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Progress Energy

May 26, 2006

VIA HAND DELIVERY

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
And Administrative Services
Florida Public Servce Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

RECEIVED-FPSC
06 MAY 26 PM 1:42
COMMISSION CLERK

Re: 2006 Ten-Year Site Plan - REVISED

Dear Ms. Bayó:

Please find enclosed for filing a revised copy of Progress Energy Florida, Inc.'s 2006 Ten-Year Site Plan dated May 18, 2006. After submission of the original filing in April, Progress Energy Florida discovered some schedules that needed two minor revisions. These revisions are noted as follows: (1) on Schedules 3.1.3 – 3.2.3, the last column was inadvertently left off in the original filing, and (2) on Schedule 6.1, energy was incorrectly allocated between "Annual Firm Interchange" and "Import from Out of State" for the years 2010 – 2015. These inadvertent errors had no impact or effect on the relevant numbers on those schedules.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. Thank you for your assistance in this matter.

Very truly yours,

John T. Burnett LMS

John T. Burnett

JTB:lms
Enclosure

cc: Mr. Michael Haff

CMP ______
COM ______
CTR ______
ECR ______
GCL ______
OPC ______
RCA ______
SCR ______
SGA ______
SEC 1
OTH kim P(2)

Progress Energy Florida, Inc.
106 E. College Avenue
Suite 800
Tallahassee, FL 32301

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Progress Energy Florida
Ten-Year Site Plan

April 2006
(revised 05/18/06)

2006-2015

Submitted to:
Florida Public Service Commission

Progress Energy

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CODE IDENTIFICATION SHEET

Generating Unit Type

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

Fuel Type

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

Fuel Transportation

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

Future Generating Unit Status

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

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INTRODUCTION

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

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

The TYSP document contains four chapters as described below:

CHAPTER 1
DESCRIPTION OF EXISTING FACILITIES

CHAPTER 2
FORECAST OF ELECTRICAL POWER DEMAND AND ENERGY CONSUMPTION

CHAPTER 3
FORECAST OF FACILITIES REQUIREMENTS

CHAPTER 4
ENVIRONMENTAL AND LAND USE INFORMATION

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

Progress Energy

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

PEF is a wholly owned subsidiary of Progress Energy, Inc. (Progress Energy). Congress enacted legislation in 2005 repealing the Public Utilities Holding Company Act of 1935 (PUCHA) effective February 8, 2006. Subsequent to that date, Progress Energy is no longer subject to regulation by the Securities and Exchange Commission as a public utility holding company. Progress Energy is the parent company of PEF and certain other subsidiaries.

AREA OF SERVICE

PEF provided electric service during 2005 to an average of 1.6 million customers in Florida. Its service area covers approximately 20,000 square miles and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. PEF is interconnected with 22 municipal and 9 rural electric cooperative systems. PEF is subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) and the FPSC. PEF's Service Area is shown in Figure 1.1.

TRANSMISSION/DISTRIBUTION

The Company is part of a nationwide interconnected power network that enables power to be exchanged between utilities. The PEF transmission system includes approximately 5,000 circuit miles of transmission lines. The distribution system includes approximately 35,000 circuit miles, with approximately 13,000 of those miles underground. A map of the Electric System can be found in Figure 1.2.

ENERGY MANAGEMENT

PEF customers participating in the company's residential Energy Management program help to manage future growth and costs. Approximately 345,000 customers participated in the Energy Management program at the end of 2005, contributing about 700,000 kW of winter peak-shaving capacity for use during high load periods.

TOTAL CAPACITY RESOURCE

As of December 31, 2005, PEF had total summer capacity resources of approximately 10,413 MW consisting of installed capacity of 8,976 MW (excluding Crystal River 3 joint ownership) and 1,437 MW of firm purchased power. Additional information on PEF's existing generating resources is shown on Schedule 1 and Table 3.1.

FIGURE 1.1

PROGRESS ENERGY FLORIDA

Service Area Map

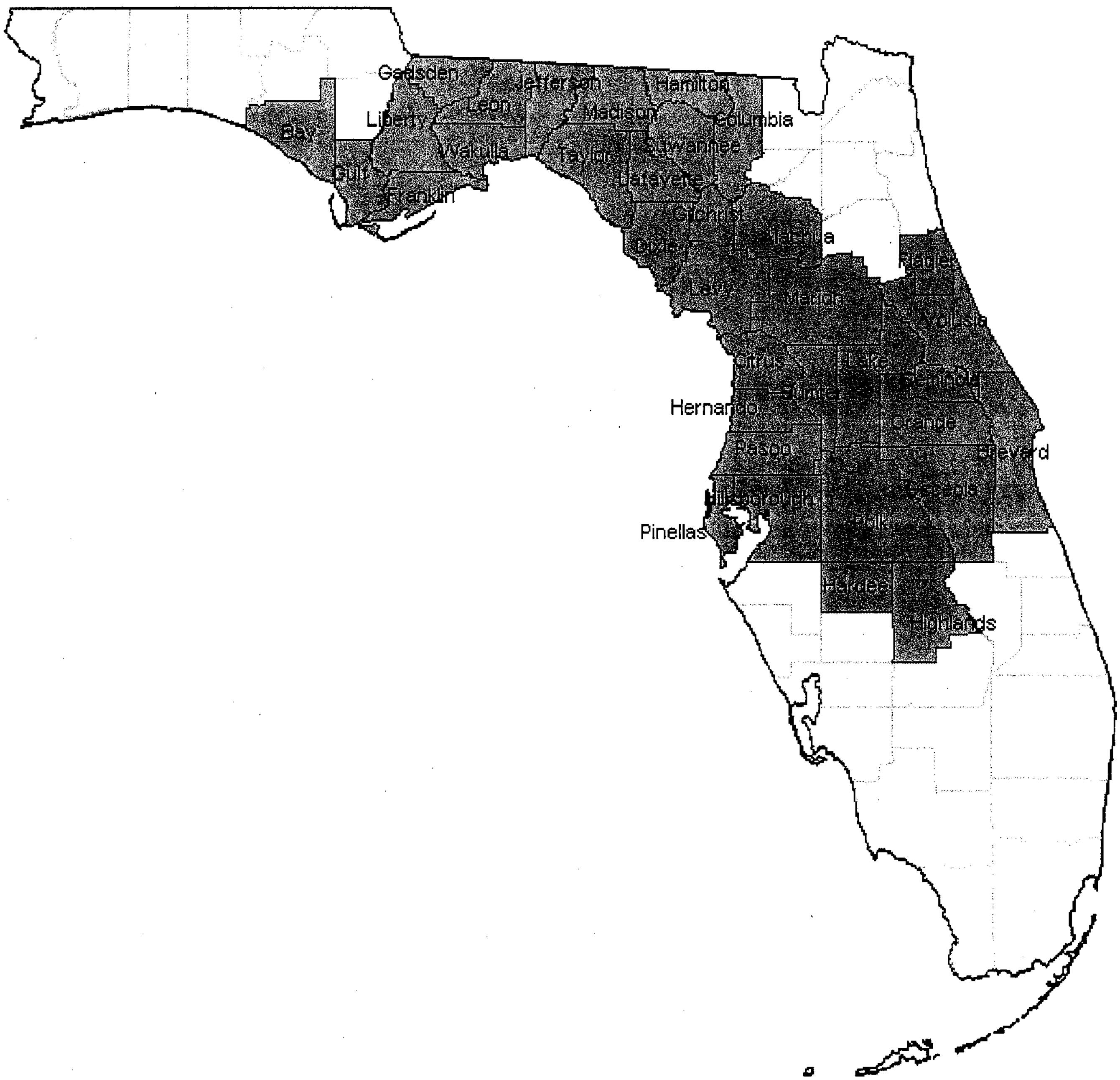
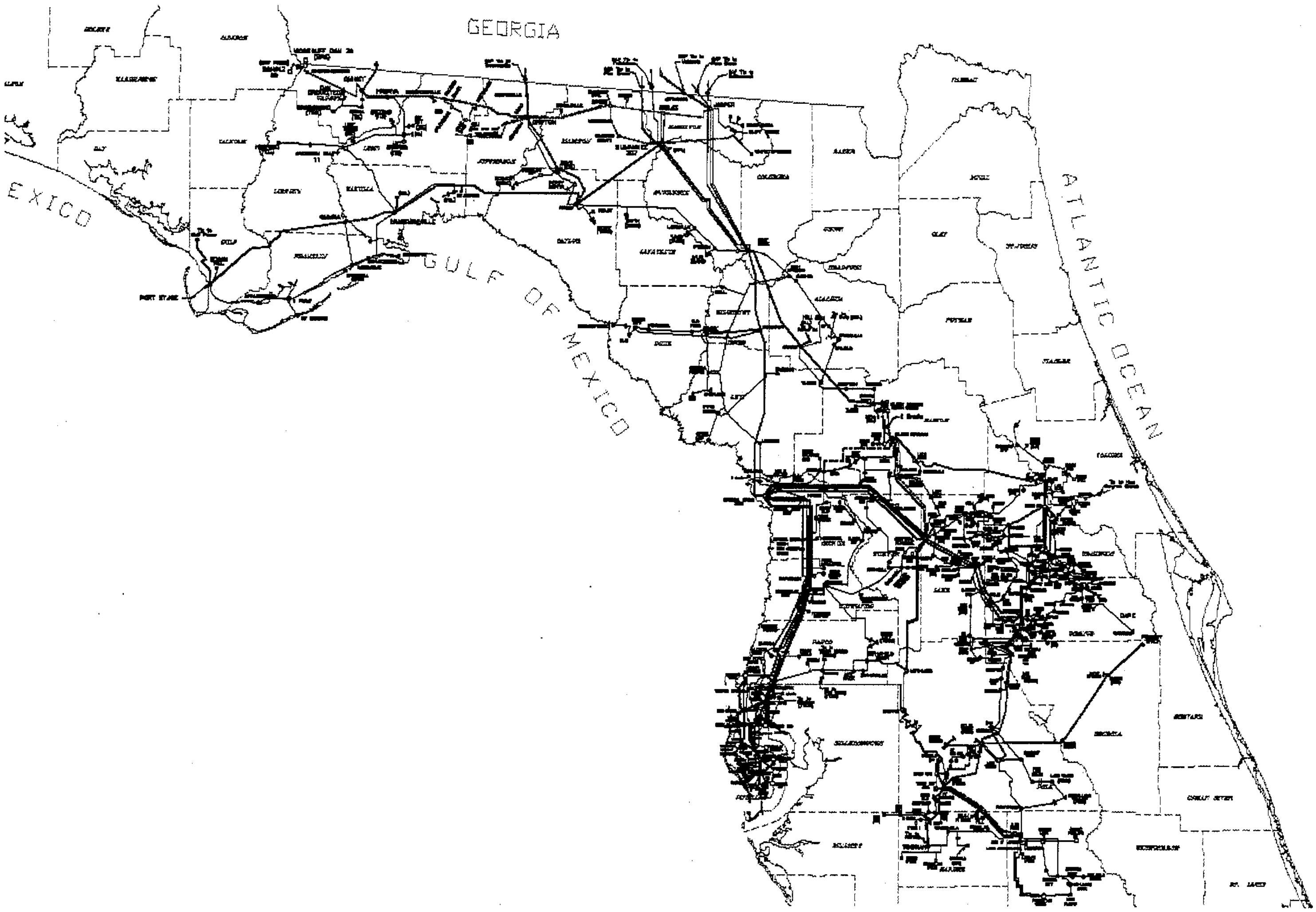


FIGURE 1.2

PROGRESS ENERGY FLORIDA

Electric System Map



PROGRESS ENERGY FLORIDA

SCHEDULE 1
EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
									COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY	
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		ALT. FUEL	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	DAYS USE	MO./YEAR	MO./YEAR	KW	MW	MW
STEAM													
ANCLOTE	1	PASCO	ST	RFO	NG	PL	PL		10/74		556,200	498	522
ANCLOTE	2	PASCO	ST	RFO	NG	PL	PL		10/78		556,200	495	522
BARTOW	1	PINELLAS	ST	RFO		WA			09/58		127,500	121	123
BARTOW	2	PINELLAS	ST	RFO		WA			08/61		127,500	119	121
BARTOW	3	PINELLAS	ST	RFO	NG	WA	PL		07/63		239,360	204	208
CRYSTAL RIVER	1	CITRUS	ST	BIT		WA			10/66		440,550	379	383
CRYSTAL RIVER	2	CITRUS	ST	BIT		WA			11/69		523,800	486	491
CRYSTAL RIVER	3 *	CITRUS	ST	NUC		TK			03/77		890,460	769	788
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA			12/82		739,260	720	735
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA			10/84		739,260	717	732
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/53		34,500	32	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO	NG	TK/RR	PL		11/54		37,500	31	32
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK/RR	PL		10/56		75,000	80	81
												4,651	**4,771**
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	2***	04/99		546,550	482	529
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK		12/03		598,000	516	582
HINES ENERGY COMPLEX	3	POLK	CC	NG	DFO	PL	TK		11/05		589,900	501	576
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,223	207	223
												1,706	**1,910**
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3***	12/68		33,790	26	32
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	26	32
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			05/72, 06/72		111,400	92	106
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	53
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	49	60
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA			04/73		226,800	184	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK			12/75-04/76		401,220	324	390
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK	8	10/92		345,000	258	279
DEBARY	P10	VOLUSIA	GT	DFO		TK			10/92		115,000	85	93
HIGGINS	P1-P2	PINELLAS	GT	NG	DFO	PL	TK		03/69, 04/69		67,580	54	64
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70, 01/71		85,850	68	70
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	294	366
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	352	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	170
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	252	294
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/70		19,290	13	16
SUWANNEE RIVER	P1, P3	SUWANNEE	GT	NG	DFO	PL	TK	9***	10/80, 11/80		122,400	110	134
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	54	67
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	26	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	65	82
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	63	80
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	35	41
												2,619	**3,069**
											TOTAL RESOURCES (MW)	**8,976**	**9,750**

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT

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

*** FOR ENTIRE PLANT

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

Progress Energy

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND
AND
ENERGY CONSUMPTION

OVERVIEW

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

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

PEF's customer growth is expected to average 1.7 percent between 2006 and 2015, less than the ten-year historical average of 2.3 percent. The ten-year historical growth rate falls to 2.0 percent when accounting for the creation of PEF's Seasonal Service Rate tariff, which artificially inflates customer growth figures. Slower population growth - based on the latest projection from the University of Florida's Bureau of Economic and Business Research – and economic conditions less favorable for the housing/construction industry (higher interest rates) result in a lower base case customer projection when compared to the higher historical growth rate. This translates into lower projected energy and demand growth rates from historic rate levels.

