AUSLEY & McMULLEN

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P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

ORIGINAL

number site plan - forward 1 cy to EAG, give remainder to Ruth

Send data req to Staff (EAG/Haff)

March 31, 1998

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Tampa Electric Company's Ten Year Site Plan

Dear Ms. Bayo:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies each of the company's 1998-2007 Ten Year Site Plan and Tampa Electric's Response to Staff's Supplemental Data Request.

We are also furnishing the Division of Electric & Gas a diskette containing the tables for the Supplemental Data Request.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

Thank you for your assistance in connection with this matter.

Sincerely,

Lee L. Willis

LLW/pp
Enclosures

cc: Michael Haff (w/encls.)

ACK ___
AFA ___
APP ___
CAF ___
CMU ___
CTR ___
EAG 1
LEG ___
LIN ___
OPC ___
RCH ___
SEC 1
WAS ___
OTH ___

DOCUMENT NUMBER-DATE
03753 MAR 31 98

TAMPA ELECTRIC

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

JANUARY 1998 TO DECEMBER 2007

445.002 1/98

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

January 1998 to December 2007

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1998

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TAMPA ELECTRIC COMPANY
CODE IDENTIFICATION SHEET

Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	P	=	Planned
	T	=	Regulatory Approval Received
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	PC	=	Petroleum Coke
	HO	=	Heavy Oil (#6 Oil)
	LO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	SC	=	Scrubber
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NO	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric has six generating plants, consisting of fossil steam units, combustion turbine peaking units, diesel units, and an integrated gasification combined cycle unit. The six generating plants include Big Bend, Gannon, Hookers Point, Dinner Lake, Phillips, and Polk. Big Bend and Gannon consist of both steam-generating units and combustion turbine units.

Generation by coal continues to be the most economical fuel alternative for satisfying Tampa Electric's energy requirements. Tampa Electric has eleven coal-fired units. Ten of these units are fired with pulverized coal, while the Polk unit is fired with synthetic gas produced from gasified coal and other carbonaceous fuels. The Polk unit is an integrated gasification combined cycle unit (IGCC). This technology integrates state-of-the-art environmental processes for creating a clean fuel gas from a variety of feedstocks with the efficiency benefits of combined cycle generation equipment.

Generating units at Hookers Point and Phillips are residual oil fired units. Dinner Lake is fueled by natural gas and oil and is currently on long term reserve standby. The four combustion turbines at Big Bend and Gannon Stations use distillate oil as the primary fuel. Total net system generation in 1997 was 17,734 GWh produced by 98% coal and 2% oil-fired generation.

Schedule 1

TABLE 1-1
Existing Generating Facilities
As of December 31, 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt	Commercial	Expected	Gen. Max	Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Fuel Days	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate KW	Summer MW	Winter MW
Big Bend		Hillsborough Co. 14/31S/19E									1,998,000	1,852	1,919
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	421	431
	2		FS	C	N	WA	N	0	4/73	*	445,500	416	426
	3		FS	C	N	WA	N	0	5/76	*	445,500	428	438
	4		FS	C	N	WA	N	0	2/85	*	486,000	442	447
	CT1		CT	LO	N	WA	TK	0	2/69	*	18,000	15	17
	CT2&3		CT	LO	N	WA	TK	0	11/74	*	157,500	130	160
Dinner Lake**		Highland Co. 12-055									12,850	11	11
	1		FS	NG	HO	PL	TK	2	12/66	Unknown	12,850	11	11
Gannon		Hillsborough Co. 4/30S/19E									1,319,880	1,150	1,187
	1		FS	C	N	WA	RR	0	8/57	Unknown	125,000	114	114
	2		FS	C	N	WA	RR	0	11/58	*	125,000	108	108
	3		FS	C	N	WA	RR	0	10/60	*	179,520	155	155
	4		FS	C	N	WA	RR	0	11/63	*	187,500	169	179
	5		FS	C	N	WA	RR	0	11/65	*	239,360	227	232
	6		FS	C	N	WA	RR	0	10/67	*	445,500	362	382
	CT1		CT	LO	N	WA	TK	0	3/69	*	18,000	15	17
Hookers Pt.		Hillsborough Co. 19/29S/19E									232,600	207	215
	1		FS	HO	N	WA	N	0	7/48	01/03*	33,000	32	34
	2		FS	HO	N	WA	N	0	8/50	01/03*	34,500	32	34
	3		FS	HO	N	WA	N	0	8/50	01/03*	34,500	32	34
	4		FS	HO	N	WA	N	0	10/53	01/03*	49,000	41	43
	5		FS	HO	N	WA	N	0	5/55	01/03*	81,600	70	70
Phillips		Highland Co. 12-055									42,030	37	37
	1		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	2		D	HO	N	TK	N	0	6/83	Unknown	19,215	17	17
	3 ***		HRSG	WH	N	N	N	0	6/83	Unknown	3,600	3	3
Polk		Polk Co. 2-3/32S/23E									326,299	250	250
	1		IGCC	C	LO	WA/TK	TK	0	9/96	Unknown	326,299	250	250
											TOTAL	3,507	3,619

* This is currently being reviewed by Tampa Electric Company

** Unit placed on long-term reserve standby 03/01/94

*** Unit on full forced outage with an undetermined return to service date

TABLE 1-2
Existing Generating Facilities/Land Use and Investment

	Land Area		Plant Capital Investment ($000)			
Plant Name	Total Acres	In Use Acres	Land	Structures & Improvements	Equipment	Total [1]
Hookers Point Station	25	25	$ 438	$ 7,867	$ 45,061	$ 53,366
Big Bend Station	1,124	1,124	5,147	157,914	852,843	1,015,904
Francis J. Gannon Station	213	213	1,556	60,942	389,843	452,341
Dinner Lake - Sebring	2	2	15	134	3,487	3,636
Phillips - Sebring	36	36	179	288	59,356	59,823
Combustion Turbine - Gannon	1	1	0	75	1,753	1,828
Combustion Turbines - Big Bend	75	75	834	1,516	21,138	23,488
Miscellaneous Production [2]	47	47	94	6,661	5,749	12,504
Polk Power Station	4,347	4,347	18,919	110,782	385,061	514,767
TOTALS			$27,182	$346,184	$1,764,291	$2,137,657

[1] Dollar values rounded to the nearest $1,000

[2] Power Plant Services, Production Service Complex, Production Warehouse, Central Testing Lab, Production Training Facilities

TABLE 1-3
Existing Generating Facilities/Environmental Considerations for Steam Generating Units

Plant Name	Unit	Flue Gas Cleaning			Cooling
		Particulate	SO_x	NO_x	Type
Francis J. Gannon	1	EP	LS	NR	OTS
	2	EP	LS	NR	OTS
	3	EP	LS	NR	OTS
	4	EP	LS	NR	OTS
	5	EP	LS	NR	OTS
	6	EP	LS	NR	OTS
	CT 1	NR	LS	NR	---
Hookers Point	1	NR	LS	NR	OTS
	2	NR	LS	NR	OTS
	3	NR	LS	NR	OTS
	4	NR	LS	NR	OTS
	5	NR	LS	NR	OTS
Big Bend	1	EP	(1)	NR	OTS
	2	EP	(1)	NR	OTS
	3	EP	SC	(2)	(4)
	4	EP	SC	(3)	(4)
	CT 1	NR	LS	NR	---
	CT 2	NR	LS	NR	---
	CT 3	NR	LS	NR	---
Dinner Lake	1	NR	FQ	NR	OTS
Phillips	1	NR	FQ	(2)	CLT
	2	NR	FQ	(2)	CLT
	HRSG 3	NA	NA	NA	NA
Polk	IGCC 1	NR	AGR	NI	OLS

CLT = Cooling Tower
CT = Combustion Turbine
EP = Electrostatic Precipitator
FQ = Fuel Quality
LS = Low Sulfur
SC = Scrubber
OTS = Once-Through System
HRSG = Heat Recovery Steam Generator
IGCC = Integrated Gasification Combined Cycle
AGR = Acid Gas Removal
NI = Nitrogen Injection
CR = Cooling Reservoir
OLS = Open Loop Cooling Water System
NA = Not Applicable
NR = Not Required

December 31, 1997 Status.
Source: Tampa Electric Company

(1) Big Bend Units 1 - 4 operate under an SO_2 emissions cap which limits the emissions from these four units in total. Coal blending of units 1 and 2 along with the scrubbing of units 3 and 4 are used to meet the limits established for these units.

(2) NO_x controlled through unit operation.

(3) NO_x controlled through unit design and operation.

(4) OTS with fine mesh screens to minimize entrainment.

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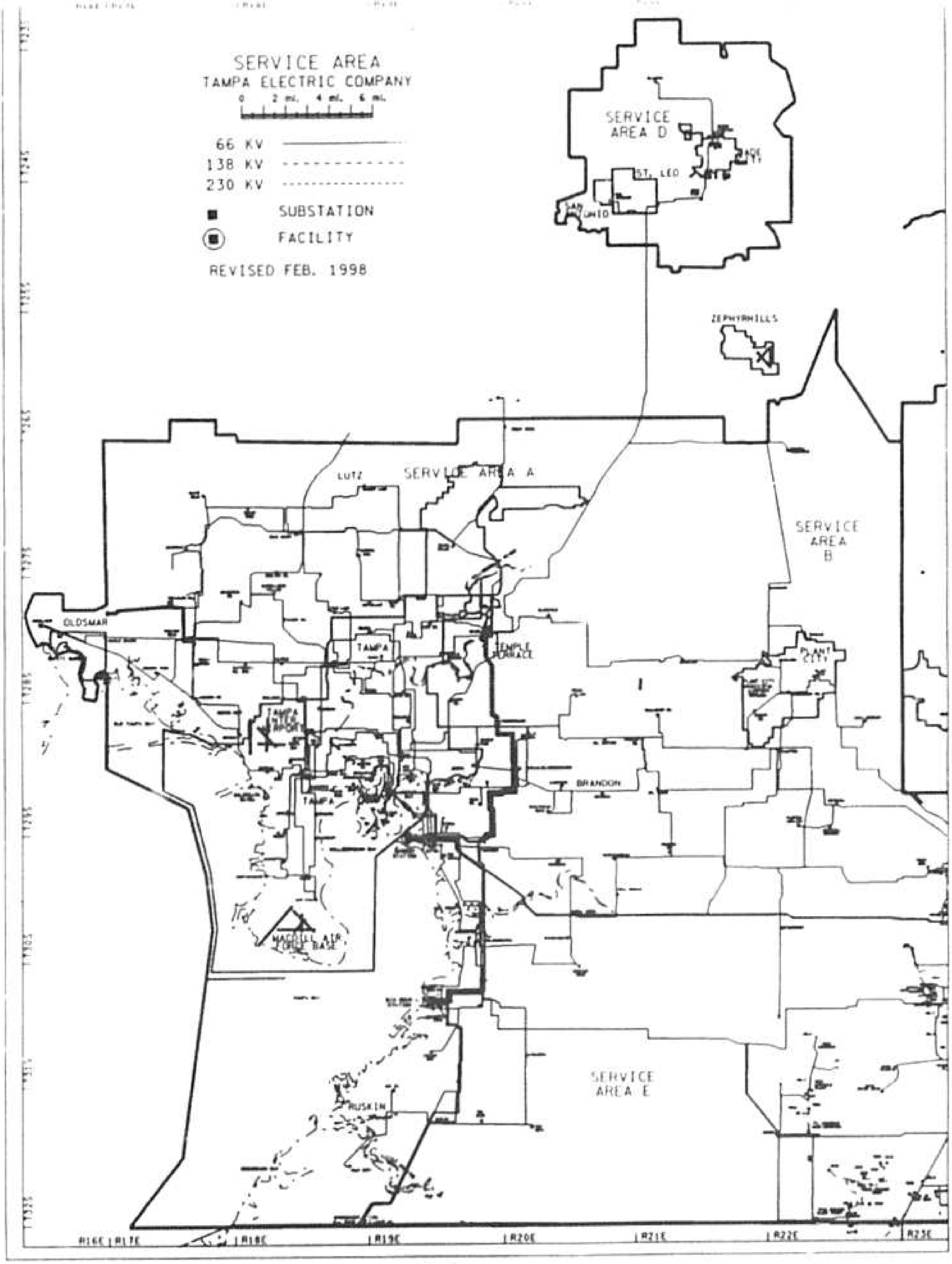


SERVICE AREA
TAMPA ELECTRIC COMPANY
0 2 mi. 4 mi. 6 mi.
66 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1998
SERVICE AREA D
ST. LEO
ZEPHYRHILLS
SERVICE AREA A
LUTZ
SERVICE AREA B
OLDSMAR
TAMPA
TEMPLE TERRACE
PLANT CITY
BRANDON
MACDILL AIR FORCE BASE
SERVICE AREA E
RUSKIN
R16E
R17E
R18E
R19E
R20E
R21E
R22E
R23E

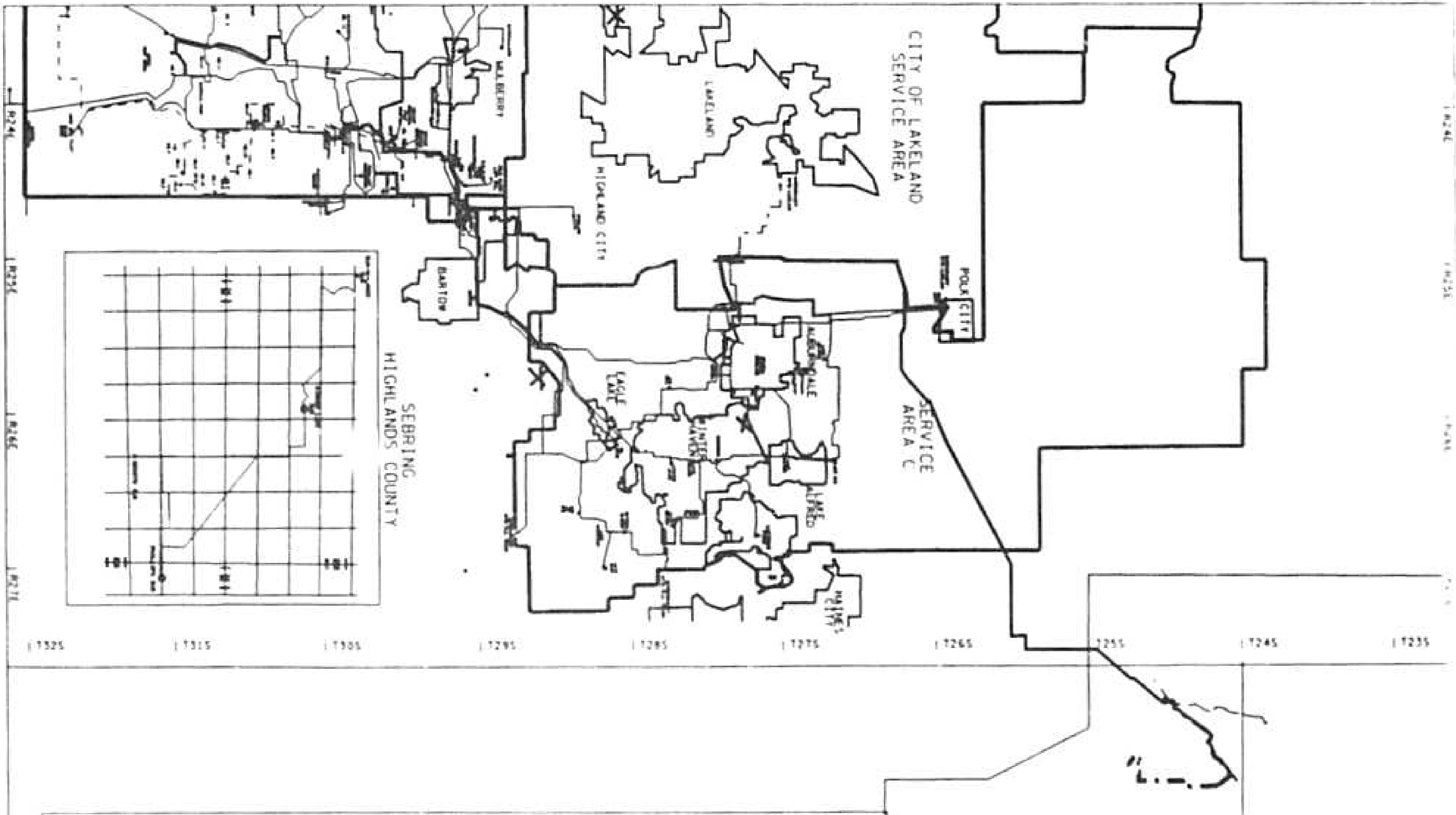


FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

TEN YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES

I - 6

CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Schedule 2.1

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 1 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Population**	Members Per Household	GWH	Average* No. of Customers	Average KWH Consumption Per Customer	GWH	Average* No. of Customers	Average KWH Consumption Per Customer
1988	809,468	2.5	4,967	383,717	12,944	3,814	48,713	78,295
1989	822,621	2.5	5,214	393,278	13,258	4,062	49,780	81,599
1990	834,054	2.5	5,412	401,172	13,490	4,231	50,287	84,137
1991	843,203	2.5	5,507	407,235	13,523	4,274	50,774	84,177
1992	853,990	2.5	5,560	412,970	13,463	4,333	51,727	83,767
1993	866,134	2.5	5,706	420,051	13,584	4,432	52,492	84,432
1994	879,069	2.5	5,947	427,594	13,908	4,583	53,482	85,692
1995	892,874	2.5	6,352	436,091	14,566	4,710	54,375	86,621
1996	910,855	2.5	6,607	445,664	14,825	4,815	55,479	86,790
1997	929,507	2.4	6,500	456,175	14,249	4,902	56,981	86,029
1998	950,614	2.4	6,875	465,019	14,784	5,176	57,845	89,481
1999	969,417	2.4	7,054	474,487	14,867	5,345	58,881	90,776
2000	987,815	2.4	7,230	483,883	14,942	5,516	59,995	91,941
2001	1,004,237	2.4	7,412	492,563	15,048	5,688	61,135	93,040
2002	1,019,371	2.4	7,594	500,128	15,184	5,861	62,064	94,435
2003	1,032,494	2.4	7,777	507,557	15,322	6,035	62,995	95,801
2004	1,045,493	2.4	7,959	514,996	15,454	6,208	63,889	97,169
2005	1,057,775	2.4	8,141	522,393	15,584	6,379	64,771	98,485
2006	1,069,717	2.4	8,320	529,793	15,704	6,549	65,652	99,753
2007	1,081,556	2.4	8,496	537,142	15,817	6,720	66,545	100,984

December 31, 1997 Status.

* Average of end-of-month customers for the calendar year.

** Hillsborough County population.

Schedule 2.2

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 2 of 3)

(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
1988	2,749	561	4,900,178	0	40	856	12,426
1989	2,672	536	4,985,075	0	40	907	12,896
1990	2,818	518	5,440,154	0	41	934	13,436
1991	2,669	515	5,182,524	0	42	963	13,455
1992	2,625	509	5,157,171	0	43	991	13,552
1993	2,236	509	4,392,927	0	45	1,028	13,447
1994	2,278	511	4,457,926	0	46	1,078	13,932
1995	2,362	491	4,810,591	0	51	1,125	14,600
1996	2,305	504	4,573,413	0	53	1,150	14,929
1997	2,465	612	4,027,778	0	53	1,170	15,090
1998	2,340	640	3,656,250	0	56	1,244	15,691
1999	2,487	640	3,885,938	0	58	1,285	16,229
2000	2,478	640	3,871,875	0	61	1,326	16,611
2001	2,461	640	3,845,313	0	63	1,368	16,992
2002	2,441	640	3,814,063	0	65	1,410	17,371
2003	2,421	640	3,782,813	0	66	1,453	17,752
2004	2,398	640	3,746,875	0	68	1,497	18,130
2005	2,376	640	3,712,500	0	69	1,535	18,500
2006	2,354	640	3,678,125	0	71	1,574	18,868
2007	2,329	640	3,639,063	0	72	1,613	19,230

December 31, 1997 Status.

* Average of end-of-month customers for the calendar year.

TABLE II-1
History and Forecast of Energy Consumption and
Number of Customers by Customer Class
(Page 3 of 3)

(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
1988	0	725	13,151	3,448	436,439
1989	0	809	13,704	3,563	447,157
1990	0	569	14,005	3,695	455,672
1991	129	695	14,279	3,736	462,260
1992	214	671	14,437	3,790	468,996
1993	246	807	14,500	3,958	477,010
1994	163	636	14,731	4,111	485,698
1995	212	870	15,682	4,241	495,198
1996	399	760	16,088	4,391	506,038
1997	507	731	16,328	4,583	518,368
1998	382	860	16,933	4,674	528,178
1999	389	888	17,506	4,769	538,777
2000	331	911	17,853	4,864	549,381
2001	382	932	18,306	4,966	559,303
2002	348	953	18,672	5,069	567,902
2003	372	973	19,097	5,175	576,367
2004	382	996	19,508	5,284	584,809
2005	373	1,015	19,888	5,394	593,198
2006	369	1,035	20,272	5,480	601,565
2007	329	1,058	20,617	5,567	609,894

December 31, 1997 Status.

* Average of end-of-month customers for the calendar year.
** Output to line including energy supplied by purchased cogeneration.
*** Values shown may be affected by rounding.
++ Utility Use and Losses include accrued sales.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
Base Case
(Page 1 of 3)

(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	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,201	112	3,089	217	105	61	46	20	2,640	
1999	3,292	128	3,164	233	109	66	60	22	2,674	
2000	3,380	128	3,252	230	112	71	75	25	2,739	
2001	3,491	139	3,352	228	116	76	90	27	2,814	
2002	3,591	140	3,451	225	119	80	107	30	2,890	
2003	3,707	141	3,566	222	123	85	123	31	2,983	
2004	3,806	141	3,665	219	126	89	140	34	3,057	
2005	3,892	130	3,762	217	129	93	158	35	3,130	
2006	3,991	130	3,861	215	132	97	176	38	3,203	
2007	4,060	111	3,949	212	135	101	195	39	3,267	

December 31, 1997 Status.

* Not coincident with system peak.

** Values shown may be affected by rounding.

\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.

\# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.1

TABLE II-2
History and Forecast of Summer Peak Demand
High Case
(Page 2 of 3)

(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	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,221	112	3,109	220	106	61	46	20	2,656	
1999	3,335	128	3,207	240	110	66	60	22	2,709	
2000	3,441	128	3,313	240	114	72	75	25	2,787	
2001	3,576	140	3,436	241	118	77	91	27	2,882	
2002	3,702	141	3,561	241	121	82	107	30	2,980	
2003	3,853	142	3,711	240	125	86	123	31	3,106	
2004	3,975	142 *	3,833	240	129	91	140	34	3,199	
2005	4,099	131	3,968	238	133	96	158	35	3,308	
2006	4,222	131	4,091	238	137	100	176	38	3,402	
2007	4,337	113	4,224	237	140	104	195	39	3,509	

December 31, 1997 Status

* Not coincident with system peak.
** Values shown may be affected by rounding.
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3 1

TABLE II-2
History and Forecast of Summer Peak Demand
Low Case
(Page 3 of 3)

(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	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,189	112	3,077	215	105	60	46	20	2,631	
1999	3,257	128	3,129	226	108	65	60	22	2,648	
2000	3,324	128	3,196	220	111	70	75	25	2,695	
2001	3,413	138	3,275	215	115	75	90	27	2,753	
2002	3,487	139	3,348	209	117	79	107	30	2,806	
2003	3,589	140	3,449	204	120	83	123	31	2,888	
2004	3,651	140	3,511	200	122	87	140	34	2,928	
2005	3,723	129	3,594	195	125	91	158	35	2,990	
2006	3,773	129	3,644	192	127	95	176	38	3,016	
2007	3,814	109	3,705	187	130	98	195	39	3,056	

December 31, 1997 Status

- * Not coincident with system peak
- ** Values shown may be affected by rounding
- \+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
- \# Commercial/Industrial Load Management includes Standby Generator

Schedule 3 2

TABLE II-3
History and Forecast of Winter Peak Demand
Base Case
(Page 1 of 3)

(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	(10) Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345 *
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,521	114	3,407	197	245	350	30	27	2,558
1998/99	3,625	129	3,496	211	254	387	42	28	2,574
1999/00	3,721	129	3,592	209	263	421	54	29	2,616
2000/01	3,823	141	3,682	207	272	454	67	29	2,653
2001/02	3,908	141	3,767	204	280	487	81	30	2,685
2002/03	4,019	143	3,876	203	288	519	95	31	2,740
2003/04	4,115	143	3,972	201	296	551	109	31	2,784
2004/05	4,204	132	4,072	198	304	582	124	32	2,832
2005/06	4,302	133	4,170	196	312	611	139	33	2,879
2006/07	4,391	113	4,278	193	319	640	155	34	2,937
2007/08	4,476	114	4,362	192	327	668	155	35	2,985

December 31, 1997 Status

- * Not coincident with system peak.
- \+ Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
- \# Commercial/Industrial Load Management includes Standby Generator.
- ** Forecasted Values: 1997/98 - 2007/08.
- *** Values shown may be affected by rounding.
- = Residential conservation includes code changes.

Schedule 3.2

TABLE II-3
History and Forecast of Winter Peak Demand
High Case
(Page 2 of 3)

(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	(10) Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,541	114	3,427	200	246	351	30	27	2,573
1998/99	3,662	129	3,533	216	256	389	42	28	2,602
1999/00	3,780	129	3,651	218	266	426	54	29	2,658
2000/01	3,894	142	3,752	219	276	461	67	29	2,700
2001/02	4,014	142	3,872	219	285	496	81	30	2,761
2002/03	4,146	144	4,002	220	295	531	95	31	2,830
2003/04	4,261	144	4,117	219	304	566	109	31	2,888
2004/05	4,391	133	4,258	218	314	599	124	32	2,971
2005/06	4,511	135	4,376	217	323	632	139	33	3,032
2006/07	4,644	115	4,529	215	332	664	155	34	3,129
2007/08	4,764	114	4,650	216	341	696	155	35	3,207

December 31, 1997 Status

- * Not coincident with system peak.
- \+ Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
- \# Commercial/Industrial Load Management includes Standby Generator.
- ** Forecasted Values: 1997/98 - 2007/08.
- *** Values shown may be affected by rounding.
- = Residential conservation includes code changes.

Schedule 3 2

TABLE II-3
History and Forecast of Winter Peak Demand
Low Case
(Page 3 of 3)

(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	(10) Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,510	114	3,396	195	244	349	30	27	2,551
1998/99	3,594	129	3,465	206	252	384	42	28	2,553
1999/00	3,672	129	3,543	200	260	416	54	29	2,584
2000/01	3,754	140	3,614	196	267	447	67	29	2,608
2001/02	3,825	140	3,685	191	274	478	81	30	2,631
2002/03	3,907	142	3,765	188	281	508	95	31	2,662
2003/04	3,979	142	3,837	183	288	537	109	31	2,689
2004/05	4,049	131	3,918	179	295	565	124	32	2,723
2005/06	4,111	132	3,979	175	301	591	139	33	2,740
2006/07	4,174	111	4,063	171	307	616	155	34	2,780
2007/08	4,234	114	4,120	170	313	641	155	35	2,806

December 31, 1997 Status.

*	Not coincident with system peak.
+	Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
#	Commercial/Industrial Load Management includes Standby Generator.
**	Forecasted Values: 1997/98 - 2007/08.
***	Values shown may be affected by rounding.
=	Residential conservation includes code changes.

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Base Case
(Page 1 of 3)

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	16,025	260	74	15,691	382	860	16,933	55.0
1999	16,604	291	84	16,229	389	888	17,506	55.4
2000	17,026	321	94	16,611	331	911	17,853	54.6
2001	17,445	350	103	16,992	382	932	18,306	54.8
2002	17,863	379	113	17,371	348	953	18,672	54.5
2003	18,282	407	123	17,752	372	973	19,097	54.3
2004	18,696	434	132	18,130	382	996	19,508	54.0
2005	19,102	460	142	18,500	373	1,015	19,888	53.9
2006	19,504	485	151	18,868	369	1,035	20,272	53.8
2007	19,901	510	161	19,230	329	1,058	20,617	53.4

December 31, 1997 Status

** Load Factor is the ratio of total system average load to peak demand.
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.

Schedule 3 3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
High Case
(Page 2 of 3)

(1) Year	(2) Total	(3) Residential Conservation ≡	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale *	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	16,147	261	74	15,812	383	866	17,061	55.1
1999	16,835	293	84	16,458	391	901	17,750	55.6
2000	17,368	324	94	16,950	333	927	18,211	54.8
2001	17,899	3[illegible]4	103	17,442	385	954	18,781	55.2
2002	18,447	385	113	17,949	352	981	19,282	54.8
2003	19,016	414	123	18,479	377	1,009	19,865	54.7
2004	19,583	444	132	19,007	388	1,037	20,432	54.6
2005	20,135	472	142	19,521	380	1,064	20,965	54.4
2006	20,704	499	151	20,054	377	1,092	21,523	54.5
2007	21,276	527	161	20,588	338	1,120	22,046	54.0

December 31, 1997 Status

** Load Factor is the ratio of total system average load to peak demand
* Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
≡ Residential conservation includes code changes

Schedule 3.3

TABLE II-4
History and Forecast of Annual Net Energy for Load - GWH
Low Case
(Page 3 of 3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation ≡	Comm./Ind. Conservation	Retail	Wholesale +	Utility Use & Losses	Net Energy for Load	Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	15,950	259	74	15,617	381	857	16,856	54.9
1999	16,424	289	84	16,051	388	882	17,320	55.2
2000	16,740	318	94	16,328	329	898	17,555	54.4
2001	17,046	346	103	16,597	379	913	17,889	54.6
2002	17,361	373	113	16,875	345	929	18,149	54.2
2003	17,657	399	123	17,135	368	944	18,447	53.9
2004	17,940	425	132	17,383	377	959	18,718	53.6
2005	18,205	449	142	17,614	367	972	18,953	53.3
2006	18,472	472	151	17,849	362	986	19,197	53.3
2007	18,717	494	161	18,062	321	999	19,382	52.7

December 31, 1997 Status

** Load Factor is the ratio of total system average load to peak demand.
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
≡ Residential conservation includes code changes.

Schedule 4

TABLE II-5

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	1997 Actual		1998 Forecast		1999 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	3,439	1,257	3,521	1,278	3,625	1,318
February	2,445	1,103	3,188	1,161	3,284	1,198
March	2,442	1,287	2,751	1,220	2,837	1,260
April	2,512	1,189	2,644	1,250	2,723	1,295
May	3,107	1,443	2,973	1,514	3,059	1,574
June	3,090	1,530	3,201	1,609	3,292	1,665
July	3,079	1,601	3,170	1,680	3,259	1,737
August	3,076	1,625	3,179	1,692	3,269	1,752
September	2,968	1,542	3,172	1,584	3,262	1,638
October	2,725	1,344	2,899	1,392	2,983	1,437
November	2,111	1,134	2,807	1,282	2,895	1,321
December	2,585	1,273	3,094	1,271	3,192	1,311
TOTAL		16,328		16,933		17,506

December 31, 1997 Status

Schedule 5

TABLE II-6
History and Forecast of Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal*		1000 Ton	7,795	8,021	7,952	7,669	7,507	7,703	7,683	7,930	7,813	8,090	8,147	8,270
(3)	Residual	Total	1000 BBL	412	427	287	306	419	572	768	128	146	155	163	171
(4)		Steam	1000 BBL	333	345	245	261	362	485	661	0	0	0	0	0
(5)		CC	1000 BBL	79	82	41	45	58	87	108	128	146	155	163	171
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	256	319	287	320	385	417	486	665	872	894	1,002	1,105
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	210	250	208	233	241	240	240	239	239	239	239	239
(11)		CT	1000 BBL	46	70	79	87	145	177	246	427	633	656	763	866
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	0	0	0	0	0	0	0	1,623	3,100	3,526	4,602	5,295
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CT	1000 MCF	0	0	0	0	0	0	0	1,623	3,100	3,526	4,602	5,295
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	176	111	237	566	581	592	584	582	582	593	590	592

December 31, 1997 Status

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon

** Values shown may be affected by rounding

*** All values exclude ignition

Schedule 6.1

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source
(Page 1 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		GWh	5	(125)	(599)	203	262	192	254	441	511	525	562	622
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		GWh	17,225	17,033	17,570	16,330	16,001	16,379	16,343	16,843	16,649	17,170	17,254	17,544
(4)	Residual	Total	GWh	182	188	124	132	180	248	330	85	97	103	108	114
(5)		Steam	GWh	129	136	96	102	142	190	259	0	0	0	0	0
(6)		CC	GWh	53	52	28	30	38	58	72	85	97	103	108	114
(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	162	202	180	200	226	236	260	366	486	495	557	609
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	146	178	153	171	177	176	176	175	176	175	175	175
(12)		CT	GWh	16	24	27	30	49	60	84	192	310	320	382	434
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	0	0	0	0	0	0	0	139	269	308	418	479
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	GWh	0	0	0	0	0	0	0	139	269	308	418	479
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	492	310	663	1,585	1,627	1,658	1,636	1,629	1,629	1,660	1,653	1,657
(20)	Net Interchange		GWh	(2,441)	(1,734)	(1,448)	(1,338)	(883)	(875)	(627)	(890)	(618)	(857)	(762)	(890)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWh	464	453	444	394	441	468	475	483	484	483	483	483
(23)	Net Energy for Load		GWh	16,088	16,328	16,933	17,506	17,653	18,306	18,672	19,097	19,508	19,888	20,272	20,617

December 31, 1997 Status

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.

** Values shown may be affected by rounding

Schedule 6.2

TABLE II-7
History and Forecast of Net Energy for Load by Fuel Source
(Page 2 of 2)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1996	Actual 1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		%	0	(1)	(4)	1	1	1	1	2	3	3	3	3
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal*		%	107	104	104	93	90	89	88	88	85	86	85	85
(4)	Residual	Total	%	1	1	1	1	1	1	2	0	0	1	1	1
(5)		Steam	%	1	1	1	1	1	1	1	0	0	0	0	0
(6)		CC	%	0	0	0	0	0	0	0	0	0	1	1	1
(7)		CT	%	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
(9)	Distillate	Total	%	1	1	1	1	1	1	1	2	2	2	3	3
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	1	1	1	1	1	1	1	1	1	1	1	1
(12)		CT	%	0	0	0	0	0	0	0	1	2	2	2	2
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	0	0	0	0	0	0	0	1	1	2	2	2
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(17)		CT	%	0	0	0	0	0	0	0	1	1	2	2	2
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	3	2	4	9	9	9	9	9	8	8	8	8
(20)	Net Interchange		%	(15)	(11)	(9)	(8)	(5)	(5)	(3)	(5)	(3)	(4)	(4)	(4)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	3	3	3	2	2	3	3	3	2	2	2	2
(23)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

December 31, 1997 Status

* Coal energy source includes an alternative fuel source consisting of a shredded tire/coal blend fuel for Gannon.

** Values shown may be affected by rounding.

CHAPTER III

FORECAST OF ELECTRIC POWER DEMAND

Tampa Electric Company Forecasting Methodology

The Customer, Demand and Energy Forecast is the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric Company employs state-of-the-art methodologies for carrying out this function. The primary objective in this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection which represents the highest probability of occurrence.

This chapter is devoted to describing Tampa Electric Company's forecasting methods and the major assumptions utilized in devel_ping the 1998-2007 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 1998-2007 time period.

Retail Load

The Tampa Electric Company retail demand and energy forecast is the result of five separate forecasting methods:

1. detailed end-use model (demand and energy);
2. multiregression model (demand and energy);
3. trend analysis (demand and energy);
4. phosphate analysis (demand and energy); and
5. conservation programs (demand and energy management).

The detailed end-use model, SHAPES, is the company's most sophisticated and primary forecasting model. As shown in Figure III-1, the first three forecasting methods are blended together to develop a demand and energy projection, excluding phosphate load. Phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric Company's conservation, load management, and cogeneration programs is incorporated into the process by subtracting their expected reduction in demand and energy from the forecast.

1. Detailed End-Use Model

The SHAPES model was developed jointly by Tampa Electric Company, Tech Resources (formerly part of the Battelle Memorial Institute), and New Energy Associates and is the foundation of the emand and energy forecasting process. SHAPES projects annual energy consumption for the service area and load profiles by end-use for typical and extreme (peak) days. The model has two major sections. The first section is the regional economic-demographic model, entitled REGIS, which generates population, households, income, and employment projections which are used in the second part of the model, called SHAPES.

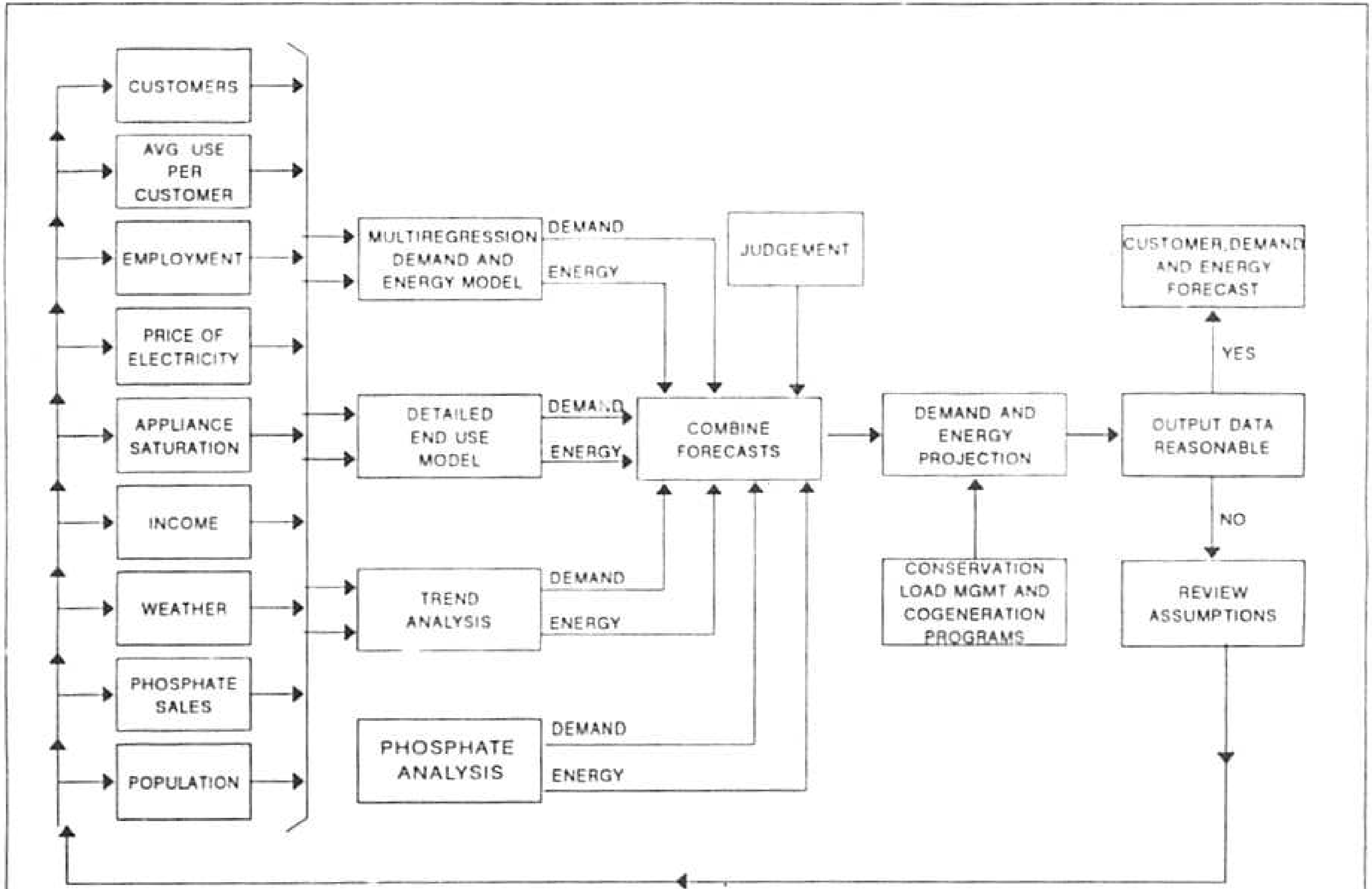


Figure III-1

TAMPA ELECTRIC COMPANY CUSTOMER, DEMAND AND ENERGY FORECAST PROCESS

SOURCE: TAMPA ELECTRIC COMPANY

TAMPA ELECTRIC COMPANY

Ten-Year Site Plan
For Electrical Generation Facilities
And Associated Transmission Lines

As an option, the parameters furnished by REGIS may be replaced with other forecasts, such as the University of Florida's population projections. The SHAPES portion of the model consists of two parts: (1) a demand section, and (2) an energy section. The demand section calculates hourly demands including peak demands based on temperature profiles for normal and extreme conditions. The energy section forecasts residential energy use by appliance, commercial consumption by end-use and building type, and energy used in the industrial and miscellaneous sectors.

REGIS

Since electricity consumption, peak demand, and load shapes depend to a large extent on the nature and level of economic activity, the first step in system demand and energy requirements forecasting is to project the economic and population base of the service area. The economic-demographic model consists of approximately twenty equations with four major components including migration and demographic, housing, labor, and income.

Population is developed through the migration/demographic component of the model which uses a cohort-survival approach as its foundation. More specifically, Hillsborough County population is partitioned into age groups and "aged" over time through the application of birth and death rates. Migration, the most significant component of population change in the service area, is calculated as a function of the relative economic opportunities in the local area and the general health of the overall economy. The population estimates are converted to residential customers by applying household formation rates to each age group. The housing sector determines the stock of housing that relates to the residential customer forecasts.

The labor market and income components are combined to determine service area employment and income. In the labor sector, employment for four manufacturing categories plus the commercial and governmental sectors is projected. Employment is then combined with the wage equation of the income sector to determine local earnings. Since earnings represent 70 to 75% of total personal income, this is an important input for deriving regional personal income.

SHAPES

The power model is comprised of four major sectors: (1) residential, (2) commercial, (3) industrial, and (4) miscellaneous (governmental, street lighting, and transmission and distribution line losses). This structure emphasizes the projection of hourly demand values by end-use based on month, day type, and temperature. Repeating these calculations for each hour of the day and for all consumption units yields the daily load curve of the system. The energy consumption for any period is calculated by summing demand in each hour in the period for all end-uses.

More specifically, the basic equation upon which the model is based is:

$$D_{ij} = \Sigma N_i * C_i * F_{ij}$$

where:

D_{ij} = Demand at hour j by end-use component i;

N_i = Number of use components of type i;

C_i = Connected load per use component i;

F_{ij} = Fraction of connected load of use component i which is operating at hour j.

In the residential sector, the energy consuming units are the major household appliances. A list of the seventeen appliances treated explicitly in the model is provided in Table III-1. The appliance stock in a given year is influenced by the number of households, the mix of dwelling unit types, and family income. The latter two variables are used to derive saturation levels for each appliance which combined with the number of households, results in the total number of units of a given appliance.

Looking at these two factors in more detail, data analysis indicates that saturation levels for certain appliances vary significantly according to housing type. To capture these differences, the occupied housing stock or number of households is partitioned into single family, multi-family, and mobile home categories. In addition, it was determined that certain appliance saturations are related to the individual household's income level. Those appliances having this characteristic included room air conditioners, electric clothes dryers, clothes washers, and dishwashers. Projections of housing mix and per capita income, therefore, were utilized in developing saturation rates for these appliance categories.

To capture the trend of including ranges, central air conditioning, electric water heating, electric space heating or electric heat pumps as standard items in new construction, penetration rates representing the percent of new housing with these features were used to project saturation levels for these appliances. Finally, certain appliances such as television sets and refrigerators have already achieved full saturation. Future saturation levels are similar to present rates except for quality shifts or intercategory adjustments from standard to frost free refrigerators and black and white to color television.

The second major factor in the demand estimation equation is the connected load of the appliance, which was developed from company and industry studies. The last factor in the equation is the use factor or the probability of the appliance operating at a given time.

TABLE III-1. Appliances Treated Explicitly In End-Use Model

Electric Range
Refrigerator - Frost Free
Refrigerator - Standard
Freezer - Frost Free
Freezer - Standard
Dishwasher
Clothes Washer
Electric Dryer
Electric Water Heater
Microwave Oven
TV-Color
TV-Black and White
Lighting
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Tampa Electric Company

In the model, appliances can be separated into two groups: temperature insensitive and temperature sensitive. Those appliances which are temperature insensitive have use factors which vary by day type, month, and hour. Thus, the usage of these appliances is characterized by 1,152 use factors (12 months x 24 hours x 4 day types). These four day types are Sunday, Monday, Tuesday-Friday, and Saturday. For temperature-sensitive appliances, which include air conditioners, electric space heaters, and electric heat pumps, the monthly use factors are replaced by a set of factors which vary with respect to time and temperature. Therefore, the energy consumption of these appliances is a function of temperature, time, and day type. These temperature-related use factors are combined with monthly temperature probability matrices to calculate energy requirements over that period.

The model is capable of developing a residential as well as a system demand profile for each hour of each day type for all twelve months. In order to calculate peak demand, a temperature profile representing the expected hottest or coldest day must be input into the model. An average day load profile for each month can also be developed by supplying an average temperature for every hour.

The commercial sector of the model forecasts energy and demand by building type by end-use. This sector estimates energy intensity by end-use for each building type in terms of kWh per square foot of floor space. The forecast of building type square footage can be developed within the model using the REGIS employment forecast by building type and estimates of projected floor space per employee.

