Progress Energy

ORIGINAL

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PROGRESS ENERGY SERVICE COMPANY, LLC

April 1, 2004

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VIA HAND DELIVERY

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

040000-PU

Re: Progress Energy's Ten-Year Site Plan as of December 31, 2003

Dear Ms. Bayó:

Enclosed for filing on behalf of Progress Energy Florida, Inc., are an original and fifteen copies of the subject Ten-Year Site Plan, as well as an additional ten copies for the other agencies and organizations on your distribution list.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. A 3½ inch diskette containing the above-referenced document in PDF format is also enclosed. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

JAM/scc
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Progress Energy Florida
Ten-Year Site Plan

April 2004

2004-2013

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 (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

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CHAPTER 1

DESCRIPTION OF EXISTING FACILITIES

EXISTING FACILITIES OVERVIEW

OWNERSHIP

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

AREA OF SERVICE

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

TRANSMISSION/DISTRIBUTION

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

ENERGY MANAGEMENT

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

TOTAL CAPACITY RESOURCE

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

FIGURE 1.1

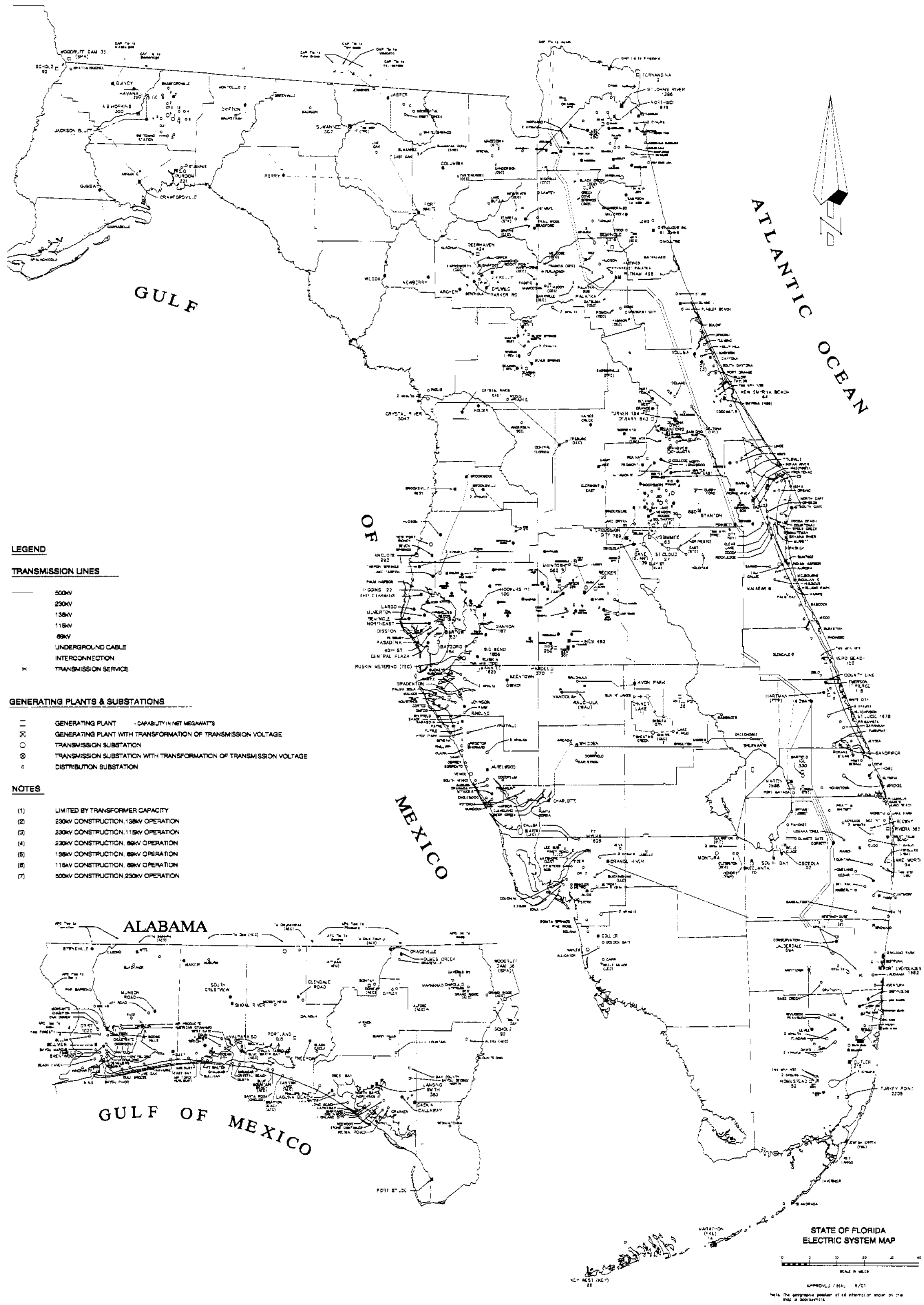
PROGRESS ENERGY FLORIDA

Service Area Map

FIGURE 1.2

PROGRESS ENERGY FLORIDA

Electric System Map



PROGRESS ENERGY FLORIDA

SCHEDULE 1

EXISTING GENERATING FACILITIES

AS OF DECEMBER 31, 2003

(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,RR			10/66		440,550	379	383
CRYSTAL RIVER	2	CITRUS	ST	BIT		WA,RR			11/69		523,800	486	491
CRYSTAL RIVER	3 *	CITRUS	ST	NUC		TK			03/77		890,460	769	788
CRYSTAL RIVER	4	CITRUS	ST	BIT		WA,RR			12/82		739,260	720	735
CRYSTAL RIVER	5	CITRUS	ST	BIT		WA,RR			10/84		739,260	717	732
SUWANNEE RIVER	1	SUWANNEE	ST	RFO	NG	TK	PL		11/53		34,500	32	33
SUWANNEE RIVER	2	SUWANNEE	ST	RFO	NG	TK	PL		11/54		37,500	31	32
SUWANNEE RIVER	3	SUWANNEE	ST	RFO	NG	TK	PL		10/56		75,000	80	81
												4,651	**4,771**
COMBINED-CYCLE													
HINES ENERGY COMPLEX	1	POLK	CC	NG	DFO	PL	TK	6	04/99		546,550	482	529
HINES ENERGY COMPLEX	2	POLK	CC	NG	DFO	PL	TK	6	12/03		598,000	516	582
TIGER BAY	1	POLK	CC	NG		PL			08/97		278,223	207	223
												1,205	**1,334**
COMBUSTION TURBINE													
AVON PARK	P1	HIGHLANDS	GT	NG	DFO	PL	TK	3	12/68		33,790	26	32
AVON PARK	P2	HIGHLANDS	GT	DFO		TK			12/68		33,790	26	32
BARTOW	P1, P3	PINELLAS	GT	DFO		WA			5/72-6/72		111,400	92	106
BARTOW	P2	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	46	53
BARTOW	P4	PINELLAS	GT	NG	DFO	PL	WA	8	06/72		55,700	49	60
BAYBORO	P1-P4	PINELLAS	GT	DFO		WA,TK			04/73		226,800	184	232
DEBARY	P1-P6	VOLUSIA	GT	DFO		TK,RR			12/75-04/76		401,220	324	390
DEBARY	P7-P9	VOLUSIA	GT	NG	DFO	PL	TK,RR	8	10/92		345,000	258	279
DEBARY	P10	VOLUSIA	GT	DFO		TK,RR			10/92		115,000	85	93
HIGGINS	P1-P2	PINELLAS	GT	DFO		TK			03/69-04/69		67,580	54	64
HIGGINS	P3-P4	PINELLAS	GT	NG	DFO	PL	TK	1	12/70-01/71		85,850	68	70
INTERCESSION CITY	P1-P6	OSCEOLA	GT	DFO		PL,TK			05/74		340,200	294	366
INTERCESSION CITY	P7-P10	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	10/93		460,000	352	376
INTERCESSION CITY	P11 **	OSCEOLA	GT	DFO		PL,TK			01/97		165,000	143	170
INTERCESSION CITY	P12-P14	OSCEOLA	GT	NG	DFO	PL	PL,TK	5	12/00		345,000	252	294
RIO PINAR	P1	ORANGE	GT	DFO		TK			11/70		19,290	13	16
SUWANNEE RIVER	P1	SUWANNEE	GT	NG	DFO	PL	TK	10	10/80		61,200	55	67
