ORIGINAL

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April 2, 2001

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RECORDS AND REPORTING

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

undocketed

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 of the company's January 2001 to December 2010 Ten Year Site Plan.

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,

James D. Beasley

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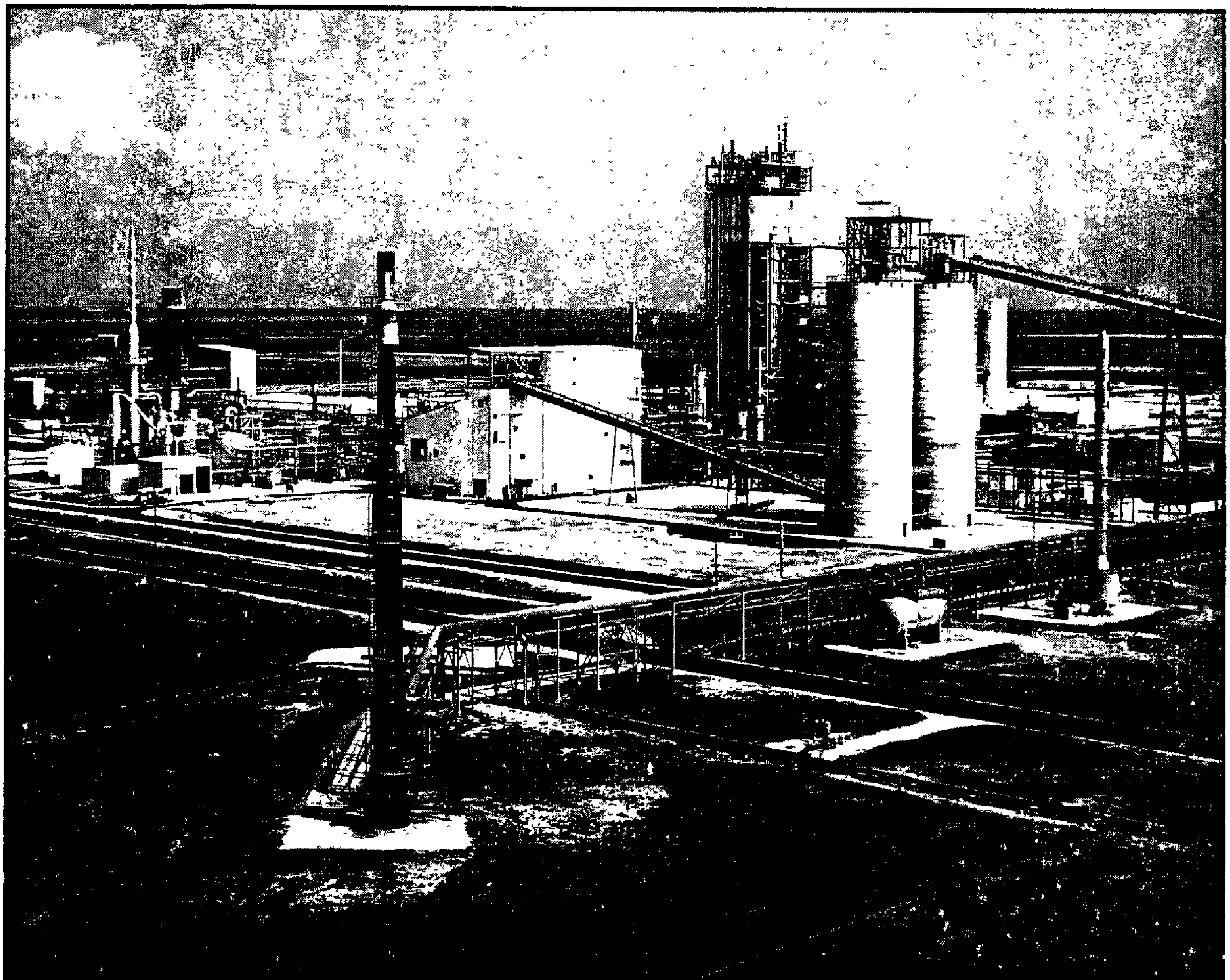

TAMPA ELECTRIC

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

JANUARY 2001 TO DECEMBER 2010

145 002 2/01

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

January 2001 to December 2010

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2001

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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
	LTRS	=	Long Term Reserve Stand-by
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

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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.

Tampa Electric currently has eleven coal-fired units. Ten of these units are fired with pulverized coal. Starting in 2003, Tampa Electric will increase the diversity of its generation mix with the repowering of Gannon Station. The station will be repowered with natural gas and renamed Bayside Power Station. The Big Bend Station contains four pulverized coal fired steam units with flue gas desulfurization. Polk Station is presently comprised of two generating units. Polk unit 1 is fired with synthetic gas produced from gasified coal and other carbonaceous fuels and 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. Polk unit 2 is a combustion turbine, fueled primarily with natural gas.

Generating units at Hookers Point and Phillips are residual oil fired plants. 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 2000 was 17,283 GWh.

Schedule 1

TABLE 1-1
Existing Generating Facilities
As of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough Co. 14/31S/19E									1,998,000	1,851	1,919
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	416	426
	2		FS	C	N	WA	N	0	4/73	"	445,500	416	426
	3		FS	C	N	WA	N	0	5/76	"	445,500	433	443
	4		FS	C	N	WA	N	0	2/85	"	486,000	442	447
	CT1		CT	LO	N	WA	TK	0	2/69	"	18,000	12	17
	CT2&3		CT	LO	N	WA	TK	0	11/74	"	157,500	132	160
Dinner Lake*		Highland Co. 12-055									12,650	11	11
	1		FS	NG	HO	PL	TK	2	12/66	Unknown	12,650	11	11
Gannon		Hillsborough Co. 4/30S/19E									1,319,880	1,132	1,177
	1		FS	C	N	WA	RR	0	9/57	Unknown	125,000	114	114
	2		FS	C	N	WA	RR	0	11/58	Unknown	125,000	98	98
	3		FS	C	N	WA	RR	0	10/60	Unknown	179,520	145	145
	4		FS	C	N	WA	RR	0	11/63	Unknown	187,500	159	169
	5		FS	C	N	WA	RR	0	11/65	Unknown	239,360	232	242
	6		FS	C	N	WA	RR	0	10/67	Unknown	445,500	372	392
	CT1		CT	LO	N	WA	TK	0	3/69	04/01/01	18,000	12	17
Hookers Pt. ***		Hillsborough Co. 19/29S/19E									232,600	196	189
	1		FS	HO	N	WA	N	0	7/48	01/1/03	33,000	30	32
	2		FS	HO	N	WA	N	0	6/50	01/1/03	34,500	30	32
	3		FS	HO	N	WA	N	0	8/50	01/1/03	34,500	30	32
	4		FS	HO	N	WA	N	0	10/53	01/1/03	49,000	39	41
	5		FS	HO	N	WA	N	0	5/55	01/1/03	81,600	67	52
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									521,299	400	430
	1		IGCC	C	LO	WA/TK	TK	0	9/96	Unknown	326,299	250	250
	2		CT	NG	LO	PL	TK	0	7/00	Unknown	195,000	150	180
											TOTAL	3,627	3,763

Notes:

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

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

*** Hooker's Pt. station limited to 100 MW of steam capacity and unit 5 is placed on long-term reserve standby as of 1/1/2001.

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

Plant Name	Land Area: Total Acres	Land Area: In Use Acres	Plant Capital Investment ($000): Land	Plant Capital Investment ($000): Structures & Improvements	Plant Capital Investment ($000): Equipment	Plant Capital Investment ($000): Total
Hookers Point Station	25	25	$437	$7,952	$45,719	$54,108
Big Bend Station	1,124	1,124	5,147	159,356	946,433	1,110,936
Francis J. Gannon Station	213	213	1,556	62,632	404,202	468,390
Dinner Lake - Sebring	2	2	15	631	2,990	3,636
Phillips - Sebring	36	36	179	9,012	52,727	61,918
Combustion Turbine - Gannon	1	1	0	75	1,790	1,865
Combustion Turbines - Big Bend	75	75	834	1,707	22,295	24,836
Miscellaneous Production Services	47	47	94	6,952	1,222	8,268
Polk Power Station	4,347	4,347	18,920	111,767	467,023	597,710
CT – Other	0	0	0	0	4,500	4,500
TOTALS			$27,182	$360,084	$1,948,901	$2,336,167

TABLE 1 - 3

Existing Generating Facilities/Environmental Considerations for Steam Generating Units

Plant Name	Unit		Flue Gas Cleaning			Cooling Type
			Particulate	SO_X	NO_X	
Francis J. Gannon		1	EP	LS	NR	OTS
		2	EP	LS	NR	OTS
		3	EP	LS	(2)	OTS
		4	EP	LS	(2)	OTS
		5	EP	LS	(1)	OTS
		6	EP	LS	(1)	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	SC	(1)	OTS
		2	EP	SC	(1)	OTS
		3	EP	SC	(3)	(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	(1)	CLT
		2	NR	FQ	(1)	CLT
	HRSG	3	NA	NA	NA	NA
Polk	IGCC	1	NR	AGR	NI	OLS
	CT	2	NR	NR	DLN	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
DLN = Dry Low Nox

December 31, 2000 Status

(1) NO_X controlled through unit operation.
(2) NO_X controlled through unit operation and fuel quality.
(3) NOx controlled through unit design and operation.
(4) OTS with fine mesh screens to minimize entrainment.

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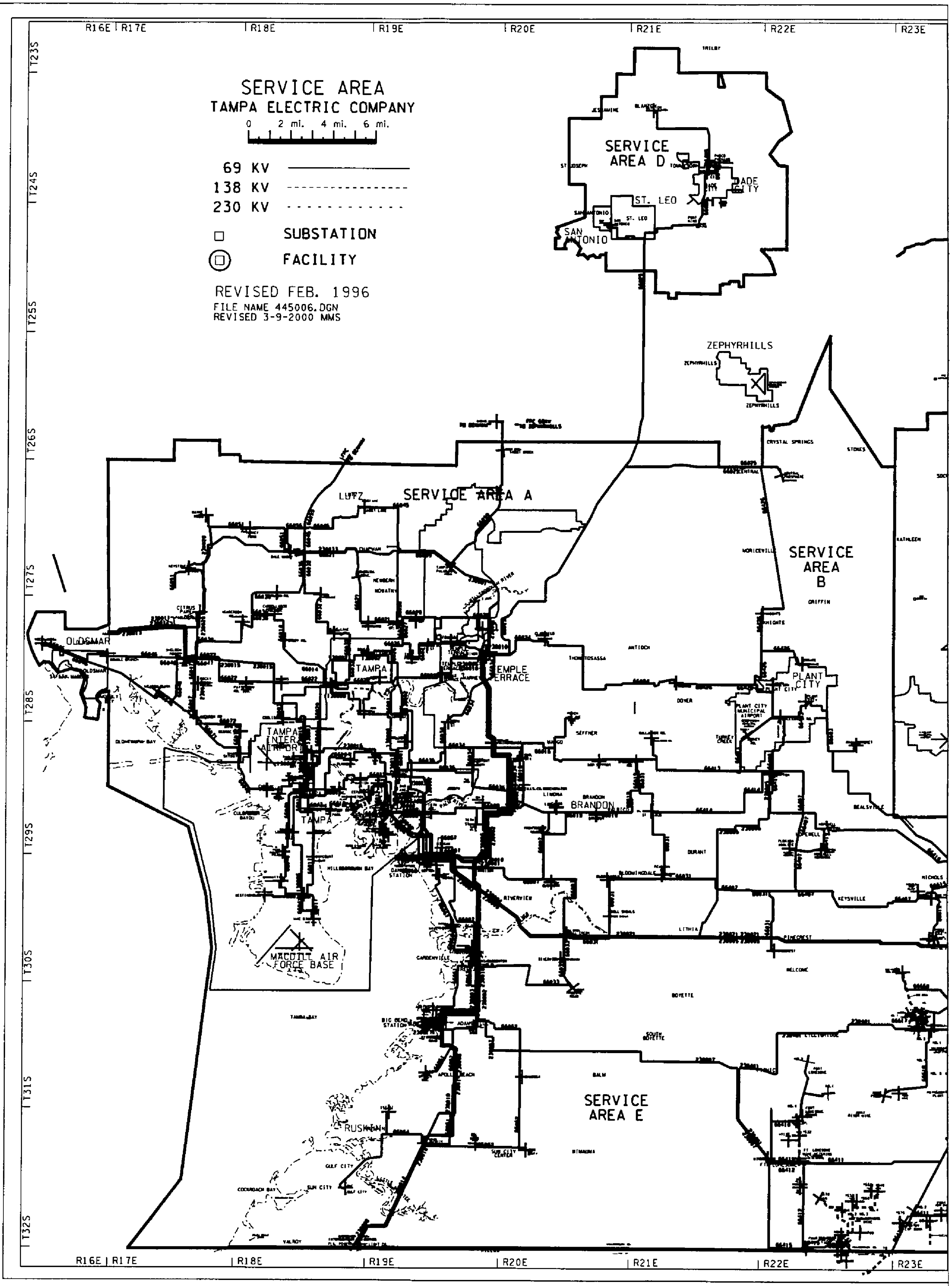