In addition, end-use saturation rate estimates are developed from surveys of the service area's commercial customers by building type. The original survey of this sector was performed by Xenergy, Inc. during 1994 as part of commission-sanctioned research into the cost effectiveness of commercial DSM programs. In the future, Tampa Electric expects to survey its commercial customers regarding their end-use saturations by fuel type, building type, employment, square footage, and vintage age and demolition rate of the equipment stock on a semiannual basis.

From the calculation of energy, commercial demand is determined by allocating annual consumption to the hours of the day through use factors. However, the commercial sector contains both temperature-sensitive and insensitive end-uses. The temperature-sensitive use patterns are a function of temperature and time. Therefore, peak demand is calculated, as in the residential sector, by specifying extreme temperatures to represent severe weather conditions.

The nine end-uses and eleven building types that are included in Tampa Electric's commercial floorspace building type model are listed in Table III-2.

TABLE III-2. Commercial Floorspace Model End-Uses and Building Types

End-Uses:

Air Conditioning	Miscellaneous
Cooking	Refrigeration
Exterior Lighting	Ventilation
Heating	Water Heating
Interior Lighting	

Building Types:

Colleges	Offices
Groceries	Retail
Health Care	Restaurants
Hospitals	Schools
Lodging	Warehouses
Miscellaneous	

The industrial and miscellaneous sectors of the model are less detailed than the residential and commercial customer classes due to a lack of connected load data. The industrial class is disaggregated into four major groups representing different levels of energy intensiveness. These include Food Products (SIC 20); Tobacco, Printing, etc. (SIC 21, 23, 24, 25, 27, 37, 39); Fabricated Metals, etc. (SIC 26, 29, 30, 34, 35, 36, 38); and Basic Industries (SIC 32, 33). In each sector, annual energy consumption is computed by multiplying energy use per employee times projected employment. Monthly energy consumption is calculated by allocating the annual energy to the corresponding month using historic ratios of monthly-to-annual consumption. Once monthly energy is computed, it is further broken down by hour for each of the four day types. That is, a use factor is applied which denotes the fraction of each month's energy that is consumed in a given hour. These use factors were developed from hourly billing data available for major industrial customers in each of the four categories.

The miscellaneous sector includes street lighting, sales to public authorities, and transmission and distribution line losses. For street lighting and public authorities, sales are expressed as a function of the number of residential customers, and demand is calculated using an allocation method similar to the industrial and commercial sectors.

The model also allows for price elasticity adjustments which represent the change in electric consumption resulting from changes in the relative price of electricity. In order to capture the price effect, an adjustment factor is applied to the annual consumption. The adjustment factor for a given year is a time-dependent weighted average of short and long-run elasticity. The general mathematical form of the consumption adjustment equation is as follows:

$$C_n = C_0 * \text{(Price Elasticity Adjustment Factor)}$$

where:

C_n = Consumption at the price level in year n, adjusted for price changes in years 0 to n.

C_0 = Consumption at the base year price level, that is, assuming no price changes.

The Adjustment Factor is given by the following:

Price Elasticity Adjustment Factor

$$\left(\frac{P_1}{P_0}\right)^{E_n} \cdots \left(\frac{P_i}{P_{i-1}}\right)^{E_{n-i+1}} \cdots \left(\frac{P_n}{P_{n-1}}\right)^{E_1}$$

where:

P_i = Price of electricity in period i (i = 1 to n).

E_i = Price elasticity coefficient expressed as a time-dependent weighted average of the short and long-run elasticity coefficients (i = 1 to n)

This relationship can be expressed as follows:

$$E_i = E_S + W_i(E_L - E_S)$$

where:

E_S = Short-run elasticity

E_L = Long-run elasticity

W_i = Weighting factor, $0 \leq W_i \leq 1$; $W_1 = 0$, $W = 1$ for $i \geq 12$.

The above relationship warrants two important observations. First, the price elasticity adjustment factor that is applied to a given year incorporates the effects of price changes not only for the given year but also for previous years. Second, the elasticity coefficient that is applied to a given year's price change increases numerically over time, gradually rising from the short-term elasticity value to the long-term. Therefore, each price increase or decrease has a lasting effect on future consumption patterns.

In the residential sector, each of the specific appliances was assigned a short-run and long-run elasticity. This was accomplished by partitioning the major appliances into three groups whose change in consumption due to price changes was considered to be either low, medium, or high (Table III-3). In certain cases, these elasticities were assigned subjectively while in other cases they were based upon studies by National Economic Research Associates (NERA) and the Electric Power Research Institute (EPRI). In addition, the resulting coefficients have the mathematical property that their combined effect, which represents the average residential elasticity coefficient, closely approximates the results of NERA and EPRI research. Therefore, their cumulative effect is in accord with extensive statistical analysis. The elasticity factors used for the commercial and industrial categories were also developed from these studies.

TABLE III-3. Sensitivity of Consumption to Price

<u>Appliances with Low Assumed Price Sensitivity:</u>

Refrigerator	Frost Free Standard
Freezer	Frost Free Standard
TV	Color Black and White

<u>Appliances with Medium Assumed Price Sensitivity:</u>

Electric Range
Clothes Washer
Electric Water Heater
Microwave Oven
Lighting

<u>Appliances with High Assumed Price Sensitivity:</u>

Dishwasher
Electric Dryer
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Based on studies by National Economic Research Associates and the Electric Power Research Institute.

Another factor influencing residential energy consumption is the movement toward more energy-efficient appliances. The forces behind this development include market pressures for more energy-efficient technologies and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

It should be noted that the base year appliance energy consumption is influenced by both price effects and efficiency improvements. Thus, while some appliances are assumed to be rather price insensitive, their individual consumption levels decrease due to efficiency improvements.

2. Multiregression Demand and Energy Model

The retail multiregression forecasting model is a nine-equation model with two major sections. The energy section forecasts energy sales by the six major customer categories. The demand section forecasts peak load other than phosphate for both summer and winter. The regression technique is a more sophisticated approach than trend analysis as it attempts to examine those factors which influence load.

The selection of appropriate variables to include in the multiregression model equations is an extensive process that begins with the identification of variables that affect demand and energy. Those variables which can not be reasonably quantified or forecast are dismissed from the process. Results from regressions using the remaining variables are evaluated to determine which variables perform best. As a result, the chosen equations are both statistically and theoretically appropriate.

The basic series that make up the regression method are supplied by Tampa Electric Company, the U.S. Bureau of Labor Statistics, the U.S. Bureau of Economic Analysis, the U.S. Geological Survey, the Federal Reserve Board, the National Oceanic and Atmospheric Administration, and the University of Florida's Bureau of Economic and Business Research. All projections of the independent variables in these equations are consistent with those used in the end-use model.

Demand Section

The demand section consists of three regression equations for load other than phosphate. One equation is for the base load which, by definition, is that load on the system that is independent of temperature. The remaining two equations describe the summer peak temperature-sensitive demand and the winter peak temperature-sensitive demand. From regression analysis, the following relationships have been determined.

1.

Base Load = 70.159 + 4.3389 * # Residential Customers - 3707.9 * ¢/kWh (lagged 1 year)

(t = 35.8) (t = -3.7)

$\bar{R}$-Squared = .97 DW = 1.9

2.

Temperature Sensitive Demand (Summer) = (F° - 65) (20.718 + 0.1106 * # A/Cs - 244.53 * ¢/kWh (lagged 2 periods))

(t = 25.5) (t = -4.9)

$\bar{R}$-Squared = .91 DW = 1.9

3.

Temperature Sensitive Demand (Winter) = (65 - F°) (-0.9842 + 0.13284 * # Electric Heaters)

(t = 24.2)

$\bar{R}$-Squared = .89 DW = 1.4

The Variables are defined as follows:

Base Load	The temperature-insensitive component of demand (MW).
Temperature-Sensitive Demand	The load component (MW) which is affected by heating or air conditioning on the system.
# Residential Customers	The average number of residential customers (in thousands).
¢/kWh	Tampa Electric Company's average cost of electricity per kWh adjusted for inflation.
F° (Summer)	Average 24-hour temperature for the day of the system peak load.
F° (Winter)	Peak hour temperature at the time of the system peak load.
# A/Cs	Number of residential air conditioners (in thousands) calculated by multiplying residential customers by cooling saturation levels.
# Electric Heaters	Number of residential electric heaters (in thousands) calculated by multiplying residential customers by electric heating saturation levels.

Energy Section

The energy section of the retail multiregression model consists of six equations that estimate future energy by the major customer classes (residential, commercial, industrial other than phosphate, phosphate, sales to public authorities, and street and highway lighting.) These equations are listed below.

1.

Average Residential Usage = 6045.7 + 51.226 * Chg in Personal Inc. Per Capita (lagged 1 year) (t = 2.3) - 563.6 * ¢/kWh (lagged 1 year) (t = -8.9)
+ 1.06167 * Total Degree Days (t = 4.5) + 8362.9 * Htg/Cooling Saturation (t = 19.1)

$\bar{R}$-Squared = .94 DW = 1.7

2.

Commercial Energy Sales = -75.95 + 13.813 * Residential Customers (t = 23.2) - 583.0 * ¢/kWh (lagged 1 year) (t = -4.1)

$\bar{R}$-Squared = .99 DW = .94

3.

Other Industrial Energy Sales = 334.44 + 5.933 * Ind Prod Index (t = 7.7) - 88.7825 *Chg. in ¢/kWh (lagged 1 year) (t = -1.7)
- 138.1 * Trade Dummy Variable (t = -6.2)

$\bar{R}$-Squared = .70 DW = 1.7

4.

Phosphate Energy Sales = 1135.2 + 51.242 * U.S. Phosphate Mining (t = 10.3) - 331.39 * ¢/kWh (lagged 1 year) (t = -3.3)

$\bar{R}$-Squared = .84 DW = 1.0

5.

Sales to Public Authorities $= 530.50 + 2.4514 * \text{Residential Customers} - 251.11 * \text{Chg in ¢/kWh}$

(t = 10.9) (t = -4.4)

$\bar{R}$-Squared = .98 DW = 1.1

6.

Street Lighting $= - 29.073 + 0.10370 * \text{Population}$

(t = 34.8)

$\bar{R}$-Squared = .98 DW = .70

The Variables are defined as follows:

Population	Hillsborough County Population (in thousands).
Residential Customers	Service Area Residential Customers (in thousands).
Chg in Personal Inc. Per Capita	Percent change in real personal income per capita in Hillsborough County.
Htg/Cooling Saturation	Weighted average of heating and cooling saturation rates.
Total Degree Days	Sum of heating and cooling degree days (billing cycle adjusted).
Ind Prod Index	Industrial Production Index (1992 = 100).
U.S. Phosphate Mining	U.S. mining production (in millions of metric tons).
¢/kWh	Cost per kWh for a given customer class adjusted for inflation.
Chg in ¢/kWh	Percent change in cost per kWh for a given customer class adjusted for inflation.
Trade Dummy Variable	Dummy variable representing import substitution of local basic industries production.

3. Trend Analysis

The role of trend analysis in the Tampa Electric Company forecasting process has changed as the stability of fuel prices and supplies has decreased. The present economic and political environment throughout the world has contributed to changing energy consumption patterns resulting in a need for more sophisticated forecasting techniques. Trending provides a useful check for the more intricate methods used by the company in developing the Customer, Demand, and Energy Forecast.

The primary strength of trend analysis is simplicity. When applied to series with stable growth patterns, this method is easy to use and is readily understood by those outside the forecasting process. The need for historical data is minimal, compared to other methods, and the need for external forecasts is alleviated as time is the only predictive variable. However, weaknesses are also a function of this simplicity. The use of time as the only explanatory variable limits the ability of the process to reflect changing economic conditions. Given the limitations of this technique, it can still be used to identify time trends, and it provides a familiarity with the data that aids in evaluating forecasts from other methods.

Trend analysis is applied to several variables including:

1. population;
2. residential customers;
3. system peak demand;
4. residential energy sales;
5. commercial energy sales;
6. industrial energy sales;
7. street lighting energy sales;
8. sales to public authorities; and
9. average usage per customer.

The implementation of trend analysis involves establishing a mathematical relationship between the independent variable (time) and the dependent variable. A forecast can be constructed by entering a future year into the equation. Evaluating the data over different time periods allows one to identify changes in the trend over time. Once trend estimates for the various components are established, they can be combined to yield a total sales forecast.

4. Phosphate Demand and Energy Analysis

Because Tampa Electric Company's phosphate customers are relatively few in number, the Bulk Power & Market Development and Cogeneration Services Departments have obtained detailed knowledge of industry developments including:

1. knowledge of expansion and close-out plans;
2. familiarity with historical and projected trends;
3. personal contact with industry personnel;
4. governmental legislation;
5. familiarity with worldwide demand for phosphate products;
6. knowledge of phosphate ore reserves; and
7. correlation between phosphate rock production and energy consumption.

These departments' familiarity with industry dynamics and their close working relationship with phosphate company representatives forms the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based. Further inputs are provided by the multiregression model's phosphate energy equation and discussions with industry experts.

5. Conservation, Load Management and Cogeneration Programs

Tampa Electric has developed conservation, load management, and cogeneration programs to achieve four major objectives:

1. to defer capital expansion, particularly production plant construction;
2. to reduce marginal fuel cost by managing energy usage during higher fuel cost periods;
3. to give customers some ability to control their energy usage and decrease their energy costs, and
4. to pursue the cost-effective accomplishment of ten-year demand and energy goals established by the Florida Public Service Commission (FPSC) for the residential and commercial/industrial sectors.

The company's current DSM plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. Additionally, we have developed residential and commercial mail-in audits designed to more economically target customers who have the potential to benefit significantly from our energy management programs. The following is a list that briefly describes the company's programs:

1. Heating and Cooling - Encourages the installation of high-efficiency heating and cooling equipment.

2. Load Management - Reduces weather-sensitive heating, cooling, water heating, and pool pump loads through a radio signal control mechanism. In addition, a commercial/industrial program is in effect.

3. Energy Audits - The program is a "how to" information and analysis guide for customers. Six types of audits will be available in 1998 to Tampa Electric customers; three types are for residential class customers and three types for commercial/industrial customers.

4. Ceiling Insulation - An incentive program for existing residential structures which will help to supplement the cost of adding additional insulation.

5. Commercial Indoor Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.

6. Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

7. Conservation Value - Encourages investments in measures that are not sanctioned by other programs.

8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky heating and cooling air ducts.

9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, produce their own electrical requirements and/or sell their surplus to the company.

In addition, the Energy Answer Home and Street and Outdoor Lighting programs were completed in 1987 and 1990, respectively.

The 1997 demand and energy savings achieved by our conservation and load management programs are listed in Table III-4.

TABLE III-4

Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Residential

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Goal	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Goal	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Goal
1995	24.0	36.0	66.7%	2.7	12.0	22.5%	12.2	21.0	58.1%
1996	56.7	72.0	78.8%	10.6	23.0	46.1%	28.3	41.0	69.0%
1997	79.2	107.0	74.0%	16.9	35.0	48.3%	43.6	60.0	72.7%

Commercial/Industrial

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Goal	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Goal	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Goal
1995	5.1	2.0	255.0%	5.0	7.0	71.4%	11.7	29.0	40.3%
1996	13.1	5.0	262.0%	15.2	13.0	116.9%	27.4	59.0	46.4%
1997	14.4	7.0	205.7%	18.6	20.0	93.0%	42.0	90.0	46.7%

Combined Total

Year	Winter Peak MW Reduction Total Achieved	Winter Peak MW Reduction Commission Approved Goal	Winter Peak MW Reduction % Goal	Summer Peak MW Reduction Total Achieved	Summer Peak MW Reduction Commission Approved Goal	Summer Peak MW Reduction % Goal	GWh Energy Reduction Total Achieved	GWh Energy Reduction Commission Approved Goal	GWh Energy Reduction % Goal
1995	29.1	38.0	76.6%	7.7	19.0	40.5%	23.9	50.0	47.8%
1996	69.8	77.0	90.6%	25.8	36.0	71.7%	55.7	100.0	55.7%
1997	93.6	114.0	82.1%	35.5	55.0	64.5%	85.6	150.0	57.1%

To support the demand and energy savings filed as part of its plan, Tampa Electric Company developed its Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources. Generally speaking, the M&E plan has as its focus two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric Company insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

Wholesale Load

Tampa Electric's wholesale sales consist of sales contracts with the City of Wauchula, the City of Fort Meade, Florida Power Corp., the City of St. Cloud, and the Reedy Creek Improvement District.

Since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of their local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. Under this methodology, three equations have been developed for each municipality for forecasting energy and peak demand. These equations are shown on the following two pages.

WAUCHULA MULTIREGRESSION EQUATIONS

1.

Average Customer Usage = 2923.9 - 120.2 * Change in ¢/kWh + 0.0687 * Per Capita Income
(t = -1.5) (t = 3.9)
+ 1.770 * Cooling Degree Days + 2.58 * Heating Degree Days
(t = 21.1) (t = 7.4)

$\bar{R}$-Squared = .96 DW = 1.9

2.

Winter Peak Demand = - 11.972 + 0.00839 * Total Customers + 0.176 * Heating Degree Days
(t = 14.0) (t = 8.5)

$\bar{R}$-Squared = .90 DW = 1.9

3.

Summer Peak Demand = - 6.339 + 0.00605 * Total Customers + 0.177 * Cooling Degree Days
(t = 12.0) (t = 3.9)
- 0.260 * Change in ¢/kWh (lagged one month)
(t = -1.5)

$\bar{R}$-Squared = .85 DW = 1.3

The Variables are defined as follows:

Change in ¢/kWh	Change in average cost per kWh adjusted for inflation.
Per Capita Income	Real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

FORT MEADE MULTIREGRESSION EQUATIONS

1.

Average Customer Usage $= 914.20 - 63.42 * ¢/kWh + 0.115 * \text{Change in Per Capita Income}$
(t = -2.0) (t = 2.2)
$+ 1.122 * \text{Cooling Degree Days} + 1.480 * \text{Heating Degree Days}$
(t = 11.8) (t = 4.1)

$\bar{R}$-Squared = .87 DW = 1.9

2.

Winter Peak Demand $= - 11.025 + 0.00713 * \text{Total Customers} + 0.1181 * \text{Heating Degree Days}$
(t = 5.4) (t = 4.7)

$\bar{R}$-Squared = .78 DW = 1.5

3.

Summer Peak Demand $= - 2.970 + 0.00460 * \text{Total Customers} + 0.1190 * \text{Cooling Degree Days}$
(t = 5.0) (t = 2.6)
$- 0.2733 * ¢/kWh$
(t = -2.3)

$\bar{R}$-Squared = .86 DW = 1.5

The Variables are defined as follows:

¢/kWh	Average cost per kWh adjusted for inflation.
Change in Per Capita Income	Change in real per capita income (seasonally adjusted).
Total Customers	The average number of total customers.
Heating Degree Days	65 degrees less the average 24-hour temperature.
Cooling Degree Days	Average 24-hour temperature less 65 degrees.

For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric.

Base Case Forecast Assumptions

Retail Load

1. Detailed End-Use Model

Numerous assumptions are inputs to the detailed end-use model of which the more significant ones are listed below.

1. Population and Residential Customers;
2. Commercial and Industrial Employment;
3. Per Capita Income;
4. Housing Mix;
5. Appliance Saturations;
6. Price Elasticity;
7. Price of Electricity;
8. Appliance Efficiency Standards; and
9. Weather.

Population/Residential Customers

The residential customer forecast is the starting point from which the demand and energy projections are developed. The most important factor in the customer forecast is the service area population estimate. The population estimate is based on Hillsborough County projections supplied by the University of Florida's Bureau of Economic and Business Research (BEBR), which are in the form of high, medium, and low forecasts. The REGIS model is utilized to determine where within the given range population growth is likely to be. For the 1997-2007 period, Hillsborough County population is expected to increase at a 1.5% average annual rate. This rate is slightly above the BEBR's medium forecast of 1.4% per year over this same period.

Household formation trends supplied by the U.S. Bureau of the Census are applied to the Hillsborough population projections to arrive at Hillsborough County households. Finally, service area household forecasts are determined by adjusting the Hillsborough County figures to reflect the relationship between service area and Hillsborough County residential customers. Since 1970, households in the service area have expanded at a faster rate than population due to a decline in household size. This decline in persons per household has been the result of lower birth rates, higher divorce rates, the postponement of marriage by young adults, and an aging overall population. During the next ten years (1998-2007), persons per household are expected to fall at an annual rate of 0.4 percent. Therefore, the household growth rate is expected to continue to exceed the population expansion rate in the service area over the next ten years.

Commercial and Industrial Employment

Commercial and industrial employment assumptions are utilized in computing energy and demand in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. REGIS, which interrelates these important variables, ensures this consistency. In addition, forecasts from outside consulting firms also provide input into formulating these assumptions. For the 1997-2007 period, commercial employment is assumed to rise at a 1.9% average annual rate while industrial employment growth of 1.6% per year is expected.

Per Capita Income, Housing Mix, Appliance Saturations

The stock of appliances, which comprises the nucleus of SHAPES' residential sector, is determined by multiplying the numb-r of households by the saturation rate for each appliance. The assumptions for real per capita income growth and housing mix are critical in computing these saturations since many of the appliances are influenced by income levels and the type of housing (single, multi-family, mobile home) in the service area. The housing mix and per capita income growth rates for the local area are based on forecasts from REGIS as well as from outside consulting services. For the 1997-2007 period, real per capita income is expected to increase at a 1.5% average annual rate.

Price Elasticity/Price of Electricity

Price elasticity measures the rate of change in the demand for a product, electricity in this case, that results from a change in its relative price. The expected elasticity effect can be quantified by multiplying this factor by the assumed change in the real price of electricity (See Page III-8). During the 1970s, price elasticity played a major role in slowing demand and energy growth due to the sharp increase in the price of electricity resulting from an explosion in fuel costs. Since 1981, an easing in fuel price pressures has been an important factor in keeping electricity cost changes below the general pace of inflation. Over the next decade, this pattern is expected to continue as the price of electricity should increase at a rate slower than other products and services.

Appliance Efficiency Standards

Another factor influencing residential energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

Weather

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on ten years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past forty years plus the temperatures on peak days for the past fifteen to twenty years.

2. Multiregression Demand and Energy Model

The multiregression model utilizes assumptions which are common to SHAPES. These assumptions include future inputs for population, residential customers, income, saturation levels for air conditioners/heaters, and the price of electricity. In all cases where the multiregression and SHAPES models use common input variables, the assumptions for these inputs are the same and result in forecasts which are consistent and comparable.

Wholesale Load

Wauchula and Ft. Meade projections are developed from regression equations which, in turn, are driven by forecasts of customers, real per capita income, and the real price of electricity. For the 1998-2007 period, total customers are projected to expand at a 1.6% and 1.2% annual rate, respectively. Also, real per capita income for both cities is projected to grow annually at a pace of 1.5% and 1.4%, respectively.

High and Low Scenario Forecast Assumptions

Retail Load

The high and low peak demand and energy projections represent alternatives to the company's base case outlook. The high band represents a more optimistic economic scenario than the base case (most likely scenario) with greater expected growth in the areas of customers, employment, and income. The low band represents a less optimistic scenario than the base case with a slower pace of service area growth.