Net energy for load (NEL), which had grown at an average of 3.4 percent between 1996 and 2005, is expected to increase by 2.6 percent per year from 2006-2015 in the base case, 2.8 percent in the high case and 2.3 percent in the low case. A lower contribution from the wholesale jurisdiction, which grew an average of 10.7 percent between 1996 and 2005, results in lower expected system growth going forward than the historic rate. Retail NEL, which grew at a

2.7 percent average rate historically, is expected to grow 2.5 percent over the next ten years. Wholesale NEL is expected to average 3.3 percent between 2006 and 2015.

Summer net firm demand is expected to grow an average of 2.6 percent per year during the next ten years. This compares to the 4.5% growth rate experienced throughout the last ten years. Again, lower contribution from the wholesale jurisdiction is expected going forward. High and low summer growth rates for net firm demand are 2.9 percent and 2.3 percent per year, respectively. Winter net firm demand is projected to grow at 2.8 percent per year after having increased by 0.3 percent per year from 1996 to 2005. The low historical growth figure is driven by an extreme weather peak day in 1996. High and low winter net firm demand growth rates are 3.1 percent and 2.6 percent, respectively.

Summer net firm retail demand is expected to grow an average of 2.5 percent per year during the next ten years; this compares to the 4.7 percent average annual growth rate experienced throughout the last ten years. The historical growth percentage is driven by an extremely hot 2005 peak day condition. High and low summer growth rates for net firm retail demand are 2.8 percent and 2.2 percent per year, respectively. Winter net firm retail demand is projected to grow at approximately 2.1 percent per year after having grown by 0.4% from 1996 to 2005. Again, an extremely cold 1996 peak day causes this anomaly. High and low winter net firm retail demand growth rates are 2.5 percent and 1.8 percent, respectively.

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	PEF POPULATION	MEMBERS PER HOUSEHOLD	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER
1996	2,847,802	2.494	15,481	1,141,671	13,560	8,848	129,440	68,356
1997	2,895,266	2.495	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,959,509	2.502	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,047,293	2.511	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,044,449	2.467	17,116	1,234,286	13,867	10,813	143,475	75,368
2001	3,141,867	2.465	17,604	1,274,672	13,810	11,061	146,983	75,251
2002	3,207,661	2.465	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,286,782	2.468	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,348,630	2.454	19,347	1,364,677	14,177	11,734	158,780	73,898
2005	3,425,783	2.452	19,894	1,397,012	14,240	11,945	161,001	74,190
2006	3,473,481	2.447	20,187	1,419,449	14,222	11,899	163,107	72,952
2007	3,530,429	2.441	20,731	1,446,239	14,334	12,292	166,477	73,836
2008	3,585,407	2.435	21,244	1,472,551	14,427	12,725	169,784	74,947
2009	3,639,074	2.428	21,789	1,498,885	14,537	13,155	173,090	75,998
2010	3,690,763	2.420	22,316	1,524,944	14,634	13,559	176,360	76,880
2011	3,740,415	2.412	22,839	1,550,477	14,730	13,966	179,611	77,759
2012	3,788,512	2.404	23,353	1,575,780	14,820	14,370	182,781	78,618
2013	3,835,918	2.396	23,882	1,600,906	14,918	14,785	185,927	79,519
2014	3,883,825	2.389	24,411	1,625,899	15,014	15,204	189,055	80,419
2015	3,932,139	2.382	24,949	1,650,873	15,113	15,629	192,181	81,323

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		INDUSTRIAL					
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1996	4,224	2,927	1,443,116	0	26	2,205	30,784
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,957
2004	4,069	2,733	1,488,840	0	28	3,016	38,193
2005	4,140	2,703	1,531,632	0	27	3,171	39,178
2006	4,152	2,687	1,545,218	0	28	3,209	39,475
2007	4,213	2,687	1,567,920	0	28	3,327	40,591
2008	4,383	2,687	1,631,187	0	28	3,436	41,816
2009	4,416	2,687	1,643,469	0	28	3,547	42,935
2010	4,453	2,687	1,657,239	0	28	3,651	44,006
2011	4,491	2,687	1,671,381	0	28	3,756	45,081
2012	4,539	2,687	1,689,245	0	28	3,861	46,150
2013	4,579	2,687	1,704,131	0	28	3,968	47,241
2014	4,622	2,687	1,720,134	0	28	4,076	48,341
2015	4,662	2,687	1,735,020	1	28	4,186	49,456

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)
YEAR	SALES FOR RESALE GWh	UTILITY USE & LOSSES GWh	NET ENERGY FOR LOAD GWh	OTHER CUSTOMERS (AVERAGE NO.)	TOTAL NO. OF CUSTOMERS
1996	2,089	1,842	34,715	18,035	1,292,073
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,004	1,400,299
2001	3,839	1,831	40,933	20,752	1,444,958
2002	3,173	2,534	42,567	21,155	1,475,783
2003	3,359	2,595	43,911	21,665	1,510,516
2004	4,301	2,773	45,268	22,437	1,548,627
2005	5,195	2,505	46,878	22,701	1,583,417
2006	4,038	2,654	46,167	23,160	1,608,403
2007	4,430	2,739	47,759	23,719	1,639,122
2008	4,410	2,850	49,076	24,279	1,669,301
2009	4,323	2,890	50,148	24,837	1,699,499
2010	4,958	3,042	52,006	25,388	1,729,379
2011	5,083	3,055	53,219	25,933	1,758,708
2012	5,159	3,125	54,434	26,474	1,787,722
2013	5,263	3,199	55,704	27,008	1,816,528
2014	5,343	3,265	56,948	27,537	1,845,178
2015	5,419	3,337	58,211	28,059	1,873,800

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,785
2004	9,554	1,071	8,483	531	283	188	37	166	75	8,274
2005	10,316	1,118	9,198	393	250	203	38	167	75	9,189
2006	9,915	1,105	8,810	419	228	214	39	169	75	8,771
2007	10,226	1,181	9,044	431	202	223	40	171	75	9,084
2008	10,487	1,223	9,264	437	179	232	41	172	75	9,351
2009	10,676	1,201	9,475	433	158	241	42	174	75	9,553
2010	11,039	1,357	9,681	424	140	250	43	176	75	9,931
2011	11,260	1,372	9,888	425	124	259	45	177	75	10,154
2012	11,487	1,396	10,091	426	109	269	46	179	75	10,383
2013	11,699	1,406	10,293	427	97	279	47	180	75	10,593
2014	11,921	1,429	10,492	428	86	289	48	182	75	10,813
2015	12,139	1,446	10,693	429	76	293	48	183	75	11,036

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,785
2004	9,554	1,071	8,483	531	283	188	37	166	75	8,274
2005	10,316	1,118	9,198	393	250	203	38	167	75	9,189
2006	10,083	1,105	8,977	419	228	214	39	169	75	8,938
2007	10,413	1,181	9,232	431	202	223	40	171	75	9,271
2008	10,699	1,223	9,476	437	179	232	41	172	75	9,563
2009	10,913	1,201	9,712	433	158	241	42	174	75	9,789
2010	11,294	1,357	9,937	424	140	250	43	176	75	10,187
2011	11,531	1,372	10,159	425	124	259	45	177	75	10,425
2012	11,798	1,396	10,402	426	109	269	46	179	75	10,693
2013	12,059	1,406	10,653	427	97	279	47	180	75	10,954
2014	12,320	1,429	10,891	428	86	289	48	182	75	11,212
2015	12,615	1,446	11,169	429	76	293	48	183	75	11,512

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,785
2004	9,554	1,071	8,483	531	283	188	37	166	75	8,274
2005	10,316	1,118	9,198	393	250	203	38	167	75	9,189
2006	9,747	1,105	8,641	419	228	214	39	169	75	8,602
2007	10,056	1,181	8,875	431	202	223	40	171	75	8,914
2008	10,293	1,223	9,070	437	179	232	41	172	75	9,157
2009	10,473	1,201	9,272	433	158	241	42	174	75	9,349
2010	10,788	1,357	9,431	424	140	250	43	176	75	9,681
2011	10,975	1,372	9,603	425	124	259	45	177	75	9,869
2012	11,162	1,396	9,766	426	109	269	46	179	75	10,057
2013	11,332	1,406	9,926	427	97	279	47	180	75	10,227
2014	11,521	1,429	10,092	428	86	289	48	182	75	10,413
2015	11,670	1,446	10,224	429	76	293	48	183	75	10,567

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	201	9,851
2003/04	9,290	1,167	8,123	498	761	343	24	125	227	7,312
2004/05	10,798	1,602	9,196	350	725	371	26	125	247	8,953
2005/06	10,987	1,413	9,574	430	696	405	28	127	254	9,047
2006/07	11,525	1,740	9,786	426	671	429	30	128	258	9,584
2007/08	11,750	1,734	10,016	444	649	453	31	130	262	9,780
2008/09	12,113	1,894	10,220	440	631	479	33	132	265	10,134
2009/10	12,514	2,088	10,426	432	615	506	35	133	269	10,524
2010/11	12,742	2,112	10,629	434	603	534	37	135	272	10,728
2011/12	13,019	2,191	10,828	435	593	566	38	136	276	10,975
2012/13	13,278	2,253	11,025	436	586	597	40	138	279	11,202
2013/14	13,537	2,314	11,223	437	581	628	42	139	282	11,428
2014/15	13,776	2,358	11,418	438	577	660	42	141	285	11,634

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	201	9,851
2003/04	9,290	1,167	8,123	498	761	343	24	125	227	7,312
2004/05	10,798	1,602	9,196	350	725	371	26	125	247	8,953
2005/06	11,167	1,413	9,755	430	696	405	28	127	254	9,227
2006/07	11,725	1,740	9,986	426	671	429	30	128	258	9,784
2007/08	11,975	1,734	10,240	444	649	453	31	130	262	10,004
2008/09	12,364	1,894	10,470	440	631	479	33	132	265	10,384
2009/10	12,785	2,088	10,697	432	615	506	35	133	269	10,795
2010/11	13,026	2,112	10,913	434	603	534	37	135	272	11,012
2011/12	13,345	2,191	11,154	435	593	566	38	136	276	11,301
2012/13	13,656	2,253	11,403	436	586	597	40	138	279	11,580
2013/14	13,954	2,314	11,640	437	581	628	42	139	282	11,845
2014/15	14,272	2,358	11,914	438	577	660	42	141	285	12,130

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	201	9,851
2003/04	9,290	1,167	8,123	498	761	343	24	125	227	7,312
2004/05	10,798	1,602	9,196	350	725	371	26	125	247	8,953
2005/06	10,806	1,413	9,394	430	696	405	28	127	254	8,866
2006/07	11,344	1,740	9,605	426	671	429	30	128	258	9,403
2007/08	11,542	1,734	9,807	444	649	453	31	130	262	9,571
2008/09	11,897	1,894	10,003	440	631	479	33	132	265	9,917
2009/10	12,249	2,088	10,161	432	615	506	35	133	269	10,259
2010/11	12,441	2,112	10,328	434	603	534	37	135	272	10,427
2011/12	12,677	2,191	10,486	435	593	566	38	136	276	10,633
2012/13	12,894	2,253	10,641	436	586	597	40	138	279	10,818
2013/14	13,120	2,314	10,806	437	581	628	42	139	282	11,011
2014/15	13,290	2,358	10,932	438	577	660	42	141	285	11,148

Historical Values (1996 - 2005):

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

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

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

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

Projected Values (2006 - 2015):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,250	445	363	564	39,177	5,195	2,506	46,878	52.3
2006	47,556	459	365	564	39,475	4,038	2,654	46,167	58.3
2007	49,165	474	368	564	40,591	4,430	2,738	47,759	56.9
2008	50,501	489	371	565	41,816	4,410	2,850	49,076	57.1
2009	51,590	504	374	564	42,935	4,323	2,890	50,148	56.5
2010	53,466	519	377	564	44,006	4,958	3,042	52,006	56.4
2011	54,699	536	380	564	45,081	5,083	3,055	53,219	56.6
2012	55,934	552	383	565	46,150	5,159	3,125	54,434	56.5
2013	57,222	568	386	564	47,242	5,263	3,199	55,704	56.8
2014	58,485	585	389	564	48,341	5,343	3,264	56,948	56.9
2015	59,749	585	389	564	49,455	5,419	3,337	58,211	57.1

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

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.1)