SUWANNEE RIVER	P2	SUWANNEE	GT	DFO		TK			10/80		61,200	54	67
SUWANNEE RIVER	P3	SUWANNEE	GT	NG	DFO	PL	TK	10	11/80		61,200	55	67
TURNER	P1-P2	VOLUSIA	GT	DFO		TK			10/70		38,580	26	32
TURNER	P3	VOLUSIA	GT	DFO		TK			08/74		71,200	65	82
TURNER	P4	VOLUSIA	GT	DFO		TK			08/74		71,200	63	80
UNIV. OF FLA.	P1	ALACHUA	GT	NG		PL			01/94		43,000	35	41
												2,619	**3,069**
											TOTAL RESOURCES (MW)	**8,475**	**9,174**

* REPRESENTS APPROXIMATELY 91.8% PEF OWNERSHIP OF UNIT

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

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

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CHAPTER 2

FORECAST OF ELECTRIC POWER DEMAND AND ENERGY CONSUMPTION

OVERVIEW

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

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

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

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

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

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

ENERGY CONSUMPTION AND DEMAND FORECAST SCHEDULES

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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
1994	2,734,821	2.485	13,863	1,100,537	12,597	8,252	122,987	67,097
1995	2,801,105	2.491	14.938	1,124,679	13,282	8,612	126,189	68,247
1996	2,847,802	2.494	15,481	1,141,671	13.560	8,848	129,440	68,356
1997	2,895,266	2.495	15,080	1,160,611	12,993	9,257	132,504	69,862
1998	2,959,509	2.502	16,526	1,182,786	13,972	9,999	136,345	73,336
1999	3,047,293	2.511	16,245	1,213,470	13,387	10,327	140,897	73,295
2000	3,044,449	2.467	17,116	1,234,286	13,867	10,813	143,475	75,368
2001	3,141,867	2.465	17,604	1,274,672	13,810	11,061	146,983	75,251
2002	3,207,661	2.465	18,754	1,301,515	14,409	11,420	150,577	75,842
2003	3,286,782	2.468	19,429	1,331,914	14,587	11,553	154,294	74,876
2004	3,352,412	2.468	19,704	1,358,414	14,505	12,105	156,903	77,150
2005	3,410,218	2.466	20,212	1,382,699	14,618	12,535	159,634	78,523
2006	3,468,155	2.465	20,706	1,406,712	14,719	12,955	162,422	79,761
2007	3,526,276	2.464	21,206	1,431,102	14,818	13,392	165,425	80,955
2008	3,588,935	2.465	21,713	1,455,971	14,913	13,833	168,552	82,070
2009	3,653.234	2.467	22,222	1.481,124	15,003	14,270	171,715	83,103
2010	3,714,098	2.466	22,705	1,505,866	15,078	14,698	174,825	84,073
2011	3,772,892	2.466	23,180	1,529,665	15,154	15,118	177,814	85,021
2012	3,827,099	2.465	23,668	1,552.660	15,244	15,533	180,703	85,959
2013	3,879,660	2.463	24,159	1,575,153	15,338	15,950	183,527	86,908

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	INDUSTRIAL						
YEAR	GWh	AVERAGE NO. OF CUSTOMERS	AVERAGE KWh CONSUMPTION PER CUSTOMER	RAILROADS AND RAILWAYS GWh	STREET & HIGHWAY LIGHTING GWh	OTHER SALES TO PUBLIC AUTHORITIES GWh	TOTAL SALES TO ULTIMATE CONSUMERS GWh
1994	3,580	3,186	1,123,666	0	26	1,954	27,675
1995	3,864	3,143	1,229,399	0	27	2,058	29,499
1996	4,224	2,927	1,443,116	0	26	2,205	30,784
1997	4,188	2,830	1,479,859	0	27	2,299	30,851
1998	4,375	2,707	1,616,180	0	27	2,459	33,386
1999	4,334	2,629	1,648,536	0	27	2,509	33,442
2000	4,249	2,535	1,676,134	0	28	2,626	34,832
2001	3,872	2,551	1,517,836	0	28	2,698	35,263
2002	3,835	2,535	1,512,821	0	28	2,822	36,859
2003	4,001	2,643	1,513,810	0	29	2,946	37,957
2004	4,144	2,625	1,578,667	0	29	3,066	39,048
2005	4,197	2,625	1,598,857	0	29	3,191	40,164
2006	4,281	2,625	1,630,857	0	29	3,310	41,281
2007	4,328	2,625	1,648,762	0	30	3,428	42,384
2008	4,372	2,625	1,665,524	0	30	3,546	43,494
2009	4,416	2,625	1,682,286	0	30	3,666	44,604
2010	4,453	2,625	1,696,381	0	30	3,789	45,675
2011	4,482	2,625	1,707,429	0	31	3,911	46,722
2012	4,511	2,625	1,718,476	0	31	4,024	47,767
2013	4,538	2,625	1,728,762	0	31	4,136	48,814