The assumptions related to the high, low, and base peak demand and energy cases are presented in Table III-5. For all other assumptions, including weather and price elasticity, the assumptions remain the same as in the base case scenario

Wholesale Load

Likewise, high and low forecast scenarios are developed for wholesale customers Wauchula and Fort Meade. For these two municipalities, the assumptions that varied under the alternative scenarios include total customers, real price of electricity, and real per capita income. The bandwidth for the high/low forecasts assumptions are 0.4%, 0.5%, and 0.5%, respectively.

History and Forecast of Energy Use

A history and forecast of energy consumption by customer classification are shown in Table II-1 (Schedules 2.1 - 2.3) and Figure III-2.

Retail Energy

For 1997-2007, retail energy sales are projected to rise at a 2.5% annual rate. The major contributors to growth will continue to be the commercial, governmental, and residential categories. As a group, these three sectors will be increasing at a 3.0% annual rate.

In contrast, industrial sales are expected to decline over this period. Non-phosphate industrial consumption should register an annual gain over the coming years. However, this will be more than offset by a drop in phosphate sales due to an increase in self-service cogeneration and the southward migration of mining activity. This pattern reflects the changing American economy where the service sector is expanding at a rapid pace relative to manufacturing activity.

The combination of service area income growth and a declining real price of electricity has resulted in rising average residential usage in recent years. Over the 1998-2007 period, usage is anticipated to maintain this upward path based on expectations of continuing economic gains and a downward drift in the real price of electricity.

TABLE III-5. Economic Outlook Assumptions (1997-2007) For Retail Load Forecast

	Average Annual Growth Rate		
	BASE CASE	LOW GROWTH SCENARIO	HIGH GROWTH SCENARIO
Residential Customers	1.7%	1.3%	2.1%
Employment	1.5%	1.1%	1.9%
Real Per Capita Income	1.5%	1.0%	2.0%
Real Price of Electricity	-1.6%	-1.1%	-2.1%

Source: Tampa Electric Company

Wholesale Energy

Wholesale energy sales to FMPA, FPC, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 1,141 GWh are expected in 1998, 389 GWh in 1999, and 331 GWh in 2000. Sales are expected to remain in the 320-380 GWh range for 2001-2007.

History and Forecast of Peak Loads

Historical and base, high, and low scenario forecasts of peak loads for the summer and winter seasons are presented in Tables II-2 and II-3 (Schedules 3.1 and 3.2), respectively. For the 1998-2007 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 1.5% and 2.4%, respectively. In addition, base, high, and low scenario forecasts of NEL are listed in Table II-4 (Schedule 3.3).

Monthly Forecast of Peak Loads for Years 1 and 2

A monthly forecast of retail peak loads (MW) and net energy for load (GWh) for years 1 and 2 of the forecast is provided in Table II-5 (Schedule 4).

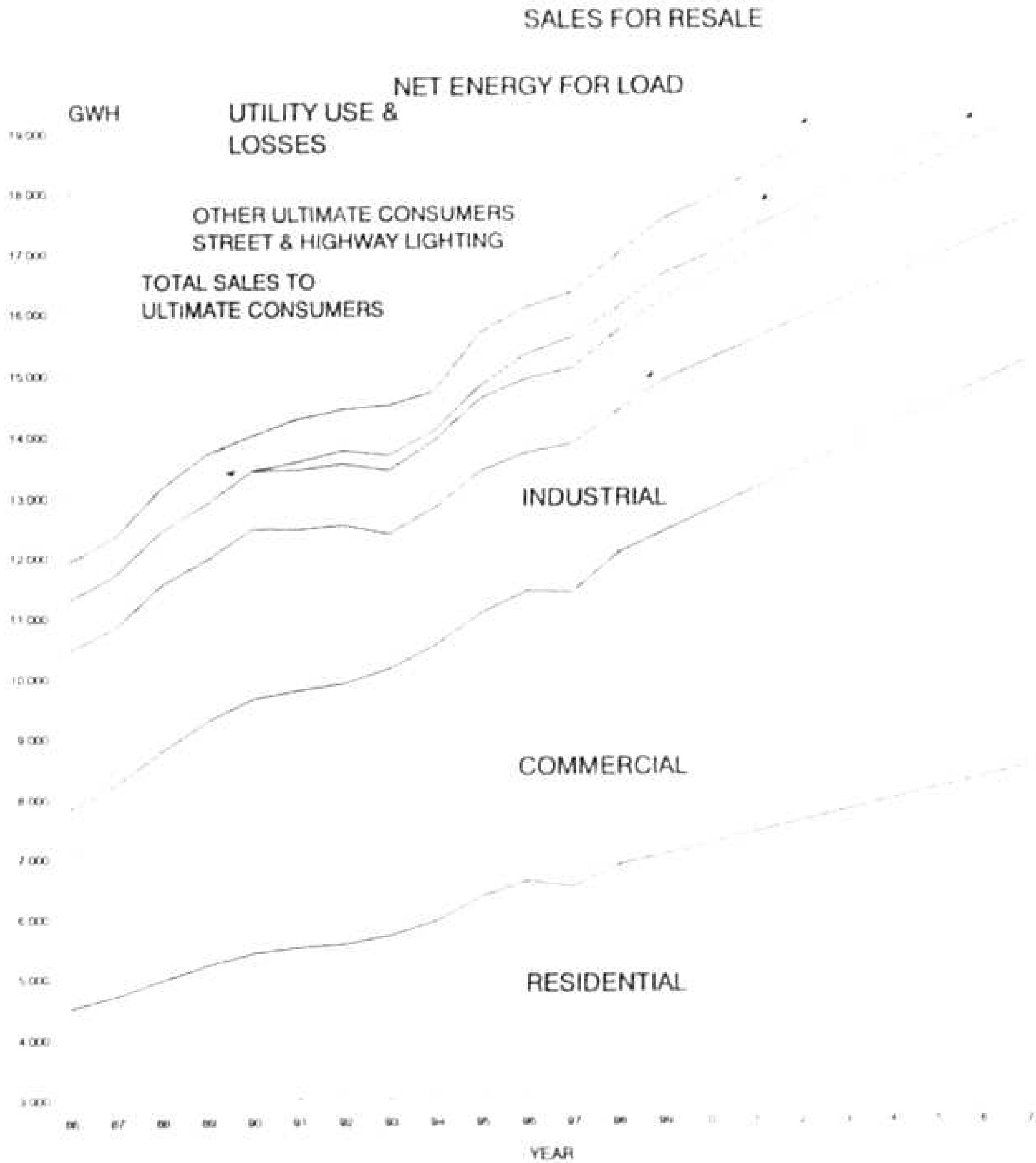


Figure III-2

HISTORY AND FORECAST OF ENERGY USE

SOURCE: TAMPA ELECTRIC COMPANY

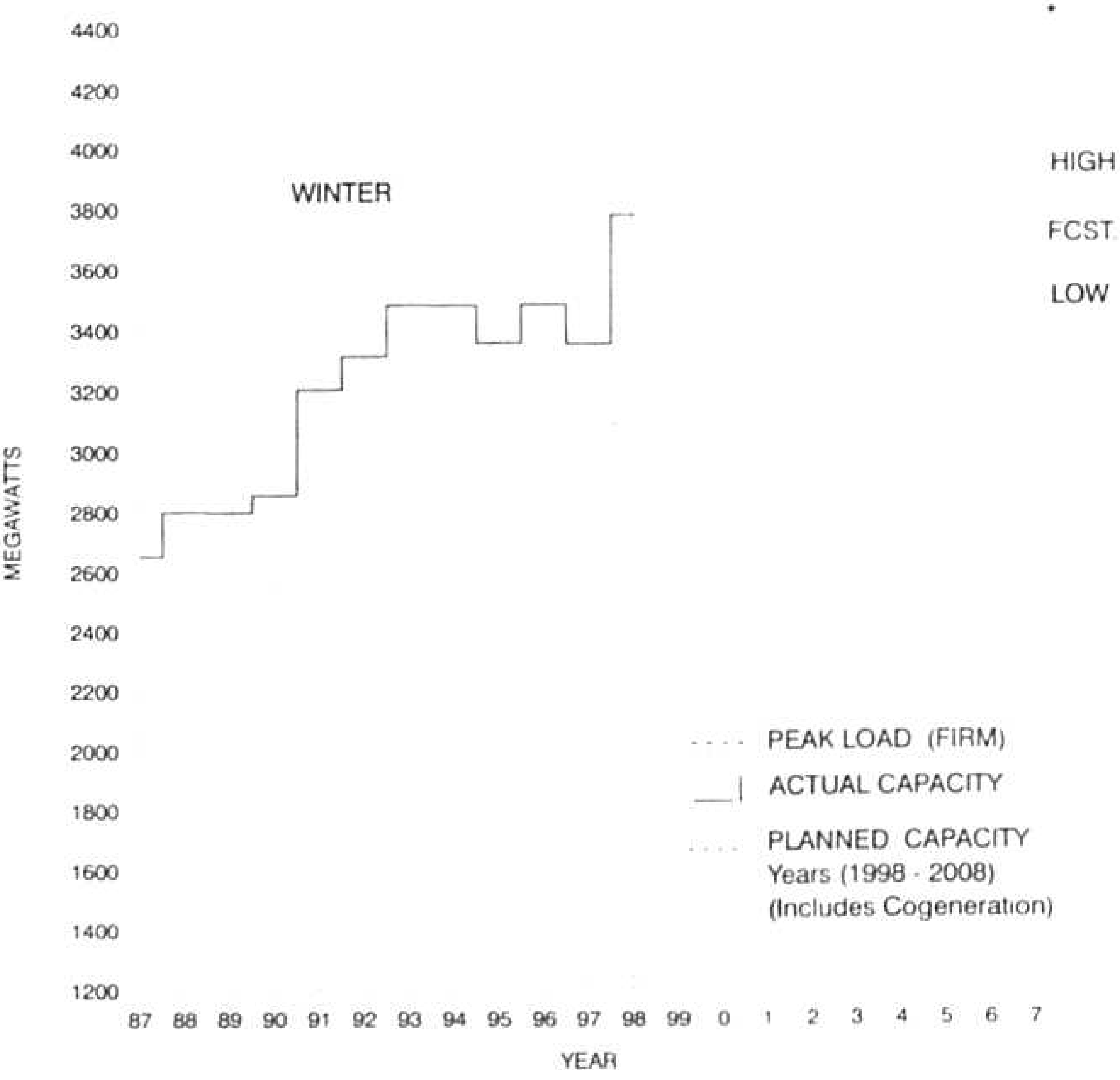
TAMPA ELECTRIC COMPANY

Ten-Year Site Plan

For Electrical Generating Facilities

And Associated Transmission Lines

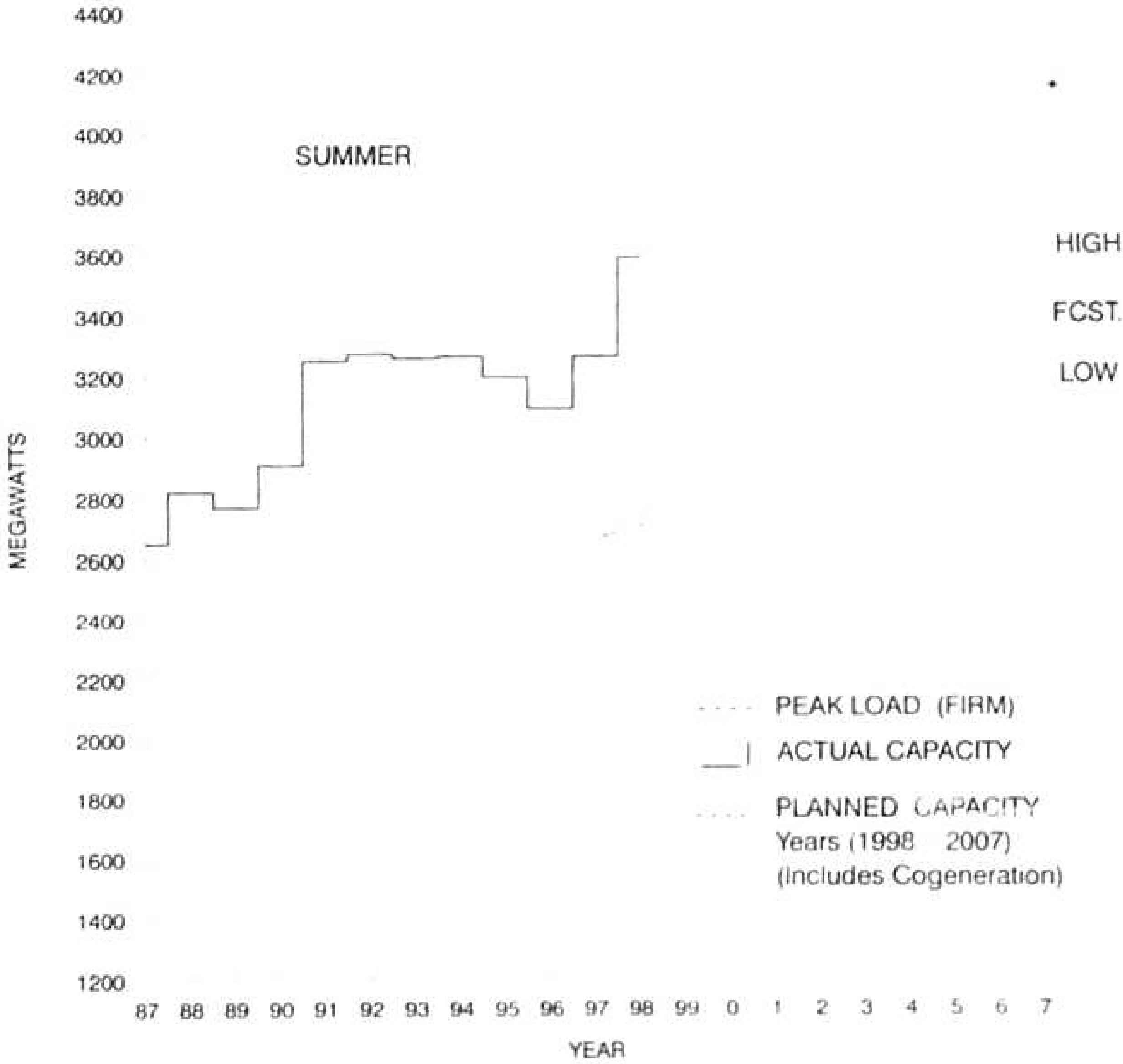
FIGURE III-3 HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
Page 1 of 2



* AGREES WITH SCHEDULE 7.2 , COL. 6

Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

FIGURE III-3 HISTORY & FORECAST OF LOAD AND CAPACITY ADDITIONS
Page 2 of 2



* AGREES WITH SCHEDULE 7.1, COL. 6

Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

CHAPTER IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Table IV-3 integrate demand side management programs and alternative generation technologies with traditional generating resources to provide economical, reliable service to Tampa Electric Company's customers. To achieve this objective, various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective demand side management programs are developed. These alternatives are analyzed with existing generating capabilities to develop a number of energy resource options which meet Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric Company's integrated resource planning process is included in Chapter V.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining system reliability and balancing other engineering, business, and industry issues. The new capacity additions are shown in Table IV-3. Additional capacity is first needed in 2003, based on an analysis of system reliability, the incorporation of the FPSC demand side management goals, projected system demand and energy requirements, purchase power, and the existing Tampa Electric generating system. To meet the expected system demand and energy requirements over the next ten years, combustion turbines are planned for service in 2003, 2004, and 2006. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. For purposes of this study, Hookers Point Station is assumed to be retired in January 2003, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period. Some of the assumptions and information that impact the plan are discussed below. Additional assumptions and information are discussed in Chapter V.

Cogeneration

Tampa Electric Company plans for 444 MW of cogeneration capacity operating in its service area in 1998. Self-service capacity of 236 MW (net) is used by cogenerators to serve internal load requirements, 62 MW are purchased by Tampa Electric on a firm contract basis, and 6 MW are purchased on a non-firm as-available basis. By 2007, the cogeneration capacity within our service area is expected to increase to 472 MW. This total will consist of 253 MW of self-service capacity, 62 MW of firm capacity purchases by Tampa Electric, and 7 MW of non-firm as-available purchases by Tampa Electric. During 1998, Tampa Electric has entered into transmission wheeling agreements with four of its cogeneration customers, supplying a total of 154 MW of firm contract capacity to two other utilities in the state. By 2007, this total is expected to decrease to 145 MW.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Tables II-6 and II-7, respectively. As shown in these tables, Tampa Electric Company plans to continue to use coal as the primary fuel for most of its generating requirements. Alternative fuels were considered and have been incorporated when appropriate to achieve a low cost fuel strategy which benefits Tampa Electric's customers while meeting environmental emissions requirements. The Polk Unit 1 IGCC unit utilizes syngas as the primary fuel with No. 2 oil as the back-up. The syngas will be produced from five demonstration fuels during the first three years of commercial operation to satisfy their demonstration requirements. The demonstration fuels include coal and a coal/petroleum coke blend. Following the demonstration period, Tampa Electric Company plans to utilize a coal/petroleum coke blend to produce syngas. This blend will result in the IGCC unit being the lowest incremental cost resource on Tampa Electric Company's system. Coal, including coal/petroleum coke blends, will provide approximately 94%-98% of the fuel requirements for Tampa Electric's total generation and 88%-93% of total system requirements. This fuel strategy, which makes use of this nation's most abundant domestic fuel, is both practical and cost-effective and minimizes exposure to a disruption in fuel supply or market price volatility.

Clean Air Act Amendments of 1990

The primary focus of Title IV of the Clean Air Act Amendments is a nationwide reduction of sulfur dioxide and nitrogen oxide emissions from existing electric utilities and non-utility sources. The potential impact of other amendments in the Act on the generating system has not been included in this Ten-Year Site Plan. Tampa Electric Company has three generating units, Big Bend Units 1-3, which are Phase I (1995-1999) affected units under Title IV of the Clean Air Act Amendments of 1990. Big Bend Unit 4 was identified as a substitution unit under Title IV of the Clean Air Act Amendments and brought under Phase I compliance requirements. The designation of Big Bend Unit 4 as a Phase I Unit provided an integrated approach for achieving SO_2 compliance for Big Bend Station. Tampa Electric Company currently maintains compliance with the Phase I emission limitations by using blends of low sulfur coal, a small quantity of purchased sulfur dioxide allowances, and integration of Big Bend Unit 3 flue gas with the Big Bend Unit 4 flue gas desulfurization system (FGD). In Phase II (2000-beyond), all of Tampa Electric's units are affected under Title IV except existing combustion turbines, Phillips Station, and Dinner Lake. To cost-effectively comply with Phase II emission standards, Tampa Electric will continue to evaluate the use of low sulfur coal blends, sulfur dioxide allowances, and flue gas scrubbing

Interchange Sales and Purchases

Tampa Electric interchanges sales include Schedule D and Partial Requirements (PR) service agreements with several utilities and a Schedule G contract with Seminole Electric Cooperative, Inc. (SEC) for non-firm capacity and energy.

Tampa Electric has a long term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with SEC, whereby Tampa Electric plans for the full net capability of the Hardee Power Station during those times when SEC plans for the full availability of Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance. A firm capacity sale from Tampa Electric's Big Bend Station Unit No. 4 is made available, on a limited energy usage basis, to Hardee Power Partners Limited for resale to SEC.

In addition to the above sales and purchases, Tampa Electric also has Schedule J service agreements for the interchanges/sale of as-available power with/to thirteen utilities in Florida and Georgia.

Wholesale power sales and purchases are included in Tables II-2, II-3, II-4, II-5, II-6, II-7, IV-1, and IV-2.

Schedule 7.1

Table IV-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
1998	3,493 *	297	(262)	62	3,590	2,833	757	27%	123	634	22%
1999	3,493	297	(176)	62	3,676	2,890	786	27%	15	771	27%
2000	3,493	297	(147)	62	3,705	2,963	742	25%	169	573	19%
2001	3,493	297	(147)	62	3,705	3,057	648	21%	0	648	21%
2002	3,493	297	(147)	62	3,705	3,140	565	18%	15	550	18%
2003	3,434	297	)	62	3,793	3,239	554	17%	0	554	17%
2004	3,582	297	0	62	3,941	3,321	620	19%	108	512	15%
2005	3,582	297	0	62	3,941	3,388	553	16%	0	553	16%
2006	3,730	297	0	62	4,089	3,468	621	18%	0	621	18%
2007	3,730	297	0	62	4,089	3,518	571	16%	0	571	16%

December 31, 1997 Status

NOTE 1 Capacity import includes the Purchase Agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative.

2 Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes a firm D transaction to New Smyrna Beach of 18 MW in 1998 and 19 MW in 1999 as well as a Schedule J transaction with New Smyrna Beach of 10 MW in 1998 and 1999 which is treated as firm for expansion planning purposes. Capacities shown in table include losses.

3 Capacity export includes a firm D transaction to Florida Municipal Power Agency of 85 MW for the summer of 1998. For periods beyond calendar year 1998, Tampa Electric plans to fulfill the FMPA capacity obligation via firm power purchases.

4 The QF column accounts for cogeneration that will be purchased under firm contracts.

* Does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.

** Values may be affected by rounding.

Schedule 7.2

Table IV-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
1997-98	3,615 *	360	(261)	62	3,776	3,049	727	24%	34	693	23%
1998-99	3,615	360	(160)	62	3,877	3,118	759	24%	34	725	23%
1999-00	3,615	360	(161)	62	3,876	3,195	681	21%	34	647	20%
2000-01	3,615	360	(147)	62	3,890	3,277	613	19%	34	579	18%
2001-02	3,615	360	(147)	62	3,890	3,343	547	16%	34	513	15%
2002-03	3,580	360	0	62	4,002	3,433	569	17%	0	569	17%
2003-04	3,760	360	0	62	4,182	3,509	673	19%	0	673	19%
2004-05	3,760	360	0	62	4,182	3,578	604	17%	0	604	17%
2005-06	3,940	360	0	62	4,362	3,655	707	19%	0	707	19%
2006-07	3,940	360	0	62	4,362	3,724	638	17%	0	638	17%

December 31, 1997 Status

NOTE 1 Capacity import includes the Purchase Agreement with TECO Power Services (TPS) beginning in 1993. Availability of this capacity is subject to back-up requirements for Seminole Electric Cooperative.

2 Capacity export includes 145 MW of Big Bend 4 which will be sold to TECO Power Services, on a limited basis, for use by Seminole Electric Cooperative. Capacity export also includes a firm D transaction to Reedy Creek Improvement District of 27 MW in 1998, 13 MW in 1999, and 14 MW in 2000.
Capacities shown in table include losses.

3 Capacity export includes a firm D transaction to Florida Municipal Power Agency of 85 MW for the summer of 1998. For periods beyond calendar year 1998, Tampa Electric plans to fulfill the FMPA capacity obligation via firm power purchases.