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,250	445	363	564	39,177	5,195	2,506	46,878	52.3
2006	48,533	459	365	564	40,256	4,038	2,850	47,144	58.3
2007	50,099	474	368	564	41,464	4,430	2,799	48,693	56.8
2008	51,560	489	371	565	42,807	4,410	2,918	50,135	57.1
2009	52,777	504	374	564	44,047	4,323	2,965	51,335	56.4
2010	54,760	519	377	564	45,220	4,958	3,122	53,300	56.4
2011	56,076	536	380	564	46,369	5,083	3,144	54,596	56.6
2012	57,522	552	383	565	47,633	5,159	3,230	56,022	56.4
2013	59,068	568	386	564	48,970	5,263	3,317	57,550	56.7
2014	60,550	585	389	564	50,266	5,343	3,404	59,013	56.9
2015	62,217	585	389	564	51,768	5,419	3,492	60,679	57.1

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

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.2)

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(OTH)	(5)	(6)	(7)	(8)	(9)
YEAR	TOTAL	RESIDENTIAL CONSERVATION	COMM. / IND. CONSERVATION	OTHER ENERGY REDUCTIONS*	RETAIL	WHOLESALE	UTILITY USE & LOSSES	NET ENERGY FOR LOAD	LOAD FACTOR (%) **
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	46,617	424	360	565	38,193	4,301	2,774	45,268	56.5
2005	48,250	445	363	564	39,177	5,195	2,506	46,878	52.3
2006	46,765	459	365	564	38,666	4,038	2,672	45,376	58.4
2007	48,293	474	368	564	39,776	4,430	2,681	46,887	56.9
2008	49,496	489	371	565	40,873	4,410	2,788	48,071	57.2
2009	50,528	504	374	564	41,946	4,323	2,817	49,086	56.5
2010	52,169	519	377	564	42,793	4,958	2,958	50,709	56.4
2011	53,220	536	380	564	43,699	5,083	2,958	51,740	56.6
2012	54,242	552	383	565	44,566	5,159	3,017	52,742	56.5
2013	55,309	568	386	564	45,450	5,263	3,078	53,791	56.8
2014	56,389	585	389	564	46,383	5,343	3,126	54,852	56.9
2015	57,307	585	389	564	47,160	5,419	3,190	55,769	57.1

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

** Load Factors for historical years are calculated using the actual winter peak demand except the 1998 and 2004 historical load factors which are based on the actual summer peak demand.
Load Factors for future years are calculated using the net firm winter peak demand (Schedule 3.2.3)

PROGRESS ENERGY FLORIDA

SCHEDULE 4
PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND
AND NET ENERGY FOR LOAD BY MONTH

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2005		FORECAST 2006		FORECAST 2007	
MONTH	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh	PEAK DEMAND MW	NEL GWh
JANUARY	10,226	3,582	9,047	3,566	9,584	3,724
FEBRUARY	7,398	3,106	6,992	3,133	7,455	3,273
MARCH	7,609	3,592	6,008	3,337	6,501	3,552
APRIL	7,011	3,283	6,970	3,284	7,467	3,438
MAY	8,478	3,923	8,025	4,041	8,511	4,190
JUNE	8,927	4,215	8,595	4,337	8,914	4,450
JULY	9,671	4,947	8,754	4,731	9,044	4,863
AUGUST	9,681	5,031	8,771	4,748	9,084	4,885
SEPTEMBER	9,090	4,461	8,184	4,308	8,488	4,433
OCTOBER	8,301	3,968	7,692	3,837	7,963	3,952
NOVEMBER	6,424	3,215	6,282	3,267	6,573	3,347
DECEMBER	7,772	3,555	7,767	3,578	7,860	3,652
TOTAL		46,878		46,167		47,759

FUEL REQUIREMENTS AND ENERGY SOURCES

PEF's two-year actual and ten-year projected nuclear, coal, oil, and gas requirements (by fuel units) are shown on Schedule 5. PEF's two-year actual and ten-year projected energy sources, in GWh and percent, are shown by fuel type on Schedules 6.1 and 6.2, respectively. PEF's fuel requirements and energy sources reflect a diverse fuel supply system that is not dependent on any one-fuel source. In the near term, natural gas consumption is projected to increase as plants and purchases with tolling agreements are added to meet future load growth. The proportion of energy provided by natural gas will decrease with the addition of new coal resources toward the latter years of the ten-year planning horizon.

PROGRESS ENERGY FLORIDA

SCHEDULE 5

FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	FUEL REQUIREMENTS		UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	NUCLEAR		TRILLION BTU	69	60	65	62	68	52	68	63	68	63	68	63
(2)	COAL		1,000 TON	5,915	6,249	5,877	6,083	5,872	6,045	6,690	6,766	6,648	7,882	9,588	10,374
(3)	RESIDUAL	TOTAL	1,000 BBL	10,864	10,324	7,658	8,219	8,055	5,379	2,935	2,951	3,101	2,677	2,605	2,443
(4)		STEAM	1,000 BBL	10,864	10,324	7,658	8,219	8,055	5,379	2,935	2,951	3,101	2,677	2,605	2,443
(5)		CC	1,000 BBL	0		0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0		0	0	0	0	0	0	0	0	0	0
(7)		DIESEL	1,000 BBL	0		0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE	TOTAL	1,000 BBL	1,019	1,098	1,255	1,204	1,144	1,116	1,063	1,078	1,056	1,027	1,003	1,040
(9)		STEAM	1,000 BBL	152	97	50	43	47	41	48	50	56	59	57	65
(10)		CC	1,000 BBL	2	3	0	0	0	0	0	0	0	0	0	0
(11)		CT	1,000 BBL	865	998	1,205	1,161	1,098	1,074	1,016	1,028	1,000	969	946	974
(12)		DIESEL	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	TOTAL	1,000 MCF	62,674	68,447	86,145	91,824	103,618	132,457	145,075	170,627	177,247	170,540	152,332	151,001
(14)		STEAM	1,000 MCF	1,071	732	0	0	0	0	10,335	10,290	10,921	9,127	9,091	8,801
(15)		CC	1,000 MCF	45,816	52,590	67,698	73,841	85,931	114,696	118,175	143,499	149,403	145,137	127,210	126,012
(16)		CT	1,000 MCF	15,787	15,125	18,447	17,983	17,687	17,760	16,566	16,838	16,923	16,276	16,031	16,187
	OTHER (SPECIFY)														
(17)	OTHER, DISTILLATE	ANNUAL FIRM INTERCHANGE	1,000 BBL	N/A	N/A	0	0	1	12	4	15	0	0	0	0
(18)	OTHER, NATURAL GA	ANNUAL FIRM INTERCHANGE,	1,000 MCF	N/A	N/A	0	0	0	0	4,953	7,856	7,716	6,931	5,502	4,999
(18)	OTHER, NATURAL GA	ANNUAL FIRM INTERCHANGE,	1,000 MCF	N/A	N/A	672	3,061	1,923	1,314	1,396	1,697	2,049	1,290	915	538

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	417	2,220	1,371	1,690	1,563	1,495	1,529	237	202	122	85	52
(2)	NUCLEAR		GWh	6,703	5,829	6,307	6,052	6,655	5,089	6,636	6,143	6,655	6,143	6,636	6,144
(3)	COAL		GWh	15,063	15,834	15,058	15,602	15,024	15,353	16,583	16,792	16,495	19,904	24,645	26,816
(4)	RESIDUAL	TOTAL	GWh	6,981	6,618	4,696	5,081	4,956	3,291	1,794	1,802	1,902	1,623	1,583	1,483
(5)		STEAM	GWh	6,981	6,618	4,696	5,081	4,956	3,291	1,794	1,802	1,902	1,623	1,583	1,483
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	361	414	430	415	390	385	362	368	356	345	336	345
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	2	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	359	414	430	415	390	385	362	368	356	345	336	345
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	7,516	8,236	10,123	10,867	12,472	16,515	18,077	21,662	22,621	21,711	19,180	19,007
(15)		STEAM	GWh	106	74	0	0	0	0	1,023	1,019	1,085	898	895	861
(16)		CC	GWh	6,227	7,025	8,786	9,565	11,182	15,188	15,827	19,394	20,267	19,603	17,094	16,937
(17)		CT	GWh	1,183	1,137	1,337	1,302	1,290	1,327	1,227	1,249	1,269	1,210	1,191	1,209
(18)	OTHER 2/														
	QF PURCHASES		GWh	4,685	4,211	4,650	4,528	4,496	4,485	4,492	4,494	4,506	4,284	3,151	3,112
	IMPORT FROM OUT OF STATE		GWh	3,862	3,599	3,532	3,525	3,521	3,535	2,532	1,720	1,697	1,572	1,333	1,251
	EXPORT TO OUT OF STATE		GWh	-320	-83	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	45,268	46,878	46,167	47,759	49,077	50,148	52,006	53,219	54,434	55,704	56,948	58,210

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

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

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(1)	ANNUAL FIRM INTERCHANGE 1/		%	0.9%	4.7%	3.0%	3.5%	3.2%	3.0%	2.9%	0.4%	0.4%	0.2%	0.1%	0.1%
(2)	NUCLEAR		%	14.8%	12.4%	13.7%	12.7%	13.6%	10.1%	12.8%	11.5%	12.2%	11.0%	11.7%	10.6%
(3)	COAL		%	33.3%	33.8%	32.6%	32.7%	30.6%	30.6%	31.9%	31.6%	30.3%	35.7%	43.3%	46.1%
(4)	RESIDUAL	TOTAL	%	15.4%	14.1%	10.2%	10.6%	10.1%	6.6%	3.5%	3.4%	3.5%	2.9%	2.8%	2.5%
(5)		STEAM	%	15.4%	14.1%	10.2%	10.6%	10.1%	6.6%	3.5%	3.4%	3.5%	2.9%	2.8%	2.5%
(6)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		CT	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)	DISTILLATE	TOTAL	%	0.8%	0.9%	0.9%	0.9%	0.8%	0.8%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
(10)		STEAM	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		CT	%	0.8%	0.9%	0.9%	0.9%	0.8%	0.8%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%
(13)		DIESEL	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(14)	NATURAL GAS	TOTAL	%	16.6%	17.6%	21.9%	22.8%	25.4%	32.9%	34.8%	40.7%	41.6%	39.0%	33.7%	32.7%
(15)		STEAM	%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	2.0%	1.9%	2.0%	1.6%	1.6%	1.5%
(16)		CC	%	13.8%	15.0%	19.0%	20.0%	22.8%	30.3%	30.4%	36.4%	37.2%	35.2%	30.0%	29.1%
(17)		CT	%	2.6%	2.4%	2.9%	2.7%	2.6%	2.6%	2.4%	2.3%	2.3%	2.2%	2.1%	2.1%
(18)	OTHER 2/														
	QF PURCHASES		%	10.3%	9.0%	10.1%	9.5%	9.2%	8.9%	8.6%	8.4%	8.3%	7.7%	5.5%	5.3%
	IMPORT FROM OUT OF STATE		%	8.5%	7.7%	7.7%	7.4%	7.2%	7.0%	4.9%	3.2%	3.1%	2.8%	2.3%	2.1%
	EXPORT TO OUT OF STATE		%	-0.7%	-0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(19)	NET ENERGY FOR LOAD		%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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

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

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

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

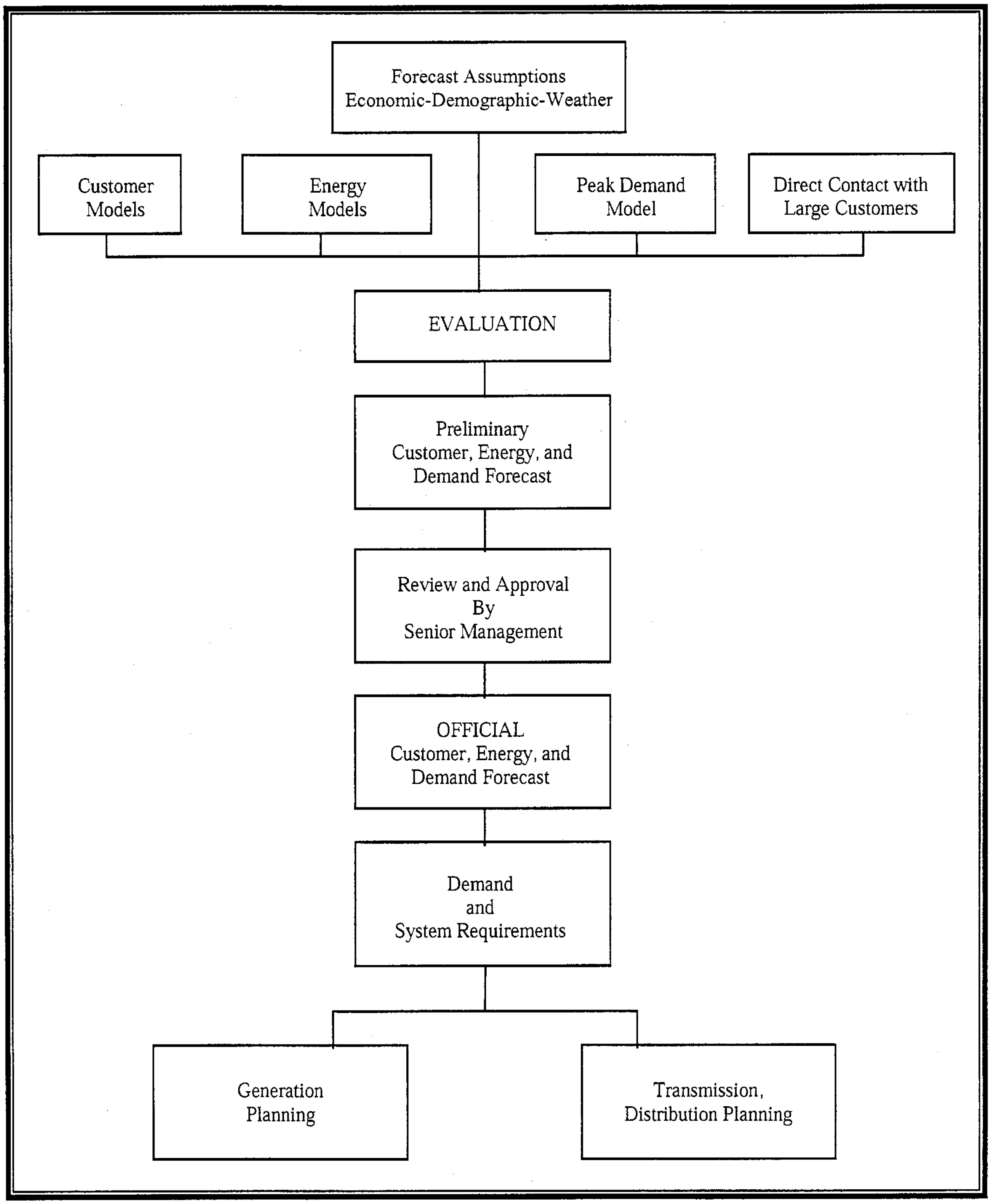
Figure 2.1, entitled "Customer, Energy and Demand Forecast", gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage as well as customer growth based on a specific set of assumptions for each class. Also accounted for is some direct contact with large customers. These inputs provide the tools needed to frame the most likely scenario of the company's future demand.

