Capacity RFP

Form # 4: Operations & Engineering Information

Facility Name: ______________________________

7) Start-up Time from Hot Conditions: ____________ Hours
Maximum Allowable Cycles (No. per Year): ____________

8) Fuel Information:
Primary Type of Fuel: ____________________
Secondary/Backup Type of Fuel: ____________________

Secondary/Backup Fuel Stored On-Site (Check One): ________Yes ________ No

If "Yes", number of hours unit can run at full output from on-site Secondary/Backup fuel storage facility without this stored fuel being replenished: ____________ Hrs

9) Availability and Outage Information for Base Operational Mode:
(Note: If there are operational constraints (for example, operate only X hours per year) for any of the other operational modes, include this information in response to item 12) on page 5 of 5 of this form.)

FOR 2005 START DATE PROJECT

Contract Year	Equivalent Availability Factor (%)	Equivalent Forced Outage Rate (%)	Guaranteed PlannedOutage Hours * (hrs/yr)
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			

* As described in Section IV.E.(7).

FPL Capacity RFP

Form # 4: Operations & Engineering Information

Facility Name: ______________________________

7) Start-up Time from Hot Conditions: ____________ Hours
Maximum Allowable Cycles (No. per Year): ____________

8) Fuel Information:
Primary Type of Fuel: ______________________
Secondary/Backup Type of Fuel: ______________________

Secondary/Backup Fuel Stored On-Site (Check One): ________Yes ________No

If "Yes", number of hours unit can run at full output from on-site Secondary/Backup fuel storage facility without this stored fuel being replenished: ____________ Hrs

9) Availability and Outage Information for Base Operational Mode:
(Note: If there are operational constraints (for example, operate only X hours per year) for any of the other operational modes, include this information in response to item 12) on page 5 of 5 of this form.)

FOR 2006 START DATE PROJECT

Contract Year	Equivalent Availability Factor (%)	Equivalent Forced Outage Rate (%)	Guaranteed PlannedOutage Hours * (hrs/yr)
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030			

* As described in Section IV.E.(7).

FPL Capacity RFP

Form # 4: Operations & Engineering Information

Facility Name: ______________________________

10) Transmission Facilities Information:

a) FPL Queue:
Does the generating unit on which the proposal is based currently have a place in FPL's Transmission Queue? (Check One) ________ Yes ________ No

If "Yes" list the Queue position number: ________

List all Queue-related studies completed by FPL in regard to this project: ______________

Attach a copy of each of these completed studies to this form in the bound hard copy of the Proposal.

b) Other Utility Queues:

Will another utility's transmission system have to be used to deliver the proposed capacity and energy to FPL? (Check One): ________ Yes ________ No

If "Yes", list the name of the other utility: ______________________________

Does the generating unit on which the proposal is based currently have a place in this other utility's transmission Queue ? (Check One): ________ Yes ________ No

If "Yes" list the Queue position number and name of the Queue: ______________

List all other Queue-related studies in regard to this project: ______________

11) Environmental Information:

a) NOx control equipment/strategy to be implemented: ______________
NOx emission rate (lbs/mmBTU) ______________

b) SO2 control equipment/strategy to be implemented: ______________
SO2 emission rate (lbs/mmBTU) ______________

FPL Capacity RFP

Form # 4: Operations & Engineering Information

Facility Name: ____

c) Cooling/Water Information:

Cooling method to be utilized: ____________________
Total amount of water needed (gals/day): ____________________
Source of water to be used (surface water,groundwater, gray water, other - specify): ____________________
Water discharge points and quantities (surface water,groundwater, other - specify): ____________________

d.) Land Use/Zoning Information: (Continued)

Current land use designation:
Change needed in land use designation? (Check One): ________ Yes ________ No
Current zoning designation: ____
Change needed in zoning designation? (Check One): ________ Yes ________ No
Comprehensive Plan amendment needed? (Check One): ________ Yes ________ No

12) Operating Limitations:

Describe in detail any operating/run hour limitation <u>by operational mode</u> due to the facility's design or to applicable permits or environmental regulations:

Operational Mode	Limitation:
Base Operation	____________________
Duct Firing	____________________
Power Augmentation	____________________
Other (specify) ________	____________________

<u>Part 2:</u>

Use this space to provide the additional information requested for the seven (7) items discussed in Section IV.E.

FPL Capacity RFP

Form # 5: Pricing Information for Purchased Power or System Proposals

Facility Name:________________________________

1) Guaranteed Capacity Pricing: *

Provide guaranteed total capacity pricing for each operational mode identified on Form # 4. Please insert "NA" for operational modes that are not applicable to your proposal.

FOR 2005 START DATE PROJECT

	for: Base Operational Mode	for: Duct-Firing Operational Mode	for: Power Augmentation Operational Mode	for: Other (specify) Operational Mode
Contract Year	Guaranteed Total Capacity Payment **($/kw-month)**	Guaranteed Total Capacity Payment **($/kw-month)**	Guaranteed Total Capacity Payment **($/kw-month)**	Guaranteed Total Capacity Payment **($/kw-month)**
2005				
2006				
2007				
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				

* Guaranteed capacity pricing values must include all proposed payments for at least the following:
- generation, fuel delivery, transmission interconnection, and infrastructure capital;
- fixed O&M; and,
- capital replacement.

FPL Capacity RFP

Form # 5: Pricing Information for Purchased Power or System Proposals

Facility Name:________________________________

1) Guaranteed Capacity Pricing: *

Provide guaranteed total capacity pricing for each operational mode identified on Form # 4. Please insert "NA" for operational modes that are not applicable to your proposal.

FOR 2006 START DATE PROJECT

	for: Base Operational Mode	for: Duct-Firing Operational Mode	for: Power Augmentation Operational Mode	for: Other (specify) Operational Mode
Contract Year	Guaranteed Total Capacity Payment **($/kw-month)**	Guaranteed Total Capacity Payment **($/kw-month)**	Guaranteed Total Capacity Payment **($/kw-month)**	Guaranteed Total Capacity Payment **($/kw-month)**
2006				
2007				
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				

* Guaranteed capacity pricing values must include all proposed payments for at least the following:
  - generation, fuel delivery, transmission interconnection, and infrastructure capital;
  - fixed O&M; and,
  - capital replacement.

FPL Capacity RFP

Form # 5: Pricing Information for Purchased Power or System Proposals

Facility Name: ______________________________

2) Guaranteed Energy Pricing:

FOR 2005 START DATE PROJECT

Contract Year	Guaranteed Fuel Commodity Price (if applicable) * **($/mmBTU)**	Guaranteed Fuel Transportation Cost (if applicable) * * **($/mmBTU)**	(for Base Operational Mode) Guaranteed Variable O&M **($/MWH)**	(for all Other Operational Modes) Guaranteed Variable O&M **($/MWH)**
2005				
2006				
2007				
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				

* If left blank, FPL will use its own fuel price forecast for purposes of proposal evaluation.

* * Please fill in the blanks with one of the following: "FGT", "Gulfstream", or a numerical $/mmBTU value. If filled in with either "FGT" or "Gulfstream", FPL will use its forecast for FGT or Gulfstream firm gas transportation costs for purposes of proposal evaluation. If filled in with a numerical $/mmBTU value, FPL will use that value for evaluation purposes. **For evaluation purposes, FPL will apply the Guaranteed Fuel Transportation Cost to the capacity associated with the Base Operational Mode only.**

FPL Capacity RFP

Form # 5: Pricing Information for Purchased Power or System Proposals

Facility Name: ______________________________

2) Guaranteed Energy Pricing:

FOR 2006 START DATE PROJECT

Contract Year	Guaranteed Fuel Commodity Price (if applicable) * (\$/mmBTU)	Guaranteed Fuel Transportation Cost (if applicable) * * (\$/mmBTU)	(for Base Operational Mode) Guaranteed Variable O&M (\$/MWH)	(for all Other Operational Modes) Guaranteed Variable O&M (\$/MWH)
2006				
2007				
2008				
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				

* If left blank, FPL will use its own fuel price forecast for purposes of proposal evaluation.

* * Please fill in the blanks with one of the following: "FGT", "Gulfstream", or a numerical \$/mmBTU value. If filled in with either "FGT" or "Gulfstream", FPL will use its forecast for FGT or Gulfstream firm gas transportation costs for purposes of proposal evaluation. If filled in with a numerical \$/mmBTU value, FPL will use that value for evaluation purposes. **For evaluation purposes, FPL will apply the Guaranteed Fuel Transportation Cost to the capacity associated with the Base Operational Mode only.**

FPL Capacity RFP

Form # 5: Pricing Information for Purchased Power or System Proposals

Facility Name: ______________________________

3) Guaranteed Startup Prices ($/startup): * * * ________ (Hot: 0 - 12 hours offline)
________ (Warm: 12 - 72 hours offline)
________ (Cold: greater than 72 hours offline)

* * * Successful starts are limited to one per dispatch cycle.

FPL Capacity RFP

Form # 6: Pricing Information for Turnkey Project Sales

Facility Name: ______________________________

1) Date (month/day/year) of the proposed sale of the turnkey facility to FPL: ____/____/____

2) Guaranteed total sale price of the proposed facility on the Sale Date (total dollars): ____________

3) Projected average annual fixed O&M cost over a ten (10) - year period from the Sale Date **($/guaranteed total Summer kW)**: ____________ *

4) Projected average annual variable O&M costs over a ten (10) - year period from the Sale Date **($/mwh)**: ____________ *

5) Projected average annual capital replacement cost over a ten (10) - year period from the Sale Date **(total dollars/year)**: ____________ *

* assumes no escalation over time

Form # 7: Key Milestones & Completion Security Agreement

Facility Name: ______________________________________

1) Key Milestones	Expected Completion Date
a) Granted Need Determination (if applicable)	____________
b) Granted Site Certification	____________
c) Financial Closing	____________
d) Fuel Supply Arrangements Finalized	____________
e) Construction Start	____________
f) Major Equipment Deliveries (specify all)	____________
g) Acceptance Testing (specify all)	____________
h) Capacity and/or Energy Delivery Date	____________

2) Completion Security Agreement (for firm capacity Bids only):

Bidder (Insert One: "Agrees" or "Disagrees")______________ with the Completion Security Agreement provisions set forth in Section IV.H. (2) of this RFP.

If Bidder disagrees with the Completion Security Agreement provisions set forth in Section IV.H. (2) of this RFP, use the space below to present revised language concerning a Completion Security Agreement that is acceptable to the Bidder.

Form # 8: Delivery Point(s) to FPL

Facility Name: ______________________________

1) State the delivery point(s) to the FPL system including nearest substation(s):

____

____

____

2) Attach a transmission map highlighting the delivery point(s) listed above.

FPL Capacity RFP

*Form # 9: Bidder Exceptions **

Facility Name:____________________________________

* Note: FPL will not consider proposed exceptions to the RFP's Minimum Requirements for proposal eligibility.

1) With regard to this proposal, the Bidder takes **no** exception to terms, conditions, or other facets of the RFP (Check One): ________ Agrees ________ Disagrees

2) If the answer to item (1) above is "Disagrees", then for each term, condition, or other facet of the RFP which the Bidder takes exception to, use the space below to:

   a) identify the language (citing page and paragraph) in the RFP for which an exception is made; and,

   b) write out revised language proposed by the Bidder

FPL Capacity RFP

Form # 10: Proposal Certification

Facility Name: ____

The undersigned certifies that (i) all of the information submitted in its proposal to FPL is complete and accurate, (ii) the terms, conditions, and other facets of the RFP are acceptable, except as specifically noted on Form # 9, if any, (iii) the proposal has been submitted in the legal name of the entity which would be bound by any resulting contract, and (iv) the proposal is firm and will remain open for 120 days from May 24, 2002.

Name of Legal Entity: ________________________

State of Incorporation: ________________________

Business Address: ________________________

Name of Person Certifying Proposal: ____________________

Title: ________________________

Date: ________________________

Telephone: ________________________

Signature:* ________________________

(* An Officer of the bidding company must sign the copy of this form which is included in the bound hard copy of the proposal.)