4 The QF column accounts for cogeneration that will be purchased under firm contracts.

* Does not include 11 MW from Dinner Lake unit which was placed on long-term reserve standby 03/01/94, nor 3 MW from Phillips HRSG which is on full forced outage with an undetermined return to service date.

** Values may be affected by rounding.

Schedule 8

Table IV-3
Planned and Prospective Generating Facility Additions

Plant Name	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW	Fuel Trans. Primary	Fuel Trans. Alternate	Status
Polk	2	Polk Co	CT	NG	LO	1/01	1/03	unknown	unknown	148	180	PL	TK	P
	3	Polk Co	CT	NG	LO	1/02	1/04	unknown	unknown	148	180	PL	TK	P
	4	Polk Co	CT	NG	LO	1/04	1/06	unknown	unknown	148	180	PL	TK	P

December 31, 1997 Status

SCHEDULE 9

TABLE IV-4
(Page 1 of 3)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 2
(2)	CAPACITY	
	A. SUMMER	148
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JAN 2001
	B. COMMERCIAL IN-SERVICE DATE	JAN 2003
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	20.3
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,241 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	272.32
	DIRECT CONSTRUCTION COST ($/kW)	228.70
	AFUDC AMOUNT ($/kW)	20.66
	ESCALATION ($/kW)	22.96
	FIXED O&M (2003 $/kW-YR)	3.25
	VARIABLE O&M (2003 $/MWh)	1.98
	K-FACTOR [1]	1.617

[1] BASED ON IN-SERVICE YEAR

[2] REPRESENTS TOTAL POLK SITE

SCHEDULE 9

TABLE IV-4
(Page 2 of 3)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 3
(2)	CAPACITY	
	A. SUMMER	148
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2002
	B. COMMERCIAL IN-SERVICE DATE	JAN 2004
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	19.1
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,151 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	279.94
	DIRECT CONSTRUCTION COST ($/kW)	228.70
	AFUDC AMOUNT ($/kW)	21.24
	ESCALATION ($/kW)	30.00
	FIXED O&M (2004 $/kW-YR)	3.35
	VARIABLE O&M (2004 $/MWh)	2.04
	K-FACTOR [1]	1.624

[1] BASED ON IN-SERVICE YEAR

[2] REPRESENTS TOTAL POLK SITE

SCHEDULE 9

TABLE IV-4
(Page 3 of 3)
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 4
(2)	CAPACITY	
	A. SUMMER	148
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2004
	B. COMMERCIAL IN-SERVICE DATE	JAN 2006
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	N/A
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.7
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	95.0
	RESULTING CAPACITY FACTOR (%) [1]	18.5
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	11,095 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	295.83
	DIRECT CONSTRUCTION COST ($/kW)	228.70
	AFUDC AMOUNT ($/kW)	22.44
	ESCALATION ($/kW)	44.69
	FIXED O&M (2006 $/kW-YR)	3.55
	VARIABLE O&M (2006 $/MWh)	2.16
	K-FACTOR [1]	1.639

[1] BASED ON IN-SERVICE YEAR
[2] REPRESENTS TOTAL POLK SITE

Schedule 10

Table IV-5
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(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

Tampa Electric has no plans to construct transmission lines which correspond to proposed generating facilities.

CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Assessments of Tampa Electric transmission system performance are based upon planning studies completed in 1997 in support of Tampa Electric's transmission expansion plan. These studies are performed annually with the results of the study varying due to updates in load projections, planning criteria, and operating flexibility. Based on existing studies and Tampa Electric's current transmission construction program, Tampa Electric anticipates no transmission constraints on our system which violate he submitted performance criteria contained in the Generation and Transmission Reliability Criteria section of this document.

Expansion Plan Economics and Load Sensitivity

The overall economics and cost-effectiveness of the plan were analyzed as stated in Tampa Electric's Integrated Resource Planning process. This process is discussed in detail later in this chapter. Sensitivity analyses using high and low bands of the base case load forecast yielded generation expansion plans that were significantly different from the base case plan of one combustion turbine in each of the years 2003, 2004, and 2006. Optimization based on the low load forecast deferred the 2004 combustion turbine two years and moved the third combustion turbine out of the ten-year planning window. The expansion plan based on the high load forecast begins one year earlier than the base plan and includes two combustion turbines and two combined cycle units.

Fuel Forecast and Sensitivity

Product price for actual and forecast data for the purpose of deriving base, high, and low forecast pricing is done by careful analysis of actual price and current and previous forecasts obtained by various consultants and agencies. These sources include the Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, Coal Markets Weekly, Coal Daily, Energy Ventures Analysis, Inc., and coal, oil, natural gas, and propane pricing publications and periodicals which include Coal Outlook, Inside FERC, Natural Gas Week, Platt's Oilgram, and the Oil and Gas Journal.

The high and low fuel price projections represent alternative forecasts to the company's base case outlook. The high price projection represents the effect of oil and natural gas prices escalating 10% above the base case on a monthly basis to the year 2000.

The low price scenario represents the effect of oil and natural gas prices escalating 10% below the product price of the base case on a monthly basis to the year 2000. Annual high and low case price projections after 2000 are based on the company's internal general approach using information provided by consultants combined with internal fuel markets analysis.

With a large percentage of fuel utilized by the company being coal, only base case forecasts are prepared for coal fuels. Base case analysis and forecasts include a large number of coal sources and diverse qualities. The individual price forecasts contained within the base forecast capture the market pressures and sensitivities that would otherwise be reflected in high and low case scenarios.

Expansion plan fuel sensitivity analyses were performed using high/low gas and oil price forecasts. The base case expansion plan did not change as a result of substitution of the base fuel forecast with the low fuel forecast. The expansion plan based on the high fuel forecast, however, did vary from the base plan in that the last unit selected was a combined cycle unit instead of a combustion turbine.

Expansion Plan Sensitivity Constant Fuel Differential

Even though Tampa Elec: .: does not recognize, as a viable forecasting method, the arbitrary development of a fuel forecast by fixing the price differential between non-linked fuels, an expansion plan fuel sensitivity was performed by holding the differential between oil/gas and coal constant. The base case expansion plan did not change as a result of this change in the fuel price forecast. This result was expected because Tampa Electric Company's base case expansion plan consists of combustion turbines. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. Because this sensitivity lowers Tampa Electric Company's natural gas and oil price forecasts and Tampa Electric Company's future resources are fired by natural gas and oil, it results in the same base case plan.

Generating Unit Performance Modeling

Tampa Electric Company models generating unit performance in the Generation and Fuel (GAF) module of PROSCREEN, a computer model developed by New Energy Associates. This module is a tool to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units in the GAF are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance weeks, and unplanned outage rates. The unit performance projections that are modeled are based on historical data trends, engineering judgement, time since last planned outage, and recent equipment performance. Specifically, unit capacity and heat rate projections are based on historical unit performance test values which are adjusted as needed for current unit conditions. Planned outage projections are modeled two ways. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on an average of the first five years.

The five-year outage schedule is based on unit-specific maintenance needs, material lead time, labor availability, budget constraints, and the need to supply our customers with power in the most economical manner. Unplanned outage rate projections are based on an average of three years of historical data adjusted, if necessary, to account for current unit conditions.

Financial Assumptions and Sensitivities

Tampa Electric makes numerous financial assumptions as part of the preparation for its Ten-Year Site Plan process. These assumptions are based on the current financial condition of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code, an amount for AFUDC is recorded by the company during the construction phase of each capital project. This rate is set by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.

- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the Ten-Year Site Plan.

- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.

- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.

- Depreciation represents the annual cost to amortize over its useful life the total original investment in a plant item less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the Ten-Year Site Plan represents the average expected life for that type of investment.

Sensitivities were performed by taking the top ranked resource plans and analyzing them with respect to varying financial assumptions, using PROSCREEN. Each financial assumption was tested by increasing and decreasing the financial assumption by one percent. The capital, operating and maintenance, and fuel costs for each resource plan were analyzed. The variation in the financial assumptions had no impact on the base plan within the ten year planning window because the top ranked plans were identical through year 2007.

Integrated Resource Planning Process

Tampa Electric Company's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders. A flow diagram of the overall process is shown in Figure V-1.

The initial pass of the process incorporates a reliability analysis to determine timing of future needs, and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. In this pass, a demand and energy forecast which excludes incremental DSM programs is developed. Then a supply plan based on the system requirements which excludes incremental DSM is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the DSM programs and supply side resources. The same planning and business assumptions are used to develop numerous combinations of DSM and supply side resources that account for variances in both timing and type of resources added to the Tampa Electric Company system.

The cost-effectiveness of DSM programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the Participants Tests. Using the Commission's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and Participants Tests in the DSM analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first.

Tampa Electric Company evaluates DSM measures using a spreadsheet developed to meet the Commission's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric Company service area. Geographic viability, weather conditions, public acceptance, economics, lead-time, environmental acceptability, safety, and proven demonstration and commercialization are used as criteria to screen the generating technologies to a manageable number.

The technologies which pass the screening are included in a supply side analysis which examines various supply side alternatives for meeting future capacity requirements. These include modifying existing units by repowering or over-pressure operation and delayed retirements. Other supply resources such as constructing new unit additions, firm power purchases from other generating entities, joint ownership of generating capacity, and modifications of the transmission system to increase import capability are included in the analysis.

Tampa Electric Company uses the PROVIEW module of PROSCREEN, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the time and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions which satisfy the specified reliability criteria and determines the schedule of additions which have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements used to rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module and the Generation and Fuel module of PROSCREEN. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

Sensitivity analysis of the top ranked plans from the economic analysis is used to determine the relative impact of various assumptions on the robustness of the base plan. These sensitivities involve parameters which are greatly influenced by the action and decisions of organizations other than Tampa Electric Company. The sensitivities include system load and energy requirements, fuel prices, and financial assumptions. These sensitivities are developed by using the top plans, which are chosen based on economics and a variety of supply side options, and analyzing them in scenarios to determine the most economically viable plan under all scenarios.

Strategic Concerns

Strategic issues which affect the type, capacity, and/or timing of future generation resource requirements are analyzed. These issues such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. Therefore, a strategic analysis is conducted to compare the overall performance of each alternative resource plan under each issue. The strategic issues and economic analysis are combined to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes.

The tool used to combine the strategic issues and economic analysis is a decision matrix. The decision matrix is used to compare and select the most cost-effective plan. Each alternative resource plan is analyzed on both a quantitative and qualitative basis. The quantitative analysis is based on comparing the cumulative present worth of revenue requirements for each alternative for both the base and sensitivity assumptions. The qualitative analysis considers these previously mentioned strategic issues. Each alternative is ranked based on pre-determined criteria and the sum of values for each category. The combined scores indicate the relative strength of each alternative on both a quantitative and qualitative basis.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Table IV-3. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, combustion turbines are planned for November of 2002, 2003, and 2005. These combustion turbines will be dual-fueled by natural gas and distillate oil. For the purposes of this study, Hookers Point Station is assumed to be retired in April of 2003, and Tampa Electric's long-term purchase power contract with Hardee Power Partners Limited remains at 297 MW summer net capability and 360 MW winter net capability for the entire study period.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY

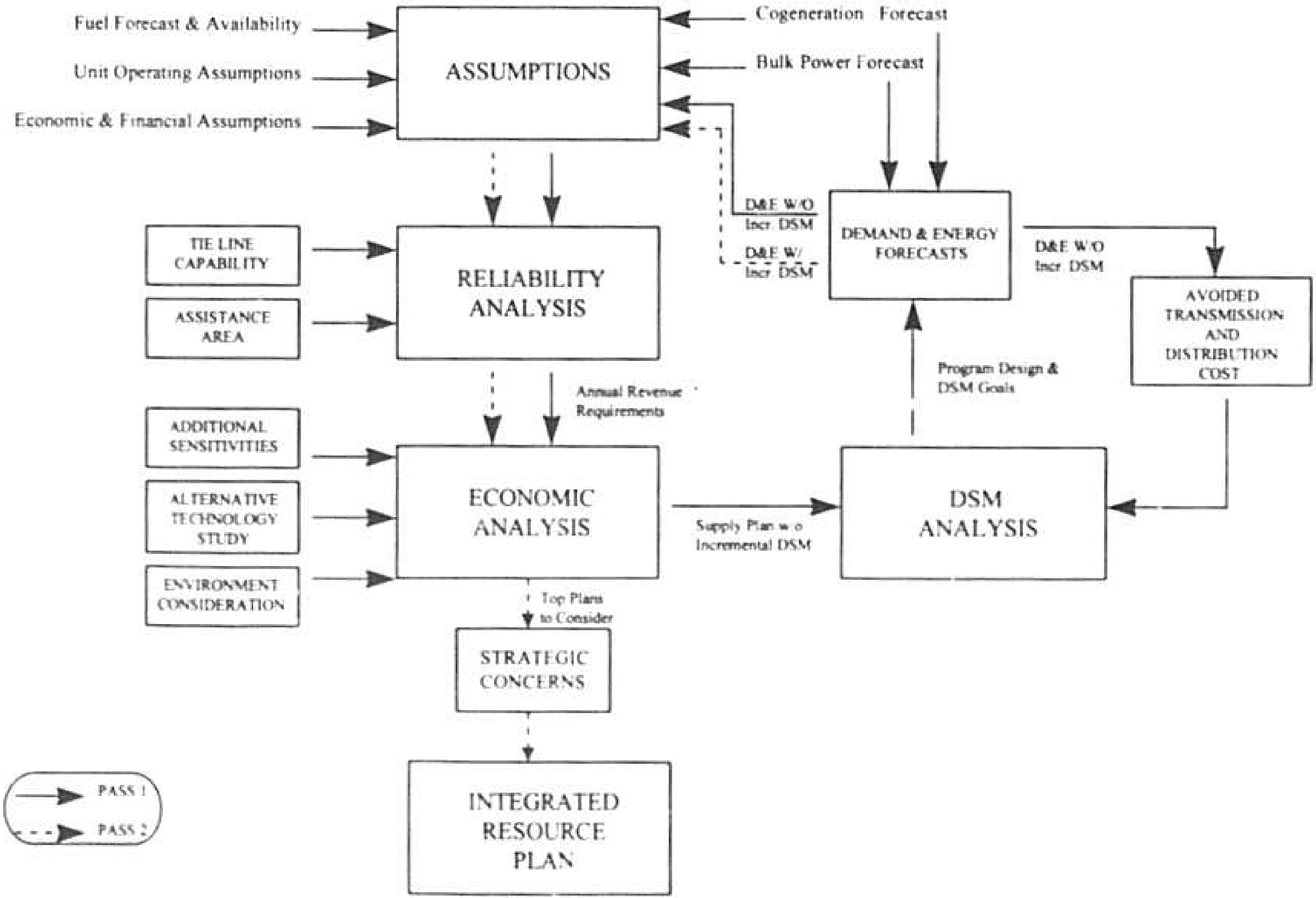


FIGURE V-1

Generation and Transmission Reliability Criteria

Generation

Tampa Electric Company uses the dual reliability criteria of 1% Expected Unserved Energy (%EUE) and a 15% minimum firm winter reserve margin for planning purposes.

Tampa Electric Company's approach to calculating percent reserves is consistent with the industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's percent Expected Unserved Energy (%EUE) criteria addresses annual reliability. Similar to calculating percent reserves, all firm unit and station power sales are accounted for in determining Tampa Electric's available capacity resources. The 1% EUE target was developed as an equivanlent to the loss of Tampa Electric's largest unit (Big Bend Unit 4, 447 MW) for an entire year and maintaining firm reserves of approximately 15%. In calculating the EUE, the Hardee Power Station is considered to be available as a Tampa Electric capacity resource only after its availability is reduced for planned outages, forced outages, and projected Seminole Electric Cooperative (SEC) usage. SEC provides Tampa Electric with its projected usage of the Hardee Power Station capacity. Percent EUE is calculated by dividing Tampa Electric's projected annual non-firm purchases (excluding economy) by its Net Energy for Load and multiplying by 100%. Under these conditions, Tampa Electric will have adequate reserves or available emergency and/or contracted short-term firm capacity to mitigate expected unserved energy.

Transmission

The following criteria are used as guidelines by Tampa Electric Company Transmission Planners during planning studies. However, they are not absolute rules for system expansion; the criteria are used to alert planners of potential transmission system capacity limitations. Engineering analysis is used in all stages of the planning process to weigh the impact of system deficiencies, the likelihood of the triggering contingency, and the viability of any operating options. Only by carefully researching each planning criteria violation can a final evaluation of available transmission capacity be made.

Generation Dispatch Modeled

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E loadflow software. The ECDI function schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the Florida Reliability Coordinating Council (FRCC).

Since unplanned and planned unit outages can result in a system dispatch that varies significantly from a base plan, bulk transmission planners also investigate several scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are analyzed to ensure the integrity of the bulk transmission system under maximized bulk power flows.

Transmission System Planning Criteria

Tampa Electric follows the FRCC planning criteria as contained in Section V of the FRCC System Planning Committee Handbook.

In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria. Listed below are the guidelines which are used prior to contingency analysis to identify any inherent system flaws:

Transmission System Loading Limits	
Transmission System Conditions	Acceptable Loading Limit for Transformers and Transmission Lines
All facilities in service	100% or less

Transmission System Voltage Limits			
	Industrial Substation Buses at point-of-service	69 kV Buses	138 kV and 230 kV Buses
All facilities in service	0.950 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu

Single Contingency Planning Criteria

The following two tables summarize the thresholds which alert planners to problematic transmission line and transformer single contingency scenarios.

Transmission System Loading Limits	
Transmission System Conditions	**Acceptable Loading Limit for Transmission Lines and Transformers**
Single Contingency, pre-switching	115% or less
Single Contingency, after all switching	100% or less
Bus Outages, pre-switching	115% or less
Bus Outages, after all switching	100% or less

Transmission System Voltage Limits			
Transmission System Conditions	**Industrial Substation Buses at point-of- service**	**69 kV Buses**	**138 kV and 230 kV Buses**
Single Contingency, pre-switching	0.925 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu
Single Contingency, after all switching	0.950 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu
Bus Outages	0.925 - 1.050 pu	0.950 - 1.050 pu	0.950 - 1.050 pu

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric adheres to the FRCC ATC calculation methodology as well as the principles contained in the NERC ATC Definitions and Determinations document.

Transmission Planning Assessment Practices

Base Case Operating Conditions

Transmission planners ensure that Tampa Electric's transmission system can first and foremost support peak and off-peak system load with no facility overload, voltage violation, or imprudent operating modes. Therefore, the first step in assessing the health of the transmission system is to guarantee that all equipment is within specified continuous loading and voltage guidelines. Consult the previous section for more specific system parameters.

Single Contingency Planning Criteria

The objective of transmission planning is to design a system that can sustain the loss of any single circuit element without loading any transmission line or transformer beyond its rating or resulting in voltage levels that deviate outside of the bandwidths set forth in the Transmission System Planning Criteria section. In the course of single contingency analysis, single contingency fault events which result in the removal of multiple transmission system elements from service due to protection system response are modeled in the manner that the system would respond to the fault. Any verified criteria violation which cannot be mitigated with an appropriate operating measure is flagged as a limitation on transmission system capacity. Consult the Transmission System Planning Criteria section of this document for more specific system parameters.

Tampa Electric plans on any given piece of transmission system equipment being unavailable for service at some point in time. In addition to Tampa Electric equipment being out of service, Tampa Electric transmission planners plan the system to tolerate the loss of service of equipment outside of Tampa Electric's control area. This mainly consists of bulk transmission system equipment and generation units throughout the state.

Multiple Contingency Planning Criteria

Criteria for multiple contingency conditions are the same as single contingency criteria but are simulated at off-peak load levels. Appropriate double contingencies are investigated at 100% load level when warranted by area load factors. Multiple contingency conditions are also used to gauge the urgency of system deficiencies which are identified during single contingency analysis as cause for concern.

First Contingency Total Transfer Capability Considerations

Bulk transmission planners also use multiple generator/transmission equipment contingency criteria to ensure that Tampa Electric's transmission system import corridors are loaded within approved limits in the event of a Tampa Electric generation shortfall. To accomplish this, statewide dispatches are investigated which load each of Tampa Electric's tie lines to their First Contingency Total Transfer Capability.

Base case and contingency conditions are then imposed to locate any transmission or sub-transmission weaknesses which would require reinforcement under such a scenario. When necessary, bulk planners identify situations where FCTTC and/or internal system capacities should be increased to raise the capability of a transmission corridor.

FCTTC's which must be observed for Tampa Electric's multi-line corridors are listed below:

Tie line	FCTTC
Lake Tarpon-Sheldon 230 kV	1100 MVA
Big Bend-Florida Power & Light 230 kV	1500 MVA

DSM Energy Savings Durability

Tampa Electric Company identifies and verifies the durability of energy savings from our conservation and DSM programs by several methods. First, Tampa Electric Company has established a monitoring and evaluation (M&E) process where historical analysis identifies the energy savings. These include:

(1) end-use metering of a load survey sample to identify the savings achieved on air conditioning, heating, and water heating;

(2) bill analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(3) in commercial programs such as Standby Generator and C/I Load Management, the reductions are verified through submetering of those loads under control to determine participant incentives relative to demand and energy savings.

Secondly, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Where programs promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs), program standards require they be of a permanent nature. For example, our Commercial Indoor Lighting Program requires full-fixture replacement or hard-wiring of fixture replacements.

Supply Side Resources Procurement Process

Tampa Electric Company will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations. The procurement process will also demonstrate continued positive efforts by Tampa Electric to include minority, small, and women-owned businesses. Goals will be established and tracked to measure opportunities and awards realized by these firms.

