AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

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

April 1, 2003

HAND DELIVERED

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

Re: Tampa Electric Company's Ten Year Site Plan

Dear Ms. Bayo:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2003 to December 2012 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.

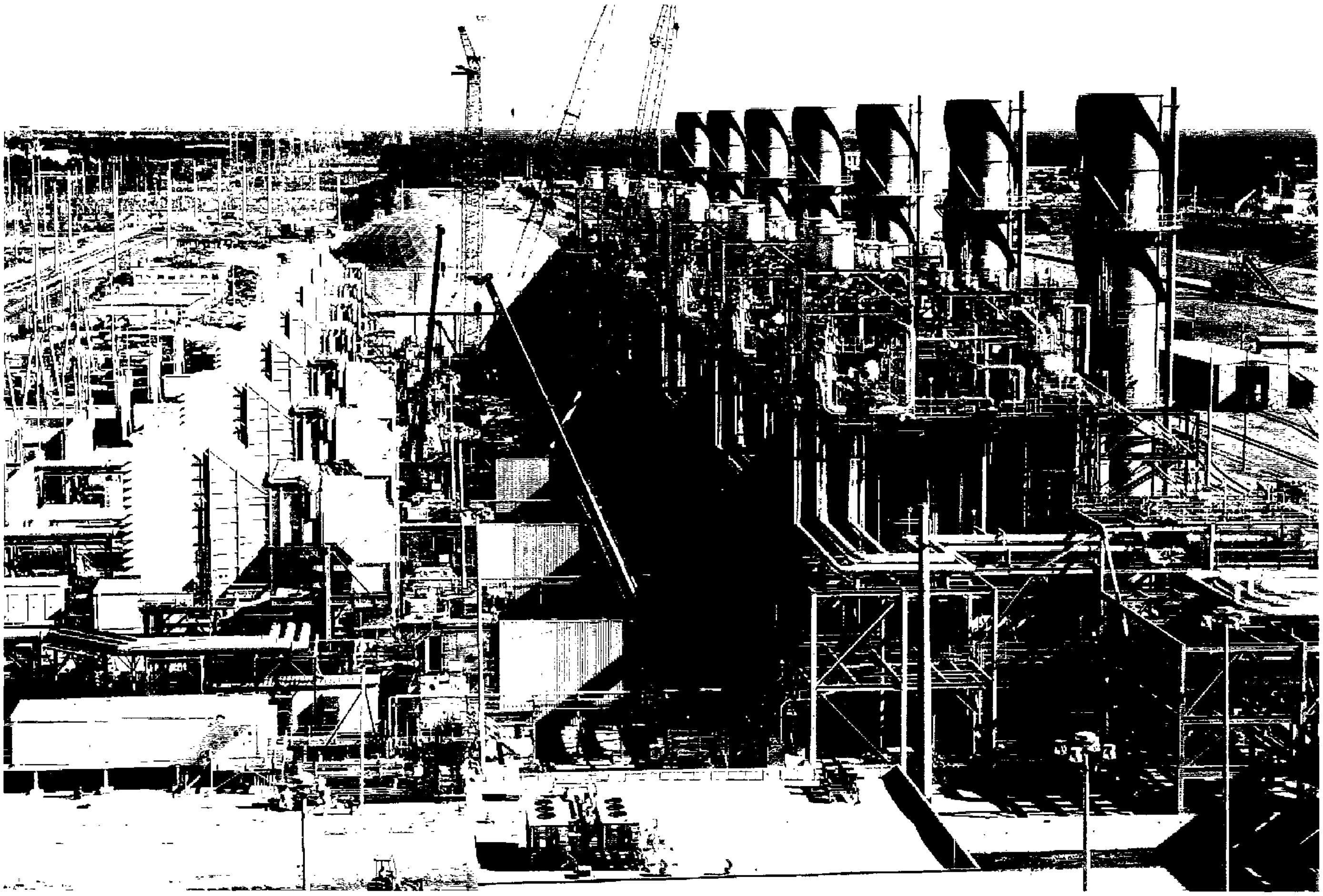
Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: Michael Haff (w/enc.)