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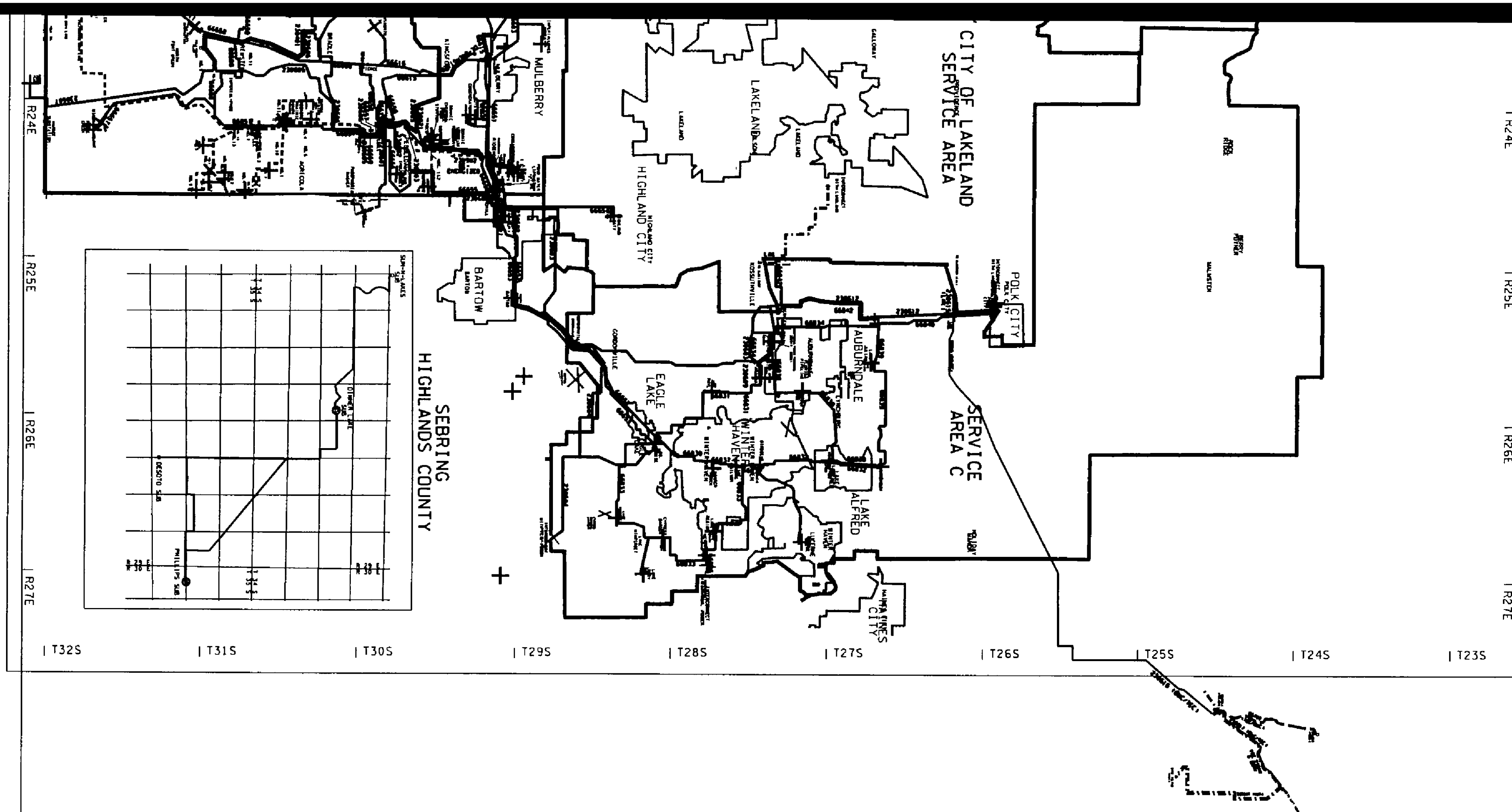

FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

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

FILE NAME 445006.DGN
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CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

1. Table II-1: History and Forecast of Energy Consumption and Number of Customers by Customer Class
2. Table II-2: History and Forecast of Summer Peak Demand
3. Table II-3: History and Forecast of Winter Peak Demand
4. Table II-4: History and Forecast of Annual Net Energy for Load
5. Table II-5: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
6. Table II-6: History and Forecast of Fuel Requirements
7. Table II-7: History and Forecast of Net Energy for Load by Fuel Source

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	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
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	928,731	2.4	6,500	456,175	14,249	4,902	56,981	86,029
1998	942,322	2.4	7,050	466,189	15,123	5,173	58,542	88,364
1999	962,153	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	982,400	2.4	7,369	491,925	14,980	5,541	61,902	89,514
2001	996,377	2.4	7,690	504,301	15,248	5,755	63,053	91,277
2002	1,010,552	2.3	7,948	515,318	15,423	5,949	63,887	93,118
2003	1,024,929	2.3	8,205	524,316	15,648	6,143	64,707	94,943
2004	1,039,511	2.3	8,449	532,339	15,871	6,338	65,423	96,878
2005	1,054,300	2.3	8,692	540,034	16,096	6,533	66,430	98,350
2006	1,067,885	2.3	8,935	547,551	16,319	6,726	67,417	99,762
2007	1,081,646	2.3	9,176	555,154	16,528	6,917	68,415	101,100
2008	1,095,583	2.3	9,418	562,845	16,732	7,109	69,424	102,403
2009	1,109,701	2.3	9,661	570,625	16,930	7,303	70,446	103,667
2010	1,124,000	2.3	9,905	578,495	17,122	7,498	71,479	104,898

December 31, 2000 Status

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

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	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
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	1028	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	14,930
1997	2,465	629	3,918,919	0	53	1,170	15,090
1998	2,520	682	3,695,015	0	54	1,231	16,028
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,390	776	3,079,897	0	53	1,285	16,638
2001	2,328	823	2,828,320	0	56	1,329	17 158
2002	2,335	859	2,718,395	0	58	1,354	17 644
2003	2,299	877	2,621,086	0	59	1,391	18,097
2004	2,308	897	2,572,899	0	61	1,428	18,584
2005	2,323	918	2,530,595	0	63	1,466	19,078
2006	2,274	938	2,424,016	0	64	1,503	19,502
2007	2,312	958	2,413,137	0	65	1,542	20,011
2008	2,343	978	2,395,940	0	67	1,580	20,517
2009	2,372	998	2,377,022	0	68	1,618	21,022
2010	2,323	1008	2,304,631	0	69	1,656	21,451

December 31, 2000 Status

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

Schedule 2.3

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 *	(6) Total Customers*
1991	129	695	14,279	3,736	462,260
1992	214	671	14,437	3,790	468,996
1993	246	808	14,501	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	16,089	4,391	506,038
1997	507	731	16,328	4,583	518,368
1998	431	783	17,242	4,839	530,252
1999	533	900	17,238	5,299	543,661
2000	750	972	18,360	5,497	560,101
2001	776	894	18,828	5,664	573,840
2002	506	919	19,069	5,823	585,886
2003	257	943	19,297	5,954	595,855
2004	265	968	19,817	6,070	604,731
2005	271	993	20,342	6,182	613,565
2006	271	1,016	20,789	6,291	622,197
2007	270	1,043	21,324	6,402	630,929
2008	273	1,068	21,858	6,513	639,761
2009	276	1,095	22,393	6,626	648,695
2010	277	1,118	22,846	6,741	657,723

December 31, 2000 Status

* Average of end-of-month customers for the calendar year
** Output to line including energy supplied by purchased cogeneration
++ 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)	(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	
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2 492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998	3,444	111	3,333	204	99	49	18	18	2,945	
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,551	171	3,380	182	74	56	19	21	3,028	
2001	3,713	175	3,538	202	100	60	25	26	3,125	
2002	3,813	175	3,638	199	101	63	25	28	3,222	
2003	3,930	175	3,755	200	101	66	26	30	3,332	
2004	4,041	176	3,865	194	101	68	26	32	3,444	
2005	4,162	186	3,976	191	101	71	26	34	3,553	*
2006	4,267	186	4,081	182	101	73	27	35	3,663	
2007	4,348	151	4,197	186	102	75	27	37	3,770	
2008	4,440	131	4,309	184	102	77	28	38	3,880	
2009	4,558	131	4,427	186	102	79	28	39	3,993	
2010	4,672	132	4,540	178	102	81	28	40	4,111	

December 31, 2000 Status

* Not coincident with system peak
\+ Includes residential and commercial/industrial conservation
++ 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	
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	•
1993	2,951	60	2,891	273	91	28	6	11	2,492	•
1994	2,865	69	2,796	200	97	31	8	11	2,451	•
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	•
1998	3,444	111	3,333	204	99	49	18	18	2,945	
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,551	171	3,380	182	74	56	19	21	3,028	
2001	3,746	175	3,571	203	101	60	25	26	3,157	
2002	3,866	175	3,691	200	102	63	25	28	3,273	
2003	4,009	176	3,833	202	102	67	26	30	3,406	
2004	4,141	177	3,964	198	103	70	26	32	3,536	
2005	4,295	187	4,108	195	104	72	26	34	3,677	
2006	4,440	187	4,253	186	104	75	27	35	3,825	
2007	4,540	152	4,388	191	105	77	27	37	3,950	
2008	4,675	133	4,542	191	105	80	28	38	4,100	
2009	4,831	133	4,698	193	106	82	28	39	4,250	
2010	4,984	133	4,851	185	106	84	28	40	4,407	

December 31, 2000 Status

- • Not coincident with system peak
- \+ Includes residential and commercial/industrial conservation.
- ++ 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	
1991	2,750	39	2,711	265	71	23	1	10	2,341	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998	3,444	111	3,333	204	99	49	18	18	2,945	
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,551	171	3,380	182	74	56	19	21	3,028	
2001	3,672	175	3,498	199	99	59	25	26	3,090	
2002	3,760	175	3,585	196	99	62	25	28	3,175	
2003	3,855	175	3,680	196	99	65	26	30	3,265	
2004	3,936	176	3,760	190	99	67	26	32	3,345	
2005	4,037	185	3,852	187	99	69	26	34	3,437	
2006	4,119	185	3,934	176	99	71	27	35	3,526	
2007	4,169	150	4,019	181	99	73	27	37	3,603	
2008	4,236	130	4,106	180	98	74	28	38	3,687	
2009	4,321	130	4,191	182	98	76	28	39	3,768	
2010	4,387	130	4,257	171	98	77	28	40	3,843	