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) SALES FOR RESALE GWh	(3) UTILITY USE & LOSSES GWh	(4) NET ENERGY FOR LOAD GWh	(5) OTHER CUSTOMERS (AVERAGE NO.)	(6) TOTAL NO. OF CUSTOMERS
1994	1,819	1,680	31,174	17,181	1,243,891
1995	1,846	2,322	33,667	17,774	1,271,785
1996	2,089	1,842	34,715	18,035	1,292,073
1997	1,758	1,996	34,605	18,562	1,314,507
1998	2,340	2,037	37,763	19,013	1,340,851
1999	3,267	2,451	39,160	19,601	1,376,597
2000	3,732	2,678	41,242	20,004	1,400,299
2001	3,839	1,830	40,933	20,752	1,444,958
2002	3,173	2,534	42,567	21,156	1,475,783
2003	3,359	2,595	43,911	21,665	1,510,516
2004	3,349	2,764	45,161	22,159	1,540,101
2005	2,927	2,654	45,745	22,735	1,567,693
2006	3,011	2,828	47,120	23,310	1,595,069
2007	2,890	2,770	48,044	23,885	1,623,037
2008	2,672	2,881	49,047	24,463	1,651,611
2009	2,593	2,950	50,147	25,039	1,680,503
2010	2,580	3,008	51,263	25,616	1,708,932
2011	2,549	3,085	52,356	26,191	1,736,295
2012	2,563	3,148	53,478	26,769	1,762,757
2013	2,581	3,213	54,608	27,345	1,788,650

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,742
2004	9,143	774	8,369	369	304	187	47	165	75	7,997
2005	9,255	689	8,565	374	272	201	49	167	75	8,117
2006	9,651	889	8,762	377	246	216	51	168	75	8,519
2007	9,888	928	8,960	378	225	230	53	169	75	8,758
2008	10,066	904	9,162	360	208	244	55	170	75	8,953
2009	10,215	848	9,367	349	194	258	58	171	75	9,110
2010	10,418	852	9,567	330	180	272	60	172	75	9,329
2011	10,582	823	9,759	331	168	286	62	173	75	9,486
2012	10,737	792	9,945	332	156	301	65	174	75	9,635
2013	10,921	795	10,127	333	146	315	67	176	75	9,810

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,742
2004	9,291	774	8,517	369	304	187	47	165	75	8,145
2005	9,418	689	8,728	374	272	201	49	167	75	8,281
2006	9,844	889	8,955	377	246	216	51	168	75	8,712
2007	10,099	928	9,171	378	225	230	53	169	75	8,969
2008	10,310	904	9,406	360	208	244	55	170	75	9,198
2009	10,475	848	9,627	349	194	258	58	171	75	9,371
2010	10,733	852	9,882	330	180	272	60	172	75	9,644
2011	10,949	823	10,126	331	168	286	62	173	75	9,853
2012	11,138	792	10,346	332	156	301	65	174	75	10,036
2013	11,391	795	10,597	333	146	315	67	176	75	10,280

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) WHOLESALE	(4) RETAIL	(5) INTERRUPTIBLE	(6) RESIDENTIAL LOAD MANAGEMENT	(7) RESIDENTIAL CONSERVATION	(8) COMM. / IND. LOAD MANAGEMENT	(9) COMM. / IND. CONSERVATION	(OTH) OTHER DEMAND REDUCTIONS	(10) NET FIRM DEMAND
1994	6,880	787	6,093	262	527	52	30	81	154	5,774
1995	7,523	959	6,564	269	503	64	40	106	160	6,381
1996	7,470	828	6,642	309	565	69	41	120	167	6,199
1997	7,786	874	6,912	288	555	78	41	131	170	6,523
1998	8,367	943	7,424	291	438	97	42	142	182	7,175
1999	9,039	1,326	7,713	292	505	113	45	153	183	7,747
2000	8,911	1,319	7,592	277	455	127	48	155	75	7,774
2001	8,841	1,117	7,724	283	414	139	54	156	75	7,720
2002	9,421	1,203	8,218	305	390	153	43	159	75	8,296
2003	8,886	887	7,999	300	347	172	44	164	75	7,742
2004	8,988	774	8,214	369	304	187	47	165	75	7,842
2005	9,088	689	8,398	374	272	201	49	167	75	7,951
2006	9,461	889	8,572	377	246	216	51	168	75	8,329
2007	9,672	928	8,744	378	225	230	53	169	75	8,542
2008	9,816	904	8,912	360	208	244	55	170	75	8,704
2009	9,925	848	9,077	349	194	258	58	171	75	8,821
2010	10,083	852	9,232	330	180	272	60	172	75	8,994
2011	10,226	823	9,403	331	168	286	62	173	75	9,130
2012	10,332	792	9,540	332	156	301	65	174	75	9,230
2013	10,465	795	9,671	333	146	315	67	176	75	9,354

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

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
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	10,626	1,408	9,218	520	735	343	30	125	248	8,625
2004/05	10,922	1,508	9,414	523	715	372	33	126	251	8,903
2005/06	11,049	1,437	9,612	379	698	401	36	127	255	9,153
2006/07	11,519	1,714	9,805	380	687	431	39	128	258	9,596
2007/08	11,672	1,672	10,001	361	681	461	43	129	261	9,737
2008/09	11,850	1,649	10,202	351	678	491	46	130	265	9,891
2009/10	12,099	1,697	10,402	341	676	519	49	131	268	10,114
2010/11	12,287	1,692	10,595	332	675	549	52	132	271	10,276
2011/12	12,475	1,694	10,781	333	675	578	55	133	274	10,426
2012/13	12,692	1,730	10,962	334	676	607	58	134	277	10,605

Historical Values (1994 - 2003):
Col. (2) = recorded peak + implemented load control + residential and commercial/industrial conservation and customer-owned self-service cogeneration.
Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = Residential Heat Works load control, voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).
Projected Values (2004 - 2013):
Cols. (2) - (4) = forecasted peak without load control, conservation, and customer-owned self-service cogeneration.
Cols. (5) - (9) = cumulative conservation and load control capabilities at peak. Col. (8) includes commercial load management and standby generation.
Col. (OTH) = voltage reduction and customer-owned self-service cogeneration.
Col. (10) = (2) - (5) - (6) - (7) - (8) - (9) - (OTH).