Bayside Power Station

TAMPA ELECTRIC

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

JANUARY 2003 TO DECEMBER 2012

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

January 2003 to December 2012

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2003

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF SCHEDULES

SCHEDULES | **PAGE**

LIST OF SCHEDULES

SCHEDULES (continued) **PAGE**

CHAPTER IV

LIST OF FIGURES

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
	UC	=	Under Construction
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
	FGD	=	Flue Gas Desulfurization
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NR	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

THIS PAGE LEFT INTENTIONALLY BLANK.

CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric retired two generating stations on January 1, 2003, Hookers Point and Dinner Lake. Tampa Electric has five other generating stations consisting of fossil steam units, combustion turbine peaking units, diesel units and an integrated gasification combined cycle unit; they are Big Bend, Gannon, Polk, Phillips, and Partnership.

Big Bend: The station contains four pulverized coal fired steam units with desulfurization scrubbers, and three distillate fueled combustion turbines.

Gannon: The present station contains six pulverized coal fired steam units. The repowering of Gannon station to Bayside station will be complete with the conversion of Gannon unit 5 to Bayside unit 1 in May 2003 and Gannon unit 6 to Bayside unit 2 in January 2004. Gannon units 1 and 2 will be placed on long term reserve standby (LTRS) in April 2003, and retired on December 31, 2004. Gannon units 3 and 4 will be placed on LTRS in September 2003 and retired from coal operation on December 31, 2004, after which the assets may be utilized for future gas operations. The agreement between Tampa Electric and the U.S. Environmental Protection Agency (EPA), and the Florida Department of Environmental Protection (DEP) requires all coal burning to cease by the end of 2004, but allows the units to be repowered on natural gas.

Polk: The station is presently comprised of three 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 units 2 and 3 are combustion turbines, fueled primarily with natural gas with distillate backup.

Phillips: The station is comprised of two residual or distillate oil fired diesel engines and one heat recovery steam generator with a steam turbine.

Partnership: The station is comprised of two natural gas fired diesel engines.