FORECAST ASSUMPTIONS

The first step in any forecasting effort is the development of assumptions upon which the forecast is based. The Corporate Planning Department develops these assumptions based on discussions with a number of departments within PEF, as well as through the research efforts of a number of external sources. These assumptions specify major factors that influence the level of customers, energy sales, or peak demand over the forecast horizon. The following set of assumptions forms the basis for the forecast presented in this document.

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

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

2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 141 (February 2005) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (February 2005) are also incorporated.

3. Within the PEF service area the phosphate mining industry is the dominant sector in the industrial sales class. Four major customers accounted for nearly 31% of the industrial class MWh sales in 2005. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations, which are heavily influenced by the state of these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions. A weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer producers becoming more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase – as we have recently experienced - to the levels just below that experienced in the late 1990 boom period. A significant risk to this projection lies in the continued high price of natural gas, which is a major cost of production.

Operations at several sites in the U.S. have already scaled back or shutdown due to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

4. PEF supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements (FR) customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Contracts for this service include the cities of Bartow, Chattahoochee, Mt. Dora, Quincy, Williston and Winter Park. Partial requirements (PR) customer load is assumed to reflect the current contractual obligations received by PEF as of May 31, 2005. The forecast of energy and demand to PR customers reflects the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for PR service included in this forecast are with the Florida Municipal Power Agency (FMPA), New Smyrna Beach, Tallahassee, Homestead, Reedy Creek Utilities, TECO Energy (Market Mitigation Sale) and Seminole Electric Cooperative, Inc. (SECI). PEF's contractual arrangement with SECI includes a "supplemental" service contract (1983 contract) for service over and above stated levels they commit to supply themselves. The firm PR contract with SECI includes 150 MW of stratified intermediate service (October 1995 contract) which is projected to continue through the forecast horizon. The firm PR contract with SECI also includes amendments to provide an additional 150 MW of stratified intermediate service beginning June 2006, and another 150 MW beginning December 2006. Agreements to provide interruptible service at three individual SECI metering sites have also been included in this projection. Finally, a FR contract to serve SECI load will commence in 2010 and last through the forecast horizon.

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

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

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

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

SHORT-TERM ECONOMIC ASSUMPTIONS

The economic outlook for this forecast was developed in 2005 as energy prices were hitting record highs around the world. The general consensus was that the U.S. economy, which was growing at a reasonable rate, would not slip into recession due to the higher cost of energy. A described "soft patch" in economic activity apparent at the time of this forecast development as high gasoline prices had been reducing consumer confidence levels. Short term interest rates, controlled mostly by Federal Reserve Board (FED) policy decisions, have increased significantly in the last 12 months as hints of inflation have filtered through the reported price indexes. The days of 45-plus year lows in interest rates have ended. The FED had moved to increase rates ten times at this point – no longer seeing the need to stimulate the national economy from the post September 11th weakness that occurred. The national economy had bounced back significantly (except for job growth statistics). Economists were not in complete agreement about where monetary policy would go from here. Most thought that the FED was much closer to ending its "tightening" policy of gradually raising interest rates than those who believed that inflationary fears would require many more rate increases.

Consensus opinion believes that the economic stimulus supplied by the three federal tax cuts and the refinancing boom have pretty much run their course. Additional stimulus from these two phenomena is not expected going forward. One item believed to become a positive factor for future economic momentum is the weaker U.S. currency. Up to this point it had not supplied the punch assumed in the last forecast. This is due to several major U.S. trading partners, mainly China, having their currencies pegged to the U.S. Dollar. The Mexican Peso has actually weakened against the Dollar. This has kept the typical advantages of a weaker currency from helping U.S. manufacturers. Also, European economies have not been robust enough to fuel added imports of U.S. products. Going forward, it is expected that economic and political pressures will force the Chinese to de-link their currency and allow it to appreciate in value. This likely will make American-produced products more competitive with imported Chinese goods around the globe.

The housing sector has continued on an unprecedented pace. Most signs, however, point to an industry that likely will not maintain this level of growth. Long term interest rates (and mortgage rates) have not increased at the same pace as short term rates allowing the momentum to continue. At some point the demand for housing pushed by new household formations will, in all likelihood, weaken. The demand for second homes could fall as interest rates finally rise.

The Florida economy has faired much better than the nation, especially in terms of job growth. The tourism industry, which has bounced back from the terrorism fears of 2001, will now have to juggle the impact of high oil prices on the travel industry.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. Many factors influence the pace of in-migration to Florida but there is one broad, demographically created influence one can expect during the next few years. The University of Florida's latest population projection (February 2005) shows a return to more normal levels of growth in Florida population as we move into the mid-decade. This is due to economy-related conditions as well as demographic conditions that measure population by age brackets. There will be a significant jump in the retirement-age population later this decade.

LONG-TERM ECONOMIC ASSUMPTIONS

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

Population Growth Trends

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

Second, the enormous growth in population and corresponding development of the 1980s, 1990s and early 2000s made portions of Florida less desirable and less affordable for retirement living. This diminished the quality of retiree life, and along with increasing competition from neighboring states, is expected to cause a slight decline in Florida's share of these prospective new residents over the long term.

Another reason for a population growth slowdown appears to be the fear and expense of Hurricanes. The summers of 2004 and 2005 may force some in-migrants to rethink their retirement location as the inconvenience caused by recent destruction and ever-increasing cost of hazard insurance makes Florida a less desirable place to live.

Economic Growth Trends

Florida has been recently experiencing a 1980s-style population explosion and service sector job creation. The State has benefited greatly from generational lows in interest rates, which along with investors' unfriendly attitude toward the equity markets, set the stage for a tremendous explosion in home construction. The national level of homebuilding in 2005, which rose to more than 31% higher than in 2000, set an all time record. This growth produced strong gains in both the construction industry and service-producing sectors of the Florida economy.

While most agree that this pace of growth is not sustainable, the economic environment that produced this construction boom has begun to wane. Interest rates are returning to more "long term" norms. Investment in equity markets appears to have bounced back of late. More importantly, affordability rates have dropped as housing prices in many parts of Florida have out-paced many areas of the country. This could have a major impact on retiree decisions to move into the area. Making matters worse is the availability and affordability of homeowners insurance, which has become a concern of increasing importance since the Hurricane seasons of 2004 and 2005.

Florida's rapid population growth of late has created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also a number of corporations migrating to Florida capitalizing on the low cost, low tax business environment. This being the case, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period but at a less significant level. Florida's successful effort to attract a large biotech firm, Scripps Research, has the potential to draw a whole new growth industry to the State, the same way Disney and NASA once did.

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

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

FORECAST METHODOLOGY

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

ENERGY AND CUSTOMER FORECAST

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

Residential Sector

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

Commercial Sector

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

Industrial Sector

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

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

Street Lighting

Electricity sales to the street and highway lighting class are projected to increase due to growth in the service area population base. Because this class comprised less than 0.01% of PEF's 2005 electric sales and just 0.1% of total customers, a simple time trend was used to project energy consumption and customer growth in this class.

Public Authorities

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

Sales for Resale Sector

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

SECI is a wholesale, or sales for resale, customer of PEF on both a supplemental contract basis and contract demand basis. Under the supplemental contract, PEF provides service for those energy requirements above the level of generation capacity served by either SECI's own facilities or its firm purchase obligations. Monthly supplemental energy is developed using an average of several years' historical load shape of total load in the PEF control area, subtracting out the level of SECI "committed" capacity from each hour. Beyond supplemental service, PEF has an agreement with SECI to serve stratified intermediate and peaking energy. This agreement involves serving 150 MW of stratified intermediate demand that is assumed to remain a requirement on the PEF system throughout the forecast horizon. This contract has been amended to provide an additional 300 MW stratified intermediate product beginning in 2006. Energy usage under this contract is projected using typical intermediate strata load factors. Agreements to provide non-firm or interruptible service are currently in effect between PEF and SECI at three separate metering points amounting to an estimated 50 MW. Another contract, signed in 2004 to supply full requirements service for 150 MW, will begin in 2010.

The municipal sales for resale class includes a number of customers, divergent not only in scope of service, (i.e., full or partial requirement), but also in composition of ultimate consumers. Each customer is modeled separately in order to accurately reflect its individual profile. Several of the customers in this class are municipalities whose full energy requirements are met by PEF. The full requirement customers are modeled individually using local weather station data and population growth trends. Since the ultimate consumers of electricity in this sector are, to a large degree, residential and commercial customers, it is assumed that their use patterns will follow those of the PEF retail-based residential and commercial customer classes. PEF serves partial requirement service (PR) to municipalities such as New Smyrna Beach (NSB), Homestead and Tallahassee, and other power providers like FMPA. In each case, these customers contract with PEF for a specific level and type of demand needed to provide their particular electrical system with an appropriate level of reliability. The terms of the FMPA and NSB contracts are subject to change each year via a letter of "declared" MW nomination. More specifically, this means that the level and type of demand and energy under contract can increase or decrease for each year a value is nominated. The energy forecast for each contract is derived using its historical load factors where enough history exists, or typical load factors for a given type of contracted stratified load. The energy projections for FMPA also include a "losses service contract" for energy PEF supplies to FMPA for transmission losses incurred when "wheeling" power to their ultimate customers in PEF's transmission area. This projection is based on the projected requirements of the aggregated needs of the cities of Ocala, Leesburg, Bushnell, Havana and Newberry.

PEAK DEMAND FORECAST

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

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

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

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

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

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

HIGH AND LOW FORECAST SCENARIOS

The high and low bandwidth scenarios around the base MWh energy sales forecast are developed using a Monte Carlo simulation applied to a multivariate regression model that closely replicates the base retail MWh energy forecast in aggregate. This model accounts for variation in Gross Domestic

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

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

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

CONSERVATION

PEF's DSM performance is shown in the following tables, which compare the conservation savings actually achieved through PEF's DSM programs for the reporting year of 2005 with the Commission-approved conservations goals.

On August 9, 2004, the FPSC issued a PAA Order approving new conservation goals for PEF that span the ten-year period from 2005 through 2014 (in Docket 040031-EG, Order No. PSC-04-0769-PAA-EG). In that same PAA Order, the Commission also approved a new DSM Plan for PEF that was specifically designed to meet the new conservation goals. The PAA Order was subsequently made effective and final in a Consummating Order (PSC-04-0852-CO-EG) issued by the Commission on September 1, 2004.

Residential Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	13	18	43	48	21	29

Commercial Conservation Savings Goals and Achievements

	Summer MW		Winter MW		Annual GWh Energy	
Year	**Goal**	**Achieved**	**Goal**	**Achieved**	**Goal**	**Achieved**
2005	4	8	3	6	3	3

The forecasts contained in this Ten-Year Site Plan document are based on PEF's new DSM Plan and, therefore, appropriately reflect the level of DSM savings required to meet the Commission-established conservation goals. PEF's DSM Plan consists of five residential programs, seven commercial and industrial programs, and one research and development program. The programs are subject to periodic monitoring and evaluation for the purpose of ensuring that all DSM resources are acquired in a cost-effective manner and that the program savings are durable. Following is a brief description of these programs.

RESIDENTIAL PROGRAMS

Home Energy Check Program

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option)-a customer-completed audit; Type 4: Phone Assisted Audit –A customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type

6: Home Energy Rating Audit (Class I, II, III). The Home Energy Check Program serves as the foundation of the Home Energy Improvement Program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement Program

This is the umbrella program to increase energy efficiency for existing residential homes. It combines efficiency improvements to the thermal envelope with upgraded electric appliances. The program provides incentives for attic insulation upgrades, duct testing and repair, and high efficiency electric heat pumps.

Residential New Construction Program

This program promotes energy efficient new home construction in order to provide customers with more efficient dwellings combined with improved environmental comfort. The program provides education and information to the design and building community on energy efficient equipment and construction. It also facilitates the design and construction of energy efficient homes by working directly with the builders to comply with program requirements. The program provides incentives to the builder for high efficiency electric heat pumps and high performance windows. The highest level of the program incorporates the Environmental Protection Agency's Energy Star Homes Program and qualifies participants for cooperative advertising.

Low Income Weatherization Assistance Program

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

Residential Energy Management Program

This is a voluntary customer program that allows PEF to reduce peak demand and thus defer generation construction. Peak demand is reduced by interrupting service to selected electrical equipment with radio controlled switches installed on the customer's premises. These interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand. Participating customers receive a monthly credit on their electricity bills prorated above 600 kWh/month.