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
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	10,788	1,408	9,381	520	735	343	30	125	248	8,788
2004/05	11,100	1,508	9,592	523	715	372	33	126	251	9,081
2005/06	11,258	1,437	9,821	379	698	401	36	127	255	9,362
2006/07	11,747	1,714	10,033	380	687	431	39	128	258	9,824
2007/08	11,936	1,672	10,264	361	681	461	43	129	261	10,001
2008/09	12,130	1,649	10,482	351	678	491	46	130	265	10,171
2009/10	12,435	1,697	10,738	341	676	519	49	131	268	10,451
2010/11	12,679	1,692	10,987	332	675	549	52	132	271	10,668
2011/12	12,902	1,694	11,208	333	675	578	55	133	274	10,854
2012/13	13,190	1,730	11,460	334	676	607	58	134	277	11,104

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

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
1993/94	7,184	972	6,212	199	759	90	2	66	165	5,903
1994/95	9,084	1,145	7,939	281	997	101	5	75	131	7,494
1995/96	10,562	1,489	9,073	255	1,156	106	15	95	201	8,734
1996/97	8,486	1,235	7,251	290	917	133	16	104	190	6,836
1997/98	7,752	941	6,811	318	663	164	17	112	168	6,310
1998/99	10,473	1,741	8,732	305	874	196	18	117	187	8,776
1999/00	10,040	1,728	8,312	225	849	229	20	119	182	8,416
2000/01	11,450	1,984	9,466	255	809	254	29	120	194	9,789
2001/02	10,676	1,624	9,052	285	770	278	24	121	188	9,010
2002/03	11,555	1,538	10,017	271	768	313	27	124	200	9,852
2003/04	10,457	1,408	9,050	520	735	343	30	125	248	8,457
2004/05	10,742	1,508	9,234	523	715	372	33	126	251	8,723
2005/06	10,843	1,437	9,406	379	698	401	36	127	255	8,947
2006/07	11,285	1,714	9,571	380	687	431	39	128	258	9,362
2007/08	11,404	1,672	9,732	361	681	461	43	129	261	9,469
2008/09	11,540	1,649	9,892	351	678	491	46	130	265	9,581
2009/10	11,740	1,697	10,043	341	676	519	49	131	268	9,756
2010/11	11,907	1,692	10,215	332	675	549	52	132	271	9,896
2011/12	12,044	1,694	10,350	333	675	578	55	133	274	9,996
2012/13	12,207	1,730	10,477	334	676	607	58	134	277	10,121

Historical Values (1994 - 2003):

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

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

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

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

Projected Values (2004 - 2013):

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

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

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

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

PROGRESS ENERGY FLORIDA

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

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

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

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

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

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

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

PROGRESS ENERGY FLORIDA

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

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS*	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR (%) **
1994	32,150	219	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,696	234	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,812	249	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,753	268	317	563	30,850	1,758	1,997	34,605	49.0
1998	38,950	289	333	565	33,387	2,340	2,036	37,763	53.9
1999	40,376	312	339	565	33,441	3,267	2,452	39,160	50.0
2000	42,486	334	345	565	34,832	3,732	2,678	41,242	50.5
2001	42,200	354	349	564	35,263	3,839	1,831	40,933	47.5
2002	43,860	377	352	564	36,859	3,173	2,535	42,567	50.0
2003	45,232	400	357	564	37,957	3,359	2,595	43,911	47.7
2004	45,659	420	359	565	38,288	3,354	2,673	44,315	59.7
2005	46,235	441	360	564	39,344	3,349	2,177	44,870	58.7
2006	47,501	462	362	564	40,338	2,927	2,848	46,113	58.8
2007	48,300	482	363	564	41,304	3,011	2,576	46,891	57.2
2008	49,142	502	365	565	42,244	2,890	2,576	47,710	57.4
2009	50,039	522	366	564	43,145	2,672	2,770	48,587	57.9
2010	50,933	542	368	564	43,980	2.593	2,886	49,459	57.9
2011	51,924	562	369	564	44,917	2,580	2,932	50,429	58.2
2012	52,796	582	371	565	45,705	2,549	3,024	51,278	58.4
2013	53,654	602	373	564	46,480	2,563	3,072	52,115	58.8

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

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

PROGRESS ENERGY FLORIDA

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

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

FUEL REQUIREMENTS AND ENERGY SOURCES

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

PROGRESS ENERGY FLORIDA

SCHEDULE 5

FUEL REQUIREMENTS

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

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	27	97	154	146	80	89	74	105	97	8	0	0
(2)	NUCLEAR		GWh	6,700	6.039	6,658	6,131	6,640	6,092	6,658	5,089	6,640	6,146	6.658	6,145
(3)	COAL		GWh	14,406	16.111	16.485	17,198	16,919	16,433	16.614	17,775	17.260	17,626	17.741	17,776
(4)	RESIDUAL	TOTAL	GWh	6,319	6.785	6,258	6,149	4,990	5.553	4,513	4,557	3,603	3,984	3,445	3,664
(5)		STEAM	GWh	6,319	6.785	6,258	6.149	4,990	5,553	4.513	4,557	3.603	3,984	3,445	3,664
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	607	405	286	336	206	260	160	318	231	363	219	316
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	19	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	607	386	286	336	206	260	160	318	231	363	219	316
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	6.446	6.155	7,020	7.589	10,101	11,558	13.054	15,018	18,362	20,645	21.821	23,314
(15)		STEAM	GWh	462	83	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	4,816	4,938	5,881	6.355	9,101	10,244	11.959	13.671	17.256	19,350	20.832	22.216
(17)		CT	GWh	1,168	1,134	1.139	1.234	1,000	1.314	1,095	1,347	1,106	1,295	989	1,098
(18)	OTHER 2/														
	QF PURCHASES		GWh	5,091	5,022	4,677	4.587	4,589	4,463	4.362	3,673	3,584	3,584	3,594	3.393
	IMPORT FROM OUT OF STATE		GWh	3,317	3.555	3,623	3.609	3.595	3,596	3.612	3,612	1,486	0	0	0
	EXPORT TO OUT OF STATE		GWh	-346	-258	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	42,567	43,911	45,161	45,745	47.120	48.044	49.047	50.147	51,263	52,356	53.478	54.608

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

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

PROGRESS ENERGY FLORIDA

SCHEDULE 6.2

ENERGY SOURCES (PERCENT)

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

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

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

FORECASTING METHODS AND PROCEDURES

INTRODUCTION

Accurate forecasts of long-range electric energy consumption, customer growth and peak demand are essential elements in electric utility planning. Accurate projections of a utility's future load growth require a forecasting methodology with the ability to account for a variety of factors influencing electric energy usage over the planning horizon. PEF's forecasting framework utilizes a set of econometric models to achieve this end. This chapter will describe the underlying methodology of 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.