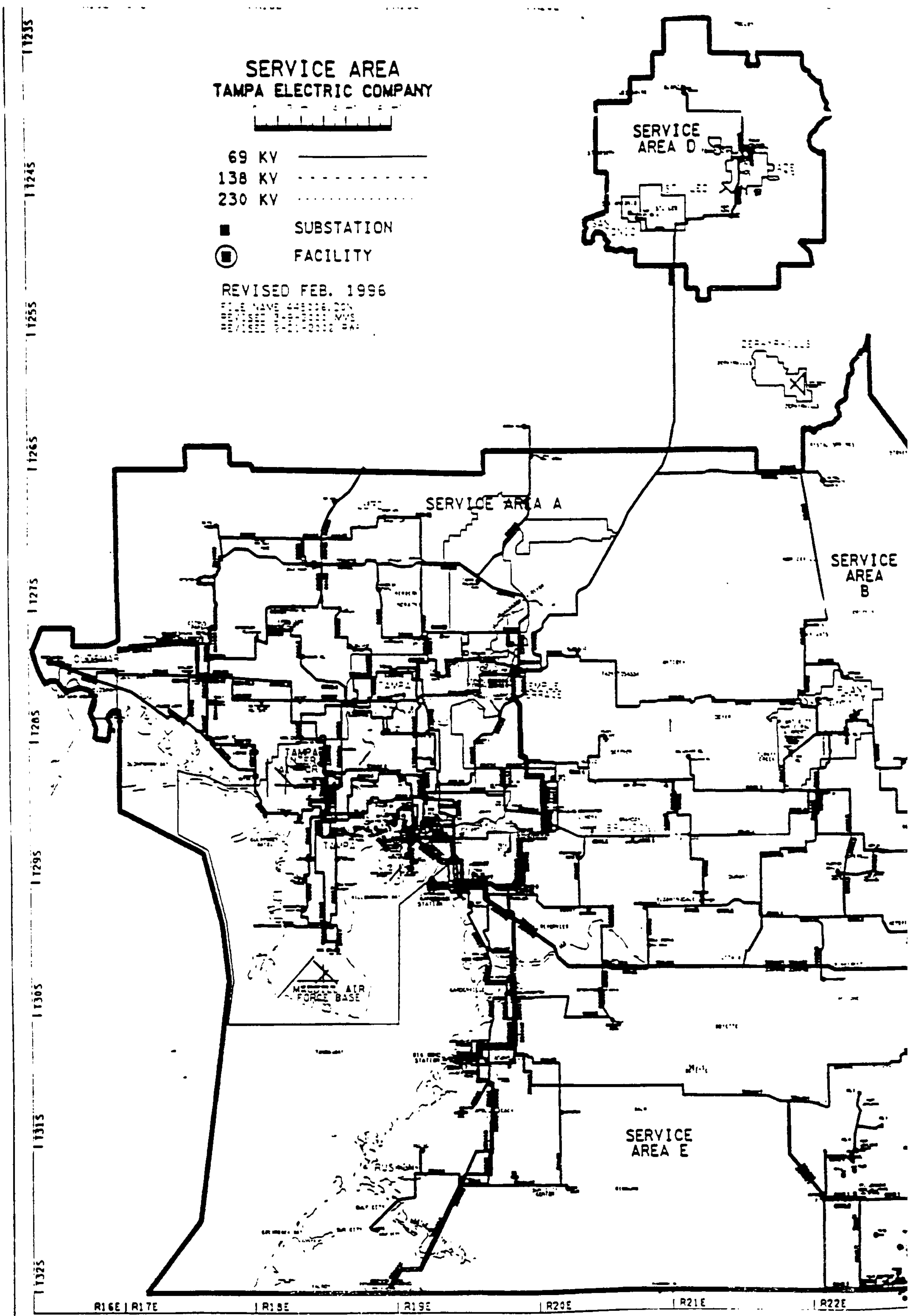
Schedule 1

Existing Generating Facilities
As of December 31, 2002

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt Fuel Days	(10) Commercial In-Service Mo/Yr	(11) Expected Retirement Mo/Yr	(12) Gen. Max. Nameplate KW	(13) Net Capabilit Summer MW	(1 Wi M
Big Bend		Hillsborough Co. 14/31S/19E									1,919,250	1,852	1,9
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	421	42
	2		FS	C	N	WA	N	0	04/73	"	445,500	411	43
	3		FS	C	N	WA	N	0	05/76	"	445,500	428	43
	4		FS	C	N	WA	N	0	02/85	"	486,000	452	46
	CT 1		CT	LO	N	WA	TK	0	02/69	"	18,000	14	1
	CT 2 (a)		CT	LO	N	WA	TK	0	11/74	"	78,750	66	8
	CT 3		CT	LO	N	WA	TK	0	11/74	"	78,750	60	7
Dinner Lake		Highland Co. 12-055									12,650	11	1
	1		FS	NG	HO	PL	TK	2	12/66	01/03	12,650	11	1
Gannon		Hillsborough Co. 4/30S/19E									1,301,880	1,083	1,1
	1 (b)		FS	C	N	WA	N	0	09/57	12/04	125,000	94	9
	2 (b)		FS	C	N	WA	N	0	11/58	12/04	125,000	100	10
	3 (c)		FS	C	N	WA	N	0	10/60	12/04	179,520	150	15
	4 (c)		FS	C	N	WA	N	0	11/63	12/04	187,500	164	16