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check Program

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

Better Business Program

This is the umbrella efficiency program for existing commercial and industrial customers. The program provides customers with information, education, and advice on energy-related issues and incentives on efficiency measures that are cost-effective to PEF and its customers. The Better Business Program promotes energy efficient heating, ventilation, air conditioning (HVAC), and some building retrofit measures (in particular, ceiling insulation upgrade, duct leakage test and repair, energy-recovery ventilation and Energy Star cool roof coating products.)

Commercial/Industrial New Construction Program

The primary goal of this program is to foster the design and construction of energy efficient buildings. The new construction program: 1) provides education and information to the design community on all aspects of energy efficient building design; 2) requires that the building design, at a minimum, surpass the state energy code; 3) provides financial incentives for specific energy efficient equipment; and 4) provides energy design awards to building design teams. Incentives will be provided for high efficiency HVAC equipment, energy recovery ventilation and Energy Star cool roof coating products.

Innovation Incentive Program

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

Commercial Energy Management Program (Rate Schedule GSLM-1)

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

Standby Generation Program

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

Interruptible Service Program

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

Curtailable Service

This direct load control program reduces PEF's demand at times of peak or emergency conditions. The program is available to qualified non-residential customers with an average billing demand of 500 kW or more, who are willing to curtail 25 percent of their average monthly billing demand. Customers participating in the Curtailable Service program receive a monthly curtailable demand credit applied to their electric bills.

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development Program

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

CHAPTER 3

FORECAST OF
FACILITIES REQUIREMENTS

Progress Energy

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

PEF has a summer total capacity resource of 10,413 MW, as shown in Table 3.1. This capacity resource includes nuclear (769 MW), fossil steam (3,882 MW), combined cycle plants (1,706 MW), combustion turbine (2,619 MW, 143 MW of which is owned by Georgia Power for the months June through September), utility purchased power (617 MW), and non-utility purchased power (820 MW). Table 3.2 shows PEF's contracts for firm capacity provided by Qualifying Facilities (QF's).

Demand-Side Programs

Total DSM resources are shown in Schedules 3.1.1 and 3.2.1 of Chapter 2. These programs include Non-Dispatchable DSM, Interruptible Load, and Dispatchable Load Control resources. PEF's 2006 Ten-Year Site Plan Demand-Side Management projections are consistent with the DSM Goals established by the Commission in Docket No. 040031-EG.

Capacity and Demand Forecast

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

Base Expansion Plan

PEF's planned supply resource additions and changes are shown in Schedule 8 and are referred to as PEF's Base Expansion Plan. This Plan includes 3,910 net MW (summer rating) of proposed new capacity additions through the summer of 2015. As identified in Schedule 8, PEF's next planned need is the Hines 4 Unit, a 461 MW (summer) power block with a December 2007 in-service date. PEF's self-build option for Hines Unit 4 was determined to be the most cost-effective alternative, followed by the Bartow Repowering Project to be completed by June 2009.

PEF's Base Expansion Plan projects requirements for additional units with proposed in-service dates of 2007 through 2015. These units, together with the Central Power & Lime Purchase (December 2005 through December 2010), the TEA purchase (from June through September 2006, December 2006 through February 2007, and June through September 2007), the Shady Hills Purchase (April 2007 through April 2014), and the Southern Company Purchase (June 2010 through December 2015), help the PEF system meet the growing energy requirements of its customer base. Some of the identified unit additions may be impacted by PEF's ability to extend or replace existing purchase power contracts, as well as contracts with cogenerators and QF's. Status reports and specifications for new generation facilities are included in Schedule 9. Shown in Schedule 10 are the new transmission lines associated with Hines #4 and the Bartow Repowering Project.

Current planning studies identify gas-fired units as the most economic alternatives for system expansion in the near term. The forecast of natural gas prices has risen to the point where new pulverized coal units appear to be a cost effective alternative. Uncertainties over future fuel price relationships, environmental regulations, and the ability to site new coal units in Florida will require ongoing re-evaluations of the coal option. New nuclear technologies appear to offer favorable long-term economics, and provide favorable environmental characteristics, measured against possible emission limits imposed by the recently issued Clean Air Interstate Rule (CAIR). PEF is currently evaluating the nuclear option with the intent to pursue preliminary licensing activities should suitable sites for new nuclear units be available. Currently, the expected lead time to site, license, engineer, and construct a new nuclear unit place its in-service date outside the ten-year planning horizon presented in this document.

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2005

PLANTS	NUMBER OF UNITS	SUMMER NET DEPENDABLE CAPABILITY (MW)	
Nuclear Steam			
Crystal River	1	769	(1)
Total Nuclear Steam	1	769	
Fossil Steam			
Crystal River	4	2,302	
Anclote	2	993	
Bartow	3	444	
Suwannee River	3	143	
Total Fossil Steam	12	3,882	
Combined Cycle			
Hines Energy Complex	3	1,499	
Tiger Bay	1	207	
Total Combined cycle	4	1,706	
Combustion Turbine			
DeBary	10	667	
Intercession City	14	1,041	(2)
Bayboro	4	184	
Bartow	4	187	
Suwannee	3	164	
Turner	4	154	
Higgins	4	122	
Avon Park	2	52	
University of Florida	1	35	
Rio Pinar	1	13	
Total Combustion Turbine	47	2,619	
Total Units	**64**		
Total Net Generating Capability		**8,976**	

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

Purchased Power			
Qualifying Facility Contracts	19	820	
Investor Owned Utilities	2	617	
TOTAL CAPACITY RESOURCES		**10,413**	

TABLE 3.2 PROGRESS ENERGY FLORIDA QUALIFYING FACILITY GENERATION CONTRACTS AS OF DECEMBER 31, 2005	
Facility Name	**Firm Capacity (MW)**
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Jefferson Power	2.0
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery 1	40.0
Pinellas County Resource Recovery 2	14.8
Ridge Generating Station	39.6
Royster	30.8
US Agrichem	5.6
TOTAL	**820.2**

PROGRESS ENERGY FLORIDA

SCHEDULE 7.1

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF SUMMER PEAK

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL INSTALLED CAPACITY	FIRM CAPACITY IMPORT	FIRM CAPACITY EXPORT	QF	TOTAL CAPACITY AVAILABLE	SYSTEM FIRM SUMMER PEAK DEMAND	RESERVE MARGIN BEFORE MAINTENANCE		SCHEDULED MAINTENANCE	RESERVE MARGIN AFTER MAINTENANCE	
YEAR	MW	MW	MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2006	8,843	817 *	0	813	10,473	8,771	1,702	19%	0	1,702	19%
2007	8,843	1,253 *	0	802	10,898	9,084	1,814	20%	0	1,814	20%
2008	9,304	1,095	0	798	11,197	9,351	1,846	20%	0	1,846	20%
2009	9,997	1,095	0	798	11,890	9,554	2,336	24%	0	2,336	24%
2010	10,136	1,093	0	798	12,027	9,931	2,096	21%	0	2,096	21%
2011	10,614	890	0	798	12,302	10,155	2,147	21%	0	2,147	21%
2012	10,775	890	0	798	12,463	10,383	2,080	20%	0	2,080	20%
2013	11,525	890	0	687	13,102	10,593	2,509	24%	0	2,509	24%
2014	12,275	412	0	500	13,187	10,813	2,374	22%	0	2,374	22%
2015	12,753	412	0	500	13,665	11,036	2,629	24%	0	2,629	24%

* Progress Energy is pursuing seasonal purchases of approximately 200 MW in 2006 and 158 MW in 2007. The deals are not yet consummated as of the time of the Ten-Year Site Plan filing. Since the purchase is expected to be from peaking capacity, no energy impact has been included in the plan at this time.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 7.2
FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK

(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	TOTAL	FIRM		FIRM		TOTAL	SYSTEM FIRM					
	INSTALLED	CAPACITY		CAPACITY		CAPACITY	WINTER PEAK	RESERVE MARGIN		SCHEDULED	RESERVE MARGIN	
	CAPACITY	IMPORT		EXPORT	QF	AVAILABLE	DEMAND	BEFORE MAINTENANCE		MAINTENANCE	AFTER MAINTENANCE	
YEAR	MW	MW		MW	MW	MW	MW	MW	% OF PEAK	MW	MW	% OF PEAK
2005/06	9,757	617		0	813	11,187	9,047	2,140	24%	0	2,140	24%
2006/07	9,757	1,117	*	0	802	11,676	9,584	2,092	22%	0	2,092	22%
2007/08	10,274	1,137		0	798	12,209	9,780	2,429	25%	0	2,429	25%
2008/09	10,656	1,137		0	798	12,591	10,134	2,457	24%	0	2,457	24%
2009/10	11,057	1,137		0	798	12,992	10,524	2,468	23%	0	2,468	23%
2010/11	11,248	1,002		0	798	13,048	10,727	2,321	22%	0	2,321	22%
2011/12	11,798	932		0	798	13,528	10,975	2,553	23%	0	2,553	23%
2012/13	11,989	932		0	798	13,719	11,203	2,516	22%	0	2,516	22%
2013/14	12,739	932		0	513	14,184	11,427	2,757	24%	0	2,757	24%
2014/15	13,489	412		0	501	14,402	11,634	2,768	24%	0	2,768	24%

* Includes Seasonal Purchase of 500 MW in 2006/07.

The recently issued Clean Air Interstate Rule (CAIR) may impact PEF's need for new capacity. While a compliance plan has not yet been finalized, some alternatives may impact the capacity of existing and/or future generation resources, resulting in a need for additional capacity. Once the compliance plan has been finalized, PEF will quantify the impacts on generating resources and determine if any additional capacity is needed.

PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2006 THROUGH DECEMBER 31, 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								CONST.	COM'L IN-	EXPECTED	GEN. MAX.	NET CAPABILITY			
	UNIT	LOCATION	UNIT	FUEL		FUEL TRANSPORT		START	SERVICE	RETIREMENT	NAMEPLATE	SUMMER	WINTER		
PLANT NAME	NO.	(COUNTY)	TYPE	PRI.	ALT.	PRI.	ALT.	MO. / YR	MO. / YR	MO. / YR	KW	MW	MW	STATUS	NOTES
HINES ENERGY COMPLEX	4	POLK	CC	NG	DFO	PL	TK	12/2005	12/2007			461	517	U	
BARTOW CT	5, 6	PINELLAS	CT	NG	DFO	PL	TK	12/2006	12/2008			322	382	P	(1)
CRYSTAL RIVER	5	CITRUS	ST	BIT	--	WA	--	--	04/2009			(22)	(22)	P	(2)
BARTOW CC	1	PINELLAS	CC	NG	DFO	PL	WA	12/2006	06/2009			837	897	P	(1)
BARTOW	1-3	PINELLAS	ST	RFO	--	WA	--	--	--	06/2009		(444)	(452)	P	(1)
CRYSTAL RIVER	4	CITRUS	ST	BIT	--	WA	--	--	11/2009			(22)	(22)	P	(2)
COMBUSTION TURBINE	1	UNKNOWN	GT	NG	DFO	PL	TK	06/2009	06/2010			161	191	P	
COMBINED CYCLE	1	UNKNOWN	CC	NG	DFO	PL	TK	01/2009	06/2011			478	550	P	
COMBUSTION TURBINE	2	UNKNOWN	GT	NG	DFO	PL	TK	06/2011	06/2012			161	191	P	
P-COAL, Supercritical	1	UNKNOWN	ST	BIT	--	RR	--	06/2008	06/2013			750	750	P	
P-COAL, Supercritical	2	UNKNOWN	ST	BIT	--	RR	--	06/2009	06/2014			750	750	P	
COMBINED CYCLE	2	UNKNOWN	CC	NG	DFO	PL	TK	01/2013	06/2015			478	550	P	

NOTES

(1) As part of the Bartow Repowering Project, two CTs will go into service 12/2008. In June of 2009, they will be combined with an additional two CTs, four HRSGs, and one steam turbine to produce a single, 4x4x1 combined cycle with a total summer capacity of 1,159 MW.

(2) Derations due to FDG scrubber installations.