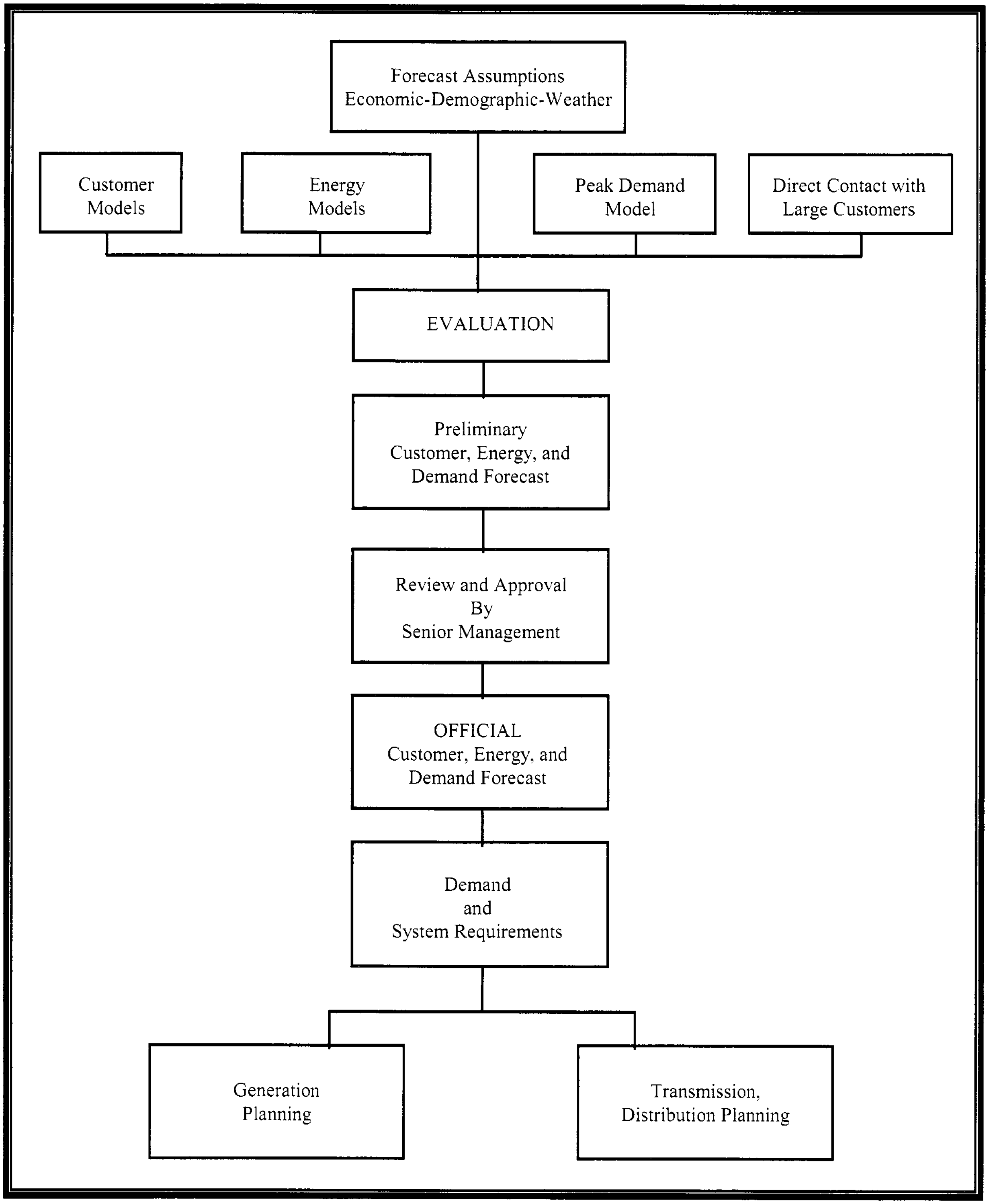
Figure 2.1, entitled "Customer, Energy and Demand Forecast", gives a general description of PEF's forecasting process. Highlighted in the diagram is a disaggregated modeling approach that blends the impacts of average class usage as well as customer growth based on a specific set of assumptions for each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

FORECAST ASSUMPTIONS

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

FIGURE 2.1

Customer, Energy, and Demand Forecast



GENERAL ASSUMPTIONS

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

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

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

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

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

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

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

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

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

SHORT-TERM ECONOMIC ASSUMPTIONS

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

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

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

LONG-TERM ECONOMIC ASSUMPTIONS

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

Population Growth Trends

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

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

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

Another reason for a population growth slowdown deals with a younger age cohort. With the bulk of Florida's in-migrants under age 45, the baby boom generation born between 1945 and

1963 helped fuel the rapid population increase Florida experienced during the 1980s. In fact, slower population in-migration to Florida can be expected as the baby boom generation enters the 40s and 50s age bracket. This age group has been significantly characterized as immobile when studies focusing on interstate population flows or job changes are conducted.

Economic Growth Trends

Florida's rapid population growth of the 1980s created a period of strong job creation, especially in the service sector industries. While the service-oriented economy expanded to support an increasing population level, there were also significant numbers of corporations migrating to Florida capitalizing on the low cost, low tax business environment. This being the case, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period but at a less significant level.

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

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

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, the forecaster can better capture subtle changes in existing customer usage as well as growth from new customers. Peak demand models are projected on a disaggregated basis as well. This allows for appropriate handling of individual assumptions in the areas of wholesale contracts, load management and interruptible service.