	5 (d)		FS	C	N	WA	N	0	11/65	05/03	239,360	222	22
	6 (d)		FS	C	N	WA	N	0	10/67	01/04	445,500	353	37
Hookers Pt.		Hillsborough Co. 19/29S/19E									232,600	157	15
	1		FS	HO	N	WA	N	0	07/48	01/03	33,000	20	2
	2		FS	HO	N	WA	N	0	06/50	01/03	34,500	20	2
	3		FS	HO	N	WA	N	0	08/50	01/03	34,500	20	2
	4		FS	HO	N	WA	N	0	10/53	01/03	49,000	30	3
	5		FS	HO	N	WA	N	0	05/55	01/03	81,600	67	67
Phillips		Highland Co. 12-055									42,030	37	37
	1		D	HO	N	TK	N	0	06/83	Unknown	19,215	17	17
	2		D	HO	N	TK	N	0	06/83	Unknown	19,215	17	17
	3 (e)		HRSG	WH	N	N	N	0	06/83	Unknown	3,600	3	3
Polk		Polk Co. 2,3/32S/23E									502,069	580	62
	1		IGCC	C	LO	WA/TK	TK	0	09/96	Unknown	326,299	255	26
	2 (f)		CT	NG	LO	PL	TK	0	07/00	Unknown	175,770	160	18
	3 (f)		CT	NG	LO	PL	TK	0	5/02	Unknown	175,770	165	18
Partnership Station		Hillsborough Co. W30/29/19									5,800	6	6
	1		D	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
	2		D	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
											TOTAL	3,726	3,86