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	HINES ENERGY COMPLEX UNIT #4	
(2)	Capacity		
	a. Summer:	461	
	b. Winter:	517	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	12/2005	
	b. Commercial in-service date:	12/2007	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	Cooling Method:	COOLING POND	
(8)	Total Site Area:	8,200 ACRES	
(9)	Construction Status:	REGULATORY APPROVAL RECEIVED UNDER CONSTRUCTION	
(10)	Certification Status:	SITE PERMITTED	
(11)	Status with Federal Agencies:	SITE PERMITTED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.0 %	
	b. Forced Outage Factor (FOF):	3.0 %	
	c. Equivalent Availability Factor (EAF):	91.2 %	
	d. Resulting Capacity Factor (%):	47.0 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,915 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	495.40	
	c. Direct Construction Cost ($/kW):	443.09	
	d. AFUDC Amount ($/kW):	52.31	
	e. Escalation ($/kW):	0.00	
	f. Fixed O&M ($/kW-yr):	1.26	
	g. Variable O&M ($/MWh):	2.38	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	BARTOW REPOWERING	
(2)	Capacity		
	a. Summer:	1,159	
	b. Winter:	1,279	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	12/2006	
	b. Commercial in-service date:	06/2009	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION	
(7)	Cooling Method:	COOLING WATER	
(8)	Total Site Area:	1,348 ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	N/A	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.6 %	
	c. Equivalent Availability Factor (EAF):	88.8 %	
	d. Resulting Capacity Factor (%):	53.9 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,236 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	435.08	
	c. Direct Construction Cost ($/kW):	403.56	
	d. AFUDC Amount ($/kW):	31.52	
	e. Escalation ($/kW):	0.00	
	f. Fixed O&M ($/kW-yr):	4.53	
	g. Variable O&M ($/MWh):	2.50	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	SIMPLE CYCLE 1	
(2)	Capacity		
	a. Summer:	161	
	b. Winter:	191	
(3)	Technology Type:	SIMPLE CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	06/2009	
	b. Commercial in-service date:	06/2010	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.7 %	
	c. Equivalent Availability Factor (EAF):	88.7 %	
	d. Resulting Capacity Factor (%):	1.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	10,579 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	349.59	
	c. Direct Construction Cost ($/kW):	273.09	
	d. AFUDC Amount ($/kW):	35.84	
	e. Escalation ($/kW):	40.66	
	f. Fixed O&M ($/kW-yr):	2.16	
	g. Variable O&M ($/MWh):	10.64	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COMBINED CYCLE 1	
(2)	Capacity		
	a. Summer:	478	
	b. Winter:	550	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	01/2009	
	b. Commercial in-service date:	06/2011	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	Cooling Method:	UNKNOWN	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.6 %	
	c. Equivalent Availability Factor (EAF):	88.8 %	
	d. Resulting Capacity Factor (%):	58.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,461 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	486.17	
	c. Direct Construction Cost ($/kW):	352.00	
	d. AFUDC Amount ($/kW):	70.02	
	e. Escalation ($/kW):	64.15	
	f. Fixed O&M ($/kW-yr):	2.03	
	g. Variable O&M ($/MWh):	1.21	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	SIMPLE CYCLE 2	
(2)	Capacity		
	a. Summer:	161	
	b. Winter:	191	
(3)	Technology Type:	SIMPLE CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	06/2011	
	b. Commercial in-service date:	06/2012	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION	
(7)	Cooling Method:	N/A	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.7 %	
	c. Equivalent Availability Factor (EAF):	88.7 %	
	d. Resulting Capacity Factor (%):	1.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	10,579 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	369.08	
	c. Direct Construction Cost ($/kW):	273.09	
	d. AFUDC Amount ($/kW):	37.84	
	e. Escalation ($/kW):	58.15	
	f. Fixed O&M ($/kW-yr):	2.16	
	g. Variable O&M ($/MWh):	10.64	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COAL-1	
(2)	Capacity		
	a. Summer:	750	
	b. Winter:	750	
(3)	Technology Type:	PULVERIZED COAL-SUPERCRITICAL	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	06/2008	
	b. Commercial in-service date:	06/2013	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	BITUMINOUS	
	b. Alternate fuel:		
(6)	Air Pollution Control Strategy (a):	LOW-NOX BURNERS, SELECTIVE	
(7)	Cooling Method:	UNKNOWN	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	4.8 %	
	b. Forced Outage Factor (FOF):	4.2 %	
	c. Equivalent Availability Factor (EAF):	91.2 %	
	d. Resulting Capacity Factor (%):	89.5 %	
	e. Average Net Operating Heat Rate (ANOHR):	8,712 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	40	
	b. Total Installed Cost (In-service year $/kW):	1651.57	
	c. Direct Construction Cost ($/kW):	1143.70	
	d. AFUDC Amount ($/kW):	224.49	
	e. Escalation ($/kW):	283.38	
	f. Fixed O&M ($/kW-yr):	31.94	
	g. Variable O&M ($/MWh):	3.21	
	h. K Factor:	NO CALCULATION	

(a) Subject to future requirements

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COAL-2
(2)	Capacity	
	a. Summer:	750
	b. Winter:	750
(3)	Technology Type:	PULVERIZED COAL-SUPERCRITICAL
(4)	Anticipated Construction Timing	
	a. Field construction start date:	06/2009
	b. Commercial in-service date:	06/2014 (EXPECTED)
(5)	Fuel	
	a. Primary fuel:	BITUMINOUS
	b. Alternate fuel:	
(6)	Air Pollution Control Strategy (a):	LOW-NOX BURNERS, SELECTIVE
(7)	Cooling Method:	UNKNOWN
(8)	Total Site Area:	UNKNOWN ACRES
(9)	Construction Status:	PLANNED
(10)	Certification Status:	PLANNED
(11)	Status with Federal Agencies:	PLANNED
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF):	4.8 %
	b. Forced Outage Factor (FOF):	4.2 %
	c. Equivalent Availability Factor (EAF):	91.2 %
	d. Resulting Capacity Factor (%):	89.5 %
	e. Average Net Operating Heat Rate (ANOHR):	8,712 BTU/kWh
(13)	Projected Unit Financial Data	
	a. Book Life (Years):	40
	b. Total Installed Cost (In-service year $/kW):	1696.99
	c. Direct Construction Cost ($/kW):	1143.70
	d. AFUDC Amount ($/kW):	230.66
	e. Escalation ($/kW):	322.63
	f. Fixed O&M ($/kW-yr):	31.94
	g. Variable O&M ($/MWh):	3.21
	h. K Factor:	NO CALCULATION

(a) Subject to future requirements

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
AS OF JANUARY 1, 2006

(1)	Plant Name and Unit Number:	COMBINED CYCLE 2	
(2)	Capacity		
	a. Summer:	478	
	b. Winter:	550	
(3)	Technology Type:	COMBINED CYCLE	
(4)	Anticipated Construction Timing		
	a. Field construction start date:	01/2013	
	b. Commercial in-service date:	06/2015	(EXPECTED)
(5)	Fuel		
	a. Primary fuel:	NATURAL GAS	
	b. Alternate fuel:	DISTILLATE FUEL OIL	
(6)	Air Pollution Control Strategy:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	Cooling Method:	UNKNOWN	
(8)	Total Site Area:	UNKNOWN ACRES	
(9)	Construction Status:	PLANNED	
(10)	Certification Status:	PLANNED	
(11)	Status with Federal Agencies:	PLANNED	
(12)	Projected Unit Performance Data		
	a. Planned Outage Factor (POF):	6.9 %	
	b. Forced Outage Factor (FOF):	4.6 %	
	c. Equivalent Availability Factor (EAF):	88.8 %	
	d. Resulting Capacity Factor (%):	58.3 %	
	e. Average Net Operating Heat Rate (ANOHR):	7,461 BTU/kWh	
(13)	Projected Unit Financial Data		
	a. Book Life (Years):	25	
	b. Total Installed Cost (In-service year $/kW):	541.89	
	c. Direct Construction Cost ($/kW):	352.00	
	d. AFUDC Amount ($/kW):	78.05	
	e. Escalation ($/kW):	111.84	
	f. Fixed O&M ($/kW-yr):	2.03	
	g. Variable O&M ($/MWh):	1.21	
	h. K Factor:	NO CALCULATION	

PROGRESS ENERGY FLORIDA

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

HINES UNIT #4

(1) POINT OF ORIGIN AND TERMINATION:	West Lake Wales Substation-Hines Energy Complex
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing Hines Energy Complex Site and new transmission right-of-way
(4) LINE LENGTH:	21
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	6/2007
(7) ANTICIPATED CAPITAL INVESTMENT:	$32,987,944 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* As recognized by the Florida Public Service Commission in its Order Granting Petition for Determination of Need for Hines Unit 4, the projected capital estimate may vary during construction of the Hines 4 facility.

PROGRESS ENERGY FLORIDA

SCHEDULE 10

STATUS REPORT AND SPECIFICATIONS OF PROPOSED DIRECTLY ASSOCIATED TRANSMISSION LINES

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Bartow Plant - Northeast Substation
(2) NUMBER OF LINES:	3
(3) RIGHT-OF-WAY:	Existing transmission line right-of-way
(4) LINE LENGTH:	4
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$74,005,735 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

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

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Northeast Substation - Thirty-Second Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	New and existing transmission line right-of-ways
(4) LINE LENGTH:	2
(5) VOLTAGE:	115kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$4,000,000 *
(8) SUBSTATIONS:	Thirty-Second Street Substation - Addition
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

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

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Northeast Substation - Fortieth Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-of-ways
(4) LINE LENGTH:	8
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$8,000,000 *
(8) SUBSTATIONS:	N/A
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

PROGRESS ENERGY FLORIDA

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

BARTOW REPOWERING

(1) POINT OF ORIGIN AND TERMINATION:	Pasadena Substation - Fifty-First Street Substation
(2) NUMBER OF LINES:	1
(3) RIGHT-OF-WAY:	Existing transmission line right-or-way
(4) LINE LENGTH:	0.4
(5) VOLTAGE:	230kV
(6) ANTICIPATED CONSTRUCTION TIMING:	09/2008
(7) ANTICIPATED CAPITAL INVESTMENT:	$5,000,000 *
(8) SUBSTATIONS:	Fifty-First Street Substation - Addition
(9) PARTICIPATION WITH OTHER UTILITIES:	N/A

* The projected capital estimate may vary during construction of the Bartow Repowering Project

INTEGRATED RESOURCE PLANNING OVERVIEW

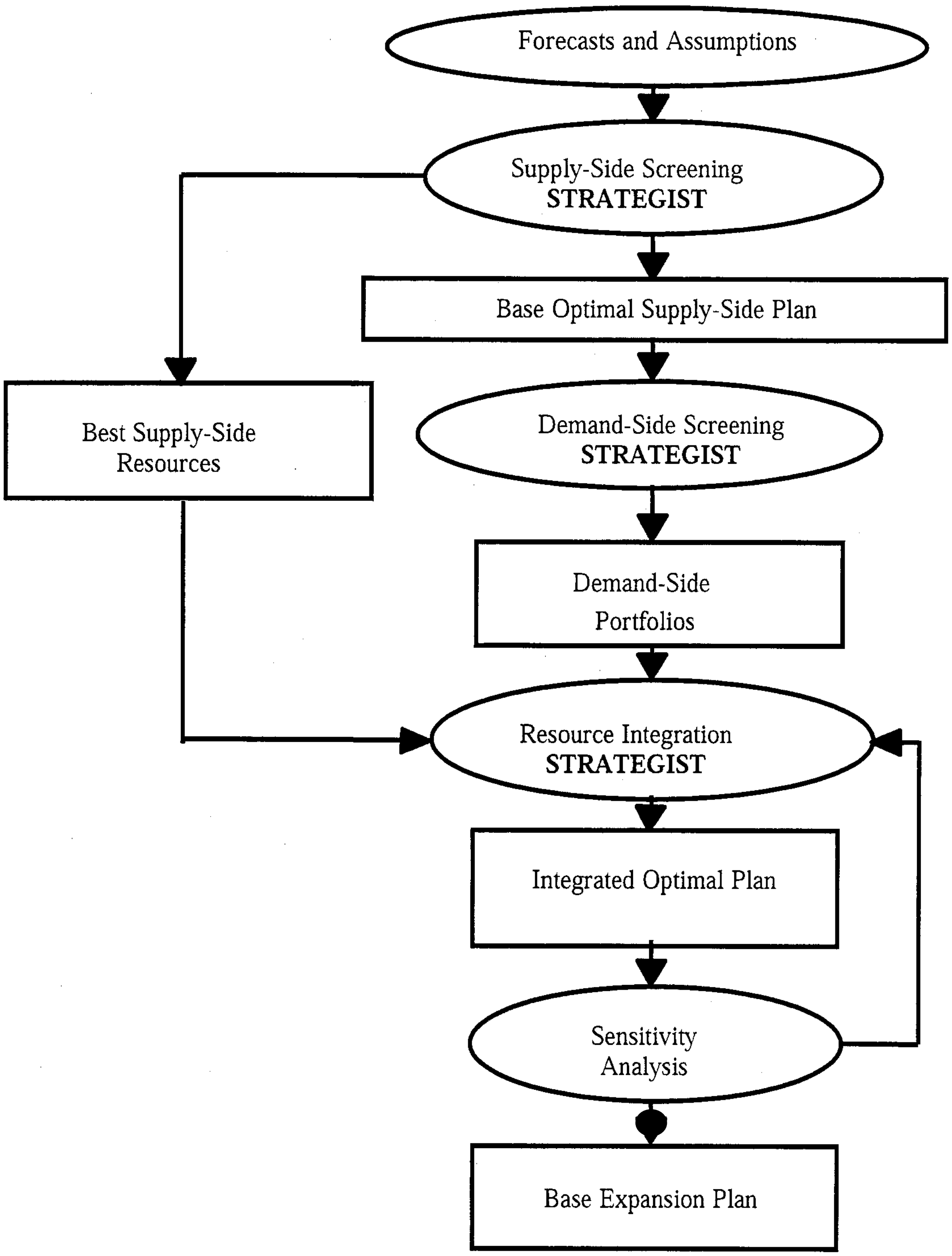
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future demand and energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide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

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

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

FIGURE 3.1

IRP Process Overview



THE IRP PROCESS

Forecasts and Assumptions

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

Reliability Criteria

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

PEF plans its resources in a manner consistent with utility industry planning practices, and employs both deterministic and probabilistic reliability criteria in the resource planning process. A Reserve Margin criterion is used as a deterministic measure of PEF's ability to meet its forecasted seasonal peak load with firm capacity. PEF plans its resources to satisfy a 20 percent minimum Reserve Margin criterion.

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

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

Supply-Side Screening

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

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

Demand-Side Screening

Like supply-side resources, data for large numbers of potential demand-side resources is also collected. These resources are pre-screened to eliminate those alternatives that are still in research and development, addressed by other regulations (building code), or not applicable to PEF's customers. STRATEGIST is updated with cost data and load impact parameters for each potential DSM measure to be evaluated.