VI. FPL's "Next Planned Generating Unit"

A. Overview

In its 2002 Ten Year Site Plan, FPL presented the following new capacity additions as its plans to meet its new capacity needs starting in 2005 and 2006:

For 2005:

- conversion of 2 combustion turbines (CT's) at FPL's existing Martin site, plus the addition of 2 more CT's into 1 combined cycle (CC) unit which adds 789 MW (Summer);
- construction of a new 4 CT-based CC unit at FPL's existing Manatee Site which adds 1,107 incremental MW (Summer).

For 2006:

- No additions.

Therefore, FPL presents these new capacity additions as its "next planned generating units" in accordance with Rule 25-22.082, Florida Administrative Code.

B. Required Information

Rule 25-22.082 (4) (a), Florida Administrative Code, requires a technical description of the utility's next planned generating units on which its RFP is based, including the following information:

1) a description of the utility's next planned generating unit and its proposed location;
2) the MW size;
3) the estimated in-service date;
4) the primary and secondary fuel type;
5) an estimate of the annual revenue requirements;
6) an estimate of the annual economic value of deferring construction;
7) an estimate of the fixed and variable operation and maintenance expenses;
8) an estimate of the fuel cost;
9) an estimate of the planned and forced outage rates, heat rate, minimum load and ramp rates;
10) a description and estimate of the costs required for associated facilities such as gas laterals and transmission interconnection;
11) a discussion of the actions necessary to comply with environmental requirements; and,
12) a summary of all major assumptions used in developing the above estimates.

C. Tables

The technical information required by Rule 25-22.082 (4) (a) is presented in Tables VI-1 and VI-2 for each of the capacity additions listed above.

Table VI – 1

Planned Unit Data – Conversion of 2 Martin CT's to CC Unit in 2005

The following data represent FPL's current estimates for this capacity addition. These estimates are provided for information purposes only. These planning estimates are subject to further refinement in regard to site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals. FPL periodically updates its planning assumptions and will use its most current planning data to evaluate proposals and its self-build options.

1. A 4x1 combined cycle generating unit to be located on FPL's existing Martin site in Martin County, Florida.
2. Planned size 1107 MW (summer rating after conversion).
3. Commercial operation for the facility is proposed to be June, 2005.
4. The primary fuel is natural gas. Low Sulfur Light Oil will be the secondary fuel type.
5. The estimated total direct cost (without AFUDC) is $426 million (in 2005$).
6. The estimated annual levelized revenue requirement with AFUDC is $74.9 million over 25 years.
7. The estimated annual value of deferral with AFUDC of this unit is $60.00/kw-yr (2005$).
8. The estimated fixed O&M and capital replacement expense is $7.75 million (2001$). The estimated variable O&M is $0.30 million (2001$).
9. The estimated fuel cost is $3.41/MMBtu (2005$), plus fixed transportation at a rate of $0.60/MMBtu.
10. The following are the estimates for:

Planned Outage Factor	2%
Forced Outage Rate	1%
Heat Rate at maximum capacity	6850 Btu/kWh @75F 100% (Base Operational Mode)
Minimum load	270 MW
Ramp Rate	15 MW/min

11. The estimated transmission interconnection and integration costs associated with this unit are $37 million (in 2005$).
12. Air and water discharge permits will be required for this unit. It is the Company's plan to comply with all air and water quality standards of both the State and Federal governments.
13. The major financial assumptions in the development of these numbers were:

Construction escalation	1.7%
General escalation	2.5%
Fuel escalation	Varies by year
Capital Structure	45% debt @ 7.40% 55% equity @ 11.7

Table VI – 2

Planned Unit Data – Manatee No. 3 CC Unit in 2005

The following data represent FPL's current estimates for this capacity addition. These estimates are provided for information purposes only. These planning estimates are subject to further refinement in regard to site specific costs, detailed engineering, or vendor quotes. The final actual cost of a project could be appreciably greater or smaller than that shown. Parties responding to this RFP should rely on their own independent evaluations and estimates of project costs in formulating their proposals. FPL periodically updates its planning assumptions and will use its most current planning data to evaluate proposals and its self-build options.

1. A 4x1 combined cycle generating unit to be located on FPL's existing Manatee site in Manatee County, Florida.
2. Planned size 1107 MW (summer rating).
3. Commercial operation for the facility is proposed to be June, 2005.
4. The primary fuel is natural gas. No secondary fuel is proposed.
5. The estimated total direct cost (without AFUDC) is $505.1 million (in 2005$).
6. The estimated annual levelized revenue requirement with AFUDC is $89.6 million over 25 years.
7. The estimated annual value of deferral with AFUDC of this unit is $76.80/kw-yr (2005$).
8. The estimated fixed O&M and capital replacement expense is $14.35 million (2001$). The estimated variable O&M is $0.30 million (2001$).
9. The estimated fuel cost is $3.41/MMBtu (2005$), plus fixed transportation at a rate of $0.60/MMBtu.
10. The following are the estimates for:

Planned Outage Factor	2%
Forced Outage Rate	1%
Heat Rate at maximum capacity	6850 Btu/kWh @75F 100% (Base Operational Mode)
Minimum load	270 MW
Ramp Rate	15 MW/min

11. The estimated transmission interconnection and integration costs associated with this unit are $23 million (in 2005$).
12. Air and water discharge permits will be required for this unit. It is the Company's plan to comply with all air and water quality standards of both the State and Federal governments.
13. The major financial assumptions in the development of these numbers were:

Construction escalation	1.7%
General escalation	2.5%
Fuel escalation	Varies by year
Capital Structure	45% debt @ 7.40% 55% equity @ 11.7

Appendix G

FPL's Forecast of Peak Demand, Net Energy for Load (NEL) and Results of Summer Peak and Winter Peak Runs

	Annual Peaks		NEL
Year	Jan (Winter)	Aug (Summer)	Annual
2001	18,199	18,754	99,162,438
2002	18,968	19,131	100,158,029
2003	19,551	19,765	104,413,713
2004	19,976	20,226	108,042,500
2005	20,418	20,719	111,772,244
2006	20,854	21,186	115,602,075
2007	21,204	21,556	118,157,253
2008	21,538	21,870	120,549,022
2009	21,966	22,271	122,922,491
2010	22,366	22,687	125,448,019
2011	22,785	23,106	127,512,390
2012	23,188	23,495	128,965,087
2013	23,592	23,887	130,434,281
2014	24,018	24,294	132,014,330
2015	24,428	24,696	133,571,234
2016	24,862	25,110	135,222,711
2017	25,256	25,489	136,989,493
2018	25,699	25,890	138,628,629
2019	26,100	26,267	140,152,858
2020	26,554	26,680	141,532,815
2021	27,016	27,100	142,926,360

YEAR	WPKUN	TotCust	WPERCUST	HTSAT	MINWDTMP	HSATEMP
1970	4716	1,253,124	3.76	42.7	35.6	1520.2
1971	5059	1,340,416	3.77	45.9	33.0	1517 4
1972	4816	1,446,114	3.33	48.4	43.2	2090.8
1973	5853	1,567,638	3 73	50.8	40.3	2048 4
1974	6258	1,676,022	3 73	53.3	42.4	2260 4
1975	5807	1,738,071	3 34	55.8	46.0	2565 4
1976	7287	1,795,793	4.06	58.2	39.6	2305 2
1977	8723	1,875,821	4.65	60.6	33.2	2009.2
1978	8617	1,967,352	4.38	63.0	35.0	2205.3
1979	8791	2,074,327	4.24	65 4	38.8	2539.7
1980	9732	2,184,974	4.45	67 8	31.0	2105.4
1981	11360	2,285,187	4.97	70.3	30.6	2149.6
1982	11345	2,358,167	4.81	72.1	30.9	2224.9
1983	9280	2,429,688	3.82	73.9	40.2	2972.2
1984	11050	2,520,523	4.38	75.7	30.0	2274.1
1985	12533	2,617,556	4.79	77.5	28 8	2228.6
1986	12139	2,723,555	4.46	79.3	32 7	2592.0
1987	10779	2,840,207	3 80	81.1	40.1	3248.6
1988	12372	2,953,663	4 19	81.7	42 4	3465.3
1989	12876	3,064,436	4 20	82.4	35.3	2907.8
1990	16046	3,158,817	5.08	83.0	28.4	2358.9
1991	11868	3,226,455	3.68	84.8	38.6	3271.3
1992	13319	3,281,238	4.06	86.6	42.7	3700.1
1993	12932	3,355,794	3.85	87.1	40.8	3551.4
1994	12594	3,422,187	3.68	87.5	48.2	4220.5
1995	16563	3,488,796	4.75	87 9	36.0	3165.8
1996	18252	3,550,747	5.14	88.3	33.5	2954.6
1997	17298	3,615,485	4.78	88 5	35.3	3120.3
1998	13060	3,680,470	3.55	88.7	48.2	4277.0
1999	16802	3,756,009	4.47	88.9	40.0	3556.0
2000	17057	3,848,401	4.43	89 1	38.8	3457.1
2001	18,199	3,935,007	4.62	89.4	36.0	3216 6
2002	.	4,004,161	.	89.2	34.5	3077.4
2003	.	4,079,038	.	90.0	34.5	3105.0
2004	.	4,151,237	.	90.6	34.5	3125.7
2005	.	4,225,960	.	91.3	34.5	3149.9
2006	.	4,299,491	.	91.9	34.5	3170.6
2007	.	4,365,095	.	92.5	34.5	3191.3
2008	.	4,428,309	.	93.1	34.5	3212.0
2009	.	4,490,271	.	93.7	34.5	3232.7
2010	.	4,551,096	.	94.1	34.5	3246.5
2011	.	4,610,993	.	94.5	34.5	3260.3
2012	.	4,670,075	.	94.9	34.5	3274.1
2013	.	4,728,447	.	95.3	34.5	3287.9
2014	.	4,786,202	.	95.7	34.5	3301.7
2015	.	4,843,426	.	96.1	34.5	3315.5
2016	.	4,900,198	.	96.5	34.5	3329.3
2017	.	4,956,589	.	96.9	34.5	3343.1
2018	.	5,012,663	.	97.3	34.5	3356.9
2019	.	5,068,480	.	97.7	34.5	3370.7
2020	.	5,124,093	.	98.1	34.5	3384.5

PRIORAM	DUMM8090	FLNONAG	MINWDTMP2	HSATEMP2	FI_inc	CPI
812	0	2,152	35.6	1520	27,419	38 8
459	0	2,276	33.0	1517	30,701	40 5
536	0	2,513	43.2	2091	35,365	41 8
407	0	2,779	40.3	2048	41,495	44 4
569	0	2,864	42.4	2260	46,712	49 3
536	0	2,746	46.0	2565	50,353	53 8
711	0	2,784	39.6	2305	55,438	56 9
755	0	2,933	33.2	2009	62,309	60 6
675	0	3,181	35.0	2205	72,332	65 2
676	0	3,381	38.8	2540	84,094	72 6
490	1	3,576	31.0	2105	98,882	82 4
855	1	3,736	30.6	2150	114,110	90.9
779	1	3,762	30.9	2225	123,450	96.5
461	1	3,905	40.2	2972	135,842	99 6
939	1	4,204	30.0	2274	151,952	103 9
927	1	4,410	28.8	2229	166,919	107 6
616	1	4,599	32.7	2592	179,952	109.6
526	1	4,848	40.1	3249	196,939	113.6
600	1	5,067	42.4	3465	216,505	118 3
738	1	5,261	35.3	2908	240,687	124 0
790	1	5,387	28 4	2359	258,479	130 7
300	1	5,294	38.6	3271	268,304	136 2
558	1	5,359	42 7	3700	279,028	140.3
601	1	5,571	40.8	3551	296,927	144.5
445	1	5,799	48.2	4221	311,909	148.2
504	1	5,996	36.0	3166	333,525	152 4
670	1	6,183	33 5	2955	355,136	156.9
743	1	6,414	35.3	3120	377,673	160 5
425	1	6,637	48.2	4277	401,489	163 0
674	1	6,827	40.0	3556	419,800	166 6
512	1	7,076	38.8	3457	449,817	172.2
642	1	7,266	36.0	3217	480,606	177.01
684	1	7,431	36.0	3211	499,515	181.41
684	1	7,573	36.0	3240	519,804	186.48
684	1	7,710	36.0	3262	542,826	191.72
684	1	7,839	36.0	3287	566,701	196.97
684	1	7,962	36.0	3308	591,616	202.10
684	1	8,083	36.0	3330	607,191	207.31
684	1	8,207	36.0	3352	637,136	212.62
684	1	8,336	36.0	3373	672,395	218.02
684	1	8,468	36.0	3388	706,092	223.51
684	1	8,602	36.0	3402	745,166	229.10
684	1	8,738	36.0	3416	782,491	234.83
684	1	8,876	36.0	3431	821,664	240.70
684	1	9,016	36.0	3445	867,135	246.72
684	1	9,158	36.0	3460	910,523	252.89
684	1	9,303	36.0	3474	960,911	259.21
684	1	9,450	36.0	3488	1,003,844	265.69
684	1	9,599	36.0	3503	1,059,396	272.33
684	1	9,753	36.0	3517	1,106,614	279 14
684	1	9,909	36.0	3532	1,167,853	286.12