Notes:
- **(a)** **Big Bend CT2 was placed on long term reserve standby in the fall of 2002.**
- **(b)** **Gannon units 1 and 2 will be placed on long term reserve standby in April 2003, and retired on December 31, 2004.**
- **(c)** **Gannon units 3 and 4 will be placed on long term reserve standby in September 2003, and retired from coal operation on December 31, 2004, after which the assets may be utilized for future operations.**
- **(d)** **Stated retirement date for Gannon 5 & 6 are the dates that the steam generators convert to Bayside 1 & 2.**
- **(e)** **Unit placed on long term reserve standby status.**
- **(f)** **Polk 2 & 3 turbine name plate rating is based on 59 deg. F. The net capacity of these units may vary with ambient air temperature.**

THIS PAGE LEFT INTENTIONALLY BLANK.


SERVICE AREA
TAMPA ELECTRIC COMPANY
69 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1996
SERVICE AREA D
SERVICE AREA A
SERVICE AREA B
SERVICE AREA E
MACDILL AIR FORCE BASE
R16E
R17E
R18E
R19E
R20E
R21E
R22E

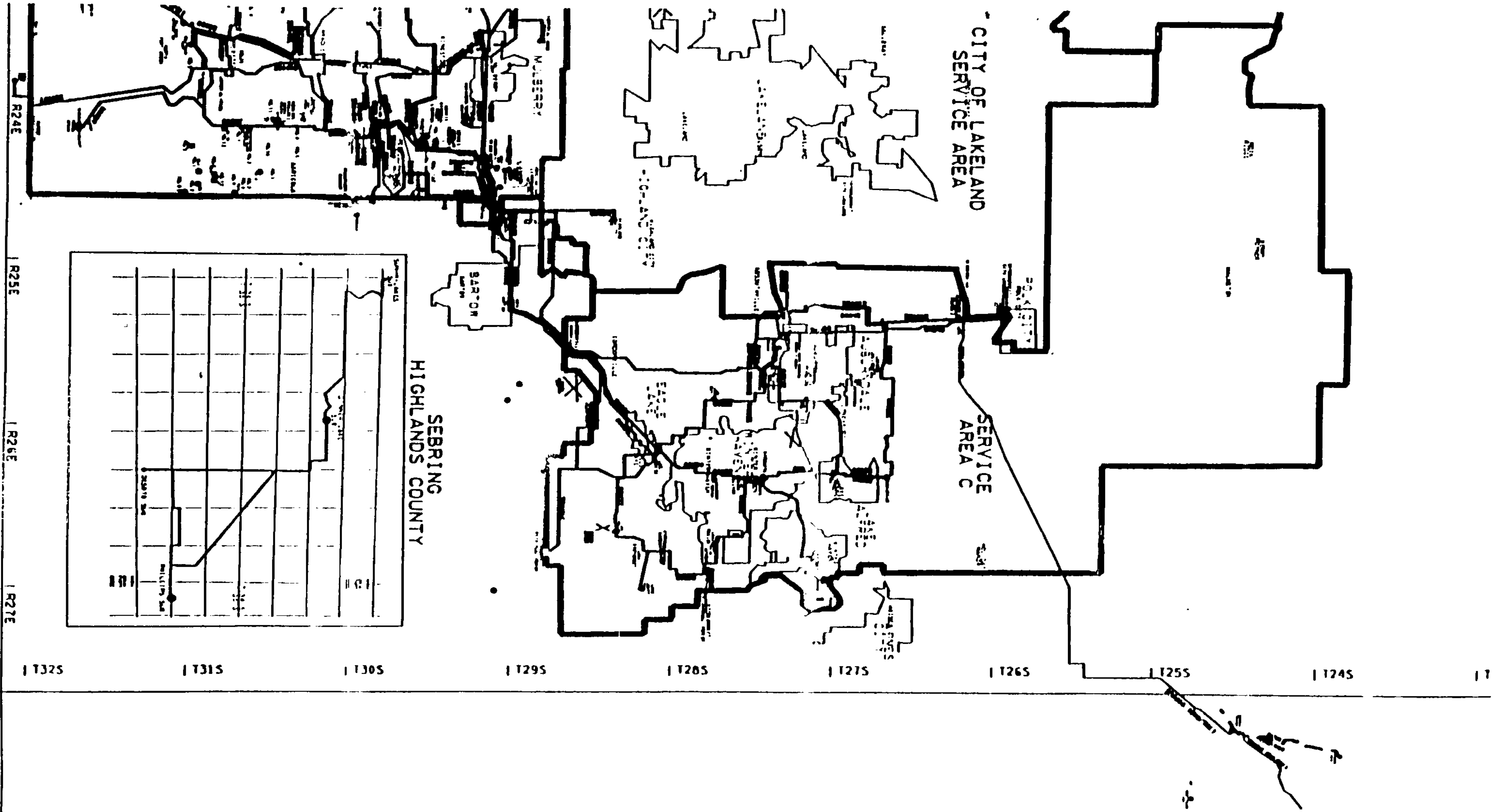


FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

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

THIS PAGE LEFT INTENTIONALLY BLANK.

CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Schedule 2.1

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					Commercial		
Year	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
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	1,006,400	2.6	7,369	491,925	14,980	5,541	61,902	89,512
2001	1,030,900	2.6	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,053,900	2.6	8,046	518,554	15,516	5,832	64,665	90,188
2003	1,075,400	2.6	8,189	530,815	15,427	6,113	66,184	92,364
2004	1,098,100	2.6	8,488	542,393	15,649	6,309	67,778	93,083
2005	1,121,700	2.6	8,778	553,796	15,851	6,534	69,284	94,307
2006	1,142,400	2.5	9,073	565,116	16,055	6,780	70,803	95,759
2007	1,160,600	2.5	9,376	576,469	16,265	7,027	72,370	97,098
2008	1,177,100	2.5	9,675	587,853	16,459	7,283	73,863	98,601
2009	1,192,300	2.5	9,981	599,261	16,656	7,548	75,319	100,214
2010	1,206,900	2.5	10,298	610,723	16,862	7,823	76,932	101,687
2011	1,220,800	2.5	10,626	622,299	17,075	8,108	78,551	103,220
2012	1,234,100	2.5	10,968	633,893	17,303	8,399	80,184	104,747