The Base Optimal Supply-Side Plan is used to establish avoidable units for screening future demand-side resources. Each future demand-side alternative is individually tested in this plan over the ten-year planning horizon to determine the benefit or detriment that the addition of this demand-side resource provides to the overall system. STRATEGIST calculates the benefits and costs for each demand-side measure evaluated and reports the appropriate ratios for the Rate Impact Measure (RIM), the Total Resource Cost Test (TRC), and the Participant Test. Demand-side programs that pass the RIM test are then bundled together to create demand-side portfolios. These portfolios contain the appropriate DSM options and make the optimization solvable with the STRATEGIST model.

Resource Integration and the Integrated Optimal Plan

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

Developing the Base Expansion Plan

The plans that provide the lowest revenue requirements are then further tested using sensitivity analysis. The economics of the plan may be evaluated under high and low forecast scenarios for load, fuel, and financial assumptions, or any other sensitivities which, in the judgment of the planner, are relevant given existing circumstances to ensure that the plan does not unduly burden the company or the ratepayers if the future unfolds in a manner significantly different from the base forecasts. From the sensitivity assessment, the ten-year plan that is identified as achieving the best balance of flexibility and cost is then reviewed within the corporate framework to determine how the plan potentially impacts or is impacted by many other factors. If the plan is judged robust under this review, it evolves as the Base Expansion Plan.

KEY CORPORATE FORECASTS

Load Forecast

The assumptions and methodology used to develop the base case load and energy forecast is described in detail in Chapter 2 of this TYSP.

Fuel Forecast

Base Fuel Case: The base case fuel price forecast was developed using short-term and long-term market price projections from industry-recognized sources. Coal prices are expected to be relatively stable month to month; however, oil and natural gas prices are expected to be more volatile on a day-to-day and month-to-month basis.

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

Financial Forecast

The key financial assumptions used in PEF's most recent planning studies were 48% debt and 52% equity capital structure, projected debt cost of 6.5%, and an equity return of 12.0%. These assumptions resulted in a weighted average cost of capital of 9.36% and an after-tax discount rate of 8.16%.

TYSP RESOURCE ADDITIONS

In this TYSP, PEF's supply-side resources include the projected combined cycle (CC) expansion of the Hines Energy Complex (HEC) with Unit 4 forecasted to be in-service by December 2007. The TYSP also includes repowering the Bartow Steam Units with F-Class combined cycle technology that would provide a portion of the capacity in-service by December 2008 with the completed combined cycle facility in-service by June 2009. Two generic combustion turbine units and two generic combined cycle units are included in the TYSP with forecasted in-service dates of June 2010 and June 2012 for the CTs and June 2011 and June 2015 for the CCs.

The Company continues to study the economics of baseload generation alternatives including gas, coal, and nuclear options. Analyses indicate that coal and nuclear resources may provide economical baseload generation in the long-term. This TYSP thus includes the addition of two supercritical pulverized coal units during the planning horizon with forecasted in-service dates of June 2013 and June 2014. The Company has also announced its intent to file a combined construction permit-operating license (COL) application for a potential new nuclear facility in Florida with a possible in-service date beyond the 2015 planning horizon.

The economics of the baseload alternatives are partly dependent on legislation, projected load growth, fuel prices, and environmental compliance considerations. Although PEF has not committed to building a new coal or nuclear facility, the Company will continue to examine the merits of new generation alternatives and adjust its resource plans accordingly to ensure the optimal selection of resource additions. The Company is also currently conducting detailed analyses of generation sites and has not finalized its decision on the preferred site(s) for possible future generic combined cycle, coal, and nuclear additions.

PLAN SENSITIVITIES

Load Forecast

In general, higher-than-projected load growth would shift the need for new capacity to an earlier year and lower-than-projected load growth would delay the need for new resources. PEF's TYSP includes the Hines 4 addition and Bartow repowering projects in the near term, with generic CT, CC, and coal additions in the longer term. The Company's resource plan would provide the flexibility to shift certain resources to earlier or later in-service dates should a significant change in projected customer demand begin to materialize. PEF therefore did not conduct detailed sensitivity analyses of the plan to the base case load forecast.

Fuel Forecast

PEF's current TYSP includes new natural gas fueled resources through 2012. The plan also includes coal units in 2013 and 2014, with 2013 being the earliest possible date that a new coal plant can be placed in-service. PEF focused its fuel forecast sensitivity on price projections for natural gas. Higher gas prices would improve the economics for pulverized coal; however, this scenario would not impact the schedule of resource additions since 2013 is the earliest date that a new coal plant can be placed in-service. PEF conducted a sensitivity analysis of the plan to lower gas prices relative to the base forecast. Results for the low gas price scenario did not shift the in-service date for the 2013 and 2014 coal units, which indicate the potential for new coal fired generation to remain economical in the long-term.

The fuel price forecasts used in development of the TYSP show a greater differential in gas/oil versus coal prices in the early years, with the differential decreasing in 2009 and increasing again beginning 2016. Similar to the discussion above, a higher differential between gas/oil and coal prices would improve the economics for pulverized coal; however, the TYSP already includes coal in the resource mix beginning June 2013 which is the earliest year that a coal plant can be constructed and placed in-service. Similarly, a smaller differential in gas/oil versus coal prices would benefit the economics for a combined cycle plant; however, the low gas price forecast sensitivity discussed above still resulted in coal units included in the optimal plan.

Fuel price forecasts can have a significant impact on the economics of generation alternatives. Results of the fuel forecast sensitivity analysis conducted for this TYSP did not suggest any significant reconsideration of the base plan. PEF will continue to monitor fuel price relationships to identify long-term structural changes and assess the potential impacts on the economics of resource selection.

Financial Forecast

PEF's current TYSP includes combustion turbine and combined cycle additions through 2012 with pulverized coal additions in 2013 and 2014. Lower cost of capital escalation and escalation rates would favor options with longer construction lead times and higher capital costs such as the pulverized coal additions. However, PEF does not expect these assumptions to go much lower than the current base case forecast and, in any event, coal units likely cannot be added any sooner than 2013 as shown in the base plan. Higher financial assumptions would disfavor the pulverized coal additions; however, the Company has not committed to building new coal generation at this time. Thus, PEF did not test the sensitivity of the base resource plan to varying financial assumptions. PEF will continue to assess the economics of future generation alternatives including consideration of the uncertainties in planning assumptions.

TRANSMISSION PLANNING

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

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

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

- FRCC: FRCC ATC Calculation and Coordination Procedures, November 4, 2003, which is posted on the FRCC website: (http://frcc.com/downloads/FRCC%20ATC%20methodology-%20final-11-03.pdf)

- NERC: Transmission Transfer Capability, May 1, 1995

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

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

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

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

TABLE 3.3
PROGRESS ENERGY FLORIDA

LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS

2006-2015

MVA RATING WINTER	LINE OWNERSHIP	TERMINALS		LINE LENGTH (CKT.-MILES)	COMMERCIAL IN-SERVICE DATE (MO./YEAR)	NOMINAL VOLTAGE (kV)
1141	PEF/FPL	VANDOLAH	CHARLOTTE	55*	12/2006	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #1	21	6 / 2007	230
1141	PEF	LAKE BRYAN	WINDERMERE #1	10 *	1 / 2008	230
1141	PEF	LAKE BRYAN	WINDERMERE #2	10	1 / 2008	230
1141	PEF	AVALON	GIFFORD	7	7 / 2008	230
612	PEF	BARTOW	NORTHEAST Circuit 1	4	9/2008	230
612	PEF	BARTOW	NORTHEAST Circuit 2	4	9/2008	230
612	PEF	BARTOW	NORTHEAST Circuit 3	4	9/2008	230
525	PEF	NORTHEAST	32ND STREET	2	9/2008	115
810	PEF	NORTHEAST	40TH STREET	8*	9/2008	230
810	PEF	PASADENA	51ST STREET	0.2	9/2008	230
810	PEF	51ST STREET	40TH STREET	0.2	9/2008	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #2	30	6 / 2010	230
1141	PEF	HINES ENERGY COMPLEX	WEST LAKE WALES #2	21	5 / 2011	230
1141	PEF	INTERCESSION CITY	WEST LAKE WALES #1	30 *	6/2011	230

* Rebuild existing circuit

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

Progress Energy

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

PEF's base expansion plan proposes new combined cycle generation at the Hines Energy Complex (HEC) site in Polk County and to repower the existing Bartow Plant in Pinellas County with combined cycle technology. Although not delineated in the base expansion plan, potential peaking simple-cycle combustion turbine generation site options for the 2010 and 2012 units include Intercession City (Osceola County), Anclote (Pasco County), Bartow (Pinellas) and DeBary (Volusia County). While these sites are suitable for new generation, PEF continues to evaluate other available options for future supply alternatives.

The next proposed combined cycle unit at the HEC site is scheduled for commercial operation in December 2007. PEF will repower its existing Bartow Plant which is scheduled for commercial operation in June 2009. PEF continues to pursue siting opportunities for undesignated coal and combined cycle units with a commercial operation date of 2011 and beyond. PEF's existing sites, as identified in Table 3.1 of Chapter 3, include the capability to further develop generation. All appropriate permitting requirements will be addressed for PEF's preferred sites as discussed in the following site descriptions. The base expansion plan does not currently include any potential new sites for generation additions. Therefore, detailed environmental or land use data are not included.

The ability to site new baseload generation (coal and/or nuclear) in Florida is extremely limited, and PEF has not identified suitable sites for these technologies at this time. Siting studies are currently underway to identify possible sites for new baseload generation.

HINES ENERGY COMPLEX SITE

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

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

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

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

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

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

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

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

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

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

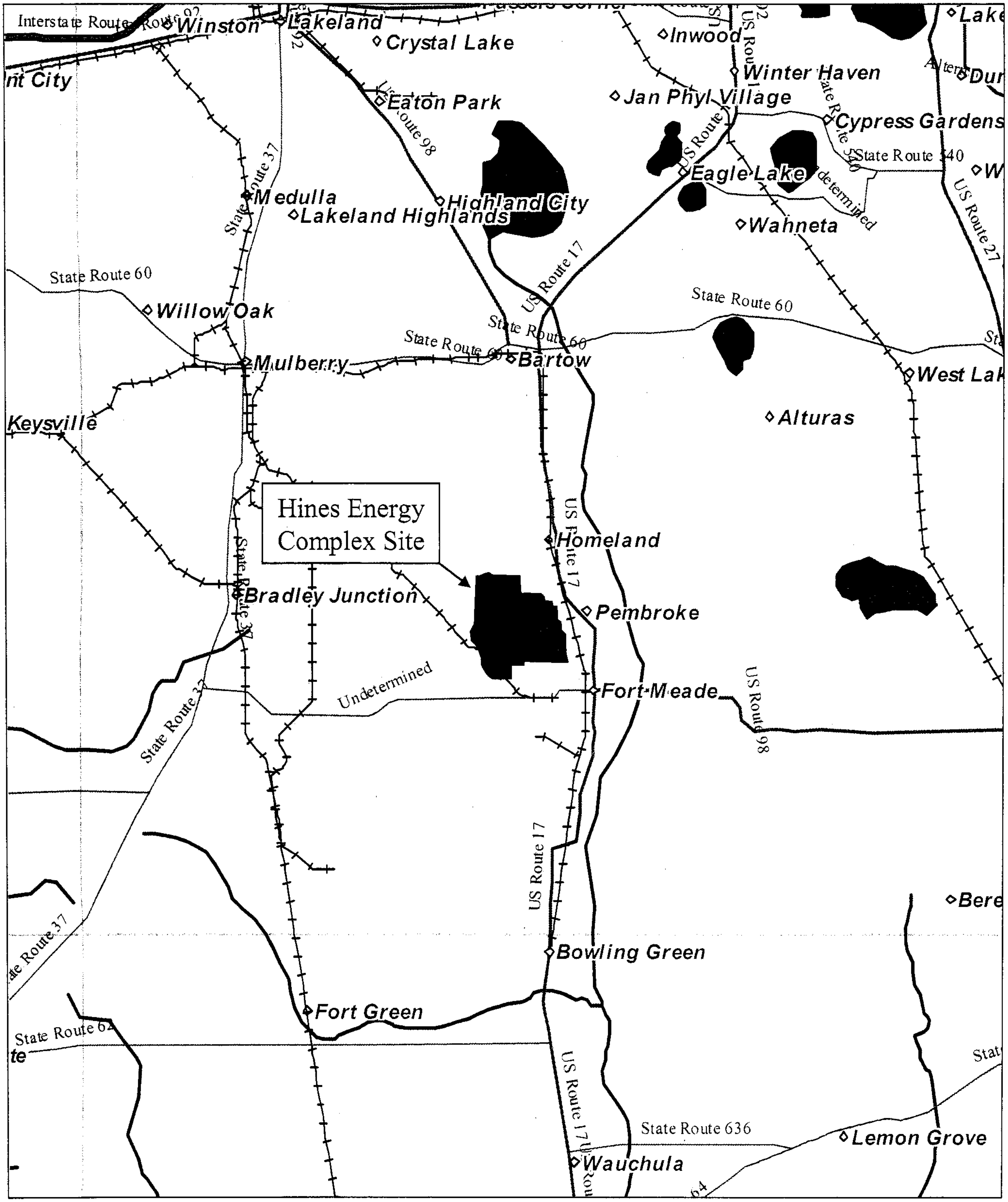
The third combined cycle unit at this site entered commercial operation in November 2005 with a seasonal capacity rating of 501 MW summer, and required no transmission upgrades.

The fourth HEC combined cycle unit is currently under construction. This unit has a commercial operation date of December 2007 with a seasonal capacity rating of 461 MW summer. The transmission improvements associated with the fourth combined cycle unit at this site involved the addition of a 230 kV circuit from the Hines Energy Complex to West Lake-Wales and associated substation expansion and breaker replacements.