December 31, 2000 Status

* Not coincident with system peak
\+ Includes residential and commercial/industrial conservation
++ 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
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,186	99	3,087	210	151	350	17	26	2,332
1998/99	3,953	131	3,822	152	250	385	17	28	2,990
1999/00	3,999	125	3,874	212	197	409	18	29	3,009
2000/01	4,362	177	4,185	188	231	436	25	30	3,275
2001/02	4,481	178	4,303	184	231	456	25	31	3,376
2002/03	4,609	178	4,431	187	232	474	25	32	3,481
2003/04	4,732	178	4,554	181	233	492	26	33	3,589
2004/05	4,875	189	4,686	178	234	509	26	34	3,705
2005/06	4,994	189	4,805	170	234	526	27	35	3,813
2006/07	5,102	154	4,948	174	234	544	27	35	3,934
2007/08	5,182	134	5,048	173	235	560	27	36	4,017
2008/09	5,321	135	5,186	174	235	577	28	37	4,135
2009/10	5,443	135	5,308	166	235	593	28	37	4,249

December 31,2000 Status

*	Not coincident with system peak.
+	Includes cumulative conservation
++	Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek
#	Commercial/Industrial Load Management includes Standby Generator.
=	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
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,186	99	3,087	210	151	350	17	26	2,332
1998/99	3,953	131	3,822	152	250	385	17	28	2,990
1999/00	3,999	125	3,874	212	197	409	18	29	3,009
2000/01	4,404	178	4,226	189	232	439	25	30	3,311
2001/02	4,556	178	4,378	187	234	461	25	31	3,439
2002/03	4,705	179	4,526	191	236	481	25	32	3,561
2003/04	4,846	179	4,667	185	237	501	26	33	3,684
2004/05	5,025	190	4,835	182	239	521	26	34	3,833
2005/06	5,168	190	4,978	174	241	540	27	35	3,962
2006/07	5,316	155	5,161	178	242	562	27	35	4,117
2007/08	5,437	136	5,301	178	243	580	27	36	4,236
2008/09	5,614	136	5,478	181	245	600	28	37	4,388
2009/10	5,781	137	5,644	173	246	619	28	37	4,540

December 31, 2000 Status

- * Not coincident with system peak
- \+ Includes residential and commercial/industrial conservation
- ++ Includes sales to FPC, Wauchula, Fort Meade, St Cloud and Reedy Creek
- \# Commercial/Industrial Load Management includes Standby Generator.
- = 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
1990/91	2,638	0	2,638	227	139	196	0	20	2,056
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,186	99	3,087	210	151	350	17	26	2,332
1998/99	3,953	131	3,822	152	250	385	17	28	2,990
1999/00	3,999	125	3,874	212	197	409	18	29	3,009
2000/01	4,332	177	4,155	187	229	433	25	30	3,252
2001/02	4,427	177	4,250	183	229	450	25	31	3,331
2002/03	4,534	178	4,356	183	229	467	25	32	3,421
2003/04	4,629	178	4,451	178	228	482	26	33	3,503
2004/05	4,748	188	4,560	174	228	497	26	34	3,600
2005/06	4,830	188	4,642	167	228	511	27	35	3,675
2006/07	4,913	153	4,760	169	227	527	27	35	3,775
2007/08	4,959	133	4,826	168	227	541	27	36	3,827
2008/09	5,066	133	4,933	170	226	555	28	37	3,917
2009/10	5,142	133	5,009	160	225	568	28	37	3,991

December 31, 2000 Status

*	Not coincident with system peak.
+	Includes residential and commercial/industrial conservation
++	Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
#	Commercial/Industrial Load Management includes Standby Generator.
=	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 % **
1991	13,592	114	23	13,455	129	695	14,279	60.9
1992	13,697	120	25	13,552	214	671	14,437	58.5
1993	13,603	127	30	13,446	246	808	14,500	57.0
1994	14,103	138	33	13,932	163	636	14,731	61.1
1995	14,798	158	40	14,600	212	870	15,682	55.2
1996	15,167	189	49	14,929	399	760	16,088	53.1
1997	15,354	210	54	15,090	507	731	16,328	57.8
1998	16,334	239	67	16,028	431	783	17,242	55.3
1999	16,162	281	76	15,805	533	900	17,238	60.3
2000	17,028	302	88	16,638	750	972	18,360	62.9
2001	17,568	314	96	17,158	776	894	18,828	55.2
2002	18,079	330	105	17,644	506	919	19,069	54.5
2003	18,555	344	114	18,097	257	943	19,297	53.7
2004	19,064	358	122	18,584	265	968	19,817	53.6
2005	19,576	369	129	19,078	271	993	20,342	53.6
2006	20,017	379	136	19,502	271	1,016	20,789	53.5
2007	20,542	390	141	20,011	270	1,043	21,324	53.8
2008	21,063	400	146	20,517	273	1,068	21,858	54.3
2009	21,583	410	151	21,022	276	1,095	22,393	54.3
2010	22,024	419	154	21,451	277	1,118	22,846	54.2

December 31, 2000 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 % **
1991	13,592	114	23	13,455	129	695	14,279	60 9
1992	13,697	120	25	13,552	214	671	14,437	58 5
1993	13,603	127	30	13,446	246	808	14,500	57 0
1994	14,103	138	33	13,932	163	636	14,731	61 1
1995	14,798	158	40	14,600	212	870	15,682	55 2
1996	15,167	189	49	14,929	399	760	16,088	53 1
1997	15,354	210	54	15,090	507	731	16,328	57 8
1998	16,334	239	67	16,028	431	783	17,242	55 3
1999	16,162	281	76	15,805	533	900	17,238	60 3
2000	17,028	302	88	16,638	750	972	18,360	62 9
2001	17,759	317	96	17,347	777	904	19,027	59 8
2002	18,370	333	105	17,931	508	934	19,373	59 5
2003	18,943	349	114	18,479	259	963	19,701	59 2
2004	19,564	365	122	19,078	268	994	20,339	59 1
2005	20,209	378	129	19,702	275	1,026	21,003	58 7
2006	20,787	390	136	20,262	275	1,055	21,592	58 4
2007	21,447	403	141	20,903	275	1,089	22,267	58.0
2008	22,136	414	146	21,575	279	1,124	22,978	58 1
2009	22,832	426	151	22,256	283	1,159	23,698	57 9
2010	23,447	437	154	22,855	285	1,190	24,330	57 5

December 31, 2000 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) 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 % **
1991	13,592	114	23	13,455	129	695	14,279	60 9
1992	13,697	120	25	13,552	214	671	14,437	58 5
1993	13,603	127	30	13,446	246	808	14,500	57 0
1994	14,103	138	33	13,932	163	636	14,731	61 1
1995	14,798	158	40	14,600	212	870	15,682	55 2
1996	15,167	189	49	14,929	399	760	16,088	53 1
1997	15,354	210	54	15,090	507	731	16,328	57 8
1998	16,334	239	67	16,028	431	783	17,242	55 3
1999	16,162	281	76	15,805	533	900	17,238	60 3
2000	17,028	302	88	16,638	750	972	18,360	62 9
2001	17,423	312	96	17,015	775	886	18,676	59 7
2002	17,843	326	105	17,412	505	907	18,822	59 7
2003	18,236	339	114	17,783	255	926	18,964	59 3
2004	18,631	351	122	18,158	263	946	19,367	59 2
2005	19,033	360	129	18,543	268	966	19,778	58 8
2006	19,343	369	136	18,838	267	981	20,087	58 5
2007	19,730	378	141	19,210	266	1,000	20,477	58 1
2008	20,120	386	146	19,588	268	1,020	20,876	58 4
2009	20,489	394	151	19,944	270	1,039	21,254	58 1
2010	20,765	401	154	20,210	270	1,052	21,533	57 8

December 31, 2000 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)
	2000 Actual		2001 Forecast		2002 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	3,560	1,367	3,895	1,460	3,994	1,460
February	2,978	1,249	3,501	1,309	3,588	1,302
March	2,744	1,338	3,088	1,404	3,164	1,419
April	2,667	1,316	3,008	1,385	3,086	1,411
May	3,295	1,684	3,400	1,643	3,489	1,679
June	3,417	1,729	3,627	1,779	3,722	1,807
July	3,408	1,753	3,599	1,870	3,694	1,898
August	3,474	1,832	3,606	1,888	3,701	1,920
September	3,401	1,741	3,595	1,747	3,690	1,780
October	3,360	1,472	3,318	1,574	3,405	1,596
November	2,772	1,348	3,165	1,352	3,252	1,369
December	3,484	1,531	3,436	1,417	3,528	1,428
TOTAL		18,360		18,828		19,069

December 31, 2000 Status

NOTE: Peak demand represents total retail and wholesale demand, excluding conservation impacts.

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 1999	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	7,229	7,327	7,755	7,550	7,401	6,924	5,302	5,333	5,337	5,333	5,365	5,331
(3)	Residual	Total	1000 BBL	507	505	99	73	107	92	89	82	68	61	60	62
(4)		Steam	1000 BBL	471	387	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	36	118	99	73	107	92	89	82	68	61	60	62
(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	458	499	226	187	263	207	244	233	152	135	122	128
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	244	115	89	83	83	86	87	92	92	92	92	89
(11)		CT	1000 BBL	214	384	138	105	180	121	157	141	60	43	30	39
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	0	1,592	1,322	3,868	24,291	52,445	63,343	61,096	58,662	56,984	58,715	60,110
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	0	0	17,745	46,682	57,576	55,340	53,041	51,547	52,706	52,606
(16)		CT	1000 MCF	0	1,592	1,322	3,868	6,546	5,763	5,767	5,756	5,622	5,437	6,009	7,505
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	90	224	241	238	248	241	242	241	251	243	242	242

Schedule 6.1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1999	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Firm Interchange		GWh	398	459	190	528	1,065	889	947	845	677	580	535	564
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWh	14,746	16,051	16,474	16,520	16,090	14,944	11,991	12,075	12,062	12,101	12,145	12,069
(4)	Residual	Total	GWh	207	225	66	49	71	61	59	54	45	40	40	41
(5)		Steam	GWh	184	146	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	23	79	66	49	71	61	59	54	45	40	40	41
(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	249	243	121	92	119	100	115	112	83	77	72	78
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	173	80	59	56	56	58	59	62	62	62	62	60
(12)		CT	GWh	76	163	62	36	63	42	56	51	21	15	11	19
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	0	136	118	365	3,215	7,363	8,955	8,625	8,272	8,036	8,256	8,375
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	0	0	0	0	2,590	6,811	8,396	8,069	7,736	7,520	7,689	7,674
(17)		CT	GWh	0	136	118	365	625	552	559	556	536	516	567	701
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	633	628	677	668	696	676	679	677	704	683	680	679
(20)	Net Interchange		GWh	581	223	764	377	(2,434)	(4,687)	(2,883)	(2,078)	(998)	(208)	117	446
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWh	424	394	418	471	475	472	480	479	479	549	549	595
(23)	Net Energy for Load*		GWh	17,238	18,360	18,828	19,069	19,297	19,818	20,342	20,789	21,324	21,858	22,393	22,846

* Values shown may be affected by rounding

Schedule 6.2

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 1999	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Firm Interchange		%	2	3	1	3	6	4	5	4	3	3	2	2
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		%	86	87	87	87	83	75	59	58	57	55	54	53
(4)	Residual	Total	%	1	1	0	0	0	0	0	0	0	0	0	0
(5)		Steam	%	1	1	0	0	0	0	0	0	0	0	0	0
(6)		CC	%	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	1	1	1	0	1	1	1	1	0	0	0	0
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	1	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	%	0	1	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	0	1	1	2	17	37	44	41	39	37	37	37
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	0	0	13	34	41	39	36	34	34	34
(17)		CT	%	0	1	1	2	3	3	3	3	3	2	3	3
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	4	3	4	4	4	3	3	3	3	3	3	3
(20)	Net Interchange		%	3	1	4	2	(13)	(24)	(14)	(10)	(5)	(1)	1	2
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	2	2	2	2	2	2	2	2	2	3	2	3
(23)	Net Energy for Load*		%	100	100	100	100	100	100	100	100	100	100	100	100

* Values shown may be affected by rounding.