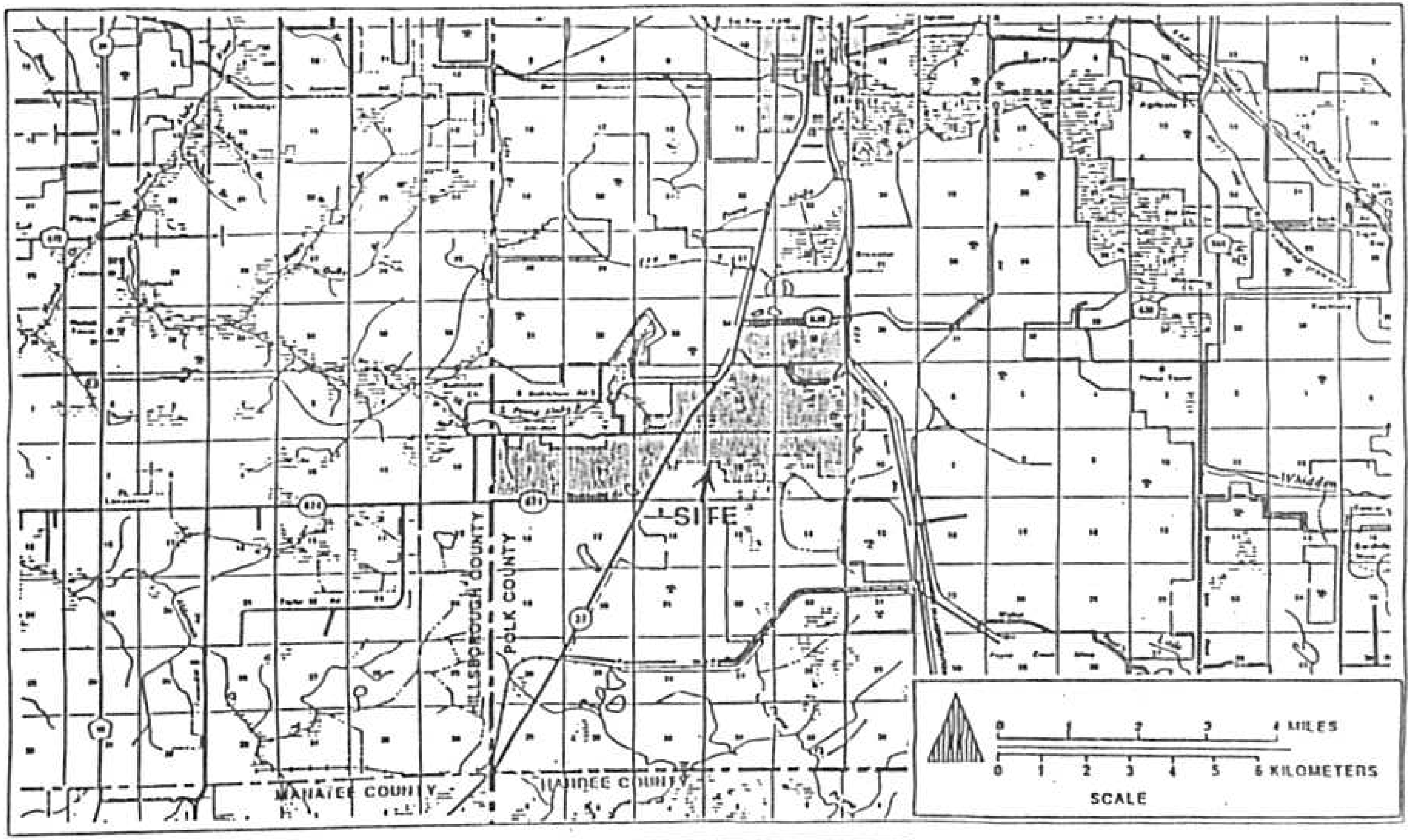
Transmission Construction and Upgrade Plans

In 2005, Tampa Electric plans to add an 11-mile 230 kV transmission line for the purpose of maintaining reliability in its Eastern Service Area. The new transmission line will be sourced from the proposed Lithia 230 kV Switching Station and will terminate at the existing Wheeler Road 69 kV Substation. This new transmission line will be used to source a new 230/69 kV transformer at the Wheeler Road Substation. This transformer will be required to alleviate potential voltage criteria violations and sub-transmission circuit overloads which are projected to occur in 2005.

CHAPTER VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter IV will occur at the existing Polk Power Plant facility. The Polk Power Plant site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-1). This facility is an existing power plant site that has been permitted under the Florida Power Plant Siting Act. There are no new potential sites being considered for the 10-year horizon.



SITE LOCATION OF POLK POWER STATION

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan
For Electrical Generating Facilities
And Associated Transmission Lines

SOURCES: FDOT MAP, FLA. ECT.

FIGURE VI-1

Q. Provide all data requested on the attached forms.

A. Data provided on the attached forms.

History and Forecast of Summer Peak Demand - MW
Base Case

(1) Year	(2) Total	(3) Wholesale+	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind Conservation	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,201	112	3,089	217	105	61	46	20	2,640	
1999	3,292	128	3,164	233	109	66	60	22	2,674	
2000	3,380	128	3,252	230	112	71	75	25	2,739	
2001	3,491	139	3,352	228	116	76	90	27	2,814	
2002	3,591	140	3,451	225	119	80	107	30	2,890	
2003	3,707	141	3,566	222	123	85	123	31	2,983	
2004	3,806	141	3,665	219	126	89	140	34	3,057	
2005	3,892	130	3,762	217	129	93	158	35	3,130	
2006	3,991	130	3,861	215	132	97	176	38	3,203	
2007	4,060	111	3,949	212	135	101	195	39	3,267	

December 31, 1997 Status

* Not coincident with system peak
** Values shown may be affected by rounding
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
\# Commercial/Industrial Load Management includes Standby Generator

History and Forecast of Summer Peak Demand - MW
High 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	(10) Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,221	112	3,109	220	106	61	46	20	2,656	
1999	3,335	128	3,207	240	110	66	60	22	2,709	
2000	3,441	128	3,313	240	114	72	75	25	2,787	
2001	3,576	140	3,436	241	118	77	91	27	2,882	
2002	3,702	141	3,561	241	121	82	107	30	2,980	
2003	3,853	142	3,711	240	125	86	123	31	3,106	
2004	3,975	142	3,833	240	129	91	140	34	3,199	
2005	4,099	131	3,968	238	133	96	158	35	3,308	
2006	4,222	131	4,091	238	137	100	176	38	3,402	
2007	4,337	113	4,224	237	140	104	195	39	3,509	

December 31, 1997 Status

* Not coincident with system peak
** Values shown may be affected by rounding
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
\# Commercial/Industrial Load Management includes Standby Generator

History and Forecast of Summer Peak Demand - MW
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
Year	Total	Wholesale+	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind Load Management #	Comm./Ind. Conservation	Net Firm Demand	
1988	2,476	0	2,476	221	75	18	1	7	2,154	
1989	2,555	0	2,555	315	71	19	2	9	2,205	*
1990	2,630	0	2,630	311	72	20	4	9	2,245	*
1991	2,717	39	2,678	265	71	23	1	9	2,309	
1992	2,821	50	2,771	294	77	25	3	10	2,366	*
1993	2,912	60	2,852	273	91	28	6	11	2,453	*
1994	2,823	69	2,754	200	97	31	8	11	2,409	*
1995	2,981	81	2,900	170	98	34	8	16	2,574	
1996	3,089	92	2,997	234	98	42	18	16	2,589	
1997	3,107	106	3,001	225	89	55	17	18	2,597	
1998	3,189	112	3,077	215	105	60	46	20	2,631	
1999	3,257	128	3,129	226	108	65	60	22	2,648	
2000	3,324	128	3,196	220	111	70	75	25	2,695	
2001	3,413	138	3,275	215	115	75	90	27	2,753	
2002	3,487	139	3,348	209	117	79	107	30	2,806	
2003	3,589	140	3,449	204	120	83	123	31	2,888	
2004	3,651	140	3,511	200	122	87	140	34	2,928	
2005	3,723	129	3,594	195	125	91	158	35	2,990	
2006	3,773	129	3,644	192	127	95	176	38	3,016	
2007	3,814	109	3,705	187	130	98	195	39	3,056	

December 31, 1997 Status

* Not coincident with system peak
** Values shown may be affected by rounding
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
\# Commercial/Industrial Load Management includes Standby Generator

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	(10) Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,521	114	3,407	197	245	350	30	27	2,558
1998/99	3,625	129	3,496	211	254	387	42	28	2,574
1999/00	3,721	129	3,592	209	263	421	54	29	2,616
2000/01	3,823	141	3,682	207	272	454	67	29	2,653
2001/02	3,908	141	3,767	204	280	487	81	30	2,685
2002/03	4,019	143	3,876	203	288	519	95	31	2,740
2003/04	4,115	143	3,972	201	296	551	109	31	2,784
2004/05	4,204	132	4,072	198	304	582	124	32	2,832
2005/06	4,302	133	4,170	196	312	611	139	33	2,879
2006/07	4,391	113	4,278	193	319	640	155	34	2,937
2007/08	4,476	114	4,362	192	327	668	155	35	2,985

December 31, 1997 Status

- * Not coincident with system peak
- \+ Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek
- \# Commercial/Industrial Load Management includes Standby Generator
- ** Forecasted Values 1997/98 - 2007/08
- *** Values shown may be affected by rounding
- = Residential conservation includes code changes

History and Forecast of Winter Peak Demand - MW
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale+	Retail	Interruptible	Residential Load Management	Residential Conservation =	Comm./Ind Load Management #	Comm./Ind Conservation	Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345 *
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,541	114	3,427	200	246	351	30	27	2,573
1998/99	3,662	129	3,533	216	256	389	42	28	2,602
1999/00	3,780	129	3,651	218	266	426	54	29	2,658
2000/01	3,894	142	3,752	219	276	461	67	29	2,700
2001/02	4,014	142	3,872	219	285	496	81	30	2,761
2002/03	4,146	144	4,002	220	295	531	95	31	2,830
2003/04	4,261	144	4,117	219	304	566	109	31	2,888
2004/05	4,391	133	4,258	218	314	599	124	32	2,971
2005/06	4,511	135	4,376	217	323	632	139	33	3,032
2006/07	4,644	115	4,529	215	332	664	155	34	3,129
2007/08	4,764	114	4,650	216	341	696	155	35	3,207

December 31, 1997 Status

- * Not coincident with system peak
- \+ Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek
- \# Commercial/Industrial Load Management includes Standby Generator
- ** Forecasted Values: 1997/98 - 2007/08
- *** Values shown may be affected by rounding
- = Residential conservation includes code changes

History and Forecast of Winter Peak Demand - MW
Low 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	(10) Net Firm Demand
1988/89	2,584	0	2,584	242	127	168	1	17	2,029
1989/90	2,712	0	2,712	178	107	183	0	19	2,345 *
1990/91	2,422	0	2,422	227	139	196	0	20	1,840
1991/92	2,815	53	2,762	294	151	207	1	21	2,088
1992/93	2,886	63	2,823	281	168	221	4	23	2,126
1993/94	2,737	69	2,668	181	177	241	7	25	2,037
1994/95	3,244	74	3,170	240	227	270	8	25	2,400
1995/96	3,449	98	3,351	152	245	311	8	29	2,606
1996/97	3,439	109	3,330	228	237	313	18	26	2,508
1997/98**	3,510	114	3,396	195	244	349	30	27	2,551
1998/99	3,594	129	3,465	206	252	384	42	28	2,553
1999/00	3,672	129	3,543	200	260	416	54	29	2,584
2000/01	3,754	140	3,614	196	267	447	67	29	2,608
2001/02	3,825	140	3,685	191	274	478	81	30	2,631
2002/03	3,907	142	3,765	188	281	508	95	31	2,662
2003/04	3,979	142	3,837	183	288	537	109	31	2,689
2004/05	4,049	131	3,918	179	295	565	124	32	2,723
2005/06	4,111	132	3,979	175	301	591	139	33	2,740
2006/07	4,174	111	4,063	171	307	616	155	34	2,780
2007/08	4,234	114	4,120	170	313	641	155	35	2,806

December 31, 1997 Status

*	Not coincident with system peak
+	Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek
#	Commercial/Industrial Load Management includes Standby Generator
**	Forecasted Values 1997/98 - 2007/08
***	Values shown may be affected by rounding
=	Residential conservation includes code changes

History and Forecast of Annual Net Energy for Load - GWh
Base Case

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	16,025	260	74	15,691	382	860	16,933	55.0
1999	16,604	291	84	16,229	389	888	17,506	55.4
2000	17,026	321	94	16,611	331	911	17,853	54.6
2001	17,445	350	103	16,992	382	932	16,306	54.8
2002	17,863	379	113	17,371	348	953	18,672	54.5
2003	18,282	407	123	17,752	372	973	19,097	54.3
2004	18,696	434	132	18,130	382	996	19,508	54.0
2005	19,102	460	142	18,500	373	1,015	19,888	53.9
2006	19,504	485	151	18,868	369	1,035	20,272	53.8
2007	19,901	510	161	19,230	329	1,058	20,617	53.4

December 31, 1997 Status

** Load Factor is the ratio of total system average load to peak demand
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
= Residential conservation includes code changes

History and Forecast of Annual Net Energy for Load - GWh
High Case

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	16,147	261	74	15,812	383	866	17,061	55.1
1999	16,835	293	84	16,458	391	901	17,750	55.6
2000	17,368	324	94	16,950	333	927	18,211	54.8
2001	17,899	354	103	17,442	385	954	18,781	55.2
2002	18,447	385	113	17,949	352	981	19,282	54.8
2003	19,016	414	123	18,479	377	1,009	19,865	54.7
2004	19,583	444	132	19,007	388	1,037	20,432	54.6
2005	20,135	472	142	19,521	380	1,064	20,965	54.4
2006	20,704	499	151	20,054	377	1,092	21,523	54.5
2007	21,276	527	161	20,588	338	1,120	22,046	54.0

December 31, 1997 Status

** Load Factor is the ratio of total system average load to peak demand
\+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
= Residential conservation includes code changes

History and Forecast of Annual Net Energy for Load - GWh
Low Case

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1988	12,529	93	10	12,426	0	725	13,151	57.1
1989	13,013	105	12	12,896	0	809	13,705	57.7
1990	13,564	111	17	13,436	0	569	14,005	60.8
1991	13,591	117	19	13,455	129	695	14,279	60.0
1992	13,697	123	22	13,552	214	671	14,437	58.3
1993	13,603	131	26	13,446	246	808	14,500	56.8
1994	14,102	141	29	13,932	163	636	14,731	59.6
1995	14,803	162	41	14,600	212	870	15,682	55.2
1996	15,181	195	57	14,929	399	760	16,088	53.1
1997	15,382	228	64	15,090	507	731	16,328	57.8
1998	15,950	259	74	15,617	381	857	16,856	54.9
1999	16,424	289	84	16,051	388	882	17,320	55.2
2000	16,740	318	94	16,328	329	898	17,555	54.4
2001	17,046	346	103	16,597	379	913	17,889	54.6
2002	17,361	373	113	16,875	345	929	18,149	54.2
2003	17,657	399	123	17,135	368	944	18,447	53.9
2004	17,940	425	132	17,383	377	959	18,718	53.6
2005	18,205	449	142	17,614	367	972	18,953	53.3
2006	18,472	472	151	17,849	362	986	19,197	53.3
2007	18,717	494	161	18,062	321	999	19,382	52.7

December 31, 1997 Status

** Load Factor is the ratio of total system average load to peak demand
+ Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek
= Residential conservation includes code changes

Existing Generating Unit Operating Performance

(1)	(2)	(3)		(4)		(5)		(6)	
		Planned Outage Factor (POF)		Forced Outage Factor (FOF) *		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.	Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
BIG BEND	1	7.23	7.09	11.12	11.94	85.14	77.1	10,145	10,025
BIG BEND	2	1.47	8.24	14.17	6.96	84.26	78.0	10,108	10,061
BIG BEND	3	7.95	7.67	13.61	7.82	77.45	76.4	10,108	10,071
BIG BEND	4	7.01	7.28	9.18	5.90	85.59	82.9	10,045	10,022
BBCT	1	3.73	3.83	4.37	20.00	90.82	78.3	21,864	20,939
BBCT	2	2.63	3.83	7.18	15.47	87.11	68.8	16,326	16,611
BBCT	3	4.94	3.83	1.17	15.47	94.03	68.8	16,559	16,462
GANNON	1	10.49	7.31	7.14	8.59	79.23	78.7	11,752	11,236
GANNON	2	7.20	8.05	12.39	7.05	75.04	76.1	12,088	11,434
GANNON	3	6.26	8.05	8.71	8.04	80.00	78.4	11,512	11,240
GANNON	4	5.94	6.70	10.39	8.56	80.03	79.2	11,206	10,786
GANNON	5	13.12	7.09	12.27	6.61	77.33	78.2	10,345	10,342
GANNON	6	7.89	8.43	11.72	5.95	81.13	77.0	10,452	10,535
GNCT	1	0.30	3.83	0.10	20.00	99.66	81.8	21,668	21,737
HOOKERS PT **	1	0.62	2.88	9.46	4.80	88.80	90.2	16,189	16,004
HOOKERS PT **	2	0.00	2.88	1.21	4.80	97.00	90.2	16,189	16,008
HOOKERS PT **	3	0.00	2.88	9.80	4.80	88.93	90.2	16,189	16,014
HOOKERS PT **	4	5.04	2.88	13.77	4.80	80.49	90.2	16,189	16,225
HOOKERS PT **	5	0.00	2.88	22.84	16.20	68.78	68.4	16,189	15,244
PHILLIPS	1	5.06	4.60	3.87	7.00	92.47	80.0	9,691	9,498
PHILLIPS	2	8.36	3.45	3.87	7.00	87.74	80.0	9,502	9,498
POLK ***	1	-	11.23	-	10.70	-	78.3	-	9,080

NOTE: Historical - average of past three years
Projected - average of next ten years
* Forced outage rates provided for projected data
** Hookers Point Station is assumed to be retired in January of 2003 for purposes of the study
*** Polk Station historical data is not available for the past three years. Commercial operation began September 30, 1996

Nominal, Delivered Residual Oil Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
1998	NOTE TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT			17.80	283.40		20.11	318.12	
1999	BURN RESIDUAL OIL LESS THAN 0.7% SULFUR CONTENT			18.37	292.43	3.2	20.75	328.22	3.2
2000				18.96	301.73	3.2	21.28	336.59	2.6
2001				19.56	311.32	3.2	21.82	345.20	2.6
2002				20.27	322.65	3.6	22.46	355.40	3.0
2003				21.01	334.38	3.6	23.13	365.95	3.0
2004				21.77	346.53	3.6	23.82	376.87	3.0
2005				22.56	359.10	3.6	24.54	388.16	3.0
2006				23.38	372.11	3.6	25.27	399.85	3.0
2007				24.22	385.59	3.6	26.04	411.94	3.0

NOTE 1998-2007 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE

Nominal, Delivered Residual Oil Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
				Residual Oil (By Sulfur Content)					
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
1998	NOTE TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT			19.47	309.85		21.64	342.31	
1999	BURN RESIDUAL OIL LESS THAN 0.7% SULFUR CONTENT			20.13	320.42	3.4	22.36	353.77	3.3
2000				20.82	331.34	3.4	22.98	363.56	2.8
2001				21.52	342.60	3.4	23.62	373.66	2.8
2002				22.35	355.84	3.9	24.37	385.56	3.2
2003				23.22	369.59	3.9	25.15	397.90	3.2
2004				24.11	383.84	3.[illegible]	25.96	410.69	3.2
2005				25.04	398.62	3.9	26.80	423.95	3.2
2006				26.01	413.96	3.8	27.67	437.69	3.2
2007				27.00	429.87	3.8	28.57	451.95	3.3

NOTE 1998-2007 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE

Nominal, Delivered Residual Oil Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
1998	NOTE TAMPA ELECTRIC'S OIL FIRED UNITS DO NOT			16.15	257.06		18.59	294.04	
1999	BURN RESIDUAL OIL LESS THAN 0.7% SULFUR CONTENT			16.63	264.67	3.0	19.15	302.89	3.0
2000				17.12	272.49	3.0	19.59	309.95	2.3
2001				17.63	280.54	3.0	20.05	317.20	2.3
2002				18.23	290.11	3.4	20.60	325.84	2.7
2003				18.85	300.00	3.4	21.16	334.75	2.7
2004				19.49	310.21	3.4	21.74	343.96	2.3
2005				20.15	320.77	3.4	22.34	353.47	2.8
2006				20.84	331.67	3.4	22.96	363.28	2.8
2007				21.55	342.94	3.4	23.60	373.42	2.8

NOTE 1998-2007 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	c/Therm	Escalation %
1998	28.44	490.29		278.67	27.87	
1999	29.31	505.37	3.1	283.57	28.36	1.8
2000	30.21	520.91	3.1	289.30	28.93	2.0
2001	31.14	536.90	3.1	295.67	29.57	2.2
2002	32.23	555.74	3.5	303.87	30.39	2.8
2003	33.37	575.24	3.5	312.32	31.23	2.8
2004	34.54	595.42	3.5	322.41	32.24	3.2
2005	35.75	616.31	3.5	332.87	33.29	3.2
2006	37.00	637.93	3.5	343.70	34.37	3.3
2007	38.30	660.30	3.5	356.46	35.65	3.7

NOTE: 1998-2007 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	c/Therm	Escalation %
1998	30.92	533.06		302.80	30.28	
1999	31.93	550.55	3.3	308.77	30.88	2.0
2000	32.98	568.60	3.3	315.68	31.57	2.2
2001	34.06	587.23	3.3	323.32	32.33	2.4
2002	35.33	609.08	3.7	333.03	33.30	3.0
2003	36.64	631.73	3.7	343.05	34.31	3.0
2004	38.00	655.23	3.7	354.95	35.50	3.5
2005	39.42	679.59	3.7	367.29	36.73	3.5
2006	40.88	704.85	3.7	380.10	38.01	3.5
2007	42.40	731.05	3.7	395.14	39.51	4.0

NOTE 1998-2007 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	c/Therm	Escalation %
1998	25.97	447.71		254.64	25.46	
1999	26.71	460.57	2.9	258.58	25.86	1.5
2000	27.48	473.79	2.9	263.25	26.33	1.8
2001	28.27	487.38	2.9	268.46	26.85	2.0
2002	29.20	503.46	3.3	275.29	27.53	2.5
2003	30.17	520.07	3.3	282.31	28.23	2.6
2004	31.16	537.23	3.3	290.76	29.08	3.0
2005	32.19	554.96	3.3	299.50	29.95	3.0
2006	33.25	573.27	3.3	308.53	30.85	3.0
2007	34.35	592.18	3.3	319.22	31.92	3.5

NOTE 1998-2007 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE

Nominal, Delivered Coal Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
1998	35.66	187.70			34.86	145.25			31.00	134.95		
1999	40.58	213.59	13.8	100	37.60	156.67	7.9	100	34.64	150.80	11.7	100
2000	41.59	218.88	2.5	100	38.60	160.85	2.7	100	35.45	154.32	2.3	100
2001	42.62	224.30	2.5	100	39.62	165.09	2.6	100	36.28	157.92	2.3	100
2002	43.67	229.87	2.5	100	40.71	169.62	2.7	100	37.14	161.67	2.4	100
2003	44.76	235.57	2.5	100	41.68	173.67	2.4	100	38.02	165.50	2.4	100
2004	45.87	241.41	2.5	100	42.68	177.83	2.4	100	38.92	169.44	2.4	100
2005	47.01	247.40	2.5	100	43.70	182.09	2.4	100	39.85	173.47	2.4	100
2006	48.17	253.54	2.5	100	44.75	186.45	2.4	100	40.80	177.59	2.4	100
2007	49.37	259.83	2.5	100	45.82	190.93	2.4	100	41.77	181.82	2.4	100

NOTE: 1997-2006 FUEL PRICES ARE BASED ON THE AVERAGE PROJECTED SUPPLEMENTAL PURCHASE PRICE

Nominal, Delivered Coal Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
1998												
1999												
2000												
2001												
2002												
2003												
2004												
2005												
2006												
2007												

NOTE: TAMPA ELECTRIC DOES NOT FORECAST HIGH COAL PRICES

Nominal, Delivered Coal Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
1998												
1999												
2000												
2001												
2002												
2003												
2004												
2005												
2006												
2007												