WINTER PEAK MODEL: DEPENDENT VARIABLE WINTER PEAK PER CUSTOMER

Variable	Coefficient	StdErr	T-Stat	P-Value	
CONST	5 821	0 7252	8 027	0 00%	Constant
RFLINC	0 00024	0 000245	0 974	34 08%	Real FL income
INWDTMP2	-0 086	0 0300	-2 878	0 87%	Min Winter Peak Day Temp
SATEMP2	0 0003	0 0004	0 881	38 76%	Heat Saturation * Temp
PRIORAM	0 001	0 0004	2 320	3 00%	HDD Prior day until 9AM day of Peak
UMTMP36	-0 009	0 0075	-1 168	25 54%	Dummy * Temp
SAR(1)	0 186	0 1956	0 952	35 12%	Auto-Regressive term

Estimation period: 1970 - 2001

Year	Winter Peak	Total Customers	Winter Peak Customer	Winter Peak Customer Pred	RFLINC	MINWDTMP2	HSATEMP2	PRIORAM	DUMTMP36
1970	4,716	1,253,124	3 76		707	36	1,520 16	812 37	0
1971	5,059	1,340,416	3 77	3 99	758	33	1,517 40	458 84	0
1972	4,816	1,446,114	3 33	3 41	846	43	2,090 81	535 86	0
1973	5,853	1,567,638	3 73	3 59	935	40	2,048 35	407 05	0
1974	6,258	1,676,022	3 73	3 66	948	42	2,260 37	568 65	0
1975	5,807	1,738,071	3 34	3 42	936	46	2,565 37	535 84	0
1976	7,287	1,795,793	4 06	4 01	974	40	2,305 15	711 13	0
1977	8,723	1,875,821	4 65	4 53	1,028	33	2,009 25	755 01	0
1978	8,617	1,967,352	4 38	4 41	1,109	35	2,205 33	674 82	0
1979	8,791	2,074,327	4 24	4 18	1,158	39	2,539 66	675 59	0
1980	9,732	2,184,974	4 45	4 30	1,200	31	2,105 45	489 84	31
1981	11,360	2,285,187	4 97	4 69	1,255	31	2,149 58	855 00	31
1982	11,345	2,358,167	4 81	4 66	1,279	31	2,224 94	778 89	31
1983	9,280	2,429,688	3 82	3 78	1,364	40	2,972 21	460 66	40
1984	11,050	2,520,523	4 38	4 89	1,462	30	2,274 11	939 30	30
1985	12,533	2,617,556	4 79	4 90	1,551	29	2,228 60	926 92	29
1986	12,139	2,723,555	4 46	4 47	1,642	33	2,591 97	615 55	33
1987	10,779	2,840,207	3 80	3 98	1,734	40	3,248 55	525 61	40
1988	12,372	2,953,663	4 19	3 89	1,830	42	3,465 26	599 65	42
1989	12,876	3,064,436	4 20	4 59	1,941	35	2,907 76	737 67	35
1990	16,046	3,158,817	5 08	4 99	1,978	28	2,358 89	789 66	28
1991	11,868	3,226,455	3 68	4 01	1,970	39	3,271 34	300 24	39
1992	13,319	3,281,238	4 06	3 92	1,989	43	3,700 12	557.77	43
1993	12,932	3,355,794	3 85	4 18	2,055	41	3,551 36	601 13	41
1994	12,594	3,422,187	3 68	3 52	2,105	48	4,220 51	445 27	48
1995	16,563	3,488,796	4 75	4 46	2,188	36	3,165 77	503 51	36
1996	18,252	3,550,747	5 14	4 82	2,263	33	2,954 60	669 67	33
1997	17,298	3,615,485	4 78	4 80	2,353	35	3,120 32	742 88	35
1998	13,060	3,680,470	3 55	3 68	2,463	48	4,277 01	425 17	48
1999	16,802	3,756,009	4 47	4 39	2,520	40	3,556 00	674 00	40
2000	17,057	3,848,401	4 43	4 39	2,612	39	3,457 08	512 00	39
2001	18,199	3,935,007	4 62	4 70	2,715	36	3,216 60	641 54	36
2002		4,004,161		4 74	2,754	36	3,211 20	684 21	36
2003		4,079,038		4 77	2,787	36	3,240 00	684 21	36
2004		4,151,237		4 79	2,831	36	3,261 60	684 21	36
2005		4,225,960		4 81	2,877	36	3,286 80	684 21	36
2006		4,299,491		4 83	2,927	36	3,308 40	684 21	36
2007		4,365,095		4 84	2,929	36	3,330 00	684 21	36
2008		4,428,309		4 86	2,997	36	3,351 60	684 21	36
2009		4 490,271		4 89	3,084	36	3,373 20	684 21	36
2010		4,551,096		4 91	3,159	36	3,387 60	684 21	36
2011		4,610,993		4 94	3,253	36	3,402 00	684 21	36
2012		4,670,075		4 97	3,332	36	3,416 40	684 21	36
2013		4,728,447		4 99	3,414	36	3,430 80	684 21	36
2014		4,786,202		5 02	3,515	36	3,445 20	684 21	36
2015		4 843 426		5 04	3,600	36	3,459 60	684 21	36
2016		4 900,198		5 07	3,707	36	3,474 00	684 21	36
2017		4,956 589		5 10	3,778	36	3,488 40	684 21	36
2018		5,012,663		5 13	3,890	36	3,502 80	684 21	36
2019		5,068,480		5 15	3,964	36	3,517 20	684 21	36
2020		5,124 093		5 18	4,082	36	3,531 60	684 21	36

Regression Statistics	
Iterations	15
Adjusted Observations	31
Deg of Freedom for Error	24
R-Squared	0 837
Adjusted R-Squared	0 797
Durbin-Watson Statistic	2 123
Durbin-H Statistic	#NA
AIC	-2.74
BIC	-2 417
F-Statistic	20 609
Prob (F-Statistic)	0
Log-Likelihood	5 31
Model Sum of Squares	7
Sum of Squared Errors	1
Mean Squared Error	0 05
Std Error of Regression	0.23
Mean Abs Dev (MAD)	0.16
Mean Abs % Err (MAPE)	3.84%
Ljung-Box Statistic	4 73
Prob (Ljung-Box)	0 449

DEPENDENT VARIABLE: WINTER PEAK PER CUSTOMER

ELASTICITIES

Variable	Coefficient	Mean	Elast	
RFLINC	0 000	1,620.9	0 092	Real FL income
MINWDTMP2	-0 086	37.365	-0 764	Min Winter Peak Day Temp
HSATEMP2	0 000	2,752 500	0 227	Heat Saturation * Temp
PRIORAM	0 001	622.721	0 120	HDD Prior day until 9AM day of Peak
DUMTMP36	-0 009	25 3	-0 052	Dummy * Temp

Year	Actual	Pred		TotCust	WINPEAK						
1970	3 763			1,253,124							
1971	3 774	3 992		1,340,416							
1972	3 330	3 411		1,446,114							
1973	3 734	3 588		1,567,638							
1974	3 734	3 660		1,676,022							
1975	3 341	3 424		1,738,071							
1976	4 058	4 008		1,795,793							
1977	4 650	4 528		1,875,821							
1978	4 380	4 408		1,967,352							
1979	4 238	4 182		2,074,327							
1980	4 454	4 302		2,184,974							
1981	4 971	4 692		2,285,187							
1982	4 811	4 662		2,358,167							
1983	3 819	3 776		2,429,688							
1984	4 384	4 889		2,520,523							
1985	4 788	4 900		2,617,556							
1986	4 457	4 473		2,723,555							
1987	3 795	3 978		2,840,207							
1988	4 189	3 891		2,953,663							
1989	4 202	4 595		3,064,436							
1990	5 080	4 995		3,158,817							
1991	3 678	4 015		3,226,455							
1992	4 059	3 919		3,281,238							
1993	3 854	4 180		3,355,794							
1994	3 680	3 517		3,422,187		**36 DEGREES**					
1995	4 747	4 455		3,488,796							
1996	5 140	4 816		3,550,747	**WPKUN**				**WINPEAK**		
1997	4 784	4 797		3,615,485							
1998	3 548	3 676		3,680,470				FMPA			
1999	4 473	4 389		3,756,009							
2000	4 432	4 392		3,848,401							
2001	4 625	4 702		3,935,007	18,199	<<Actual			18,199	<<Actual	
2002		4 737		4,004 161	18,968	769	4 2%	[redacted]	**18,968**	769	4 2%
2003		4 775		4,079,038	19,476	507	2 7%	75	**19,551**	582	3 1%
2004		4 794		4,151,237	19,901	426	2 2%	75	**19,976**	426	2 2%
2005		4 814		4,225 960	20,343	441	2 2%	75	**20,418**	441	2 2%
2006		4 833		4 299 491	20,779	436	2 1%	75	**20,854**	436	2 1%
2007		4 840		4,365,095	21,129	350	1 7%	75	**21,204**	350	1 7%
2008		4 864		4,428 309	21,538	409	1 9%		**21,538**	334	1 6%
2009		4 892		4,490 271	21,966	427	2 0%		**21,966**	427	2 0%
2010		4 914		4 551 096	22,366	400	1 8%		**22,366**	400	1 8%
2011		4 941		4,610,993	22,785	419	1 9%		**22,785**	419	1 9%
2012		4 965		4,670,075	23,188	403	1 8%		**23,188**	403	1 8%
2013		4 989		4,728 447	23,592	404	1 7%		**23,592**	404	1 7%
2014		5 018		4,786 202	24,018	426	1 8%		**24,018**	426	1 8%
2015		5 043		4,843 426	24,428	409	1 7%		**24,428**	409	1 7%
2016		5 074		4 900,198	24,862	434	1 8%		**24,862**	434	1 8%
2017		5 095		4,956 589	25,256	394	1 6%		**25,256**	394	1 6%
2018		5 127		5,012 663	25,699	443	1 8%		**25,699**	443	1 8%
2019		5 149		5,068 480	26,100	400	1 6%		**26,100**	400	1 6%
2020		5 182		5,124 093	26,554	454	1 7%		**26,554**	454	1 7%