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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 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 developing the 2001-2010 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2001-2010 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 demand 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.

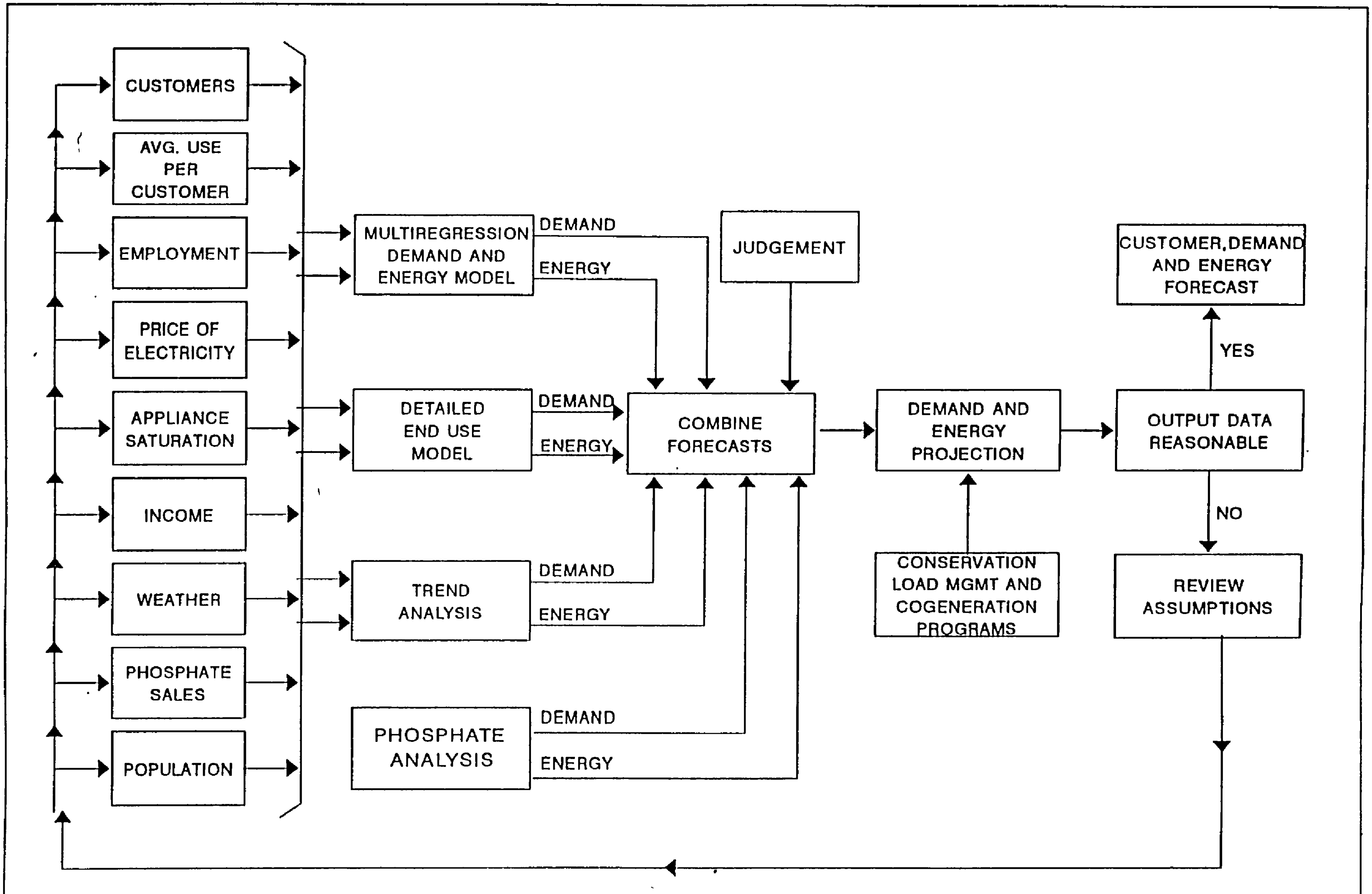


Figure III-1

TAMPA ELECTRIC COMPANY CUSTOMER, DEMAND AND ENERGY FORECAST PROCESS

SOURCE: TAMPA ELECTRIC COMPANY

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 sections, 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 seventeen 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
Miscellaneous

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

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, $0 \leq W_i \leq 1$; $W_1 = 0$, $W_i = 1$ 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

Appliances with Low Assumed Price Sensitivity:

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

Appliances with Medium Assumed Price Sensitivity:

Electric Range
Clothes Washer
Electric Water Heater
Microwave Oven
Lighting

Appliances with High Assumed Price Sensitivity:

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 cannot 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.

$$\text{Base Load} = -174.7 + \underset{(t = 62.4)}{4.635} * \text{\# Residential Customers} \; \underset{(t = -2.4)}{-1835.7} * \text{\$/kWh (lagged 1 year)}$$
$$+ 0.1830 * MA(2) + 0.3743 * MA(4)$$

$\bar{R}$-Squared = .99 DW = 1.9

2.

Temperature Sensitive Demand (Summer)
$$= (F^\circ - 65)\,(32.95 + \underset{(t = 10.3)}{0.1084} * \text{\# A/Cs} \; \underset{(t = -3.8)}{-411.8} * \text{\$/kWh (lagged 2 periods)})$$

$\bar{R}$-Squared = .91 DW = 1.7

3.

Temperature Sensitive Demand (Winter)
$$= (65 - F^\circ)\,(-0.6282 + \underset{(t = 31.9)}{0.1297} * \text{\# Electric Heaters})$$

$\bar{R}$-Squared = .93 DW = 1.9

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 = 5945.4 + 67.5 * Chg in Personal Inc. Per Capita - 595.8 * Cts/Kwh
Residential (t = 2.7) (lagged 1 year) (t= -10.3) (lagged 1 year)
Usage + 1.3 * Total Degree Days + 7732.3 * Htg/Cooling Saturation
(t = 5.3) (t = 21.7)

$\bar{R}$-Squared = .96 DW = 1.7

2.

Commercial = -1745.1 + 15.0 * Residential Customers - 82.0 * Cts/Kwh (lagged 1 yr)
Energy (t = 98.6) (t = -7.0)
Sales + 0.111 * Total Degree Days + 1.564 * MA (1)
(t = 2.6)
$\bar{R}$-Squared = .99 DW = 1.1

3.

Other = 395.6 + 5.7 * Ind Prod Index - 32.2 * Chg. in Cts/Kwh (lagged 1 yr)
Industrial (t = 14.4) (t = -1.9)
Energy - 136.8 * Trade Dummy Variable
Sales (t = -8.9)

$\bar{R}$-Squared = .90 DW = 1.6

4.

Phosphate = 1684.6 + 43.1 * U.S. Phosphate Mining - 113.4 * Cts/Kwh (lagged 1Year)
Energy (t = 8.8) (t = -1.6)
Sales + 0.865 * AR (1)

$\bar{R}$-Squared = .93 DW = 1.8

5.

Sales to Public Authorities	= 346.6 + 3.4 * Residential Customers - 46.9 * Chg in Cts/Kwh
	(t = 10.4) (t = -.9)
	+ .860 * AR (1)

$\bar{R}$-Squared = .99 DW = 1.6

6.

Street Lighting	= - 27.3 + 0.101 * Population = .648 * AR (1)
	(t = 16.3)

$\bar{R}$-Squared = .99 DW = 1.6

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 a 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 company's Marketing and Sales Department has 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.

This department's 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 five 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.
5. To achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act as enacted in guiding conservation policy for utilities in Florida.

The company's current DSM plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. 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, commercial and industrial programs exist.

3. Energy Audits - The program is a "how to" information and analysis guide for customers. Five types of audits are available to Tampa Electric customers; three types are for residential class customers and two 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 commercial programs.

8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air-conditioning systems.

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

10. Commercial Cooling - Encourages the installation of high efficiency direct expansion (DX) commercial cooling equipment.

11. Energy Plus Homes - Encourages the construction of residential dwellings at efficiency levels greater than current Florida building code baseline practices.

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 991791-EG, approved on March 28, 2000. In addition, the Energy Answer Home and Street and Outdoor Lighting programs were completed in 1987 and 1990, respectively. The 2000 demand and energy savings achieved by 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

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2000	12.1	16.7	72.5%	4.3	5.8	74.1%	11.6	10.3	112.6%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2000	1.8	1.5	120.0%	5.2	3.5	148.6%	19.0	12.9	147.3%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2000	13.9	18.2	76.4%	9.5	9.3	102.2%	30.6	23.2	131.2%

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 firm long-term 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

$$= 3505.128 - \underset{(t = -0.7)}{4.5696} * \text{Change in \$/kWh} + \underset{(t = 1.8)}{0.03290} * \text{Per Capita Income}$$

$$+ \underset{(t = 19.6)}{1.7670} * \text{Cooling Degree Days} + \underset{(t = 6.4)}{2.1620} * \text{Heating Degree Days}$$

$\bar{R}$-Squared = .94 DW = 1.4

2.

Winter Peak Demand

$$= -11.6166 + \underset{(t = 16.7)}{0.008141} * \text{Total Customers} + \underset{(t = 11.2)}{0.1862} * \text{Heating Degree Days}$$

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

3.

Summer Peak Demand

$$= -6.3040 + \underset{(t = 13.5)}{0.005976} * \text{Total Customers} + \underset{(t = 4.5)}{0.1854} * \text{Cooling Degree Days}$$

$$- \underset{(t = -1.1)}{21.4865} * \text{Change in \$/kWh (lagged one month)}$$

$\bar{R}$-Squared = .85 DW = 1.8

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.

$$
\begin{aligned}
\text{Average Customer Usage} = {} & 3691.8890 - \underset{(t\,=\,-6.4)}{19.3155 * \text{\$/kWh}} + \underset{(t\,=\,0.9)}{0.0837 * \text{Change in Per Capita Income}} \\
& + \underset{(t\,=\,12.8)}{1.1203 * \text{Cooling Degree Days}} + \underset{(t\,=\,4.9)}{1.6195 * \text{Heating Degree Days}}
\end{aligned}
$$

$\bar{R}$-Squared = .89 DW = 1.7

2.

$$
\text{Winter Peak Demand} = -10.5291 + \underset{(t\,=\,4.8)}{0.006888 * \text{Total Customers}} + \underset{(t\,=\,4.6)}{0.1313 * \text{Heating Degree Days}}
$$

$\bar{R}$-Squared = .68 DW = 1.8

3.

$$
\begin{aligned}
\text{Summer Peak Demand} = {} & 0.1546 + \underset{(t\,=\,4.4)}{0.004033 * \text{Total Customers}} + \underset{(t\,=\,1.5)}{0.05732 * \text{Cooling Degree Days}} \\
& - \underset{(t\,=\,-3.3)}{37.0750 * \text{\$/kWh}}
\end{aligned}
$$

$\bar{R}$-Squared = .87 DW = 1.6

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 2001-2010 period, Hillsborough County population is expected to increase at a 1.3% average annual rate.

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 (2001-2010), persons per household are expected to fall at an annual rate of 0.2%. 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 2001-2010 period, commercial employment is assumed to rise at a 2.3% average annual rate while industrial employment growth of 2.2% 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 number 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 2001-2010 period, real per capita income is expected to increase at a 2.3% 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 2001-2010 period, total customers are projected to expand at a 0.6% and 1.3% annual rate, respectively. Also, real per capita income for both cities is projected to grow annually at a pace of 1.8% and 1.7%, 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, a percent change was applied to the wholesale base case to get the wholesale high and low forecast.

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 2001-2010, 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 2.9% annual rate.