ENERGY AND CUSTOMER FORECAST

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

Residential Sector

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

Commercial Sector

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

Industrial Sector

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

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

Street Lighting

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

Public Authorities

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

Sales for Resale Sector

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

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

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

PEAK DEMAND FORECAST

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

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

Energy conservation and direct load control estimates are consistent with PEF's DSM goals that have been approved by the Florida Public Service Commission. These estimates are incorporated into the MW forecast. Projections of dispatchable and cumulative non-dispatchable DSM are subtracted from the projection of potential firm 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 GOALS

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

Historical Residential Conservation Savings Goals and Achievements

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

Historical Commercial/Industrial Conservation Savings Goals and Achievements

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

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

RESIDENTIAL PROGRAMS

Home Energy Check Program

This energy audit program provides customers with an analysis of their current energy use and recommendations on how they can save on their electricity bills through low-cost or no-cost energy-saving practices and measures. The Home Energy Check program offers PEF customers the following types of audits: Type 1: Free Walk-Through Audit (Home Energy Check); Type 2: Customer-completed Mail In Audit (Do It Yourself Home Energy Check); Type 3: Online Home Energy Check (Internet Option) - a customer-completed audit; Type 4: Phone Assisted Audit - a customer assisted survey of structure and appliance use; Type 5: Computer Assisted Audit; Type 6: Home Energy Rating Audit (Class I, II, III). The Home Energy Check Program serves as the foundation of the Home Energy Improvement Program in that the audit is a prerequisite for participation in the energy saving measures offered in the Home Energy Improvement Program.

Home Energy Improvement Program

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

Residential New Construction Program

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

Low Income Weatherization Assistance Program

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

Residential Energy Management Program

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

COMMERCIAL/INDUSTRIAL (C/I) PROGRAMS

Business Energy Check Program

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

Better Business Program

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

Commercial/Industrial New Construction Program

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

Innovation Incentive Program

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

Commercial Energy Management Program (Rate Schedule GSLM-1)

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

Standby Generation Program

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

Interruptible Service Program

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

Curtailable Service

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

RESEARCH AND DEVELOPMENT PROGRAMS

Technology Development Program

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

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

Progress Energy

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CHAPTER 3

FORECAST OF FACILITIES REQUIREMENTS

RESOURCE PLANNING FORECAST

OVERVIEW OF CURRENT FORECAST

Supply-Side Resources

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

Demand-Side Programs

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

Capacity and Demand Forecast

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

Base Expansion Plan

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

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

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

TABLE 3.1

PROGRESS ENERGY FLORIDA

TOTAL CAPACITY RESOURCES OF POWER PLANTS AND PURCHASED POWER CONTRACTS

AS OF DECEMBER 31, 2003

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

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

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

TABLE 3.2 PROGRESS ENERGY FLORIDA QUALIFYING FACILITY GENERATION CONTRACTS AS OF DECEMBER 31, 2003	
Facility Name	**Firm Capacity (MW)**
Bay County Resource Recovery	11.0
Cargill	15.0
Dade County Resource Recovery	43.0
El Dorado	114.2
Jefferson Power	2.0
Lake Cogen	110.0
Lake County Resource Recovery	12.8
LFC Jefferson	8.5
LFC Madison	8.5
Mulberry	79.2
Orange Cogen (CFR-Biogen)	74.0
Orlando Cogen	79.2
Pasco Cogen	109.0
Pasco County Resource Recovery	23.0
Pinellas County Resource Recovery	54.8
Ridge Generating Station	39.6
Royster	30.8
Timber Energy	12.5
US Agrichem	5.6
TOTAL	**832.7**

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
2004	8,332	474		0	833	9,639	7,997	1,642	21%	0	1,642	21%
2005	8,332	642	*	0	820	9,794	8,117	1,677	21%	0	1,677	21%
2006	8,848	642	*	0	820	10,310	8,519	1,791	21%	0	1,791	21%
2007	9,322	484		0	802	10,608	8,758	1,850	21%	0	1,850	21%
2008	9,783	484		0	787	11,054	8,954	2,100	23%	0	2,100	23%
2009	9,783	484		0	647	10,914	9,110	1,804	20%	0	1,804	20%
2010 **	10,739	70		0	647	11,456	9,330	2,126	23%	0	2,126	23%
2011	10,739	0		0	647	11,386	9,486	1,900	20%	0	1,900	20%
2012	11,217	0		0	647	11,864	9,634	2,230	23%	0	2,230	23%
2013	11,217	0		0	537	11,754	9,811	1,943	20%	0	1,943	20%