Year	Summer Peak	TotCust	ELECPRI	MAXTMP	FLNONAG	FLINC	CPI	Dummy
1965	2,529	949,591	2.06	89.0	1,619.1	14,872,711	31.5	0
1966	2,827	1,000,020	1.97	90.8	1,726.8	16,388,588	32.4	0
1967	3,160	1,051,335	1.87	90.3	1,816.4	18,155,097	33.4	0
1968	3,789	1,050,200	1.83	91.8	1,932.3	20,897,819	34.8	0
1969	4,329	1,177,347	1.81	93.3	2,069.9	24,297,276	36.7	0
1970	5,001	1,253,124	1.80	93.5	2,152.1	27,419,366	38.8	0
1971	5,378	1,340,416	1.88	92.6	2,276.4	30,701,044	40.5	0
1972	6,011	1,446,114	1.96	89.9	2,513.1	35,365,052	41.8	0
1973	6,894	1,567,638	2.18	91.1	2,778.6	41,494,668	44.4	0
1974	7,235	1,676,022	2.87	90.5	2,863.8	46,712,426	49.3	0
1975	7,076	1,738,071	3.42	90.0	2,746.4	50,353,108	53.8	1
1976	7,598	1,795,793	3.36	92.7	2,784.3	55,437,981	56.9	1
1977	7,841	1,875,821	3.86	92.0	2,933.2	62,309,059	60.6	1
1978	8,345	1,967,352	4.02	90.8	3,180.6	72,332,145	65.2	1
1979	8,650	2,074,327	4.54	91.9	3,381.2	84,093,751	72.6	1
1980	9,623	2,184,974	5.19	94.8	3,576.2	98,881,848	82.4	1
1981	9,738	2,285,187	6.53	95.7	3,736.0	114,109,540	90.9	1
1982	9,862	2,358,167	6.48	92.5	3,761.9	123,450,308	96.5	1
1983	10,676	2,429,688	6.62	95.9	3,905.4	135,842,481	99.6	1
1984	10,270	2,520,523	7.93	93.6	4,204.2	151,951,597	103.9	1
1985	10,654	2,617,556	8.25	94.5	4,410.0	166,919,255	107.6	1
1986	11,022	2,723,555	7.50	93.2	4,599.4	179,951,679	109.6	1
1987	12,394	2,840,207	7.44	95.8	4,848.1	196,939,232	113.6	1
1988	12,382	2,953,663	7.66	93.5	5,066.6	216,504,523	118.3	1
1989	13,425	3,064,436	7.36	95.4	5,260.9	240,686,677	124.0	1
1990	13,754	3,158,817	7.36	95.0	5,387.4	258,479,049	130.7	1
1991	14,123	3,226,455	7.57	92.9	5,294.3	268,304,176	136.2	1
1992	14,661	3,281,238	7.32	95.4	5,358.7	279,028,337	140.3	1
1993	15,266	3,355,794	7.38	94.3	5,571.4	296,927,420	144.5	1
1994	15,179	3,422,187	6.85	91.6	5,799.4	311,908,852	148.2	1
1995	16,172	3,488,796	6.96	94.2	5,996.1	333,525,354	152.4	1
1996	16,064	3,550,747	7.39	91.3	6,183.3	355,135,853	156.9	1
1997	16,613	3,615,485	7.57	92.6	6,414.4	377,673,158	160.5	1
1998	17,897	3,680,470	7.12	94.9	6,636.5	401,488,554	163.0	1
1999	**18,040**	3,756,009	6.83	94.3	6,827.0	419,800,453	166.6	1
2000	**18,086**	3,848,401	6.84	92.3	7,076.4	449,816,610	172.2	1
2001	**18,755**	3,935,007	8.13	**93.0**	7,266	**480,605,551**	177.01	1
2002		4,004,161	7.96	92.0	7,431	**499,515,489**	181.41	1
2003		4,079,038	7.39	92.0	7,573	**519,804,294**	186.48	1
2004		4,151,237	7.25	92.0	7,710	**542,826,291**	191.72	1
2005		4,225,960	7.05	92.0	7,839	**566,700,563**	196.97	1
2006		4,299,491	6.94	92.0	7,962	**591,616,338**	202.10	1
2007		4,365,095	6.92	92.0	8,083	**607,191,303**	207.31	1
2008		4,428,309	6.96	92.0	8,207	**637,135,849**	212.62	1
2009		4,490,271	7.01	92.0	8,336	**672,394,561**	218.02	1
2010		4,551,096	6.96	92.0	8,468	**706,091,576**	223.51	1
2011		4,610,993	6.93	92.0	8,602	**745,166,257**	229.10	1
2012		4,670,075	6.98	92.0	8,738	**782,490,853**	234.83	1
2013		4,728,447	7.01	92.0	8,876	**821,664,457**	240.70	1
2014		4,786,202	7.04	92.0	9,016	**867,134,871**	246.72	1
2015		4,843,426	7.05	92.0	9,158	**910,522,989**	252.89	1
2016		4,900,198	7.07	92.0	9,303	**960,910,781**	259.21	1
2017		4,956,589	7.12	92.0	9,450	**1,003,843,700**	265.69	1
2018		5,012,663	7.21	92.0	9,599	**1,059,395,803**	272.33	1
2019		5,068,480	7.29	92.0	9,753	**1,106,613,737**	279.14	1
2020		5,124,093	7.36	92.0	9,909	**1,167,853,073**	286.12	1

SUMMER PEAK MODEL: DEPENDENT VARIABLE SUMMER PEAK PER CUSTOMER

Variable	Coefficient		StdErr	T-Stat	P-Value	Definition
CONST	0.292		1.198	0.244	80.92%	Constant term
RPRICE	-0.137		0.055	-2.479	1.92%	Real Price
RFLINC	0.00000017		0.00000018	0.924	36.29%	Real FL Income (Income divided by CPI)
MAXTMP	0.050		0.011	4.463	0.01%	Max Summer Temp
AR(1)	0.813		0.076	10.763	0.00%	Auto-regresive term

Estimation Period: 1965 - 2001

Year	Summer Peak/Customer	Pred	RPRICE	RFLINC	MAXTMP	Customers
1965	2.66		6.53	472,150	89.00	949,591
1966	2.83	3.05	6.07	505,821	90.80	1,000,020
1967	3.01	3.10	5.58	543,566	90.30	1,051,335
1968	3.61	3.34	5.25	600,512	91.80	1,050,200
1969	3.68	3.85	4.93	662,051	93.30	1,177,347
1970	3.99	3.86	4.64	706,685	93.50	1,253,124
1971	4.01	4.03	4.63	758,050	92.60	1,340,416
1972	4.16	3.95	4.70	846,054	89.90	1,446,114
1973	4.40	4.22	4.92	934,565	91.10	1,567,638
1974	4.32	4.23	5.82	947,514	90.50	1,676,022
1975	4.07	4.18	6.36	935,931	90.00	1,738,071
1976	4.23	4.27	5.90	974,305	92.70	1,795,793
1977	4.18	4.14	6.36	1,028,202	92.00	1,875,821
1978	4.24	4.16	6.17	1,109,389	90.80	1,967,352
1979	4.17	4.27	6.25	1,158,316	91.90	2,074,327
1980	4.40	4.32	6.30	1,200,022	94.80	2,184,974
1981	4.26	4.32	7.18	1,255,330	95.70	2,285,187
1982	4.18	4.17	6.71	1,279,278	92.50	2,358,167
1983	4.39	4.37	6.64	1,363,880	95.90	2,429,688
1984	4.07	4.16	7.63	1,462,479	93.60	2,520,523
1985	4.07	4.14	7.67	1,551,294	94.50	2,617,556
1986	4.05	4.16	6.84	1,641,895	93.20	2,723,555
1987	4.36	4.27	6.55	1,733,620	95.80	2,840,207
1988	4.19	4.29	6.47	1,830,131	93.50	2,953,663
1989	4.38	4.41	5.94	1,941,022	95.40	3,064,436
1990	4.35	4.44	5.63	1,977,651	95.00	3,158,817
1991	4.38	4.30	5.56	1,969,928	92.90	3,226,455
1992	4.47	4.57	5.22	1,988,798	95.40	3,281,238
1993	4.55	4.47	5.11	2,054,861	94.30	3,355,794
1994	4.44	4.50	4.62	2,104,648	91.60	3,422,187
1995	4.64	4.61	4.57	2,188,487	94.20	3,488,796
1996	4.52	4.50	4.71	2,263,453	91.30	3,550,747
1997	4.59	4.61	4.72	2,353,104	92.60	3,615,485
1998	4.86	4.78	4.37	2,463,120	94.94	3,680,470
1999	4.80	4.87	4.10	2,519,811	94.31	3,756,009
2000	4.70	4.74	3.97	2,612,175	92.30	3,848,401
2001	4.77	4.68	4.59	2,715,132	93.00	3,935,007
2002		4.76	4.39	2,753,517	92.00	4,004,161
2003		4.83	3.96	2,787,453	92.00	4,079,038
2004		4.85	3.78	2,831,349	92.00	4,151,237
2005		4.89	3.58	2,877,091	92.00	4,225,960
2006		4.91	3.44	2,927,345	92.00	4,299,491
2007		4.92	3.34	2,928,905	92.00	4,365,095
2008		4.94	3.28	2,996,594	92.00	4,428,309
2009		4.96	3.21	3,084,096	92.00	4,490,271
2010		4.98	3.11	3,159,105	92.00	4,551,096
2011		5.01	3.03	3,252,581	92.00	4,610,993
2012		5.03	2.97	3,332,159	92.00	4,670,075
2013		5.05	2.91	3,413,645	92.00	4,728,447
2014		5.08	2.85	3,514,652	92.00	4,786,202
2015		5.10	2.79	3,600,471	92.00	4,843,426
2016		5.12	2.73	3,707,075	92.00	4,900,198
2017		5.14	2.68	3,778,252	92.00	4,956,589
2018		5.17	2.65	3,890,118	92.00	5,012,663
2019		5.18	2.61	3,964,368	92.00	5,068,480
2020		5.21	2.57	4,081,690	92.00	5,124,093

Regression Statistics	
Iterations	55
Adjusted Observations	36
Deg. of Freedom for Error	31
R-Squared	0 937
Adjusted R-Squared	0 928
Durbin-Watson Statistic	2 327
Durbin-H Statistic	#NA
AIC	-4.211
BIC	-3.991
F-Statistic	114 539
Prob (F-Statistic)	0
Log-Likelihood	29.72
Model Sum of Squares	6
Sum of Squared Errors	0
Mean Squared Error	0.01
Std. Error of Regression	0.11
Mean Abs. Dev. (MAD)	0.09
Mean Abs. % Err. (MAPE)	2.20%
Ljung-Box Statistic	3 78
Prob (Ljung-Box)	0.581

DEPENDENT VARIABLE: SUMMER PEAK PER CUSTOMER

ELASTICITIES

Variable	Coefficient	Mean	Elast	
RPRICE	-0.137	5.654	-0 185	Real Price
RFLINC	0 000	1,477,110 0	0.059	Real FL Income (Income divided by CPI)
MAXTMP	0 050	92.891	1.099	Max Summer Temp

Year	Summer Peak Customer	Actual	Pred		TotCust	SPKUN	DIFF	%						
1965	2 66	2 663			949 591									
1966	2 83	2 827	3 050		1,000,020									
1967	3 01	3 006	3 103		1,051,335									
1968	3 61	3 608	3 340		1 050,200									
1969	3 68	3 677	3 851		1,177,347									
1970	3 99	3 991	3 861		1,253,124									
1971	4 01	4 012	4 034		1,340,416									
1972	4 16	4 157	3 952		1,446,114									
1973	4 40	4 398	4 217		1,567,638									
1974	4 32	4 317	4 227		1,676,022									
1975	4 07	4 071	4 182		1,738 071									
1976	4 23	4 231	4 268		1,795 793									
1977	4 18	4 180	4 144		1,875,821									
1978	4 24	4 242	4 155		1,967,352									
1979	4 17	4 170	4 274		2,074,327									
1980	4 40	4 404	4 317		2,184,974									
1981	4 26	4 261	4 323		2,285,187									
1982	4 18	4 182	4 171		2 358 167									
1983	4 39	4 394	4 372		2,429,688									
1984	4 07	4 075	4 156		2,520,523									
1985	4 07	4 070	4 140		2,617 556									
1986	4 05	4 047	4 156		2,723,555									
1987	4 36	4 364	4 269		2,840,207									
1988	4 19	4 192	4 290		2,953,663									
1989	4 38	4 381	4 407		3,064,436									
1990	4 35	4 354	4 438		3,158,817									
1991	4 38	4 377	4 298		3,226,455									
1992	4 47	4 468	4 568		3,281,238								92 Degrees	
1993	4 55	4 549	4 472		3,355,794									
1994	4 44	4 435	4 502		3,422,187									
1995	4 64	4 635	4 607		3,488,796	SPKUN	DIFF	%		FMPA		SPEAK	DIFF	%
1996	4 52	4 524	4 498		3,550,747									
1997	4 59	4 595	4 608		3 615,485									
1998	4 86	4 863	4 784		3 680,470									
1999	4 80	4 803	4 869		3,756,009									
2000	4 70	4 700	4 741		3 848,401									
2001	4 77	4 766	4 678		3 935 007	18,754	<< Actual					18,754	<< Actual	
2002			4 759		4 004 161	19,056	302	1 6%		75		19,131	377	2 0%
2003			4 827		4 079,038	19,690	634	3 3%		75		19,765	634	3 3%
2004			4 854		4 151 237	20,151	462	2 3%		75		20,226	462	2 3%
2005			4 885		4 225,960	20,644	493	2 4%		75		20,719	493	2 4%
2006			4 910		4,299 491	21,111	467	2 3%		75		21,186	467	2 3%
2007			4 921		4 365,095	21,481	370	1 8%		75		21,556	370	1 7%
2008			4 939		4,428 309	21,870	389	1 8%				21,870	314	1 5%
2009			4 960		4 490 271	22 271	401	1 8%				22,271	401	1 8%
2010			4 985		4 551 096	22,687	415	1 9%				22,687	415	1 9%
2011			5 011		4,610 963	23,106	420	1 8%				23,106	420	1 8%
2012			5 031		4 670 075	23,495	389	1 7%				23,495	389	1 7%
2013			5 052		4 728 447	23,887	392	1 7%				23,887	392	1 7%
2014			5 076		4,786 202	24,294	408	1 7%				24,294	408	1 7%
2015			5 099		4 843,426	24,696	401	1 7%				24,696	401	1 7%
2016			5 124		4,900 198	25,110	415	1 7%				25,110	415	1 7%
2017			5 142		4,956,589	25,489	378	1 5%				25,489	378	1 5%
2018			5 165		5 012 663	25,890	402	1 6%				25,890	402	1 6%
2019			5 182		5 068 460	26,267	377	1 5%				26,267	377	1 5%
2020			5 207		5,124 093	26,680	413	1 6%				26,680	413	1 6%