In contrast, industrial sales are expected to remain flat 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 market conditions and the southward migration of mining 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 2001-2010 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 (2001-2010) For Retail Load Forecast

	Average Annual Growth Rate		
	BASE CASE	LOW GROWTH SCENARIO	HIGH GROWTH SCENARIO
Residential Customers	1.5%	1.1%	1.9%
Employment	2.3%	1.9 %	2.7%
Real Per Capita Income	2.3%	1.8%	2.8%
Real Price of Electricity	-1.1%	-0.6%	-1.6%

Source: Tampa Electric Company

Wholesale Energy

Wholesale energy sales to FPC, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 776 GWh are expected in 2001, 506 GWh in 2001 and 257 GWh in 2003. Sales are expected to remain in the 265-277 GWh range for 2004-2010.

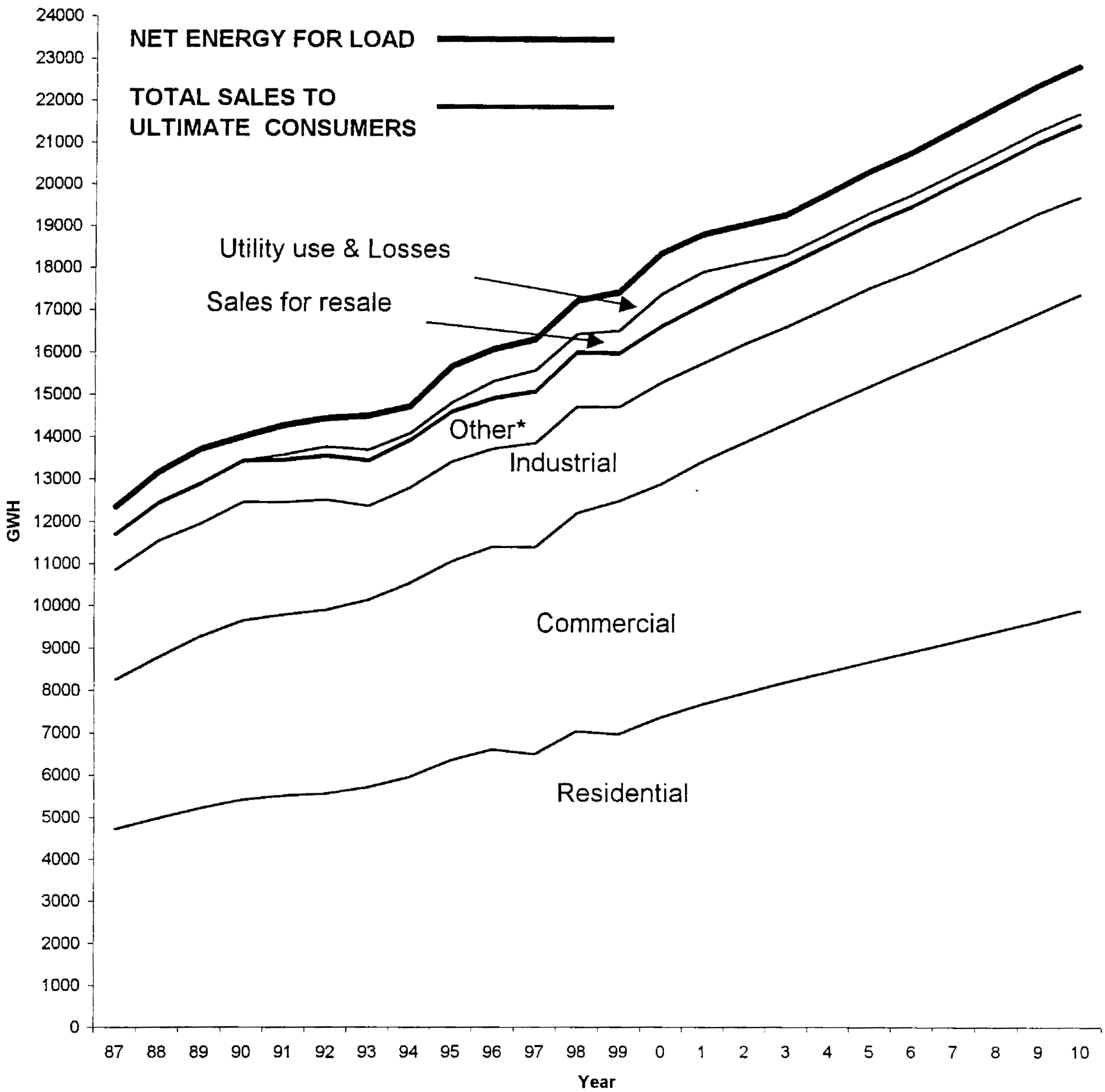
History and Forecast of Peak Loads

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 2001-2010 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 2.9% and 3.1%, 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) along with actual for 2000.

FIGURE III-2
HISTORY AND FORECAST OF ENERGY USE

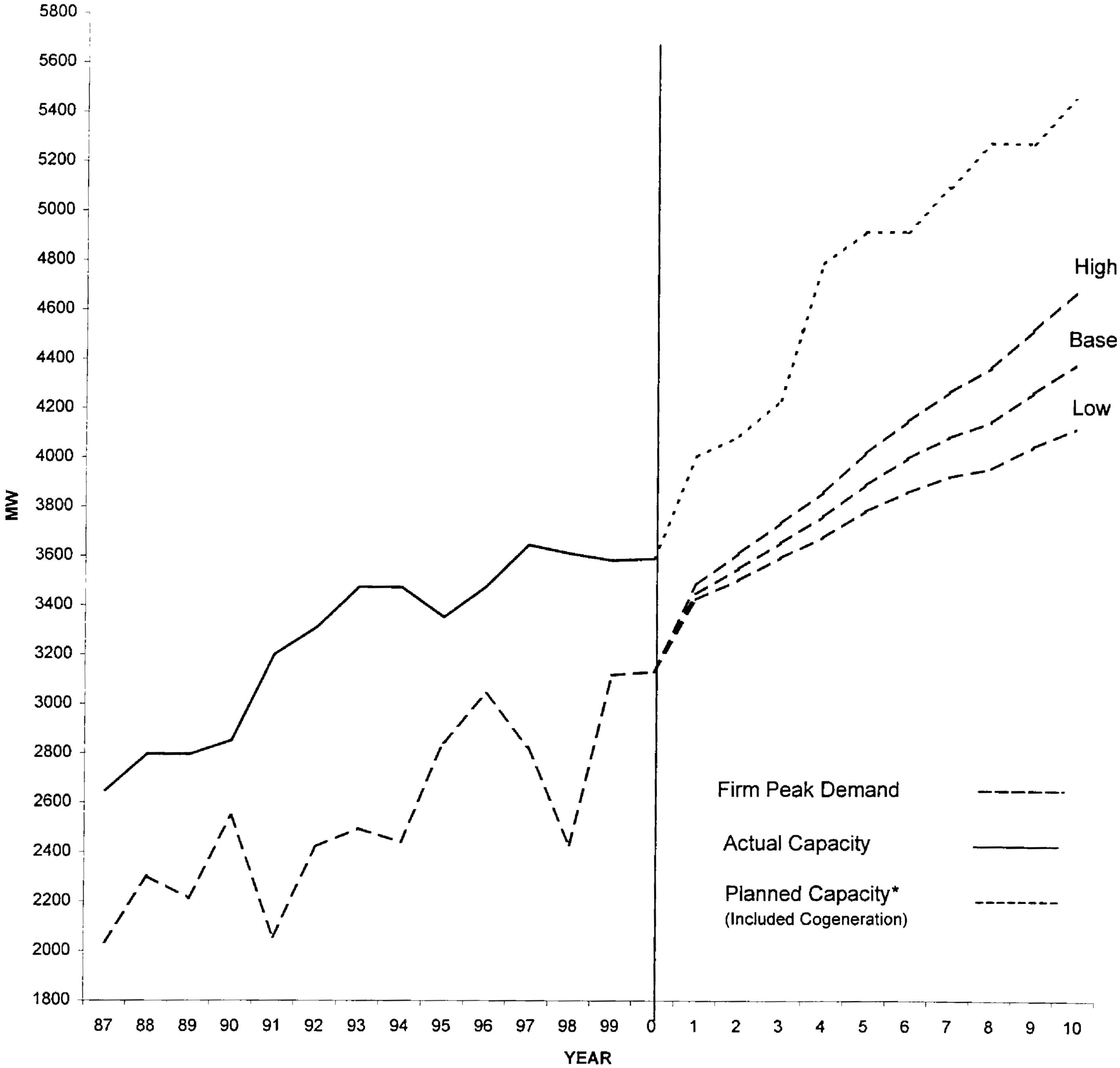


* Street & Highway Lighting and Sales to Public Authorities

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

SOURCE: Tampa Electric Company

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

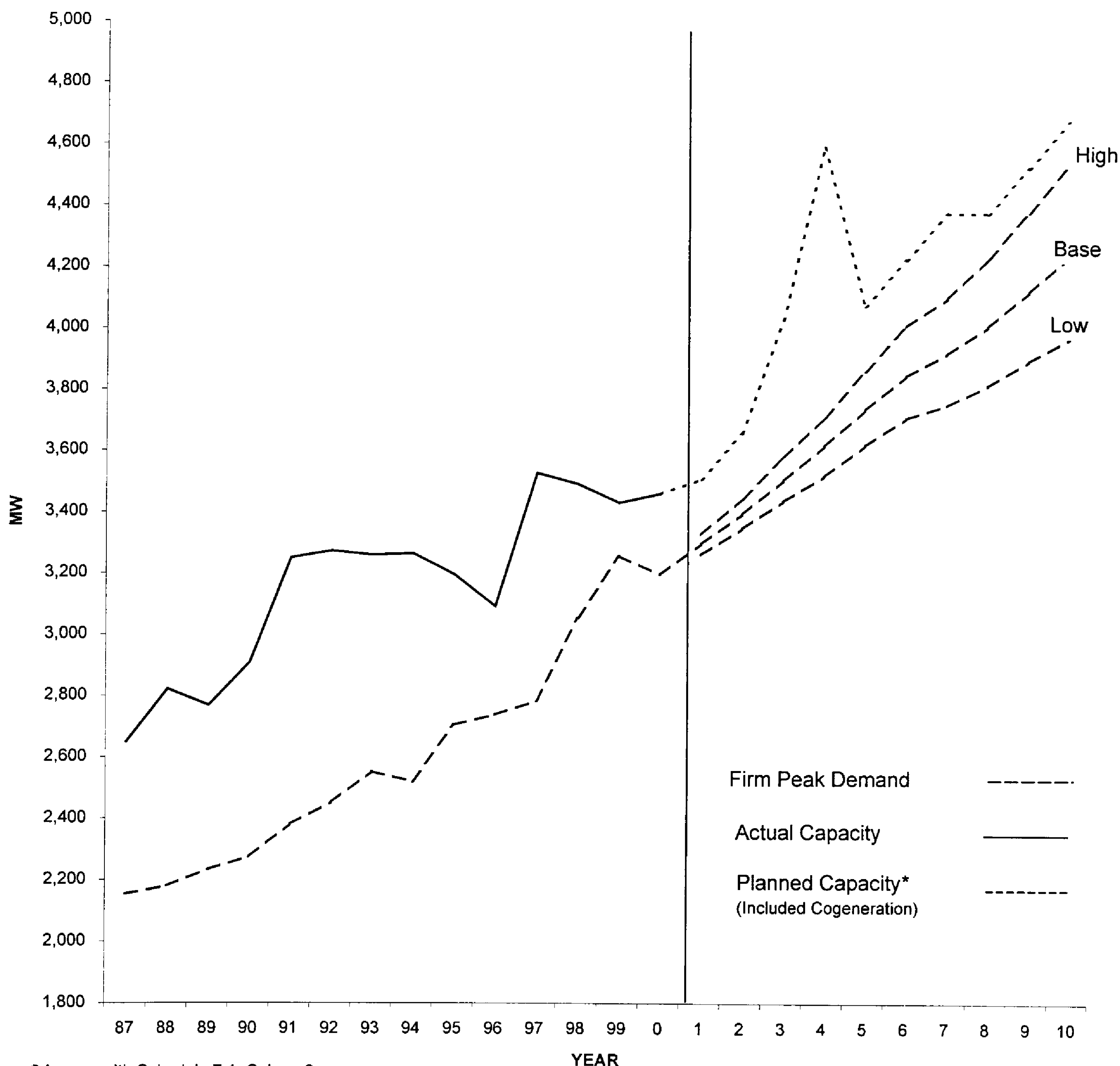


* Agrees with Schedule 7.2, Column6

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

SOURCE: Tampa Electric Company

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



*Agrees with Schedule 7.1, Column6

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

SOURCE: Tampa Electric Company

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 resulting from the analysis are shown in Table IV-3. Additional capacity is planned for 2001, based on an analysis of system reliability, the incorporation of the FPSC demand side management goals, projected system demand and energy requirements, purchased 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 2002, 2006, 2007, 2009 and 2010. Tampa Electric will increase the diversity of its generation mix with the repowering of Gannon Station. The station will be repowered with natural gas and renamed Bayside Power Station. The repowering will consist of the addition of three CT's and three HRSG's to supply steam to Unit 5 steam turbine and four CT's and four HRSG's to supply steam to Unit 6 steam turbine. The repowered units, will be named Bayside 1 and 2, and fueled with natural gas. The units are scheduled to come on-line in May 2003 and May 2004. In addition, Gannon Units 1 through 4 will be placed on long-term reserve standby (LTRS) by December 31, 2004. Furthermore, two units, COT Unit 1 and COT Unit 2, have planned in-service dates of April 2001. These units were developed in partnership with the City of Tampa. Each of the units has a maximum capacity of 2.91 MW and will be fired by natural gas. Hookers Point Station has an assumed retirement date of January 1, 2003. Some of the assumptions and information that impact the plan are discussed in the following sections. Additional assumptions and information are discussed in Chapter V.