The HEC is also a potential site for a combined cycle unit required in 2011.

FIGURE 4.1

Hines Energy Complex Site (Polk County)



INTERCESSION CITY SITE

Intercession City was chosen as a potential site for installation of peaking combustion turbine units.

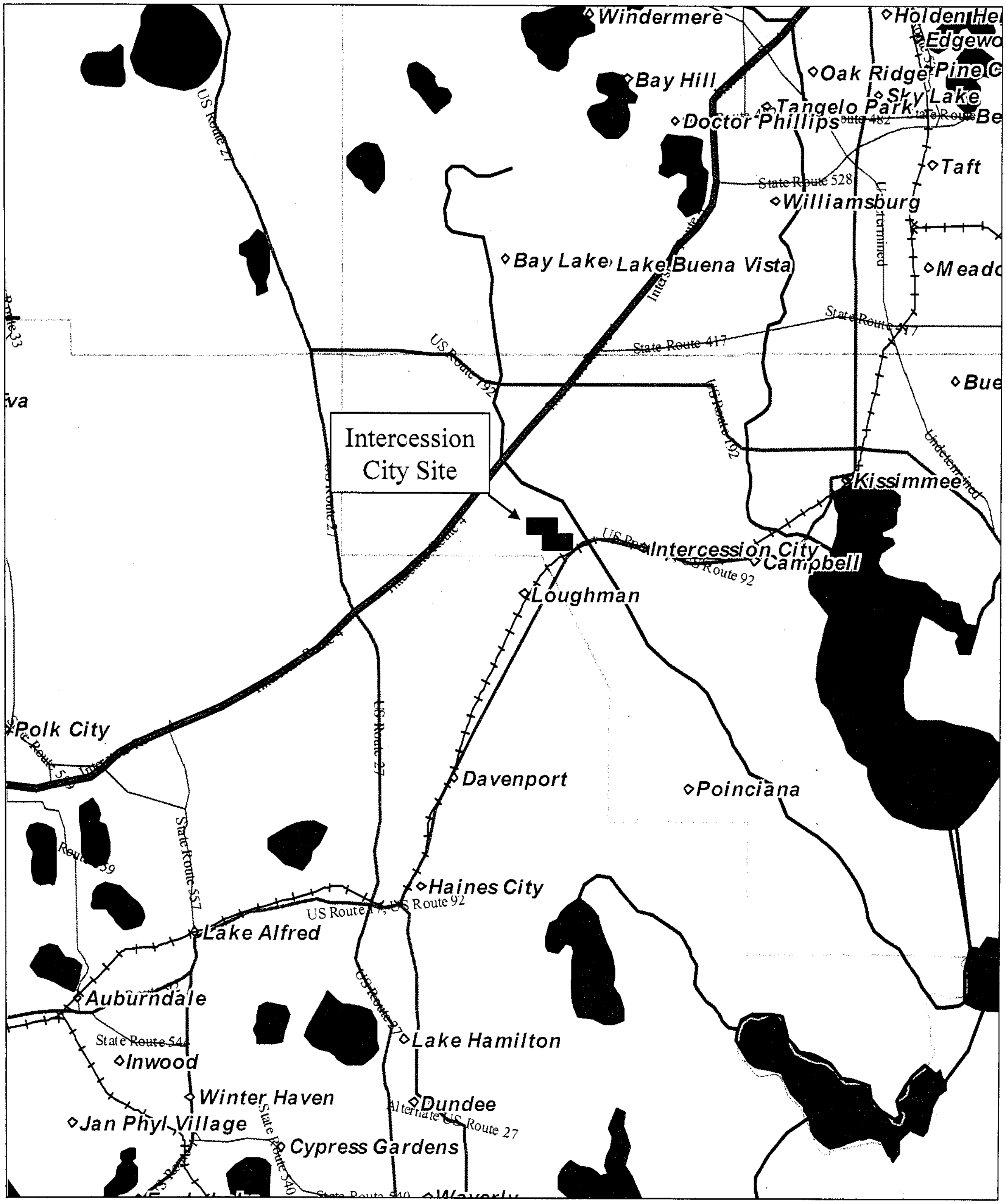
The Intercession City site (Figure 4.2) consists of 162 acres in Osceola County, two miles west of Intercession City. The site is immediately west of Reedy Creek and the adjacent Reedy Creek Swamp. The site is adjacent to a secondary effluent pipeline from a municipal wastewater treatment plant, an oil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

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

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.2

Intercession City Site (Osceola County)



DEBARY SITE

DeBary was chosen as a potential site for installation of peaking combustion turbine units.

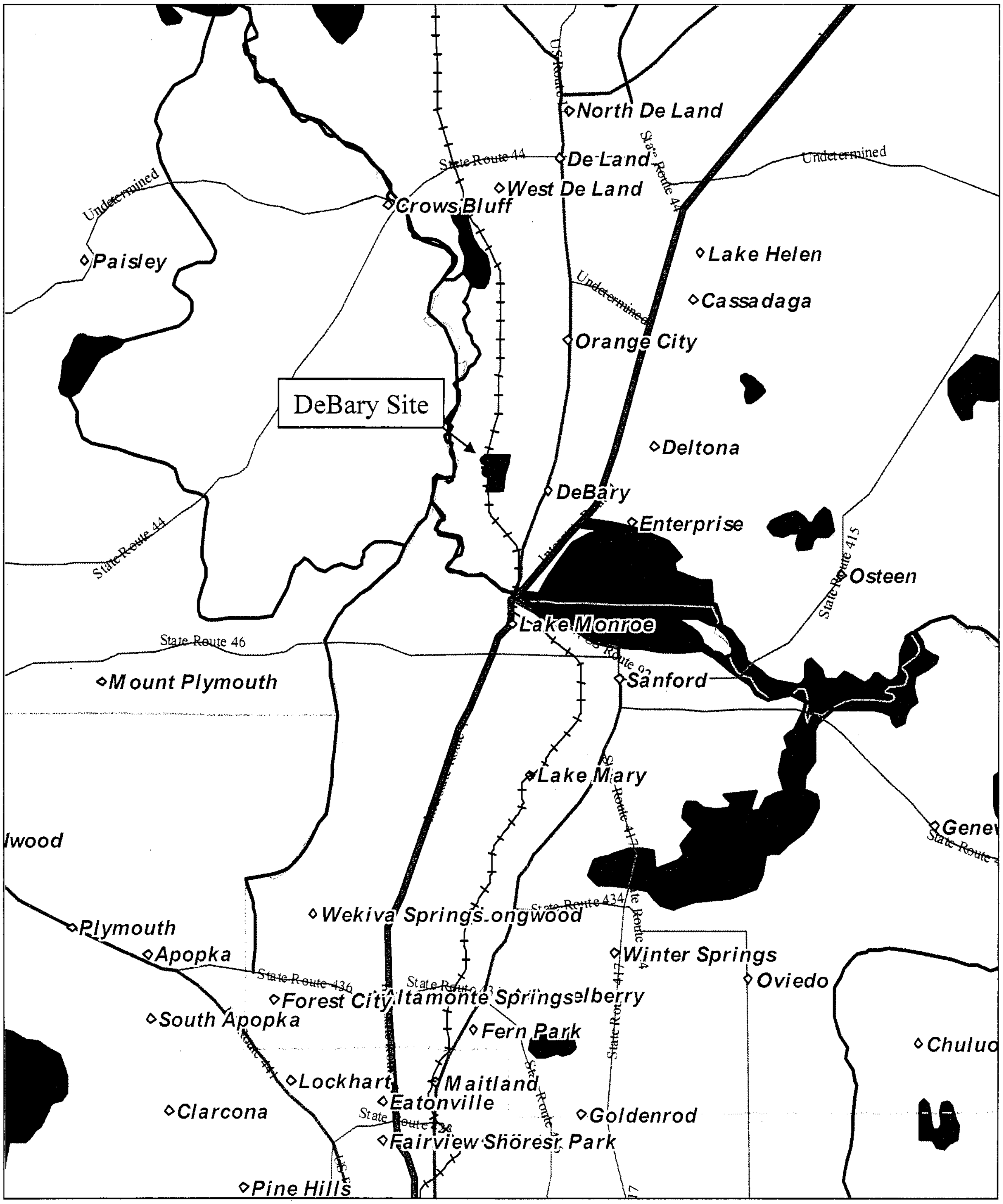
The DeBary site (Figure 4.3) consists of 2,210 acres in Volusia County, immediately west of the town of DeBary. The site is bordered on the west by the St. Johns River and on the north by Blue Springs State Park. This site is adjacent to an oil pipeline and natural gas supply from the Florida Gas Transmission (FGT) pipeline.

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

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.3

DeBary Site (Volusia County)



ANCLOTE SITE

Anclote was chosen as a potential site for installation of peaking combustion turbine units.

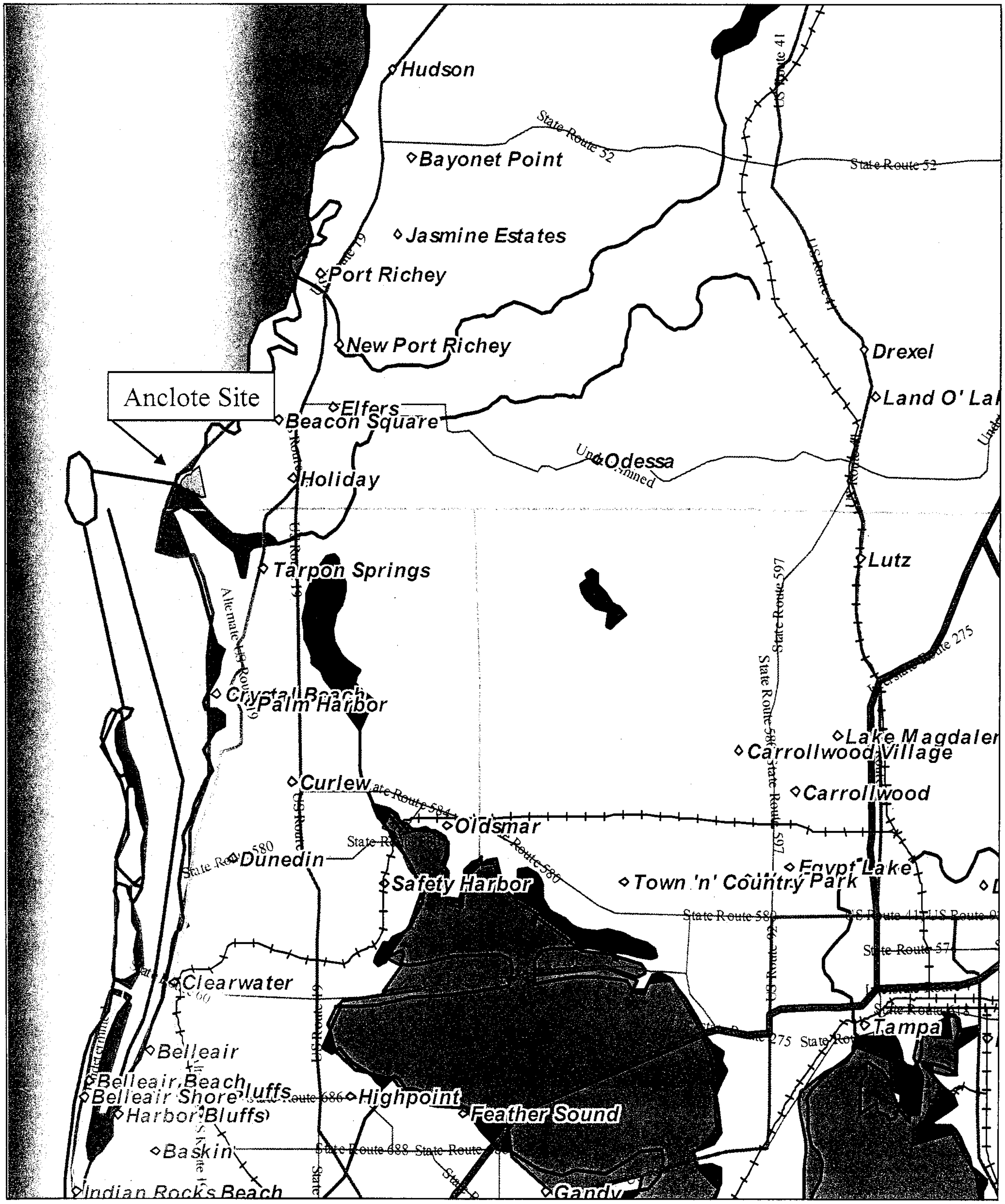
The Anclote site (Figure 4.4) consists of approximately 400 acres in Pasco County. The site is located in Holiday Florida at the mouth of the Anclote River. The site receives make-up water from the city of Tarpon Springs, fuel oil through a pipeline from the Bartow plant, and natural gas supply from the Florida Gas Transmission (FGT) pipeline.

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

Transmission modifications will be required to accommodate additional combustion turbine peaking units at this site.

FIGURE 4.4

Anclote (Pasco County)



BARTOW SITE

PEF has chosen to repower its existing Bartow Plant with combined cycle technology, which is scheduled for commercial operation in June 2009.

The Bartow site (Figure 4.5) consists of 1,348 acres in Pinellas County, on the west shore of Tampa Bay. The site is on Weedon Island, north of downtown St. Petersburg. The site is adjacent to a barge fuel oil off-loading facility, a natural gas supply from the Florida Gas Transmission (FGT) pipeline, and a proposed Gulfstream natural gas pipeline.

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

Transmission modifications will be required to accommodate the repowering of Bartow steam units.

FIGURE 4.5
Bartow Site (Pinellas County)