FPL 2002 THROUGH 2030 MOST LIKELY OIL PRICE FORECAST

MAY 10, 2002 - EUGENE UNGAR

	****DELIVERED DISTILLATE FUEL OIL****										******
				****GAS TURBINES AT****		*COMBINED CYCLES AT*				NEW CT'S AT	**0.7%**
	SHADY HILLS	DESOTO	OLEANDER	EVERGLADES	LAUDERDALE	FT MYERS	PUTNAM	LAUDERDALE		MARTIN	MARTIN
	NOMINAL	NOMINAL	NOMINAL	NOMINAL	NOMINAL	NOMINAL	NOMINAL	NOMINAL		NOMINAL	NOMINAL
YEAR	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU		$/MMBTU	$/MMBTU
2002				$5.34	$5.34	$5.59	$5.34	$5.34		$5.60	$3.69
2003				$5.31	$5.31	$5.55	$5.31	$5.31		$5.57	$3.65
2004				$5.35	$5.35	$5.59	$5.36	$5.35		$5.62	$3.67
2005				$5.40	$5.40	$5.64	$5.40	$5.40		$5.67	$3.67
2006				$5.45	$5.45	$5.69	$5.46	$5.45		$5.72	$3.70
2007				$5.50	$5.50	$5.73	$5.50	$5.50		$5.77	$3.72
2008				$5.68	$5.68	$5.91	$5.68	$5.68		$5.95	$3.84
2009				$5.86	$5.86	$6.09	$5.86	$5.86		$6.14	$3.95
2010				$6.04	$6.04	$6.27	$6.04	$6.04		$6.32	$4.07
2011				$6.23	$6.23	$6.46	$6.23	$6.23		$6.51	$4.20
2012				$6.42	$6.42	$6.65	$6.43	$6.42		$6.71	$4.33
2013				$6.63	$6.63	$6.85	$6.63	$6.63		$6.92	$4.46
2014				$6.84	$6.84	$7.05	$6.84	$6.84		$7.13	$4.60
2015				$7.06	$7.06	$7.28	$7.07	$7.06		$7.36	$4.75
2016				$7.30	$7.30	$7.51	$7.30	$7.30		$7.60	$4.90
2017				$7.55	$7.55	$7.75	$7.55	$7.55		$7.86	$5.07
2018				$7.81	$7.81	$8.01	$7.81	$7.81		$8.12	$5.24
2019				$8.09	$8.09	$8.29	$8.09	$8.09		$8.41	$5.42
2020				$8.37	$8.37	$8.57	$8.38	$8.37		$8.69	$5.60
2021				$8.67	$8.67	$8.85	$8.67	$8.67		$8.99	$5.79
2022				$8.97	$8.97	$9.15	$8.98	$8.97		$9.30	$5.99
2023				$9.29	$9.29	$9.46	$9.29	$9.29		$9.62	$6.20
2024				$9.62	$9.62	$9.79	$9.62	$9.62		$9.98	$6.42
2025				$9.96	$9.96	$10.13	$9.97	$9.96		$10.31	$6.64
2026				$10.33	$10.33	$10.48	$10.33	$10.33		$10.68	$6.88
2027				$10.70	$10.70	$10.85	$10.71	$10.70		$11.06	$7.12
2028				$11.09	$11.09	$11.23	$11.10	$11.09		$11.45	$7.37
2029				$11.50	$11.50	$11.63	$11.50	$11.50		$11.86	$7.64
2030				$11.90	$11.90	$12.02	$11.91	$11.90		$12.27	$7.91

FPL 2002 THROUGH 2030 MOST LIKELY OIL PRICE FORECAST

MAY 10, 2002 - EUGENE UNGAR

D E L I V E R E D R E S I D U A L F U E L O I L***************************

	1.0% SULFUR RESIDUAL FUEL OIL							1.8% SULFUR	***2.0% SULFUR***		2.2% SULFUR
YEAR	MARTIN (1) NOMINAL $/MMBTU	EVERGLADES NOMINAL $/MMBTU	MANATEE NOMINAL $/MMBTU	TURKEY POINT NOMINAL $/MMBTU	CANAVERAL NOMINAL $/MMBTU	SANFORD NOMINAL $/MMBTU	RIVIERA NOMINAL $/MMBTU	SANFORD NOMINAL $/MMBTU	EVERGLADES (2) NOMINAL $/MMBTU	TURKEY POINT (2) NOMINAL $/MMBTU	RIVIERA NOMINAL $/MMBTU
2002	$3.55	$3.45	$3.47	$3.53	$3.47	$3.50	$3.55	$3.46	$3.42	$3.49	$3.50
2003	$3.49	$3.46	$3.45	$3.47	$3.49	$3.52	$3.49	$3.48	$3.41	$3.41	$3.42
2004	$3.50	$3.48	$3.47	$3.49	$3.51	$3.54	$3.50	$3.49	$3.41	$3.42	$3.42
2005	$3.50	$3.47	$3.46	$3.48	$3.50	$3.54	$3.50	$3.47	$3.39	$3.40	$3.40
2006	$3.52	$3.49	$3.48	$3.50	$3.52	$3.56	$3.52	$3.49	$3.40	$3.41	$3.41
2007	$3.53	$3.51	$3.50	$3.52	$3.54	$3.58	$3.53	$3.50	$3.42	$3.42	$3.42
2008	$3.64	$3.62	$3.61	$3.63	$3.65	$3.69	$3.64	$3.60	$3.52	$3.53	$3.52
2009	$3.75	$3.73	$3.72	$3.74	$3.76	$3.80	$3.75	$3.71	$3.62	$3.63	$3.62
2010	$3.86	$3.84	$3.83	$3.85	$3.87	$3.91	$3.86	$3.81	$3.72	$3.73	$3.72
2011	$3.98	$3.96	$3.95	$3.97	$3.99	$4.03	$3.98	$3.93	$3.83	$3.84	$3.83
2012	$4.11	$4.08	$4.07	$4.09	$4.11	$4.15	$4.11	$4.04	$3.95	$3.96	$3.95
2013	$4.23	$4.21	$4.20	$4.22	$4.24	$4.28	$4.23	$4.16	$4.06	$4.07	$4.06
2014	$4.36	$4.34	$4.33	$4.35	$4.37	$4.41	$4.36	$4.29	$4.19	$4.19	$4.18
2015	$4.50	$4.48	$4.47	$4.49	$4.51	$4.55	$4.50	$4.42	$4.31	$4.32	$4.31
2016	$4.65	$4.63	$4.61	$4.64	$4.66	$4.70	$4.65	$4.56	$4.45	$4.46	$4.44
2017	$4.81	$4.78	$4.77	$4.79	$4.82	$4.86	$4.81	$4.70	$4.59	$4.60	$4.58
2018	$4.97	$4.95	$4.93	$4.95	$4.98	$5.02	$4.97	$4.86	$4.74	$4.75	$4.73
2019	$5.14	$5.11	$5.10	$5.12	$5.15	$5.19	$5.14	$5.01	$4.89	$4.90	$4.88
2020	$5.31	$5.29	$5.27	$5.30	$5.32	$5.36	$5.31	$5.18	$5.05	$5 06	$5.03
2021	$5.50	$5.47	$5.46	$5.48	$5.51	$5.55	$5.50	$5.34	$5.22	$5.23	$5.20
2022	$5.69	$5.66	$5.64	$5.67	$5.70	$5.74	$5.69	$5.52	$5.39	$5.40	$5.36
2023	$5.88	$5.85	$5.84	$5.86	$5.89	$5.93	$5.88	$5.70	$5.56	$5.57	$5.53
2024	$6.09	$6.06	$6.04	$6.07	$6.10	$6.14	$6.09	$5.89	$5.75	$5.76	$5.71
2025	$6.30	$6.27	$6.26	$6.28	$6.31	$6.35	$6.30	$6.08	$5.94	$5.95	$5.90
2026	$6.53	$6.50	$6.48	$6.51	$6.54	$6.58	$6.53	$6.29	$6.13	$6.14	$6.09
2027	$6.76	$6.73	$6.71	$6.74	$6.77	$6.81	$6.76	$6.50	$6.34	$6.35	$6.29
2028	$7.00	$6.97	$6.95	$6.98	$7.01	$7.05	$7.00	$6.72	$6.55	$6.56	$6.50
2029	$7.25	$7.22	$7.20	$7.23	$7.26	$7.30	$7.25	$6.94	$6.77	$6.78	$6.71
2030	$7.51	$7.48	$7.46	$7.49	$7.52	$7.57	$7.51	$7.18	$6.99	$7.00	$6.93