Cogeneration

Tampa Electric Company plans for 442 MW of cogeneration capacity operating in its service area in 2001. Self-service capacity of 242 MW (net) is used by cogenerators to serve internal load requirements, 45 MW are purchased by Tampa Electric on a firm contract basis, and 16 MW are purchased on a non-firm, as-available basis. The remaining 139 MW of cogeneration capacity is contracted to other utilities and exports out of Tampa Electric's system.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Tables II-6 and II-7, respectively. At present, Tampa Electric Company plans to continue to use coal as the primary fuel for most of its generating requirements between 2000 and 2003. After 2003, Tampa Electric will increase the diversity of its fuel supply with the repowering of the coal fired Gannon Units 5 and 6 to the natural gas fired Bayside 1 and 2 combined cycle units. Tampa Electric has entered into a firm transportation contract with the Florida Gas Transmission (FGT) company for delivery of natural gas to the new Bayside units. The implementation of repowering these units will reduce Tampa Electric's coal generation from 87% in 2000 to 59% in 2005.

Environmental Considerations

Tampa Electric reached resolution of environmental lawsuits by the Florida DEP (the Consent Final Judgment) and the U.S. EPA/U.S. Department of Justice (the Consent Decree), through settlements on December 6, 1999 and February 29, 2000, respectively. These agreements are substantially similar with respect to environmental controls and pollution reductions required by Tampa Electric. The following is a summary of the pollutant specific requirements of these settlements.

Gannon Station Operations

Tampa Electric will cease all coal operations at the Gannon Station by December 31, 2004. Gannon units 5 and 6 will be repowered by May 2003 and May 2004, respectively. Gannon units 1 – 4 will be placed on LTRS standby by the end of 2004. The Gannon units placed on LTRS will be available to Tampa Electric as future supply-side resource options, via repowering or conversion to natural gas to meet the growing demand and energy needs of its customers.

Particulate Matter (PM)

Tampa Electric must complete an optimization study on each of the Electrostatic Precipitators (ESP) at Big Bend Station. The optimization study shall recommend the best operational practices to minimize particulate matter emissions from each ESP, and the company must deliver the completed report to EPA for approval. Following approval by EPA, Tampa Electric is required to operate each ESP in conformance with the recommendations of the study.

At the same time, Tampa Electric is required to complete a Best Available Control Technology (BACT) analysis of the ESPs at Big Bend Station and submit it to EPA for approval. Tampa Electric must then complete physical and operational changes as indicated by the optimization and BACT analysis to minimize emissions from each ESP at Big Bend on or before May 1, 2003 as defined in the Consent Final Judgment, or May 1, 2004 as defined in the Consent Decree.

Tampa Electric is also required to install, calibrate, and begin operations of a PM Continuous Emission Monitor (CEM) in the Unit 4 duct on or before March 1, 2002. If Tampa Electric decides to continue to combust coal at Big Bend and is successfully operating the PM CEM in the Unit 4 duct, Tampa Electric is required to install one additional PM CEM on a second unit or duct at Big Bend by May 1, 2007.

Sulfur Dioxide (SO_2)

Commencing on January 1, 2001, Tampa Electric Company is required to operate the scrubber at all times that either Big Bend Unit 1 or 2 are in operation, except in specific situations. The emissions from Big Bend Units 1 and 2 must be scrubbed with at least 95% removal efficiency. Tampa Electric may operate Big Bend Units 1 and 2 during a scrubber outage if Tampa Electric operates all other units at Big Bend and Gannon/Bayside Station with fully operational pollution control equipment before operating Big Bend Units 1 and 2 unscrubbed with the following limitations: from 2001-2012 operating Big Bend Units 1 and 2 unscrubbed is limited to 45 days annually; and, from 2001-2012 Tampa Electric may operate Big Bend Units 1 and 2 unscrubbed to avoid interrupting power to customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida. Starting in 2013 Big Bend Units 1 and 2 may not operate unscrubbed.

Commencing October 5, 2000, Tampa Electric must operate the scrubber at all times that Big Bend Unit 3 is in operation except in specific situations. The emissions from Big Bend Unit 3 must be scrubbed with at least 93% removal efficiency. After May 1, 2002 and until January 1, 2010 emissions from Unit 3 shall be scrubbed with at least 95% removal efficiency when Big Bend Unit 4 is not in operation. Tampa Electric is permitted to operate Big Bend Unit 3 during a scrubber outage if Tampa Electric operates all other units at Big Bend and Gannon Stations with fully operational pollution control equipment before operating Big Bend Unit 3 unscrubbed with the following limitations: during calendar year 2000-2009 operating Big Bend Unit 3 unscrubbed is limited to 30 days annually; and, from 2000-2009 Tampa Electric may operate Big Bend Unit 3 unscrubbed to avoid interrupting power to customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida. Starting in 2010, Big Bend unit 3 may not operate unscrubbed. Whenever Big Bend Units operate unscrubbed, they must do so utilizing coal with a sulfur content of 2.2 lb SO_2/mmBtu or less during 2000-2009 for Big Bend Unit 3 and 1.2 lb SO_2/mmBtu during 2010-2012 for Big Bend Units 1 and 2.

Tampa Electric is also required to develop and submit to EPA a plan to maximize the availability and removal efficiency of the scrubbers treating emissions from Big Bend Units 1, 2 and 3 by considering operation and maintenance changes.

Oxides of Nitrogen (NO_x)

By December 31, 2002, Tampa Electric must spend up to $3 million to attempt to reduce NO_x by up to 30% below 1998 levels on Big Bend Units 1 & 2 and up to 15% below 1998 levels on Big Bend Unit 3. Tampa Electric is also required to decide on a methodology to control NO_x emissions from all of the Big Bend units by 2007. By May 1, 2005, Tampa Electric must decide whether to install NO_x control, repower or shut down Big Bend Unit 4 and must implement the chosen methodology by June 1, 2007. If NO_x controls are installed, Big Bend Unit 4 must meet a NO_x emission rate of 0.10 lb/mmBtu.

By May 1, 2007, Tampa Electric will decide whether to install NO_x control, repower, or shut down Big Bend Units 1, 2, and 3 and will implement the chosen methodology beginning in 2008. If NO_x controls are installed on either Big Bend 1, 2 or 3, the unit must meet a NO_x emission rate between 0.10 and 0.15 lb/mmBtu. Tampa Electric is also required to develop and submit to EPA a plan to implement $5 to $6 million dollars worth of innovative NO_x control technologies at either the Bayside or Big Bend Stations. This requirement must be implemented by December 31, 2004.

Interchange Sales and Purchases

Tampa Electric's long-term interchange sales include Schedule D, a Partial Requirements service agreement with Florida Power Corporation, a supplemental Schedule D service agreement with the Florida Municipal Power Authority 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. Tampa Electric also has an additional long-term purchase power contract with Hardee Power Partners Limited for 90 MW of firm non-shared winter capacity. The contract began in May 2000 and expires in 2012. A firm capacity sale from Tampa Electric's Big Bend Station Unit 4 is made available, on a limited energy usage basis, to Hardee Power Partners Limited for resale to SEC.

Tampa Electric has short-term purchase power agreements for the winter of 2000/2001. These transactions amount to a total of 155 MW of firm capacity, including 15 MWs from Auburndale Power Partners, 40 MWs from Okeelanta and 100 MWs from Florida Power & Light. In addition, Tampa Electric has a purchase power agreement with Ringhaver Equipment Co. Power Division for firm capacity of 70 MWs for the summer of 2001 and 50 MWs for the summer of 2002. Tampa Electric also has another purchase agreement for firm capacity with Okeelanta starting April 1, 2001, running through March 31, 2002. This purchase agreement will provided 55 MWs for the summer 2001 and 40 MWs for the winter 2001/2002. Furthermore, Tampa Electric has identified the need for an additional 40 MWs of power for the winter of 2001/2002, but has not determined a supplier at this time.

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
2001	3,511	494	(147)	45	3,903	3,300	603	18%	0	603	18%
2002	3,661	419	(147)	60	3,993	3,397	596	18%	0	596	18%
2003	4,032	369	0	60	4,461	3,507	954	27%	0	954	27%
2004	4,594	369	0	59	5,022	3,619	1,403	39%	0	1,403	39%
2005	4,078	369	0	60	4,507	3,738	769	21%	0	769	21%
2006	4,228	369	0	60	4,657	3,849	808	21%	0	808	21%
2007	4,378	369	0	60	4,807	3,922	885	23%	0	885	23%
2008	4,378	369	0	60	4,807	4,011	796	20%	0	796	20%
2009	4,528	369	0	60	4,957	4,124	833	20%	0	833	20%
2010	4,678	369	0	60	5,107	4,242	865	20%	0	865	20%

NOTE 1 Per FPSC ruling (Docket No 981890-EU, Order No PSC-99-2507-S-EU, Issued December 22,1999) 15% Reserve Margin to be increased to 20% starting summer 2004,

2 Capacity import includes the Purchase Agreement with TECO Power Services (TPS) Capacity imports also includes firm transactions from Ringhaver's Hookers Pt distributive generation (50 MW) in the summer of 2001 and 2002, and Ringhaver Substation Distributive generation (20 MW) in the summer of 2001 Also 55 MW from Okeelanta for summer 2001

3 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

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

* 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
2000-01	3,660	604	(299)	45	4,010	3,452	558	16%	51	507	15%
2001-02	3,649	529	(147)	60	4,091	3,554	537	15%	0	537	15%
2002-03	3,729	449	0	60	4,238	3,659	579	16%	0	579	16%
2003-04	4,284	449	0	60	4,793	3,767	1,026	27%	0	1,026	27%
2004-05	4,411	449	0	60	4,920	3,894	1,026	26%	0	1,026	26%
2005-06	4,411	449	0	60	4,920	4,002	918	23%	0	918	23%
2006-07	4,591	449	0	60	5,100	4,088	1,012	25%	0	1,012	25%
2007-08	4,771	449	0	60	5,280	4,151	1,129	27%	0	1,129	27%
2008-09	4,771	449	0	60	5,280	4,270	1,010	24%	0	1,010	24%
2009-10	4,951	449	0	60	5,460	4,384	1,076	25%	0	1,076	25%

NOTE 1 Per FPSC ruling (Docket No 981890-EU, Order No PSC-99-2507-S-EU, Issued December 22,1999) 15% Reserve Margin to be increased to 20% starting summer 2004,

2 Capacity import includes the Purchase Agreement with TECO Power Services (TPS) Capacity imports also include 155 MW firm transaction from APP, Okeelanta, and FPL in the winter of 2000/2001 Also 40 MW from Okeelanta and 40 MW from a yet to be determined supplier for the winter of 2001/2002

3 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 firm transactions to FMPA of 150 MW in 2000/2001 Capacities shown in table include losses.