NOTE TAMPA ELECTRIC DOES NOT FORECAST LOW COAL PRICES

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
Year	c/MBTU	Escalation %	$/MWh	Escalation %
1998			25.41	
1999			27.34	7.6
2000	NOTE TAMPA ELECTRIC COMPANY HAS NEVER SERVED ITS LOAD FROM		29.31	7.2
2001	OWNED OR PURCHASED NUCLEAR POWER. AND TAMPA ELECTRIC'S		30.33	3.5
2002	CURRENT EXPANSION PLAN DOES NOT PROJECT A NUCLEAR GENERATING		31.58	4.1
2003	FACILITY		31.95	1.2
2004			33.26	4.1
2005			31.97	(3.9)
2006			33.27	4.1
2007			34.15	2.7

NOTES: FIRM PURCHASE COSTS INCLUDE FUEL AND VARIABLE O&M COSTS ONLY

Financial Assumptions
Base Case

AFUDC RATE	7.79 %
CAPITALIZATION RATIOS:	
DEBT	40 %
PREFERRED	0 %
EQUITY	60 %
RATE OF RETURN	
DEBT	7.75 %
EQUITY	12.75 %
INCOME TAX RATE	
STATE	5.50 %
FEDERAL	35.00 %
EFFECTIVE	38.58 %
OTHER TAX RATE	3 %*
DISCOUNT RATE	9.55 %
TAX DEPRECIATION RATE	NA **

* Escalates 3% annually

** Double Declaining to Straight Line (CT's = 15 years)

Financial Escalation Assumptions

(1) Year	(2) General Inflation %	(3) Plant Construction Cost %	(4) Fixed O&M Cost %	(5) Variable O&M Cost %
1998	3.0	2.8	3.0	3.0
1999	3.0	2.8	3.0	3.0
2000	3.0	2.8	3.0	3.0
2001	3.0	2.8	3.0	3.0
2002	3.0	2.8	3.0	3.0
2003	3.0	2.8	3.0	3.0
2004	3.0	2.8	3.0	3.0
2005	3.0	2.8	3.0	3.0
2006	3.0	2.8	3.0	3.0
2007	3.0	2.8	3.0	3.0

Loss of Load Probability, Reserve Margin,
and Expected Unserved Energy
Base Case Load Forecast
(Base Case Expansion Plan)

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Isolated			Annual Assisted		
Year	EUE/NEL* %	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (GWh)	EUE/NEL* %	Reserve Margin** (%)	Expected Unserved Energy (GWh)
1998	0.21%	23%	36.1	0%	23%	0
1999	0.23%	23%	40.6	0%	23%	0
2000	0.40%	20%	70.9	0%	20%	0
2001	0.51%	18%	94.2	0%	18%	0
2002	0.83%	15%	154.7	0%	15%	0
2003	0.74%	17%	140.7	0%	17%	0
2004	0.70%	19%	136.9	0%	1[illegible]%	0
2005	0.70%	17%	140.0	0%	17%	0
2006	0.43%	19%	86.3	0%	19%	0
2007	0.51%	17%	105.7	0%	17%	0

* Tampa Electric Company's planning criteria is 1% EUE to NEL and 15% winter reserve margin

** Tampa Electric Company's annual isolated values include firm purchases

Loss of Load Probability, Reserve Margin,
and Expected Unserved Energy
High Case Load Forecast
(Base Case Expansion Plan)

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Isolated			Annual Assisted		
Year	EUE/NEL* %	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (GWh)	EUE/NEL* %	Reserve Margin** (%)	Expected Unserved Energy (GWh)
1998	0.24%	22%	40.2	0%	22%	0
1999	0.28%	22%	50.2	0%	22%	0
2000	0.51%	18%	93.3	0%	18%	0
2001	0.69%	15%	130.0	0%	15%	0
2002	1.16%	12%	223.8	0%	12%	0
2003	1.17%	13%	231.5	0%	13%	0
2004	1.22%	15%	249.1	0%	15%	0
2005	1.31%	12%	274.8	0%	12%	0
2006	0.96%	14%	207.6	0%	14%	0
2007	1.22%	11%	269.9	0%	11%	0

* Tampa Electric Company's planning criteria is 1% EUE to NEL and 15% winter reserve margin

** Tampa Electric Company's annual isolated values include firm purchases

Loss of Load Probability, Reserve Margin,
and Expected Unserved Energy
Low Case Load Forecast
(Base Case Expansion Plan)

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Isolated			Annual Assisted		
Year	EUE/NEL* %	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (GWh)	EUE/NEL* %	Reserve Margin** (%)	Expected Unserved Energy (GWh)
1998	0.20%	23%	33.8	0%	23%	0
1999	0.20%	24%	34.3	0%	24%	0
2000	0.31%	21%	55.2	0%	21%	0
2001	0.39%	19%	69.3	0%	19%	0
2002	0.60%	17%	108.1	0%	17%	0
2003	0.47%	20%	87.1	0%	20%	0
2004	0.39%	23%	73.6	0%	23%	0
2005	0.36%	21%	67.9	0%	21%	0
2006	0.16%	25%	29.9	0%	25%	0
2007	0.18%	23%	34.0	0%	23%	0

* Tampa Electric Company's planning criteria is 1% EUE to NEL and 15% winter reserve margin

** Tampa Electric Company's annual isolated values include firm purchases

Commission-Approved Demand Side Management Programs

Program: Residential Alternate Audit (Free)

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	465,019	5,500	37.9%
1999	474,487	474,487	5,000	38.2%
2000	483,883	483,883	4,500	38.4%
2001	492,563	492,563	4,500	38.6%
2002	500,128	500,128	4,500	39.0%
2003	507,557	507,557	4,000	39.2%
2004	514,996	514,996	4,000	39.4%
2005	522,393	522,393	4,000	39.6%
2006	529,793	529,793	3,500	39.7%
2007	537,142	537,142	3,500	39.8%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Residential Mail-In Audit

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	465,019	12,500	6.0%
1999	474,487	474,487	12,000	8.5%
2000	483,883	483,883	12,000	10.8%
2001	492,563	492,563	12,000	13.0%
2002	500,128	500,128	11,750	15.2%
2003	507,557	507,557	11,500	17.2%
2004	514,996	514,996	11,250	19.1%
2005	522,393	522,393	11,000	21.0%
2006	529,793	529,793	10,500	22.7%
2007	537,142	537,142	10,000	24.2%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Residential RCS Audit

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	465,019	25	0.8%
1999	474,487	474,487	25	0.8%
2000	483,883	483,883	25	0.8%
2001	492,563	492,563	25	0.8%
2002	500,128	500,128	25	0.8%
2003	507,557	507,557	25	0.8%
2004	514,996	514,996	25	0.8%
2005	522,393	522,393	25	0.8%
2006	529,793	529,793	25	0.8%
2007	537,142	537,142	25	0.8%

* Includes participation since program inception

Commission-Approved Demand Side Management Programs

Program: Residential Ceiling Insulation

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	389,004	3,700	7.6%
1999	474,487	393,925	3,600	8.4%
2000	483,883	398,882	3,500	9.2%
2001	492,563	403,294	3,400	9.9%
2002	500,128	406,802	3,300	10.6%
2003	507,557	410,288	3,200	11.3%
2004	514,996	413,883	3,100	12.0%
2005	522,393	417,541	3,000	12.6%
2006	529,793	421,301	2,900	13.2%
2007	537,142	425,115	2,800	13.7%

* Includes participation since program inception.

Commission-Approved Der and Side Management Programs

Program: Residential Duct Repair

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	392,665	5,000	6.6%
1999	474,487	396,386	4,800	7.7%
2000	483,883	400,243	4,600	8.8%
2001	492,563	403,655	4,400	9.8%
2002	500,128	406,263	4,200	10.8%
2003	507,557	408,949	4,000	11.7%
2004	514,996	411,844	3,800	12.5%
2005	522,393	415,102	3,400	13.3%
2006	529,793	418,562	3,200	13.9%
2007	537,142	422,176	3,000	14.5%

* Includes participation since program inception

Commission-Approved Demand Side Management Programs

Program: Residential Heating And Cooling Level 1

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	117,972	2,000	6.1%
1999	474,487	112,572	1,800	8.0%
2000	483,883	107,772	1,600	9.8%
2001	492,563	103,572	1,400	11.6%
2002	500,128	99,972	1,200	13.2%
2003	507,557	96,972	1,000	14.6%
2004	514,996	94,272	900	16.0%
2005	522,393	91,872	800	17.3%
2006	529,793	89,772	700	18.5%
2007	537,142	87,972	600	19.5%

* Includes participation since program inception

Commission-Approved Demand Side Management Programs

Program: Residential Heating And Cooling Level 2

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	117,972	2,000	4.1%
1999	474,487	114,372	1,800	5.8%
2000	483,883	111,172	1,600	7.4%
2001	492,563	108,372	1,400	8.8%
2002	500,128	105,972	1,200	10.2%
2003	507,557	103,972	1,000	11.3%
2004	514,996	102,172	900	12.4%
2005	522,393	100,572	800	13.4%
2006	529,793	99,172	700	14.3%
2007	537,142	97,972	600	15.1%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Residential Load Management

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	465,019	347,025	3,000	23.3%
1999	474,487	352,836	2,900	23.7%
2000	483,883	358,680	2,800	24.1%
2001	492,563	363,966	2,700	24.5%
2002	500,128	368,426	2,500	24.9%
2003	507,557	373,010	2,250	25.2%
2004	511,996	377,854	2,000	25.4%
2005	522,393	382,910	1,750	25.5%
2006	529,793	388,218	1,500	25.6%
2007	537,142	393,779	1,200	25.5%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Free C/I Audit

(1)	(2)	(3)	(4)	(5)
		Number of Customers		
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	57,845	57,845	400	22.7%
1999	58,881	58,881	375	22.9%
2000	59,995	59,995	350	23.1%
2001	61,135	61,135	325	23.2%
2002	62,064	62,064	300	23.3%
2003	62,995	62,995	275	23.4%
2004	63,889	63,889	250	23.5%
2005	64,771	64,771	225	23.5%
2006	65,652	65,652	200	23.5%
2007	66,545	66,545	175	23.4%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Commercial Mail-In Audit

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	57,845	57,845	450	1.9%
1999	58,881	58,881	400	2.6%
2000	59,995	59,995	350	3.1%
2001	61,135	61,135	350	3.6%
2002	62,064	62,064	300	4.1%
2003	62,995	62,995	300	4.5%
2004	63,889	63,889	250	4.8%
2005	64,771	64,771	200	5.1%
2006	65,652	65,652	200	5.3%
2007	66,545	66,54[illegible]	200	5.5%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Comprehensive C/I Audit

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	57,845	57,845	10	0.4%
1999	58,881	58,881	8	0.4%
2000	59,995	59,995	6	0.4%
2001	61,135	61,135	6	0.4%
2002	62,064	62,064	6	0.4%
2003	62,995	62,995	5	0.4%
2004	63,889	63,889	5	0.4%
2005	64,771	64,771	4	0.4%
2006	65,652	65,652	4	0.4%
2007	66,545	66,545	3	0.4%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Commercial Indoor Lighting Program

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	57,845	57,131	125	1.2%
1999	58,881	58,042	125	1.4%
2000	59,995	59,031	125	1.6%
2001	61,135	60,046	125	1.8%
2002	62,064	60,850	125	2.0%
2003	62,995	61,681	100	2.1%
2004	63,889	62,475	100	2.3%
2005	64,771	63,257	100	2.4%
2006	65,652	64,038	100	2.5%
2007	66,545	64,831	100	2.6%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Commercial/Industrial Load Management - Cyclic

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	57,845	57,810	10	0.1%
1999	58,881	58,836	10	0.1%
2000	59,995	59,942	8	0.1%
2001	61,135	61,074	8	0.1%
2002	62,064	61,997	6	0.1%
2003	62,995	62,922	6	0.1%
2004	63,889	63,812	4	0.1%
2005	64,771	64,690	4	0.1%
2006	65,652	65,569	2	0.1%
2007	66,545	66,460	2	0.1%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Commercial/Industrial Load Management - Extended

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
		Eligible To	Annual	Cumulative
	Total In	Participate	Participation	Penetration
Year	Service Area	In Program	In Program	Rate (%)*
1998	57,845	57,839	2	0.01%
1999	58,881	58,873	2	0.01%
2000	59,995	59,985	2	0.02%
2001	61,135	61,123	2	0.02%
2002	62,064	62,050	2	0.02%
2003	62,995	62,979	2	0.03%
2004	63,889	63,872	1	0.03%
2005	64,771	64,753	1	0.03%
2006	65,652	65,633	1	0.03%
2007	66,545	66,525	1	0.03%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Standby Generator

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	57,845	243	4	18.9%
1999	58,881	244	4	20.5%
2000	59,995	248	2	21.0%
2001	61,135	252	2	21.5%
2002	62,064	254	2	22.0%
2003	62,995	257	2	22.6%
2004	63,889	260	1	22.7%
2005	64,771	264	1	22.7%
2006	65,652	267	1	22.8%
2007	66,545	271	1	22.9%

* Includes participation since program inception.

Commission-Approved Demand Side Management Programs

Program: Conservation Value

(1)	(2)	(3)	(4)	(5)
	Number of Customers			
Year	Total In Service Area	Eligible To Participate In Program	Annual Participation In Program	Cumulative Penetration Rate (%)*
1998	57,845	2,876	12	0.6%
1999	58,881	2,916	12	1.0%
2000	59,995	2,962	10	1.3%
2001	61,135	3,009	10	1.6%
2002	62,064	3,047	8	1.8%
2003	62,995	3,086	8	2.1%
2004	63,889	3,124	6	2.2%
2005	64,771	3,163	6	2.4%
2006	65,652	3,203	4	2.5%
2007	66,545	3,243	4	2.6%

* Includes participation since program inception.

Q. Explain all assumptions used to derive the high case and low case demand and energy forecast.

A. The high and low peak demand and energy projections represent alternatives to the company's base case outlook. The high band represents a more optimistic economic scenario than the base case (most likely scenario) with greater expected growth in the areas of customers, employment, and income. The low band represents a less optimistic scenario than the base case with a slower pace of service area growth.

The assumptions related to the high, low, and base peak demand and energy cases are presented below. For all other assumptions, including weather and price elasticity, the assumptions remain the same as in the base case scenario.

ECONOMIC OUTLOOK ASSUMPTIONS
(1997 - 2007)

(Average Annual Growth Rate)

	BASE CASE	LOW GROWTH SCENARIO	HIGH GROWTH SCENARIO
Residential Customers	1.7%	1.3%	2.1%
Employment	1.5%	1.1%	1.9%
Real Per Capita Income	1.5%	1.0%	2.0%
Real Price of Electricity	-1.6%	-1.1%	-2.1%

Q. Explain all assumptions used to derive the high case and low case fuel price forecast.

A. Product price for actual and forecast data for the purpose of deriving base, high, and low forecast pricing is done by careful analysis of actual price and current and previous forecasts obtained by various consultants and agencies. These sources include the Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, Coal Markets Weekly, Coal Daily, Energy Ventures Analysis, Inc., and coal, oil, natural gas, and propane pricing publications and periodicals which include: Coal Outlook, Inside FERC, Natural Gas Week, Platt's Oilgram, and the Oil and Gas Journal.

The high and low fuel price projections represent alternative forecasts to the company's base case outlook. The high price projection represents the effect of oil and natural gas prices escalating 10% above the base case on a monthly basis to the year 2000.

The low price scenario represents the effect of oil and natural gas prices escalating 10% below the product price of the base case on a monthly basis to the year 2000. Annual high and low case price projections after 2000 are based on the company's internal general approach using information provided by consultants combined with internal fuel markets analysis.

With a large percentage of fuel utilized by the company being coal, only base case forecasts are prepared for coal fuels. Base case analysis and forecasts include a large number of coal sources and diverse qualities. The individual price forecasts contained within the base forecast capture the market pressures and sensitivities that would otherwise be reflected in high and low case scenarios.

Q. Using the demand, energy, and fuel price forecasts provided in (1), illustrate what your utility's generation expansion plan would be as a result of each of the following sensitivities: high fuel price/base demand, low fuel price/base demand, high demand/base fuel price, and low demand/base fuel price. Include the cumulative present worth revenue requirements (CPWRR) of each sensitivity and provide this information in a format like that shown in the table below.

A. Fuel assumptions for future units used in the sensitivity screening process were based on the projected supplemental purchase price. High and low fuel forecasts include natural gas and oil. Tampa Electric Company does not forecast for high and low coal prices. Coal prices for these sensitivities remained at base level.

The resulting expansion plans and cumulative present worth revenue requirements (CPWRR) for each sensitivity requested are shown in the attached table on page 2 to this response.

UTILITY TAMPA ELECTRIC COMPANY
1998 REVENUE REQUIREMENTS
GENERATION EXPANSION PLAN SENSITIVITIES

	Base Case Demand Forecast				Base Case Fuel Forecast			
	High Fuel Price		Low Fuel Price		High Demand		Low Demand	
Year	Unit	CPWRR ($000)	Unit	CPWRR ($000)	Unit	CPWRR ($000)	Unit	CPWRR ($000)
1998	-	313,242	-	308,246	-	312,907	-	308,441
1999	-	612,114	-	603,041	-	614,147	-	600,991
2000	-	903,271	-	889,087	-	909,408	-	882,669
2001	-	1,186,920	-	1,167,735	-	1,199,347	-	1,155,177
2002	-	1,464,156	-	1,439,483	CT	1,492,907	-	1,418,953
2003	CT	1,734,100	CT	1,704,303	CC	1,792,219	CT	1,674,168
2004	CT	2,002,314	CT	1,966,193	-	2,081,693	-	1,918,101
2005	-	2,260,156	-	2,217,288	CT	2,367,303	-	2,150,168
2006	CC	2,523,419	CT	2,465,049	-	2,644,041	CT	2,378,234
2007	-	2,774,461	-	2,701,866	CC	2,923,803	-	2,594,387

CT - Combustion Turbine
CC - Combined Cycle

Notes
(1) Hookers Point Station is assumed retired in January 2003 for the purposes of this study
(2) Assumed no build-out of Hardee Power Station in January 2003

Q. Provide a table of annual and cumulative present worth revenue requirements (CPWRR) for all combinations of units that were evaluated in order to arrive at your utility's base case generation expansion plan. Include the type and timing of the unit or units that comprise each alternative, and the impact of these unit additions on the system loss of load probability (LOLP) and reserve margin. Provide this information in a format like that shown at the top of the next page.

A. Tampa Electric Company uses the PROVIEW module of PROSCREEN, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the time and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions which satisfy the specified reliability criteria and determines the schedule of additions which have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements used to rank each plan.

The top ranked generation expansion plans were identical through year 2007. Therefore, only one table of data is provided in response to this questions. For additional details on the optimization process see the response to item 14.

UTILITY: TAMPA ELECTRIC COMPANY
1998 REVENUE REQUIREMENTS
BASE CASE EXPANSION PLAN SENSITIVITIES

Year	Unit (s)	Annual (1) PWRR ($000)	Cumulative (1) PWRR ($000)	EUE/NEL (3) %	Reserve Margin % Summer	Winter
1998	-	310,777	310,777	0.21%	22%	23%
1999	-	296,856	607,633	0.23%	27%	23%
2000	-	288,622	896,255	0.40%	19%	20%
2001	-	281,203	1,177,458	0.51%	21%	18%
2002	-	274,469	1,451,927	0.83%	18%	15%
2003 (2)	CT	267,386	1,719,313	0.74%	17%	17%
2004	CT	265,043	1,984,356	0.70%	15%	19%
2005	-	254,452	2,238,808	0.70%	16%	17%
2006	CT	251,698	2,490,505	0.43%	18%	19%
2007		240,903	2,731,408	0.51%	16%	17%

Notes

(1) PWRR values are based on average projected supplemental fuel purchase prices
(2) Hookers Point Station is assumed retired in January 2003 for the purposes of this study
(3) Tampa Electric Company's planning criteria is 1% EUE and 15% winter reserve margin

Q. Identify your utility's base case generation expansion plan if the current differential in the price of oil/gas and coal, in cents/MBTU, were to be kept constant over the planning horizon. Provide a table of annual and cumulative present worth revenue requirements (CPWRR) for this scenario, in a format like that shown (6).

A. Even though Tampa Electric does not recognize, as a viable forecasting method, the arbitrary development of a fuel forecast by fixing the price differential between non-linked fuels, an expansion plan fuel sensitivity was performed by holding the differential between oil/gas and coal constant. The base case expansion plan did not change as a result of this change in the fuel price forecast. This result was expected because Tampa Electric Company's base case expansion plan consists of combustion turbines. These dual-fuel combustion turbines will be fired by natural gas and distillate oil. Because this sensitivity lowers Tampa Electric Company's natural gas and oil price forecasts and Tampa Electric Company's future resources are fired by natural gas and oil, it results in the same base case plan.

UTILITY: TAMPA ELECTRIC COMPANY
1998 REVENUE REQUIREMENTS
CONSTANT FUEL DIFFERENTIAL
BASE CASE EXPANSION PLAN SENSITIVITIES

Year	Unit (s)	Annual (1) PWRR ($000)	Cumulative (1) PWRR ($000)	EUE/NEL (3) %	Reserve Margin %	
					Summer	Winter
1998	-	310,777	310,777	0.21%	22%	23%
1999	-	297,044	607,822	0.23%	27%	23%
2000	-	288,402	896,223	0.40%	19%	20%
2001	-	280,545	1,176,769	0.51%	21%	18%
2002	-	273,170	1,449,939	0.83%	18%	15%
2003 (2)	CT	265,490	1,715,429	0.74%	17%	17%
2004	CT	262,040	1,977,468	0.70%	15%	19%
2005		250,624	2,228,092	0.70%	16%	17%
2006	CT	246,404	2,474,496	0.43%	18%	19%
2007		234,714	2,709,210	0.51%	16%	17%

Notes

(1) PWRR values are based on average projected supplemental fuel purchase prices
(2) Hookers Point Station is assumed retired in January 2003 for the purposes of this study
(3) Tampa Electric Company's planning criteria is 1% EUE and 15% winter reserve margin

Q. Using your utility's generation expansion planning assumptions, estimate annual emissions (in tons) for SO_2, No_x, particulates, VOCs, CO_2, and Hg in the format shown below and on the following page. Include estimates of emissions for the base case and for sensitivities using high/low fuel price forecasts and high/low demand forecasts as shown.

A. The total system emissions for the various scenarios are shown on the attached page.

SO_2 - Estimates include emissions for affected and non-affected units and do not include any allowance purchases, which would offset total emissions.

NO_x - Estimates are based on Environmental Permits Limits and AP-42 Air Pollutant Emission Factors, 1995.

PM - Estimates are based on Environmental Permits Limits and AP-42 Air Pollutant Emission Factors, 1995.

VOCs - Estimates are based on Environmental Permits Limits and AP-42 Air Pollutant Emission Factors, 1995.

CO_2 - Estimates are based on the DOE report *Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases Under Section 1605 (b) of the Energy Policy Act of 1992.*

Hg Estimates are based on FCG Emission Factors, 1995.