December 31, 2002 Status

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

Schedule 2.2

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	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
1993	2,236	509	4,392,927	0	45	1,028	13,447
1994	2,278	511	4,457,926	0	46	1,078	13,932
1995	2,362	491	4,810,591	0	51	1,125	14,600
1996	2,305	504	4,573,413	0	53	1,150	14,930
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	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,612	948	2,755,274	0	55	1,380	17,925
2003	2,314	933	2,480,171	0	59	1,394	18,069
2004	2,356	977	2,411,464	0	60	1,418	18,631
2005	2,391	1,003	2,383,848	0	62	1,446	19,211
2006	2,483	1,033	2,403,679	0	64	1,477	19,876
2007	2,523	1,067	2,364,574	0	65	1,508	20,499
2008	2,526	1,101	2,294,278	0	67	1,542	21,093
2009	2,570	1,137	2,260,334	0	68	1,579	21,746
2010	2,592	1,176	2,204,082	0	69	1,618	22,400
2011	2,648	1,215	2,179,424	0	71	1,657	23,110
2012	2,701	1,255	2,152,191	0	72	1,701	23,841

December 31, 2002 Status

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

Schedule 2.3

History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for * Resale GWH	Utility Use ** & Losses GWH	Net Energy *** for Load GWH	Other **** Customers	Total **** Customers
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	763	972	18,373	5,497	560,100
2001	685	794	18,455	5,649	575,780
2002	502	935	19,362	6,032	590,199
2003	500	897	19,466	5,885	603,817
2004	450	924	20,005	6,011	617,159
2005	473	952	20,636	6,134	630,217
2006	474	986	21,337	6,256	643,208
2007	475	1,017	21,991	6,376	656,282
2008	476	1,045	22,614	6,497	669,314
2009	477	1,078	23,301	6,617	682,334
2010	478	1,111	23,989	6,737	695,568
2011	263	1,145	24,518	6,858	708,923
2012	243	1,181	25,265	6,979	722,310

December 31, 2002 Status

* Includes sales to FPC, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
** Utility Use and Losses include accrued sales.
*** Net Energy for Load includes output to line including energy supplied by purchased cogeneration.
**** Average of end-of-month customers for the calendar year.

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale**	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind.*** Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
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	3,712	178	3,534	181	83	61	19	25	3,165
2002	3,849	122	3,727	206	99	63	20	30	3,318 ☑
2003	3,986	175	3,811	181	94	65	20	32	3,419
2004	4,082	175	3,907	182	97	68	20	34	3,506
2005	4,208	186	4,022	180	98	70	21	36	3,617
2006	4,330	186	4,144	182	98	72	21	37	3,734
2007	4,456	186	4,270	184	98	74	22	38	3,854
2008	4,575	186	4,389	180	98	76	22	40	3,973
2009	4,698	187	4,511	179	98	78	23	40	4,093
2010	4,824	187	4,637	175	98	79	23	41	4,221
2011	4,889	116	4,773	178	98	81	24	42	4,350
2012	5,026	116	4,910	175	98	82	24	42	4,489

December 31, 2002 Status

* 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.
☑ Net Firm Demand is not coincident with system peak.
Note: Values shown may be affected due to rounding.

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total *	(3) Wholesale **	(4) Retail *	(5) Interruptible	(6) Residential Load Management	(7) Residential *** Conservation	(8) Comm./Ind. **** Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
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	4,390	136	4,254	191	184	422	19	31	3,407
2001/02	4,253	127	4,126	168	165	482	20	32	3,259
2002/03	4,753	180	4,573	166	216	510	17	33	3,630
2003/04	4,882	181	4,701	166	223	537	18	34	3,724
2004/05	5,019	192	4,827	163	223	563	18	35	3,825
2005/06	5,162	192	4,970	166	224	588	19	36	3,937
2006/07	5,320	193	5,127	169	224	613	19	37	4,065
2007/08	5,471	194	5,277	166	225	637	20	37	4,192
2008/09	5,617	195	5,422	165	225	661	20	38	4,313
2009/10	5,772	195	5,577	161	225	684	20	39	4,448
2010/11	5,932	196	5,736	162	226	707	21	39	4,581
2011/12	6,031	126	5,905	161	226	730	21	40	4,727

December 31, 2002 Status

*   Includes cumulative conservation.
**   Includes sales to FPC, Wauchula, Fort Meade, St. Cloud and Reedy Creek.
***   Residential conservation includes code changes.
**** Commercial/Industrial Load Management includes Standby Generator.
Note: Values shown may be affected due to rounding.