FPL 2002 THROUGH 2030 MOST LIKELY NATURAL GAS PRICE AND AVAILABILITY FORECAST

MAY 10, 2002 - EUGENE UNGAR

PIPELINE ECONOMICS

	NATURAL GAS PRICE FORECAST FOR NON-FIRM AND EXISTING FIRM TRANSPORTATION CONTRACTS THROUGH PHASE V												ALL PLANTS EXCEPT MANATEE, MARTIN AND MIDWAY NATURAL GAS PRICE FORECAST FIRM FGT PHASE VI TRANSPORTATION			MARTIN, MANATEE AND MIDWAY NATURAL GAS PRICE FORECAST FIRM TRANSPORTATION ON GULFSTREAM PIPELINE		
	HENRY HUB NATURAL GAS PRICE	SYSTEM WEIGHTED AVERAGE TOTAL (NON-FIRM & FIRM) NATURAL GAS PRICE		VARIABLE (DISPATCH) COST FOR GAS MOVING UNDER NON-FIRM TRANSPORATION		VARIABLE (DISPATCH) COST FOR GAS MOVING UNDER FIRM TRANSPORATION		DEMAND (SUNK) COST FOR GAS MOVING UNDER FIRM TRANSPORATION		TOTAL COST FOR GAS MOVING UNDER FIRM TRANSPORATION		DELIVERED PRICE	VARIABLE DISPATCH PRICE	DEMAND (SUNK) COST	DELIVERED PRICE	VARIABLE DISPATCH PRICE	DEMAND (SUNK) COST
YEAR	NOMINAL $/MMBTU	NOMINAL $/MMBTU	NOMINAL MM$	NOMINAL $/MMBTU	NOMINAL MM$	NOMINAL $/MMBTU	NOMINAL MM$	NOMINAL $/MMBTU	NOMINAL MM$	NOMINAL $/MMBTU	NOMINAL MM$	NOMINAL $/MMBTU	NOMINAL $/MMBTU	NOMINAL $/MMBTU	NOMINAL $/MMBTU	NOMINAL $/MMBTU	NOMINAL $/MMBTU
2001	$4.38	$4.87	$2,29327	$4.75	$1,115.82	$4.36	$1,026.85	$0.61	$15060	$4.96	$1,177.45	$5.11	$4.35	$0.76	$4.95	$4.35	$0.60
2002	$3.36	$3.99	$1,924.34	$3.85	$692.43	$3.46	$1,053.12	$0 60	$178 79	$4.06	$1,231.92	$4.29	$3.53	$0.76	$4.13	$3.53	$0.60
2003	$3.88	$4.54	$2,342.42	$4.42	$941.98		$1,218.90	$0.60	$181.54	$4.62	$1,400.44	$4.87	$4.11	$0.76	$4.71	$4.11	$0.60
2004	$3.58	$4.25	$1,894 31	$4.11	$585.08		$1,127.23	$0.60	$182.01	$4.32	$1,309.24	$4.56	$3.79	$0.76	$4.39	$3.79	$0.60
2005	$3.47	$4.16	$1,599.07	$4.00	$327.78		$1,089.76	$0.60	$181.54	$4.20	$1,271.29	$4.44	$3.68	$0.76	$4.28	$3.68	$0.60
2006	$3.46	$4.16	$1,513 66	$3.99	$268.92		$1,065.32	$0.60	$179.42	$4.19	$1,244.74	$4.43	$3.66	$0.76	$4.26	$3.68	$0.60
2007	$3.44	$4.14	$1,506.74	$3.98	$267.84		$1,059.49	$0.60	$179.42	$4.17	$1,238.91	$4.40	$3.64	$0.76	$4.24	$3.64	$0.60
2008	$3.54	$4.24	$1,549.42	$4.09	$276.56		$1,092.97	$0.60	$179.89	$4 28	$1,272.86	$4.51	$3.75	$0.76	$4.35	$3.75	$0.60
2009	$3.64	$4.34	$1,582.10	$4.19	$282 54	$3.78	$1,120.14	$0.60	$179.42	$4.38	$1,299.56	$4.61	$3.85	$0.76	$4.45	$3.85	$0.60
2010	$3.74	$4.45	$1,619 18	$4.30	$289 77	$3.88	$1,150.00	$0.60	$179.42	$4.48	$1,329.42	$4.72	$3.95	$0.76	$4.55	$3.95	$0.60
2011	$3.83	$4.55	$1,655.25	$4.40	$296.82		$1,179.01	$0.60	$179.42	$4.58	$1,358.43	$4.62	$4.05	$0.76	$4.65	$4.05	$0.60
2012	$3.93	$4.65	$1,697.31	$4 51	$305.46		$1,211.96	$0.60	$179.89	$4.68	$1,391.65	$4.92	$4.16	$0.76	$4.76	$4.16	$0.60
2013	$4.03	$4.75	$1,729.47	$4.62	$311.28		$1,238 77	$0.60	$179.42	$4 78	$1,418 19	$5.02	$4.26	$0.76	$4.86	$4.26	$0.80
2014	$4.13	$4.86	$1,768.29	$4.73	$318.84		$1,270.03	$0.60	$179.42	$4.68	$1,449.45	$5.13	$4.37	$0.76	$4.97	$4.37	$0.60
2015	$4.24	$4.97	$1,809.56	$4.85	$326 87		$1,368.50	$0.39	$114.19	$5.00	$1,482.69	$5.24	$4.48	$0.76	$5.08	$4.48	$0.60
2016	$4.35	$5.09	$1,859.18	$4.97	$337 03		$1,442.87	$0.27	$79.28	$5 12	$1,522 15	$5 37	$4.60	$0.76	$5.20	$4.60	$0.60
2017	$4.48	$5.21	$1,899.15	$5.11	$344.31		$1,475.79	$0.27	$79.06	$5.24	$1,554.84	$5 49	$4.73	$0.76	$5.33	$4.73	$0.60
2018	$4.60	$5.35	$1,946.83	$5.24	$353.59		$1,514.18	$0.27	$79.06	$5 37	$1,593.24	$5.63	$4.86	$076	$5.46	$4.86	$0.60
2019	$4.73	$5.48	$1,996 30	$5.39	$363.22	$5.24	$1,554.02	$0.27	$79.06	$5 50	$1,833.08	$5 76	$5.00	$0.76	$5.60	$5.00	$0.60
2020	$4.87	$5.62	$2,053.83	$5.53	$374.99	$5.37	$1,599.56	$0.27	$79.28	$5.64	$1,678.84	$5.90	$5.14	$0.76	$5.74	$5.14	$0 60
2021	$5.01	$5.77	$2,099.96	$5.68	$383.40	$5.52	$1,637.50	$0.27	$79.06	$5.79	$1,716.56	$6.05	$5.29	$0.76	$5.89	$5.29	$0.60
2022	$5.15	$5.91	$2,154.20	$5.84	$393.96	$5.68	$1,740.02	$0.07	$20.23	$5.93	$1,760 24	$6.20	$5.44	$0.76	$6.04	$5.44	$0.60
2023	$5.30	$6.07	$2,209.97	$6.00	$404.82		$1,805.15	$0.00	$0 00	$6.08	$1,805.15	$6 38	$5.59	$0.76	$6.19	$5.59	$0.60
2024	$5.45	$6.23	$2,275 20	$6.17	$418.15	$6.24	$1,857.05	$0.00	$0.00	$6.24	$1,857.05	$6 52	$5.75	$0.76	$6.35	$5.75	$0.60
2025	$5.61	$6.39	$2,328.30	$6.34	$427.84		$1,900.46	$0.00	$0.00	$6.41	$1,900.46	$6.68	$5.92	$0.76	$6.52	$5.92	$0.60
2026	$5.78	$6.56	$2,391.17	$6.52	$440.06	$6.58	$1,951.10	$0.00	$000	$6.58	$1,951.10	$6.86	$6.10	$0.76	$6.70	$6.10	$0.60
2027	$5.95	$6.74	$2,456.05	$6 71	$452.69	$6.75	$2,003.36	$0.00	$0.00	$6.75	$2,003.36	$7.04	$6.28	$0.76	$6.88	$6.28	$0.60
2028	$6.13	$6.93	$2,530 90	$6.90	$467.97		$2,062.92	$0.00	$0.00	$6 93	$2,062.92	$7.22	$6.46	$0.76	$7.06	$6.46	$0.60
2029	$6.31	$7.11	$2,591.65	$7 10	$479.06	$7.12	$2,112.58	$0.00	$0.00	$7.12	$2,112 58	$7.41	$6.65	$0 76	$7 25	$6.65	$0.60
2030	$6.50	$7.31	$2,662.46	$7.30	$492.84		$2,169.64	$0.00	$0.00	$7.31	$2,169.64	$7.61	$6.85	$0.76	$7.45	$6.85	$0.60

FPL 2002 THROUGH 2030 MOST LIKELY COAL AND PETROLEUM COKE PRICE FORECAST

JUNE 8, 2001 - EUGENE UNGAR

	PLANT SCHERER UNIT 4		MARTIN PLANT: 1.0% SULFUR COAL				PETROLEUM COKE DELIVERED TO FLORIDA	
	WEIGHTED AVERAGE	SPOT PRICE	SPOT PRICE		WEIGHTED AVERAGE			
YEAR	NOMINAL $/MMBTU	NOMINAL $/MMBTU	NOMINAL $/TON	NOMINAL $/MMBTU	NOMINAL $/TON	NOMINAL $/MMBTU	NOMINAL $/TON	NOMINAL $/MMBTU
2002		$1.57	$37.92	$1.61	$37.92	$1.61	$22.24	$0.79
2003	$1.94	$1.78	$39.71	$1.68	$39.71	$1.68	$21.92	$0.78
2004		$1.63	$40.84	$1.73	$40.84	$1.73	$21.36	$0.76
2005	$1.67	$1.65	$41.32	$1.75	$41.32	$1.75	$21.18	$0.76
2006		$1.67	$41.84	$1.77	$41.84	$1.77	$21.26	$0.76
2007	$1.72	$1.69	$42.41	$1.80	$42.41	$1.80	$21.57	$0.77
2008		$1.71	$43.01	$1.82	$43.01	$1.82	$21.59	$0.77
2009		$1.74	$43.64	$1.85	$43.64	$1.85	$21.88	$0.78
2010		$1.77	$44.32	$1.88	$44.32	$1.88	$22.13	$0.79
2011		$1.79	$45.07	$1.91	$45.07	$1.91	$22.30	$0.80
2012		$1.82	$45.82	$1.94	$45.82	$1.94	$22.74	$0.81
2013		$1.85	$46.59	$1.97	$46.59	$1.97	$23.24	$0.83
2014		$1.88	$47.38	$2.01	$47.38	$2.01	$23.63	$0.84
2015		$1.91	$48.17	$2.04	$48.17	$2.04	$23.94	$0.86
2016		$1.94	$48.99	$2.07	$48.99	$2.07	$24.31	$0.87
2017		$1.97	$49.81	$2.11	$49.81	$2.11	$24.78	$0.88
2018		$2.01	$50.65	$2.14	$50.65	$2.14	$25.27	$0.90
2019	$2.04	$2.04	$51.51	$2.18	$51.51	$2.18	$25.77	$0.92
2020		$2.07	$52.39	$2.22	$52.39	$2.22	$26.27	$0.94
2021		$2.11	$53.28	$2.26	$53.28	$2.26	$26.83	$0.96
2022		$2.14	$54.19	$2.29	$54.19	$2.29	$27.40	$0.98
2023		$2.18	$55.12	$2.33	$55.12	$2.33	$27.98	$1.00
2024	$2.21	$2.21	$56.07	$2.37	$56.07	$2.37	$28.57	$1.02
2025		$2.25	$57.04	$2.41	$57.04	$2.41	$29.19	$1.04
2026		$2.29	$58.03	$2.46	$58.03	$2.46	$29.81	$1.06
2027	$2.32	$2.32	$59.03	$2.50	$59.03	$2.50	$30.45	$1.09
2028		$2.36	$60.05	$2.54	$60.05	$2.54	$31.11	$1.11
2029		$2.40	$61.09	$2.59	$61.09	$2.59	$31.77	$1.13
2030	$2.44	$2.44	$62.15	$2.63	$62.15	$2.63	$32.45	$1.16

FPL 2002 THROUGH 2030 MOST LIKELY COAL AND PETROLEUM COKE PRICE FORECAST

JUNE 8, 2001 - EUGENE UNGAR

DELIVERED ST. JOHNS RIVER POWER PARK FUEL PRICES (INCLUDES VARIABLE O & M COSTS)