Year	Base Case Demand Forecast / Base Case Fuel Price Forecast					
	SO2 (tons)	NOx (tons)	PM (tons)	VOC (tons)	CO2 (tons)	Hg (tons)
1998	176,014	108,364	7,812	410	19,591,108	0.50
1999	176,741	109,317	7,595	423	19,482,001	0.49
2000	104,691	73,556	7,551	463	19,039,257	0.48
2001	106,708	75,339	7,660	541	19,561,515	0.49
2002	106,708	75,499	7,734	630	19,561,520	0.49
2003	107,025	78,327	7,833	432	20,056,891	0.51
2004	107,264	78,001	7,869	467	19,913,988	0.50
2005	107,575	81,173	8,039	480	20,504,991	0.52
2006	107,692	82,0[illegible]	8,128	516	20,690,824	0.52
2007	108,498	83,778	8,297	542	21,042,170	0.53

Base Case Demand Forecast

Year	High Fuel Price Forecast					
	SO2 (tons)	NOx (tons)	PM (tons)	VOC (tons)	CO2 (tons)	Hg (tons)
1998	176,002	108,380	7,809	403	19,587,596	0.50
1999	176,740	109,342	7,592	417	19,495,219	0.49
2000	104,693	73,567	7,783	460	19,041,849	0.51
2001	105,143	74,812	7,723	506	19,464,176	0.52
2002	105,143	74,683	7,745	589	19,408,240	0.51
2003	105,100	77,003	7,693	429	19,783,989	0.50
2004	105,099	76,573	7,718	463	19,819,187	0.50
2005	105,156	79,172	7,843	487	20,178,597	0.51
2006	105,027	80,206	7,919	511	20,294,287	0.51
2007	105,083	81,502	8,045	529	20,538,121	0.52

Year	Low Fuel Price Forecast					
	SO2 (tons)	NOx (tons)	PM (tons)	VOC (tons)	CO2 (tons)	Hg (tons)
1998	176,067	108,325	7,819	423	19,590,183	0.50
1999	176,735	109,243	7,601	439	19,483,851	0.49
2000	104,745	73,535	7,569	474	19,038,141	0.49
2001	105,140	74,722	7,607	519	19,448,041	0.49
2002	105,140	74,567	7,627	598	19,392,367	0.49
2003	105,044	76,699	7,686	432	19,773,043	0.50
2004	105,193	76,709	7,724	469	19,853,817	0.50
2005	105,162	79,290	7,843	494	20,201,915	0.51
2006	105,173	80,498	7,929	525	20,383,143	0.51
2007	105,201	81,738	8,050	540	20,528,824	0.52

Base Case Fuel Price Forecast

Year	High Demand Forecast					
	SO2 (tons)	NOx (tons)	PM (tons)	VOC (tons)	CO2 (tons)	Hg (tons)
1998	176,639	108,732	7,843	418	19,649,752	0.51
1999	178,004	110,076	7,656	440	19,609,397	0.49
2000	106,002	74,366	7,642	494	19,214,570	0.49
2001	106,948	76,483	7,807	565	19,799,604	0.50
2002	106,948	76,793	7,899	697	19,859,274	0.50
2003	109,326	79,868	7,979	447	20,415,533	0.52
2004	109,753	80,043	8,045	490	20,371,349	0.51
2005	110,403	83,394	8,237	518	21,075,510	0.53
2006	111,106	84,989	8,364	566	21,334,799	0.53
2007	112,097	86,942	8,566	582	21,749,450	0.54

Year	Low Demand Forecast					
	SO2 (tons)	NOx (tons)	PM (tons)	VOC (tons)	CO2 (tons)	Hg (tons)
1998	175,604	108,128	7,795	405	19,556,722	0.50
1999	175,810	108,749	[illegible]	412	19,403,144	0.49
2000	103,583	72,893	7,469	439	18,894,488	0.48
2001	104,823	74,392	7,583	506	19,357,881	0.49
2002	104,823	74,467	7,626	576	19,313,956	0.49
2003	105,125	76,881	7,704	421	19,741,621	0.50
2004	105,245	76,439	7,733	451	19,564,432	0.50
2005	105,125	79,109	7,886	472	20,114,776	0.51
2006	105,013	80,004	7,948	491	20,228,414	0.51
2007	105,189	81,222	8,077	506	20,489,441	0.52

NOTE: SO2 estimates include emissions for the total system (affected and non-affected units)

Q. Discuss how your utility's Clean Air Act Compliance plan is integrated into the generation expansion plan.

A. Tampa Electric Company calculates its fuel blend required to meet system compliance based on the necessary annual emissions target (tons SO_2/yr). Compliance is taken into consideration as a system requirement and not a unit requirement. Thus, the incremental variable costs of compliance are included in the cost of fuel and the effects are included in the system production cost component of the economic analysis. The effects of both the demand side and supply side alternatives are included in the system marginal and average fuel and purchased power expense on an annual basis. The benefits of any displaced generation due to DSM programs are captured as a reduction in system fuel expense as a result of reducing the system low sulfur coal requirements in a given year.

Q. Identify and discuss all proposed or reasonably expected State and Federal environmental regulations or legislation that impacted your utility's generation expansion plan.

A. The Clean Air Act Amendments of 1990 and EPA's related rulemaking are the primary legislative and rulemaking activities that affect the generation expansion plan. Emission constraints related to this legislation are factored into projected generating unit performance and dispatch.

Q. Identify and discuss all your utility's environmental research activities in the various areas of public concern such as air toxics, EMF, heavy metals and greenhouse gases.

A. Tampa Electric Company's involvement in environmental research is limited to activities performed by trade associations of which we are members. The most significant research that we are involved in is the Florida mercury research activities being conducted by the Florida Electric Power Coordinating Group (FCG) and the Florida Department of Environmental Protection (FDEP). In addition to the above mercury research, Tampa Electric is studying the thermal impact of Big Bend station and collecting site specific information for use in an ongoing permitting efforts.

Tampa Electric has been involved in many activities related to EMF and Florida Acid Deposition through the FCG. Specific studies were also undertaken as part of the licensing of Big Bend 4 and the Polk Power Plant. These cover many issues including benthic, groundwater and fine mesh screen efficiency evaluations.

Q. Discuss how your utility incorporates public concern over air toxic emissions, EMF exposure, heavy metals emissions and greenhouse gases into the generation expansion plan as well as plans for transmission and distribution additions.

A. Most major construction projects associated with power production and transmission lines require environmental authorizations. The permitting process typically provides steps by which the public can have input. For example, new power plants are reviewed by multiple agencies as part of the Florida Power Plant Siting Act. These agencies not only cover the breadth of env.ronmental concern, but also provide ample ways to receive public comments.

Q. Identify and discuss how elements of risk (such as heavy reliance on natural gas, transmission system constraints, inadequate fuel diversity, evolving environmental regulations, or unusually high or low forecasts of load and fuel price) are addressed in your utility's generation expansion plan. Explain how your utility will adapt to such contingencies.

A. Sensitivity analysis of the top ranked plans from the economic analysis is used to determine the relative impact of various assumptions on the robustness of the base plan. These sensitivities involve parameters which are greatly influenced by the action and decisions of organizations other than Tampa Electric Company. The sensitivities include system load and energy requirements, fuel prices, and financial assumptions. These sensitivities are developed by using the top plans, which are chosen based on economics and a variety of supply side options, and analyzing them in scenarios to determine the most economically viable plan under all scenarios.

Strategic issues which affect the type, capacity, and/or timing of future generation resource requirements are analyzed. These issues such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. Therefore, a strategic analysis is conducted to compare the overall performance of each alternative resource plan under each issue. The strategic issues and economic analysis are combined to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes.

The tool used to combine the strategic issues and economic analysis is a decision matrix. The decision matrix is used to compare and select the most cost-effective plan. Each alternative resource plan is analyzed on both a quantitative and qualitative basis. The quantitative analysis is based on comparing the cumulative present worth of revenue requirements for each alternative for both the base and sensitivity assumptions. The qualitative analysis considers these previously mentioned strategic issues. Each alternative is ranked based on pre-determined criteria and the sum of the values for each category. The combined scores indicate the relative strength of each alternative on both a quantitative and qualitative basis.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment.

Q. Identify and discuss any firm power purchases that your utility expects to make from other utilities over the planning horizon. If some unidentified or unconfirmed future power purchase is part of your utility's generation expansion plan, explain the nature of that purchase is part of your utility's generation expansion plan, explain the nature of that purchase.

A. Tampa Electric has a long term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with SEC, whereby Tampa Electric plans for the full net capability of the Hardee Power Station during those times when SEC plans for the full availability of Seminole Units 1 and 2 and the SEC Crystal River Unit 3 allocation, and reduced availability during times when Seminole Units 1 and 2 are derated or unavailable due to planned maintenance.

Q. Discuss your utility's optimization process, indicating whether plan optimization was based on revenue requirements, strategic concerns, rates, or total resource cost.

A. Tampa Electric Company's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders. A flow diagram of the overall process is shown in Figure V-1.

The initial pass of the process incorporates a reliability analysis to determine timing of future needs, and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. In this pass, a demand and energy forecast which excludes incremental DSM programs is developed. Then a supply plan based on the system requirements which excludes incremental DSM is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the DSM programs and supply side resources. The same planning and business assumptions are used to develop numerous combinations of DSM and supply side resources that account for variances in both timing and type of resources added to the Tampa Electric Company system.

The cost-effectiveness of DSM programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the Participants Tests. Using the Commission's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and Participants Tests in the DSM analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first.

Tampa Electric Company evaluates DSM measures using a spreadsheet developed to meet the Commission's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric Company service area. Geographic viability, weather conditions, public acceptance, economics, lead-time, environmental acceptability, safety, and proven demonstration and commercialization are used as criteria to screen the generating technologies to a manageable number.

The technologies which pass the screening are included in a supply side analysis which examines various supply side alternatives for meeting future capacity requirements. These include modifying existing units by repowering or over pressure operation and delayed retirements. Other supply resources such as constructing new unit additions, firm power purchases from other generating entities, joint ownership of generating capacity, and modifications of the transmission system to increase import capability are included in the analysis.

Tampa Electric Company uses the PROVIEW module of PROSCREEN, a computer model developed by New Energy Associates, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the time and type of capacity additions which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions which satisfy the specified reliability criteria and determines the schedule of additions which have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements used to rank each plan.

A detailed cost analysis for each of the top ranked resource plans is performed using the Capital Expenditure and Recovery module and the Generation and Fuel module of PROSCREEN. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

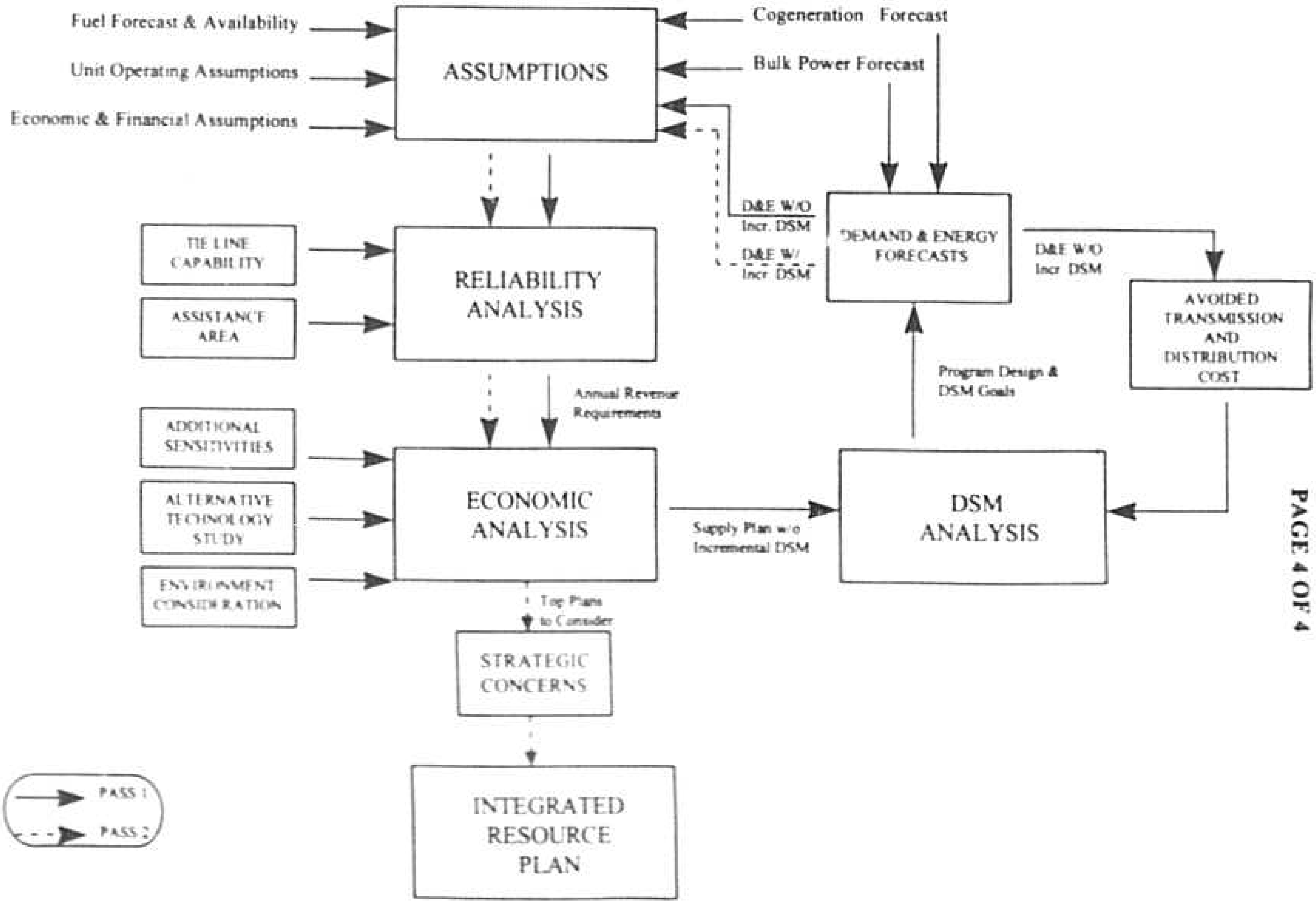
Sensitivity analysis of the top ranked plans from the economic analysis is used to determine the relative impact of various assumptions on the robustness of the base plan. These sensitivities involve parameters which are greatly influenced by the action and decisions of organizations other than Tampa Electric Company. The sensitivities include system load and energy requirements, fuel prices, financial assumptions, and alternative supply side options. These sensitivities are developed by using the top plans, which are chosen based on economics and a variety of supply side options, and analyzing them in scenarios to determine the most economically viable plan under all scenarios.

Strategic issues which affect the type, capacity, and/or timing of future generation resource requirements are analyzed. These issues such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. Therefore, a strategic analysis is conducted to compare the overall performance of each alternative resource plan under each issue. The strategic issues and economic analysis are combined to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes.

The tool used to combine the strategic issues and economic analysis is a decision matrix. The decision matrix is used to compare and select the most cost-effective plan. Each alternative resource plan is analyzed on both a quantitative and qualitative basis. The quantitative analysis is based on comparing the cumulative present worth of revenue requirements for each alternative for both the base and sensitivity assumptions. The qualitative analysis considers these previously mentioned strategic issues. Each alternative is ranked based on pre-determined criteria and the sum of the values for each category. The combined scores indicate the relative strength of each alternative on both a quantitative and qualitative basis.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY



Q. Discuss your utility's resource selection criteria. Include documentation which allows one to determine how your utility integrates supply-side and demand-side resources into the resource plan on a consistent and equal basis.

A. Initially, Tampa Electric Company develops a demand and energy forecast which excludes incremental DSM program. Then the initial pass of the process incorporates a reliability analysis to determine timing of future needs, and an economic analysis to determine what resource alternatives best meet future needs, and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. In this pass, a demand and energy forecast which excludes incremental DSM programs is developed. Then a supply plan based on the system requirements which excludes incremental DSM is developed. This interim supply plan becomes the basis for potential avoided units(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the DSM programs and supply side resources. The same planning and business assumptions are used to develop numerous combinations of DSM and supply side resources that account for variances in both timing and type of resources added to the Tampa Electric Company system. See response to item number 14 for additional details.

Q. Define and discuss your utility's reliability criteria.

A. Tampa Electric Company uses the dual reliability criteria of 1% Expected Unserved Energy (%EUE) and a 15% minimum firm winter reserve margin for planning purposes.

Tampa Electric Company's approach to calculating percent reserves is consistent with the industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's percent Expected Unserved Energy (%EUE) criteria addresses annual reliability. Similar to calculating percent reserves, all firm unit and station power sales are accounted for in determining Tampa Electric's available capacity resources. The 1% EUE target was developed as an equivalent to the loss of Tampa Electric's largest unit (Big Bend Unit 4, 447 MW) for an entire year and maintaining firm reserves of approximately 15%. In calculating the EUE, the Hardee Power Station is considered to be available as a Tampa Electric capacity resource only after its availability is reduced for planned outages, forced outages, and projected Seminole Electric Cooperative (SEC) usage. SEC provides Tampa Electric with its projected usage of the Hardee Power Station capacity. Percent EUE is calculated by dividing Tampa Electric's projected annual non-firm purchases (excluding economy) by its Net Energy for Load and multiplying by 100%. Under these conditions, Tampa Electric will have adequate reserves or available emergency and/or contracted short-term firm capacity to mitigate expected unserved energy.

Q. Discuss your utility's ability to dispatch non-utility generators on its system.

A. Tampa Electric Company dispatches one non-utility generator on its system, the independent power project located at the Hardee Power Station (297 summer MW / 360 winter MW) is owned and operated by TECO Power Services. Tampa Electric Company's central dispatch center can dispatch the Hardee Power Station as required by means of an AGC (Automatic Generation Control) system. None of the remaining non-utility generators on its system are dispatched by Tampa Electric Company.

Q. Discuss your utility's historic, existing, and proposed activities regarding renewable energy resources.

A. Tampa Electric Company continually monitors the status of renewable technologies through monthly publications, conference papers, research papers, and technical guides. Tampa Electric Company also evaluates the economics, geographic viability, public acceptance, and commercial availability of renewable energy resources as part of its alternative technology study.

Tampa Electric Company purchases firm power from two non-utility, renewable, refuse-to-energy cogeneration facilities. Tampa Electric Company also purchases as-available energy from several non-utility cogenerators utilizing waste-heat-recovery from sulfuric acid production of fertilizer manufacturing.

Tampa Electric Company's Electric Technology Resource Center (ETRC) opened its doors on November 1, 1995, with a goal of bringing energy efficient technologies to the doorstep of Florida's businesses. The ETRC is located on the campus of the University of South Florida in Tampa. The 10,000 square foot facility serves as a showcase and full-service demonstration facility for displaying interactive testing centers in lighting, foodservice, and advanced technology. It also contains an information center which provides access to technology related information and areas for conducting training and meetings.

Tampa Electric Company is a member of the National Earth Comfort program, an initiative of electric utilities, geothermal heat pump manufacturers, the U.S. EPA, and the Consortium for Energy Efficiency. In partnership with the U.S. Department of Energy (DOE), the program aims to increase the geothermal heat pump market from 40,000 to 4000,000 units per year. This program calls for a six-year, $100 million commitment to be shared by the private sector on a 2:1 basis with the DOE.

A geothermal heat pump installed at the ETRC and is one of the technologies being featured and demonstrated. Additionally, Tampa Electric works with local air conditioning contractors, builder, and geothermal manufacturers to increase the use of geothermal heat pumps in this market. Tampa Electric annually hosts several teleconferences, seminars, and cooperative marketing meetings to develop the local geothermal infrastructure. The geothermal technology is featured in Tampa Electric's bill which provides informational inserts to increase customer awareness of this energy efficient technology as well as many local trade shows and expositions.

A grant from the Department of Energy (DOE), administered by USAPV, is allowing Tampa Electric to expand its research of photovoltaic applications. A 15 kW PV array, previously build to offset the charging requirements of electric buses in the Hillsborough Area Regional Transit Authority (HART) fleet, has been modified to also power a dehumidifying heat pump at the HART north terminal building. The research will continue in order to determine whether the PV-heat pump can be commercialized.

Tampa Electric Company in conjunction with the University of Florida's Energy Extension Service and other formed a work group to research and test solar systems for commercial use (parking lot lighting, sign lighting, irrigation, etc.). In 1993, eight different lighting system were installed at our Western Service Area testing facility for evaluation and monitoring. The evaluation study began as a Phase I pilot project for Wendy's International which resulted in three solar lighting systems being installed in a state-of-the-art restaurant near Atlanta, Georgia. Through this solar lighting project a local manufacturer, Mor-Lite, developed a very high efficiency florescent fixture for use with PV charging systems. Tampa Electric Company's successful involvement with the PV lighting systems was highlighted in the 1993 Paul Harvey commentary.

Tampa Electric Company worked closely with EPRI and the Sandia National Laboratories PV Design Assistance Center to foster the development and utilization of cost-effective PV system for powering remotely operated transmission sectionalizing switches. Currently five systems are installed with several more scheduled to be added to the Tampa Electric system. We are actively installing these PV systems for transmission switches when economically feasible.

In 1991, Tampa Electric Company, the Polk County Builders Association, and FAMU/USF Architecture Program designed and build the Optimar home south of Lakeland, Florida. Optimar challenged conventional practices by demonstrating affordable, leading edge energy-saving technologies that have minimal impact on Florida's energy and water resources. Some the other passive solar practices that were applied included the preservation of trees for maximum shading, orientation of the home to minimize sun exposure, operable windows to maximize cross ventilation and natural lighting, use of specially coated glass with neutral colors, extended overhangs, and deep porches for shading. The home is air conditioned and heated using a geothermal system also provides low cost domestic hot water. Over 10,000 of our customers have visited the Optimar home, seeking ideas for their own new or remodeled homes.

Q. Discuss how your utility identifies and verifies the durability of demand and energy savings of its conservation and DSM programs.

A. Tampa Electric Company identifies and verifies the durability of energy savings from our conservation and DSM programs by several methods. First, Tampa Electric Company has established a monitoring and evaluation (M&E) process where historical analysis identifies the energy savings. These include:

(1) end-use metering of a load survey sample to identify the savings achieved on air conditioning, heating, and water heating;

(2) bill analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(3) in commercial programs such as Standby Generator and C/I Load Management, the reductions are verified through submetering of those loads under control to determine participant incentives relative to demand and energy savings.

Secondly, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Where programs promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs), program standards require they be of a permanent nature. For example, our Commercial Indoor Lighting Program requires full-fixture replacement or hard- wiring of fixture replacements.

Q. Discuss your utility's plans regarding the evaluation of district heating and cooling as a demand-side measure.

A. Tampa Electric Company's evaluation of district heating and cooling measures would be conducted on a case by case analysis for customers and consultants under our Conservation Value Program. Cost-effective evaluations that meet the program's standards would be eligible for incentives.