Schedule 3.3

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

(1) Year	(2) Total	(3) Residential * Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale **	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load *** Factor %
1993	13,603	127	30	13,446	246	808	14,500	56.8
1994	14,103	138	33	13,932	163	636	14,731	59.6
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	58.3
1999	16,162	281	76	15,805	533	900	17,238	55.6
2000	17,028	302	88	16,638	763	972	18,373	58.8
2001	17,388	316	96	16,976	684	794	18,455	53.5
2002	18,346	316	105	17,925	502	935	19,362	58.9
2003	18,518	333	116	18,069	500	897	19,466	52.8
2004	19,105	351	123	18,631	450	924	20,005	52.8
2005	19,706	365	130	19,211	473	952	20,636	53.3
2006	20,389	378	135	19,876	474	986	21,337	53.7
2007	21,030	391	140	20,499	475	1017	21,991	53.7
2008	21,641	404	144	21,093	476	1045	22,614	53.7
2009	22,310	416	148	21,746	477	1078	23,301	54.1
2010	22,979	428	151	22,400	478	1111	23,989	54.2
2011	23,704	440	154	23,110	263	1145	24,518	54.0
2012	24,448	451	156	23,841	243	1181	25,265	54.7

December 31, 2002 Status

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

Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2002 Actual		2003 Forecast		2004 Forecast	
Month	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH	Peak Demand * MW	NEL ** GWH
January	3,739	1,491	4,210	1,458	4,311	1,502
February	3,359	1,220	3,656	1,325	3,796	1,365
March	3,188	1,454	3,255	1,413	3,383	1,455
April	3,423	1,568	3,122	1,439	3,248	1,482
May	3,623	1,794	3,485	1,710	3,620	1,760
June	3,581	1,755	3,889	1,793	3,980	1,845
July	3,756	1,835	3,853	1,953	3,945	1,990
August	3,563	1,857	3,862	1,959	3,953	1,996
September	3,596	1,818	3,702	1,766	3,789	1,819
October	3,425	1,749	3,445	1,680	3,527	1,732
November	3,130	1,365	3,289	1,418	3,368	1,461
December	3,113	1,459	3,571	1,549	3,658	1,598
TOTAL		19,362		19,466		20,005

December 31, 2002 Status

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

** Values shown may be affected due to rounding.

Schedule 5

History and Forecast of Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
	Fuel Requirements		Units	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	6,962	6,556	5,849	4,831	4,824	4,652	4,813	4,792	4,825	4,832	4,855	4,801
(3)	Residual	Total	1000 BBL	144	138	151	48	77	194	291	331	349	353	361	370
(4)		Steam	1000 BBL	4	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	140	138	151	48	77	194	291	331	349	353	361	370
(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	408	319	294	240	306	401	496	613	615	743	852	960
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	224	214	176	192	192	189	194	193	190	193	195	183
(11)		CT	1000 BBL	184	105	118	48	114	212	303	419	425	550	658	777
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	3,349	5,151	24,116	34,100	48,715	58,798	56,382	58,345	65,546	70,805	73,091	74,779
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	22,163	34,010	48,325	58,128	54,895	56,643	63,333	67,775	69,710	69,148
(16)		CT	1000 MCF	3,349	5,151	1,953	90	390	670	1,487	1,702	2,213	3,030	3,381	5,631
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	327	545	243	221	221	212	220	219	221	221	222	221