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

* 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	3	Polk Co.	CT	NG	LO	2/01	5/02	unknown	unknown	150	180	PL	TK	T
Bayside	1	Hills. Co	CC	NG	N	4/01	5/03	unknown	unknown	703	797	PL	N	P
Bayside	2	Hills. Co.	CC	NG	N	8/02	5/04	unknown	unknown	934	1045	PL	N	P
Polk	4	Polk Co.	CT	NG	LO	1/05	5/06	unknown	unknown	150	180	PL	TK	P
Polk	5	Polk Co	CT	NG	LO	1/06	5/07	unknown	unknown	150	180	PL	TK	P
Polk	6	Polk Co.	CT	NG	LO	1/08	5/09	unknown	unknown	150	180	PL	TK	P
Unnamed	1	unknown	CT	NG	LO	1/09	5/10	unknown	unknown	150	180	PL	TK	P

Note. 1 Gannon units 1, 2, 3, and 4 are planned for long term reserve stand-by (LTRS) by 12/31/2004. Gannon unit 5 steam turbine will be repowered with three combustion turbines and renamed Bayside Power Station unit 1. Gannon unit 6 steam turbines will be repowered with four combustion turbines and renamed Bayside Power Station unit 2.

SCHEDULE 9

TABLE IV-4
(Page 1 of 7)

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	150
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	FEB 2001
	B. COMMERCIAL IN-SERVICE DATE	MAY 2002
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_X BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	Construction Permits Obtained
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2003)	8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh

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

SCHEDULE 9

TABLE IV-4
(Page 2 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 1
(2)	CAPACITY	
	A. SUMMER	703
	B. WINTER	797
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	APR 2001
	B. COMMERCIAL IN-SERVICE DATE	MAY 2003
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	NONE
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	ONCE THROUGH
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	ENGINEERING IN-PROGRESS
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	Permit Application in-progress
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2004)	55%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,034 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL GANNON OR BAYSIDE SITE.

SCHEDULE 9

TABLE IV-4
(Page 3 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 2
(2)	CAPACITY	
	A. SUMMER	934
	B. WINTER	1,045
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	AUG 2002
	B. COMMERCIAL IN-SERVICE DATE	MAY 2004
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	NONE
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	ONCE THROUGH
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	ENGINEERING IN-PROGRESS
(10)	CERTIFICATION STATUS	N/A
(11)	STATUS WITH FEDERAL AGENCIES	Permit Application in-progress
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2005)	40%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,130 Btu/kWh

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL GANNON OR BAYSIDE SITE.

SCHEDULE 9

TABLE IV-4
(Page 4 of 7)

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	150
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2005
	B. COMMERCIAL IN-SERVICE DATE	MAY 2006
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2006)	7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh

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

SCHEDULE 9

TABLE IV-4
(Page 5 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 5
(2)	CAPACITY	
	A. SUMMER	150
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	JAN 2006
	B. COMMERCIAL IN-SERVICE DATE	MAY 2007
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2007)	6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh

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

SCHEDULE 9

TABLE IV-4
(Page 6 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 6
(2)	CAPACITY	
	A. SUMMER	150
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2008
	B. COMMERCIAL IN-SERVICE DATE	MAY 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2009)	6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh

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

SCHEDULE 9

TABLE IV-4
(Page 7 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE SITE UNIT 1
(2)	CAPACITY	
	A. SUMMER	150
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2009
	B. COMMERCIAL IN-SERVICE DATE	MAY 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	UNDETERMINED
(7)	COOLING METHOD	UNDETERMINED
(8)	TOTAL SITE AREA	UNDETERMINED
(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)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2010)	7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh

1 BASED ON IN-SERVICE YEAR.

Schedule 10

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

Point of Origin and Termination	Number of Circuits	Right-of-Way	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
SR 60 S. Tap Relocation	1	No new right of way required	0.1 mi	230 kV	Spring 2001	$0.2 million	No new substations	None
S. Gibsonton 230 kV Circuit Addition	1	No new right of way required	0.3 mi	230 kV	Summer 2001	$0.7 million	No new substations	None
Barcola - Pebbledale	1	No new right of way required	TEC: 2.7 mi FPC: 1.2 mi	230 kV	Fall 2003	TBD	No new substations	FPC
Gannon/Juneau Conversion	1	Possible road ROW required	14.5 mi	230 kV	Summer 2003	$13.0 million	2 - 230/69 kV autos at Juneau	None
Juneau - Ohio	1	Possible road ROW required	4.5 mi	230 kV	Summer 2003	$4.0 million	No new substations	None
Chapman - Davis	1	No new right of way required	8.4 mi	230 kV	Summer 2004	$7.0 million	No new substations	None
Gannon - Davis	1	No new right of way required	14.8 mi	230 kV	Summer 2004	$11.0 million	Davis Rd. 230 kV Substation	None
Lithia - Wheeler	1	No new right of way required	11.0 mi	230 kV	Summer 2008	$8.5 million	Wheeler 230/69 kV Substation	None
Lithia - Davis	1	No new right of way required	14.4 mi	230 kV	Summer 2008	$9.0 million	No new substations	None
Davis - Dale Mabry	1	No new right of way required	13.3 mi	230 kV	Summer 2004	$11.0 million	No new substations	None

CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Based on an assessment of the Tampa Electric transmission system using year 2000 FRCC databank models, no transmission constraints which violate the criteria stated in the Generation and Transmission Reliability Criteria section of this document were identified.

Expansion Plan Economics and Fuel Forecast

The overall economics and cost-effectiveness of the plan were analyzed as stated in Tampa Electric's Integrated Resource Planning process, discussed in detail later in the chapter. As part of this process, Tampa Electric evaluated various planning and operating alternatives to current operations, with objectives ranging from meeting compliance requirements in the most cost-effective and reliable manner to maximizing operational flexibility and minimizing operational costs. Load forecasts used in the analysis are from the company's 2001 Fuel and Interchange Forecast.

The study was also updated from the most current planning assumptions including minimum reliability criteria of 15 percent firm reserve margin to 20 percent with a minimum 7 percent reserve margin from supply-side resources based on the stipulation between the FPSC and the three Peninsular Florida investor owned utilities. This was a result of Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, approved in December 1999.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible options, overall. Those alternatives that failed to meet environmental acceptability, economics, technical feasibility, operational criteria, maintainability and reliability were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in the more detailed economic analysis.

Fuel commodity price for actual and forecasted data for the purpose of deriving base, high and low forecast pricing is done by careful analysis of historical, current and previous price 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 and low price projection represents the effect of oil and natural gas prices escalating 10% above or below the base case and escalating at a slightly higher or lower escalation rate on a monthly basis for the year 2001. Annual high and low case price projections after 2001 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.

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

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 the total original investment in a plant over its useful life 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.

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 that comports with Rule 25-17.008, F.A.C., 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.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY

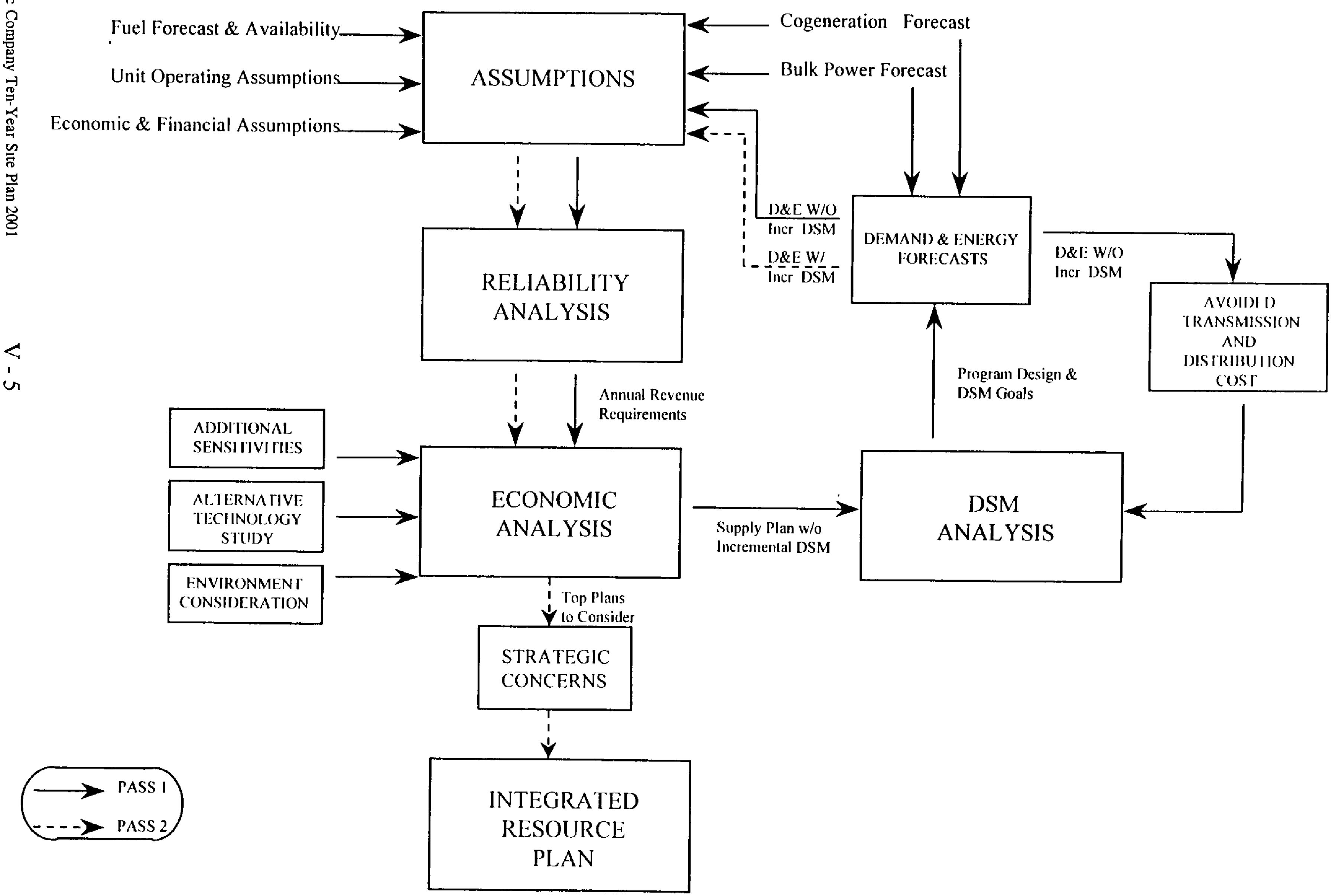


FIGURE VI

Strategic Concerns

Strategic concerns affect the type, capacity, and/or timing of future generation resource requirements. These concerns such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. These strategic concerns 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 results of the Integrated Resource Planning process 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 May 2002, 2006, 2007, 2009, and 2010. The Gannon repowering to Bayside is planned for May 2003 and May 2004. For the purposes of this study, Hookers Point Station is assumed to be retired in January of 2003. Tampa Electric's long-term purchased power contract which began in the summer of 2000 for Hardee Power Partners Limited has increased with 369 MW summer net capability and 449 MW winter net capability for the entire study period.

Generation and Transmission Reliability Criteria

Generation

As part of the stipulation reached in Docket No. 981890-EU, Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida, the minimum firm Reserve Margin adopted by Tampa Electric has been voluntarily adjusted from 15% to 20%. As part of the stipulation, Tampa Electric agreed to achieve the planned 20% reserve margin criterion over a transition period of four years. Thus, Tampa Electric will reach a planned reserve margin of 20% by the summer of 2004 (Order No. PSC-99-2507-S-EU). In addition, Tampa Electric has further adopted a 7% minimum summer supply-side reserve margin, which will be transitioned into the planning process by the summer of 2004.