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

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

PROGRESS ENERGY FLORIDA

SCHEDULE 7.2

FORECAST OF CAPACITY, DEMAND AND SCHEDULED MAINTENANCE

AT TIME OF WINTER PEAK

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

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

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

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

PROGRESS ENERGY FLORIDA

SCHEDULE 8
PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

AS OF JANUARY 1, 2004 THROUGH DECEMBER 31, 2013

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

AS OF JANUARY 1, 2004

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

PROGRESS ENERGY FLORIDA

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

HINES UNIT #3

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

INTEGRATED RESOURCE PLANNING OVERVIEW

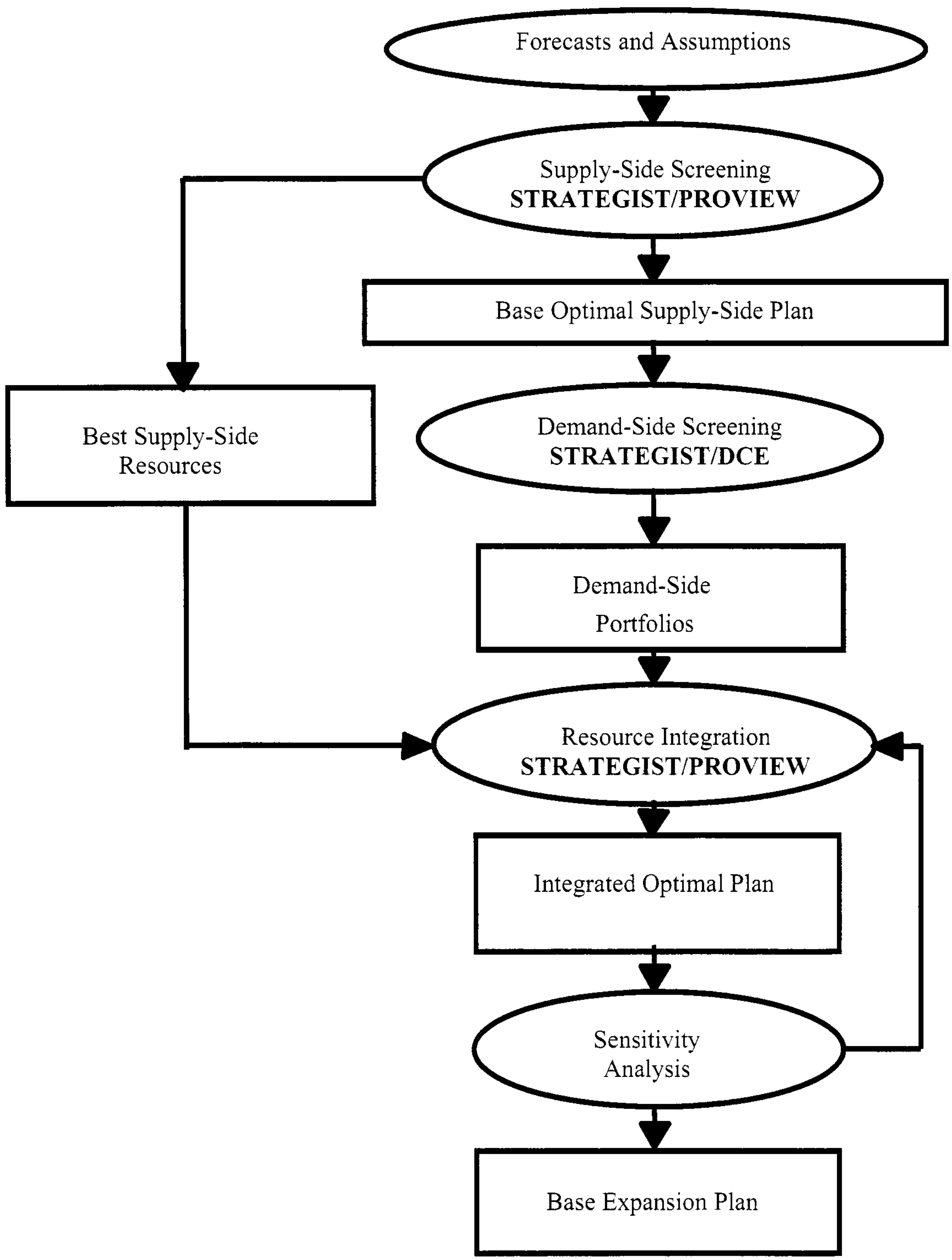
PEF employs an Integrated Resource Planning (IRP) process to determine the most cost-effective mix of supply- and demand-side alternatives that will reliably satisfy our customers' future energy needs. PEF's IRP process incorporates state-of-the-art computer models used to evaluate a wide range of future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

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

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

FIGURE 3.1

IRP Process Overview



THE IRP PROCESS

Forecasts and Assumptions

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

Reliability Criteria

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

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

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

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

Supply-Side Screening

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

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

Demand-Side Screening

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

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

Resource Integration and the Integrated Optimal Plan

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

Developing the Base Expansion Plan

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

KEY CORPORATE FORECASTS

Fuel Forecast

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

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

Financial Forecast

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

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

CURRENT PLANNING RESULTS

TYSP Supply-Side Resources

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

Plan Sensitivities

Sensitivities to load and fuel forecasts were analyzed against the base plan. The base plan of constructing combined-cycle and combustion turbine units on gas was determined to be robust with respect to changes in the load and fuel forecasts. The low load forecast sensitivity required less combined-cycle and combustion turbine generation; the high load forecast indicated that additional combined-cycle and combustion turbine units would potentially be required.

The high and low fuel forecast sensitivity results did not suggest any significant reconsideration of the base plan. The higher fuel prices resulted in an improvement in the economics of pulverized coal, particularly beyond the 10-year planning horizon. The additional sensitivity, which assumes the current differential price of oil and gas to coal remains constant over time, did not demonstrate any significant change in the relative economics of alternatives when compared to the base plan. This current differential in oil and gas to coal prices, however, includes recent spikes in natural gas prices that historically have been of a short-term nature and, thus, are not expected to continue over the planning horizon. PEF will continue to monitor these fuel price relationships and watch for any signs of a long-term structural change.

Request for Proposals

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

TRANSMISSION PLANNING

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

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

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

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

- NERC: Transmission Transfer Capability, May 1, 1995

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

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

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

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

TABLE 3.3

PROGRESS ENERGY FLORIDA

LIST OF PROPOSED BULK TRANSMISSION LINE ADDITIONS

2004-2013

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

* Rebuild existing circuit

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

Progress Energy

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CHAPTER 4

ENVIRONMENTAL AND LAND USE INFORMATION

PREFERRED SITES

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

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

HINES ENERGY COMPLEX SITE

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

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

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

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

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

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

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

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

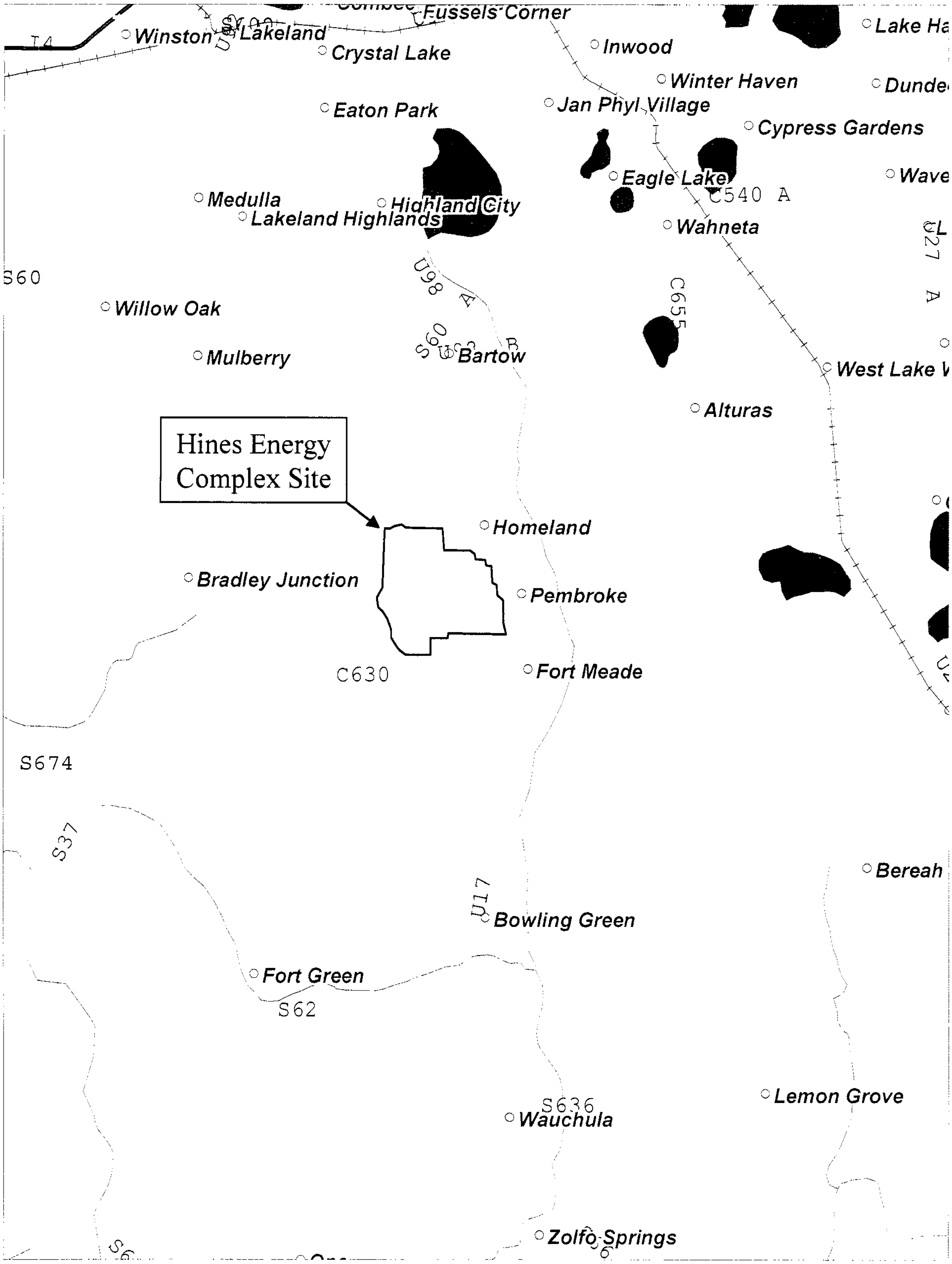
The first combined-cycle unit at this site, with a capacity of 482 MW summer and 529 MW winter, began commercial operation in April 1999. The transmission improvements associated with this first unit were the rebuilding of the 230/115 kV double circuit Barcola to Ft. Meade line by increasing the conductor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