YEAR	CONTRACT COAL PRICE NOMINAL $/TON	CONTRACT COAL PRICE NOMINAL $/MMBTU	SPOT COAL PRICE NOMINAL $/TON	SPOT COAL PRICE NOMINAL $/MMBTU	WEIGHTED AVERAGE COAL PRICE NOMINAL $/TON	WEIGHTED AVERAGE COAL PRICE NOMINAL $/MMBTU	PETROLEUM COKE NOMINAL $/TON	PETROLEUM COKE NOMINAL $/MMBTU	WEIGHTED AVERAGE FUEL PRICE NOMINAL $/TON	WEIGHTED AVERAGE FUEL PRICE NOMINAL $/MMBTU	DISPATCH PRICE OF FUEL AT SJRPP (85% SPOT COAL; 15 % PETROLEUM COKE) NOMINAL $/TON	DISPATCH PRICE OF FUEL AT SJRPP (85% SPOT COAL; 15 % PETROLEUM COKE) NOMINAL $/MMBTU
2002	$40.82	$1.66	$36.65	$1.55	$40.56	$1.66	$20.93	$0.75	$37.33	$1.51	$34.29	$1.43
2003	$40.25	$1.65	$38.42	$1.63	$40.07	$1.65	$20.88	$0.75	$36.83	$1.49	$35.79	$1.49
2004	$40.78	$1.67	$39.53	$1.65	$40.67	$1.67	$21.36	$0.76	$37.41	$1.51	$36.80	$1.51
2005	$41.69	$1.71	$40.00	$1.67	$41.53	$1.70	$21.18	$0.76	$38.09	$1.54	$37.17	$1.53
2006	$44.52	$1.73	$40.49	$1.69	$41.88	$1.70	$21.26	$0.76	$38.40	$1.54	$37.61	$1.55
2007	$44.96	$1.75	$41.04	$1.71	$42.38	$1.72	$21.57	$0.77	$38.87	$1.56	$38.12	$1.57
2008			$41.61	$1.73	$41.61	$1.73	$21.59	$0.77	$38.23	$1.57	$38.61	$1.59
2009			$42.22	$1.76	$42.22	$1.76	$21.88	$0.78	$38.78	$1.59	$39.16	$1.61
2010			$42.87	$1.79	$42.87	$1.79	$22.13	$0.79	$39.37	$1.62	$39.76	$1.64
2011			$43.59	$1.82	$43.59	$1.82	$22.30	$0.80	$39.99	$1.64	$40.40	$1.66
2012			$44.31	$1.85	$44.31	$1.85	$22.74	$0.81	$40.67	$1.67	$41.07	$1.69
2013			$45.05	$1.88	$45.05	$1.88	$23.24	$0.83	$41.36	$1.70	$41.77	$1.72
2014			$45.80	$1.91	$45.80	$1.91	$23.63	$0.84	$42.06	$1.73	$42.48	$1.75
2015			$46.57	$1.94	$46.57	$1.94	$23.94	$0.86	$42.75	$1.76	$43.17	$1.78
2016			$47.34	$1.97	$47.34	$1.97	$24.31	$0.87	$43.46	$1.79	$43.89	$1.81
2017			$48.14	$2.01	$48.14	$2.01	$24.78	$0.88	$44.19	$1.82	$44.63	$1.84
2018			$48.94	$2.04	$48.94	$2.04	$25.27	$0.90	$44.95	$1.85	$45.39	$1.87
2019			$49.77	$2.07	$49.77	$2.07	$25.77	$0.92	$45.72	$1.88	$46.17	$1.90
2020			$50.61	$2.11	$50.61	$2.11	$26.27	$0.94	$46.50	$1.91	$46.96	$1.93
2021			$51.46	$2.14	$51.46	$2.14	$26.83	$0.96	$47.30	$1.94	$47.77	$1.97
2022			$52.33	$2.18	$52.33	$2.18	$27.40	$0.98	$48.12	$1.98	$48.59	$2.00
2023			$53.22	$2.22	$53.22	$2.22	$27.98	$1.00	$48.96	$2.01	$49.44	$2.03
2024			$54.13	$2.26	$54.13	$2.26	$28.57	$1.02	$49.82	$2.05	$50.30	$2.07
2025			$55.06	$2.29	$55.06	$2.29	$29.19	$1.04	$50.69	$2.08	$51.18	$2.11
2026			$56.00	$2.33	$56.00	$2.33	$29.81	$1.06	$51.58	$2.12	$52.08	$2.14
2027			$56.97	$2.37	$56.97	$2.37	$30.45	$1.09	$52.49	$2.16	$52.99	$2.18
2028			$57.94	$2.41	$57.94	$2.41	$31.11	$1.11	$53.41	$2.19	$53.92	$2.22
2029			$58.94	$2.46	$58.94	$2.46	$31.77	$1.13	$54.35	$2.23	$54.86	$2.26
2030			$59.95	$2.50	$59.95	$2.50	$32.45	$1.16	$55.31	$2.27	$55.82	$2.30

Appendix I

FPL's Financial and Economic Assumptions

Projected Capitalization Ratios		Projected Cost of Capital
Debt = 45%		Debt = 7.4%
Preferred = 0%		Preferred = 0%
Equity = 55%		Equity = 11.7%
	Discount Rate = 8.5%	
	AFUDC Rate = 9.8%	

Tax Assumptions		
Rates:		Book Life
Composite Income Tax = 38.575%		Combustion Turbines = 25 Years
(Includes Federal and State Tax)		Combined Cycle = 25 Years
	Tax Depreciation Life = 20 Years	

Annual Escalation Assumptions
(In Percent)

Year	Generator Capital	Generator Fixed O&M	Generator Variable O&M
2001	1.70%	4.90%	2.70%
2002	1.70%	3.80%	2.50%
2003	1.70%	4.40%	2.80%
2004	1.70%	3.80%	2.80%
2005	1.70%	3.40%	2.70%
2006	1.70%	3.40%	2.60%
2007	1.70%	3.60%	2.60%
2008	1.70%	3.80%	2.60%
2009	1.70%	4.00%	2.50%
2010	1.70%	4.20%	2.50%
2011	1.70%	4.50%	2.50%
2012	1.70%	4.50%	2.50%
2013	1.70%	4.50%	2.50%
2014	1.70%	4.50%	2.50%
2015	1.70%	4.50%	2.50%
2016	1.70%	4.50%	2.50%
2017	1.70%	4.50%	2.50%
2018	1.70%	4.50%	2.50%
2019	1.70%	4.50%	2.50%
2020	1.70%	4.50%	2.50%
2021	1.70%	4.50%	2.50%
2022	1.70%	4.50%	2.50%
2023	1.70%	4.50%	2.50%
2024	1.70%	4.50%	2.50%
2025	1.70%	4.50%	2.50%
2026	1.70%	4.50%	2.50%
2027	1.70%	4.50%	2.50%
2028	1.70%	4.50%	2.50%
2029	1.70%	4.50%	2.50%

THE WALL STREET JOURNAL.

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DOWJONES

STATE OF FLORIDA)
COUNTY OF ORANGE) SS:
CITY OF ORLANDO)

I, Pamela J. Garstka, being duly sworn,

depose and say that I am the Advertising Clerk of the Publisher of

The Wall Street Journal (National Edition), a daily

national newspaper published and of general circulation in

(Princeton, New Jersey, Chicopee, Massachusetts, Silver Spring, Maryland, Charlotte, North Carolina, LaGrange, Georgia, Orlando, Florida, Sharon, Pennsylvania, Bowling Green, Ohio, Naperville, Illinois, Des Moines, Iowa, Highland, Illinois, Dallas, Texas, Beaumont, Texas, Seattle, Washington, Denver, Colorado, Palo Alto, California and Riverside, California), and that the attached Notice

has been regularly published in The Wall Street Journal

(National Edition) for insertion on the following date(s):

April 26, 2002

and that the foregoing statements are true and correct to the best

of my knowledge, information and belief.

Pamela J. Garstka
(Signature)

Sworn to before me this 26th
day of April, 2002.

Carrie Lee Wolfe

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Asian Exports Stage Shaky Rebound

U.S. Firms Are Stocking Warehouses, but They May Be Full Again Soon

By Jason Booth

HONG KONG–Asian exports are on the rebound But for how long?

U S companies are beginning to rebuild their inventories after months of cutting back But economists and businesses worry that once the warehouses of corporate America are full–a cycle that could last just six months–there won t be enough demand across the Pacific to keep Asian exports growing in the longer term

What has Asian business worried is that even though exports are up–cellular phones, liquid-crystal displays, passenger cars and petrochemicals come to mind–uncertainty over future growth means the prices of those exports are still falling in some places, or else are rising weakly So while export volumes may be grabbing headlines any recovery in demand from the U S will have a muted effect on corporate profits and employment in Asia until the prices pick up

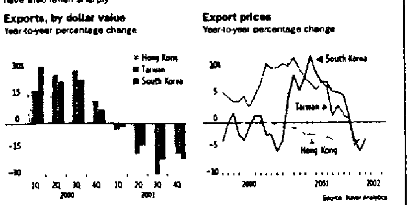
Economists figure investment by U.S companies will be weak this year, as businesses continue to work off the excesses of the late 1990s That leaves U.S consumers to help keep things humming The problem is, they never significantly slowed their spending, so they, too, are unlikely to go on a shopping spree anytime soon

"Once we get through the inventory recovery, we have to ask what will sustain the recovery," says George Magnus, chief economist at UBS Warburg

"This recovery will be sparked by exports to the U.S but won t be led by those exports " predicts Timothy Bond, an economist with Merrill Lynch in Hong Kong, who argues that the balance of power when it comes to Asian economic growth is shifting to domestic demand

Selling Less ... or Selling for Less?

The volume of exports from Asia s big exporting nations initially hardest hit by the U S and global economic slowdown has begun to rebound However the trend is less meaningful than it might be since the prices of certain exports from these countries have also fallen sharply



Early signs of an Asian export rebound are easy to find While U S companies cut their inventories by some $20 billion in the first quarter compared with the end of 2001, that is a drastic improvement from the $120 billion of destocking in the fourth quarter of last year Second-quarter figures are expected to show moderate inventory accumulation

Reflecting that trend China s exports climbed 9 9% in the first quarter led by exports to the U S Taiwanese exports rose 5.5% in March from a year earlier, to the highest level in 17 months Singapore s nonoil exports fell 17.3% in March from a year ago but swung to a strong 25% month-on-month gain

In fact, the promise of an export recovery has inspired the World Bank to upgrade its forecast for gross domestic product growth in Asia excluding Japan, to 4 7% this year GDP growth was 3.5% in 2001

So far though, the trade growth isn t reflected in the value of Asian exports Prices of Japanese products imported by the U S fell 0.3% in March, the 14th decline in the past 15 months Prices of goods from Hong Kong, Taiwan, Singapore and South Korea declined for the 15th consecutive month falling 0.2%, on average

"Customers want to stock up but they don t want to pay too much–just in case the demand isn t there " says Steven Peniger, chief executive officer of the Hong Kong apparel exporter Linmark Group, whose U S customers include retailer J C. Penney Co , among others

Whether prices ever recover will depend partly on how quickly U S demand for Asian products grows U.S consumers and, less so, consumers around the world are looking overextended and may not be able to carry the economic recovery Consumption as a portion of nominal GDP among the Group of Seven leading industrial nations remains near a record high average of 63% Even a moderate retrenchment in consumption, to levels seen in the early 1990s, would put Asia s own economic recovery in reverse, says Warburg s Mr Magnus

"If you take three of four percentage points out of consumption" as a portion of total GDP, he says "then the real recession has yet to begin "

Japan Telecom to Cut Costs, Refocus

Vodafone Affiliate Targets Corporate Clients to Boost Fixed-Line Operations

By Robert A. Guth

TOKYO–Japan Telecom Co will cut costs and dispose of noncore assets and it may reorganize into a holding company as part of a plan by the Vodafone Group PLC affiliate to shore up its fixed line telecom business

The Japanese telecom operator said it will focus capital investment on services for corporate customers and on profitable segments of the consumer market To beef up its corporate business, Japan Telecom will begin an operation that designs and runs communications networks for companies Also, Japan Telecom will focus on consumer services in densely populated areas

The company expects the moves will allow it to post "double-digit growth" in annual revenue for its core areas in the year ending March 2005 Over that period, Japan Telecom will lower personnel costs by about 10%, the company said

The company previously said that because of investment write-downs and debt refinancing it expects to post a group loss of 71 billion yen ($547.5 million) on sales of 1 67 trillion yen for the year ended March 31, 2002 It announces earnings later this month

In an interview, Japan Telecom President William Morrow said the company might reorganize into a holding-company structure to set clear lines of responsibility among its operating units Analysts say the structure could also make it easier to spin off units or take them public

Overall, the plan was light on details but underscored the systematic approach that Vodafone, the world s largest mobile-phone operator is taking to energize the Japanese company since it took a 67% stake in it late last year for $11 5 billion Some analysts expected Vodafone would sell off the fixed-line business because its chief target in buying the company was Japan Telecom s mobile unit, J Phone Japan s No 3 mobile operator With the initiatives announced yesterday, Japan Telecom appears set on holding on to the fixed line business, or at least a slimmer version of it

Separately Vodafone said it added 1 3 million net customers in the first quarter The figure was at the low end of analysts expectations and down from 4 4 million a year earlier

—*David Pringle contributed to this article*

Siemens Tops Forecasts, Plans to Slash More Jobs

By Matthew Karnitschnig

ERFURT, Germany–Siemens AG shattered market forecasts with robust second-quarter earnings but warned that the results don t herald a broader turnaround

A bulging order book in the German engineering giant s power-generation division and strong gains in its medical-solutions business helped earnings in the fiscal second quarter, but continued weakness at the group s telecommunications units cast a shadow over its outlook Siemens said it would cut an additional 6,500 jobs at its ICN fixed-line network unit in addition to 10,000 cuts announced previously