Tampa Electric's approach to calculating percent reserves is consistent with that outlined in the settlement agreement incorporated. The calculation of the minimum 20% reserve margin employs an 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 summer supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads.

Transmission

The following criteria are used as guidelines for proposing system expansion and/or improvement projects. A detailed engineering study including risk analysis must be performed prior to making a prudent decision to initiate a project.

Tampa Electric Company complies with the planning criteria contained in Section V of the FRCC System Planning Committee Handbook. In addition, more stringent criteria for normal system operation and single contingency operation are applied as follows:

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.

The following table summarizes the thresholds which alert planners to problematic transmission lines and transformers.

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

The transmission system is planned to allow voltage control on the 13.2 kV distribution buses between 1.023 and 1.043 per unit. For screening purposes, this criteria can be approximated by the following transmission system voltage limits.

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	0.925 - 1.050 pu	0.950 - 1.060 pu
Single Contingency, after all switching	0.925 - 1.050 pu	0.925 - 1.050 pu	0.950 - 1.060 pu
Bus Outages	0.925 - 1.050 pu	0.925 - 1.050 pu	0.950 - 1.060 pu

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric Company complies with 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

The Transmission Planning department ensures that the Tampa Electric Company transmission system can support peak and off-peak system load levels without violation of the loading and voltage criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Single Contingency Planning Criteria

The Tampa Electric Company transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service at any load level without violation the criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Multiple Contingency Planning Criteria

Double contingencies involving two branches out of service simultaneously are analyzed at 70% of peak load level. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of the criteria stated in the Generation and Transmission Reliability Criteria section of this document.

First Contingency Total Transfer Capability Considerations

The following First Contingency Total Transfer Capability (FCTTC) limits for Tampa Electric Company's multiple-circuit corridors must be observed:

Tie Line Corridor	FCTTC
Lake Tarpon - Sheldon Rd. 230 kV (FPC)	1100 MVA
Big Bend - Manatee 230 kV (FPL)	1550 MVA

DSM Energy Savings Durability

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

(1) end-use sub-metering of survey samples to identify savings achieved in residential duct repair and commercial indoor lighting programs;

(2) periodic notch test, for residential load management (Prime Time) to confirm the accuracy of Tampa Electric Company's load reduction estimation formulas;

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

(4) 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, the company's 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

A detailed list of the construction projects can be found in Chapter IV, Schedule 10. This list represents the latest transmission expansion plan available. However, given the significance of the Gannon Station repowering to the Bayside Power Station, this plan is currently being reviewed and updated.

Green Energy Program

In 2000, Tampa Electric completed an 18kW photovoltaic installation at the Museum of Science and Industry (MOSI) located in Tampa, Florida. This endeavor is the flagship project for the company's proposed Green Energy Program. With customer support of the program, Tampa Electric anticipates adding 32 kW of photovoltaic capacity to our grid by year-end 2004. This addition of 32kW is expected to occur in two separate 16kW installations; one installation in 2001 and one in 2004. This will bring the company's total photovoltaic capacity to 50kW by year-end 2004.

An additional energy source for the Green Energy Program utilizes biomass. Tampa Electric's mix of solar and biomass renewable resources is expected to satisfy the levels of customer subscriptions to the Green Energy Program. The company anticipates a significant portion of biomass energy to be generated at Gannon Station temporarily. However, as Gannon Station is repowered to the Bayside Power Station, the need for replacement facilities to generate "green energy" will exist. Tampa Electric is exploring various long-term options to ensure future availability of renewable energy sources.

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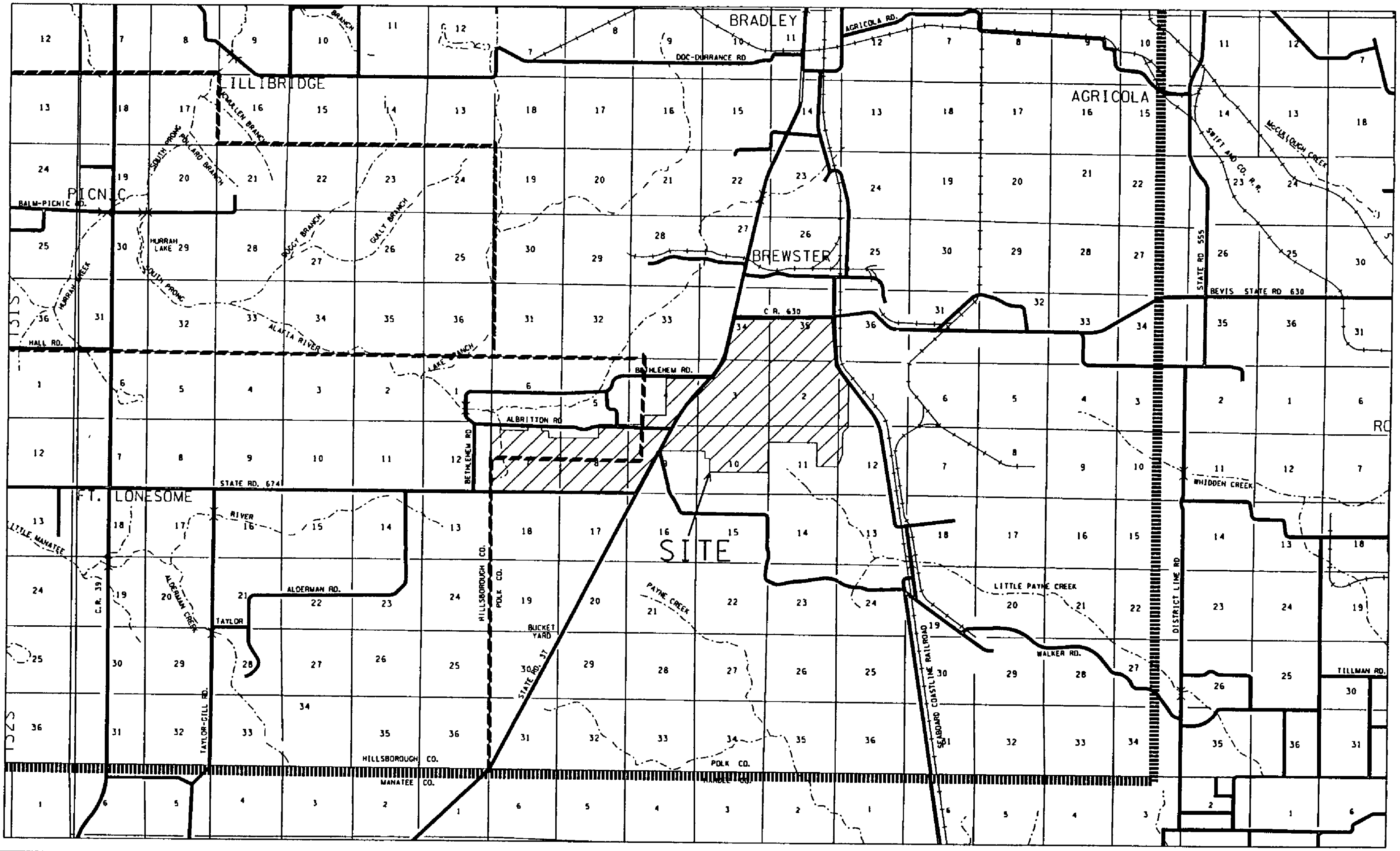
CHAPTER VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter IV will occur at the existing Gannon Station (to be renamed Bayside Power Station) and the existing Polk Power Station. The Gannon/Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-2) and the Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-1). Both facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.

FIGURE VI-1



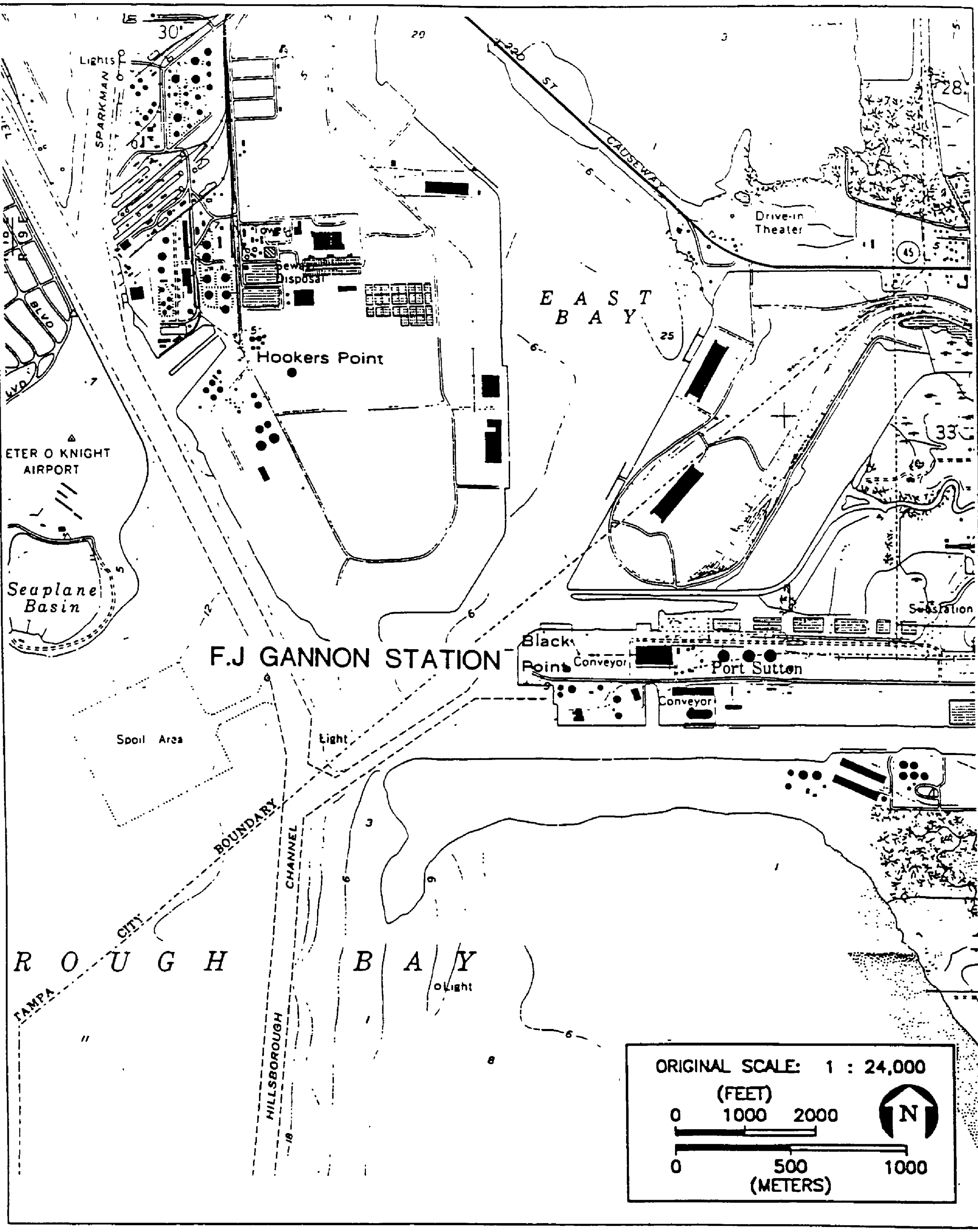
TAMPA ELECTRIC COMPANY

SITE LOCATION OF POLK POWER STATION

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

SOURCES: FDOT MAP, FLA, ECT

FILE NAME 403020.DGN
REVISION 3/9/2000 MMS



F.J. GANNON STATION AREA MAP

Sources: USGS Quad, Tampa, FL 1981.

Figure VI-2

TECO SM
TAMPA ELECTRIC