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

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

FIGURE 4.1

Hines Energy Complex Site (Polk County)



INTERCESSION CITY SITE

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

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

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

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

FIGURE 4.2

Intercession City Site (Osceola County)

ANCLOTE SITE

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

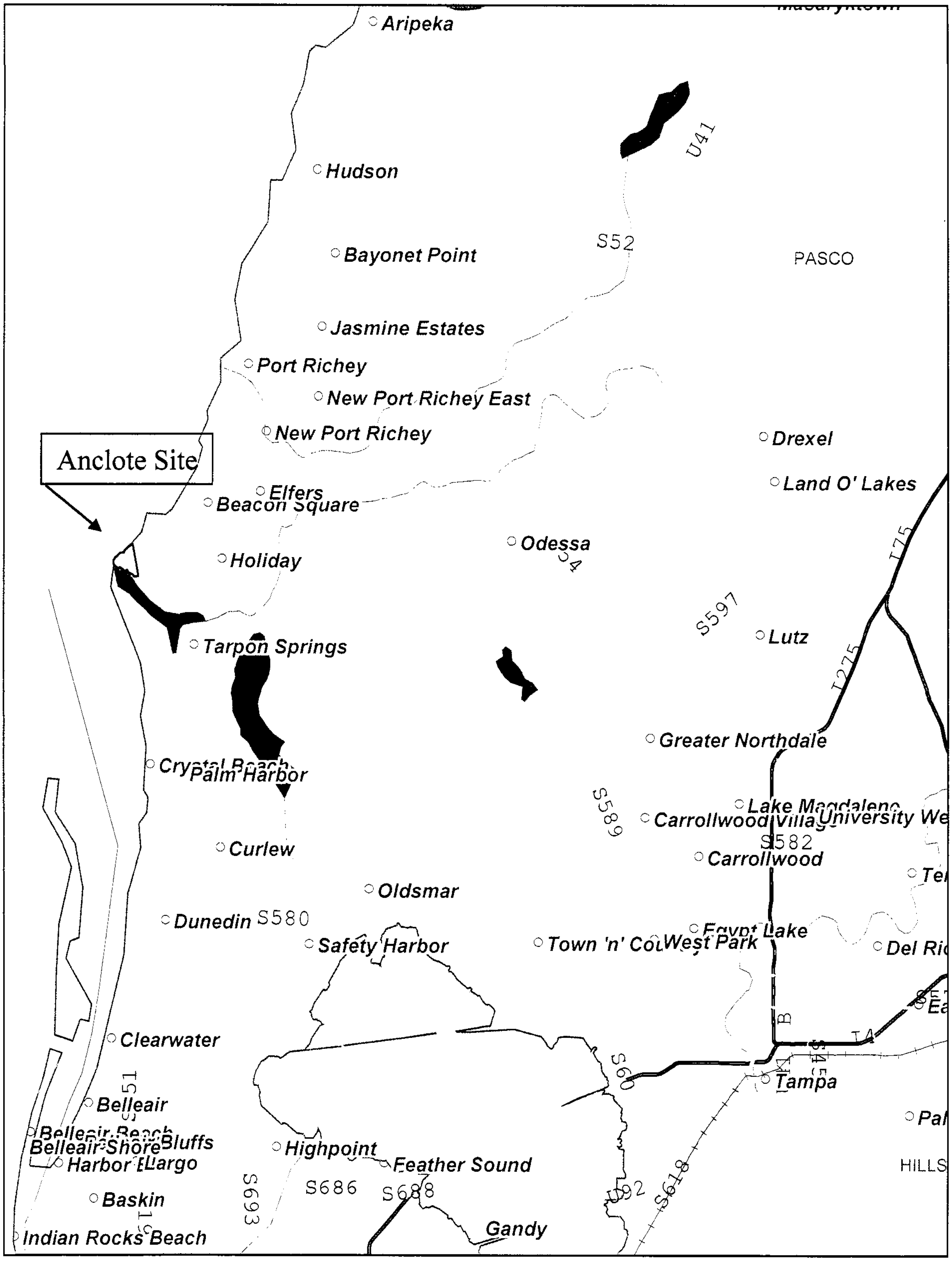
The Anclote site (Figure 4.3) consists of approximately 400 acres in Pasco County. The site is located in Holiday Florida at the mouth of the Anclote River. The site receives make-up water from the city of Tarpon Springs, fuel oil through a pipeline from the Bartow plant, and natural gas from the Florida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

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

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

FIGURE 4.3

Anclote Site (Pasco County)



DEBARY SITE

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

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

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

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

FIGURE 4.4

DeBary Site (Volusia County)