Siemens said net income in the quarter more than doubled to 1 28 billion euros ($1 14 billion), boosted by a 561 million-euro extraordinary gain from share sales Earnings before interest and taxes, or Ebit including nearly 200 million euros in special charges totaled 919 million euros Though a touch below the 922 million euros recorded a year earlier, the result was well ahead of analysts Ebit consensus estimates of 553 million euros, excluding extraordinary charges

Siemens executives said full year earnings would be "significantly better" than last year s, which were weighed down by special charges But they cautioned that management would have to rely on further cost cutting and restructuring measures to squeeze out further gains rather than an economic upswing

"The current economic environment still can t be accurately evaluated," said Chief Executive Heinrich von Pierer

Nevertheless, Mr von Pierer clearly relished surprising the market "I still recall the advice that I was given at the end of the '90s during the New Economy hysteria focus focus, focus and we were often the butt of strong criticism," he said "Ultimately we have proven to others in recent months that our business portfolio helps us master difficult times better than many others "

On the divisional level Siemens s main area of concern remains its flagging telecommunications business, which is plagued by weak demand from debt-ridden telecom operators and a collapse in prices ICN lost 158 million euros in the second quarter, following a 124 million euro first-quarter loss The total job cuts at the fixed-line network division amount to a 30% decrease in the division s staff Mr von Pierer said ICN s cost-cutting program will also be stepped up By the end of 2003, the business will have to reduce costs by a further 1 5 billion euros, on top of two billion euros in previously announced cuts

Mr von Pierer said he didn't expect any real improvement in the business for 12 to 18 months Siemens will book 300 million euros in restructuring charges this year as a result of the job cuts

In Frankfurt trading, Siemens shares rose 4 3% to 66 31 euros

Mizuho's Snafus Show How Tokyo Coddles Banks

By Phred Dvorak

TOKYO–For fresh insight into why Japan s so-called megabanks are such lumbering creatures, peer inside the computers at Mizuho Holdings Inc

Severe computer-systems troubles at Mizuho–the world s biggest lender in terms of loans outstanding–are riling the public and the bank s blue-chip customers, who have seen millions of transactions go haywire But so far, regulators and political leaders seem unlikely to use the snafus to force Mizuho and other troubled Japanese banks to fundamentally change the way they operate

"This problem is likely to result in some sense of emergency," says Takamasa Yamaoka who covers Mizuho for Standard & Poor s, the credit rater "But I m concerned it may end up with a reform of the computer system only "

Japanese banks, for all the woes they have caused the world s No 2 economy, get kid-glove treatment from the government Authorities are letting the megabanks revamp their operations at a glacial pace, despite the banks trillions of yen in bad-loan losses, plummeting stock prices and loud calls from around the world for Japan to overhaul its struggling financial system

No one is holding bankers feet to the fire Their shareholders are still mostly big, friendly Japanese corporations Despite government rhetoric to the contrary, Japan s biggest banks are arguably so big that the government would never let them fail

Nine major lenders and banking groups, including Mizuho and four other megabanks, accounted for 65% of the 526 trillion yen ($4 trillion) worth of credit extended by Japanese banks as of Sept 30 Mizuho, a merger of three banks conceived in 1999 during Japan s last financial crisis had by itself extended 97 trillion yen–18% of the total

Japanese megabank executives thus have had little incentive to make the aggressive and unpopular decisions, such as drastic personnel cuts or borrower restructuring, needed to turn profits around

Instead, the megabank marriages, all of which have been consummated in the past two years, have generally followed the pattern of the 1971 merger that produced Dai-Ichi Kangyo Bank Ltd one of the three banks that later formed Mizuho That union took 25 years to truly complete, analysts say as bankers from the two sides struggled internally for control

Though Mizuho still is investigating the core cause of its system troubles, analysts suggest slow integration due to political infighting was a contributing factor A look at the bank s systems integration, more than two years after it started the process, shows just how slow progress has been.

Although Mizuho s three member banks formally merged into two corporate entities on April 1, they are still operating their three original computer systems All three systems were designed–and are still being serviced by–three computer makers Fujitsu Ltd , International Business Machines Corp s IBM Japan Ltd and Hitachi Ltd No one company has been retained to oversee overall systems operation One of the computer systems–that of the old Industrial Bank of Japan Ltd –is being used at Mizuho Corporate Bank, the entity created to serve large companies The other two, from Dai-Ichi Kangyo and Fuji Bank Ltd , are handling accounts at Mizuho Bank, the entity that handles retail and small-business clients

In a year, Mizuho says, the two systems serving the retail bank will be merged But until then, the various pieces are connected by computers programmed to sort and adjust customer data to fit each different system It was in those connecting pieces where Mizuho s troubles arose

For example the retail-bank computer that sorted data for processing automated payments, a Dai-Ichi Kangyo component, had to take customer information from companies such as Tokyo Electric Power Co and pass it on to whichever of Mizuho s three systems had been assigned to process it Because the corporate bank s system was untested with large-lot payments processing Mizuho executives say, they decided to send data from big corporate-bank customers to the retail-bank sorter as well An overload of information at that sorter was responsible for Mizuho s biggest computer glitch a processing delay that at one point led to a backlog of 2.5 million transactions

EU Leaders Enter Le Pen Fray

By Charles Fleming

PARIS–The widespread condemnation of France s Jean-Marie Le Pen by European leaders marks the first time since the creation of the European Union that heads of government have so openly attempted to tell voters in a member state how to cast their ballots

The far right presidential candidate s surprising showing in Sunday s first round of voting has provoked demonstrations across France against Mr Le Pen s policies, which include the repatriation of immigrants and the withdrawal of France from the EU

But perhaps more surprising, Europe s top politicians have entered the fray Among them British Prime Minister Tony Blair, Spanish Premier José María Aznar and Italy's Silvio Berlusconi, who criticized Mr Le Pen s movement as a "populist fringe " Yesterday, Germany s Gerhard Schröder said Mr Le Pen is someone "who stokes fears and hate "

EU leaders have criticized politicians and parties of other member states in the past–most notably Joerg Haider s far right Freedom Party in Austria after it joined the Austrian government in 2000 But the way they have sided with Jacques Chirac, the current French president and Mr Le Pen's rival for the May 5 runoff election, trumps that response

"It s a common rule not to interfere in other countries domestic politics and [this] shows how fearful EU leaders are that the rise of the nationalist right could unravel 50 years of hard work in building a solid, stable and prosperous union " said Alasdair Murray, a director at the Center for European Reform in London

In addition there is concern in some European capitals that their governments aren t immune from a similar phenomenon Analysts also caution that any perception of foreign interference in a domestic election could have the opposite effect "There could be a backlash," Mr Murray said

Meanwhile, Mr Le Pen issued a statement yesterday saying that interference from other nations is "a serious insult to the entire French nation "

Karachi Murder Trial Is Halted for a Day

Associated Press

KARACHI, Pakistan–The trial of Muslim militants charged in the kidnap-slaying of Wall Street Journal correspondent Daniel Pearl was halted for the day while defense attorneys protested a coming referendum to extend President Pervez Musharraf s stay in office

The strike led to the arrest of 50 lawyers who joined a rally to declare the April 30 vote unconstitutional, said Iftikhar Javed, president of the Karachi Bar Council The government has banned all rallies prior to the referendum Protesters carried banners that read "We will not accept military rule "

Mr Musharraf seized power in a bloodless coup in October 1999, and since the Sept 11 terrorist attacks has been an important U.S ally The referendum would secure his position ahead of October elections for a new parliament, which is supposed to select a president and prime minister

Argentina Will Allow Its Banks to Reopen

Continued From Page A8

to float freely for others Though the government said the system would be in place for six months, it was scrapped a month later

Argentines widely supported the previous currency peg, known as convertibility But the current government lacks the credibility to make such a system stick, economists said Additionally, under convertibility, the Central Bank was barred from printing money to finance the government and was required to stash away one dollar in hard-currency reserves for every peso in circulation Any move to readopt a pegged exchange rate wouldn't incorporate those two conditions, the aide said

Orlando Sentinel communications

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Mike Eri, General Advertising Account Executive
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meri@orlandosentinel.com

May 3, 2002

Augusto Esclusa
The Beber Silverstein Group
3361 SW 3rd Ave.
Miami, FL 33145

Dear Augusto,

This letter is to confirm that Florida Power & Light placed advertising on the following date:

Date	AD Size	Section	Cost
5/3/02	2col x 5"	Business	$2,580 gross

Sincerely,

Mike Eri
Account Executive
General Advertising
(407) 420-5357

The foregoing instrument was acknowledged before me this 3rd day of May, 2002, by Mike Eri, who is personally known to me.

NOTARY

STATE OF FLORIDA
COUNTY OF ORANGE

NOTARY PUBLIC STATE OF FLORIDA
JEAN M. GAILIE
MY COMMISSION # CC921262
EXPIRES: March 22, 2004
1-800-3-NOTARY FL Notary Service & Bonding, Inc.

The Miami Herald

A Knight-Ridder Newspaper

PUBLISHED DAILY

MIAMI, FLORIDA

STATE OF FLORIDA
COUNTY OF DADE

Before the undersigned authority personally appeared:
STAN MACNEILL

who on oath says that he/she is
DISPLAY ACCOUNT EXECUTIVE

of The Miami Herald, a daily newspaper published at Miami in Dade County, Florida; that the advertisement for **Florida Power & Light** appeared in said newspaper in the issue of:

MAY 3, 2002

Affiant further says that the said The Miami Herald is a newspaper published at Miami, in the said Dade County, Florida and that the said newspaper has heretofore been continuously published in said Dade County, Florida, each day and has been entered as second class mail matter at the post office in Miami, in said Dade County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement.

H Daniela BM

Sworn to and subscribed before me

this 6th day of May, 2002

H. DANIELA BARRIOS
MY COMMISSION # CC 978372
EXPIRES: October 29, 2004
Bonded Thru Notary Public Underwriters

St. Petersburg Times

May 6, 2002

Beber Silverstein
3361 SW Third Avenue
Miami, FL

RE: Florida Power & Light

AFFIDAVIT OF PUBLICATION

STATE OF FLORIDA
COUNTY OF PINELLAS

Before the undersigned authority personally appeared, Christine Paul, who on oath says that she is a Senior Category Manager of the St. Petersburg Times, a daily newspaper published at St. Petersburg, in Pinellas County, Florida. Client, Florida Power and Light ran a 2x5" advertisement in the St. Petersburg Times on May 3, 2002.

Signature Christine Paul

Title Senior Category Manager

Sworn to and subscribed

before me this 6 day of

May, 2002

Patricia A. Haskins
Notary Public

PATRICIA A. HASKINS
MY COMMISSION # CC 801913
EXPIRES 01/13/2003
1-800-3-NOTARY ... Services & Bonding Co.

Request for Proposals

Florida Power & Light Company (FPL) is soliciting proposals for a supply of up to 1,722 megawatts of firm capacity and energy to FPL starting in 2005 and 2006.

The 1,722-megawatt solicitation is for firm capacity and energy projects that could be more economical than FPL's next planned capacity additions for 2005. FPL's projects for 2005, as described in its 2002 Ten-Year Power Plant Site Plan, are as follows:

Two combustion turbines (CT's) at FPL's Martin site, plus two new CT's that would be added to the site, are planned to be converted into a four CT-based combined cycle (CC) unit that will supply 789 incremental MW (Summer). A four CT-based CC unit that will supply 1,107 incremental MW (Summer) is also planned for construction at FPL's Manatee site.

Parties interested in submitting proposals for this solicitation need to request a copy of the RFP document from Steve R Sim, RFP Contact Person, Florida Power & Light Company, Resource Assessment and Planning Department, P.O. Box 029100, Miami, FL 33102-9100, (305) 552-2246. Copies of the RFP will be available starting on April 26, 2002. Responses to the RFP are due back to FPL by May 24, 2002. Initial negotiations with a short list of proposers will begin June 18, 2002 and is scheduled to conclude July 2, 2002. The final announcement of a contract is projected for August 2002.

FPL reserves the right to reject all proposals, to modify or cancel the RFP, or to refine its cost estimates for FPL's own resource options, up or down, based upon more recent data available when FPL performs its evaluations.

FPL
an FPL Group company