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source in GWH

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2001	Actual 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Annual Firm Interchange		GWH	203	359	671	135	212	278	257	336	301	325	330	421
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	14,623	13,353	12,801	10,654	10,629	10,273	10,617	10,588	10,638	10,658	10,711	10,605
(4)	Residual	Total	GWH	90	86	101	32	52	129	194	220	232	234	239	246
(5)		Steam	GWH	(2)	(2)	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	92	89	101	32	52	129	194	220	232	234	239	246
(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	211	191	161	135	168	217	266	323	326	391	446	501
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	141	149	101	111	110	109	111	111	109	111	112	105
(12)		CT	GWH	70	43	60	25	58	108	154	211	217	280	334	395
(13)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	311	474	3,239	4,675	6,680	8,069	7,696	7,965	8,934	9,627	9,930	10,058
(15)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWH	0	0	3,048	4,664	6,639	8,003	7,559	7,804	8,728	9,346	9,619	9,548
(17)		CT	GWH	311	474	191	11	40	66	137	161	206	280	311	510
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWH	911	1,522	679	619	618	594	615	612	619	619	621	619
(20)	Net Interchange		GWH	1,669	2,902	1,352	3,301	1,816	1,313	1,883	2,024	1,707	1,721	1,927	2,551
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWH	439	477	461	454	462	463	463	546	543	414	315	265
(23)	Net Energy for Load*		GWH	18,455	19,363	19,465	20,005	20,636	21,336	21,991	22,614	23,301	23,988	24,519	25,265

* Values shown may be affected due to rounding.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source as Percentage

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2001	Actual 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Annual Firm Interchange		%	1	2	3	1	1	1	1	1	1	1	1	2
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		%	79	69	66	53	52	48	48	47	46	44	44	42
(4)	Residual	Total	%	0	0	1	0	0	1	1	1	1	1	1	1
(5)		Steam	%	(0)	(0)	0	0	0	0	0	0	0	0	0	0
(6)		CC	%	0	0	1	0	0	1	1	1	1	1	1	1
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	1	1	1	1	1	1	1	1	1	2	2	2
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	1	1	1	1	1	1	1	0	0	0	0	0
(12)		CT	%	0	0	0	0	0	1	1	1	1	1	1	2
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	2	2	17	23	32	38	35	35	38	40	40	40
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	16	23	32	38	34	35	37	39	39	38
(17)		CT	%	2	2	1	0	0	0	1	1	1	1	1	2
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	5	8	3	3	3	3	3	3	3	3	3	2
(20)	Net Interchange		%	9	15	7	17	9	6	9	9	7	7	8	10
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	2	2	2	2	2	2	2	2	2	2	1	1
(23)	Net Energy for Load*		%	100	100	100	100	100	100	100	100	100	100	100	100

* Values shown may be affected due to rounding.

THIS PAGE LEFT INTENTIONALLY BLANK.

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 employs the necessary methodologies for carrying out this function. The primary objective of 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's forecasting methods and the major assumptions utilized in developing the 2003-2012 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2003-2012 time period.

Retail Load

This year the company made significant changes in its forecasting tools and methodology. MetrixND, designed by Regional Economic Research (RER) - a leader in energy forecasting, was used to develop the 2003-2012 Customer, Demand and Energy forecasts.

MetrixND

MetrixND is an advanced statistics program for analysis and forecasting. This new software has replaced the REGIS, SHAPES and regression models used in the past and has provided a new platform for developing more dynamic and fully integrated models.

MetrixLT

In addition, Tampa Electric has purchased MetrixLT, which integrates with MetrixND to develop multiple-year forecasts of energy usage at the hourly level. This tool allows the annual or monthly forecasts in MetrixND to be combined with hourly load shape data to develop a long-term "bottom-up" forecast, which is consistent with short-term statistical forecasts.

Tampa Electric's retail customer, demand and energy forecasts are the result of six separate forecasting analyses:

1. economic analysis;
2. customer analysis;
3. energy analysis;
4. peak demand analysis;
5. phosphate analysis; and
6. conservation programs analysis

The MetrixND models are the company's most sophisticated and primary load forecasting models. The phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric's conservation, load management, and cogeneration programs is incorporated into the process by subtracting the expected reduction in demand and energy from the forecast.

1. Economic Analysis

The economic assumptions used in the forecast models are derived from forecasts from Economy.com and the University of Florida's Bureau of Economic and Business Research (BEBR).

See the "Base Case Forecast Assumptions" section of this chapter for an explanation of the most significant economic inputs to the MetrixND models.

2. Customer Multiregression Model

The customer multiregression forecasting model is a six-equation model. The equations forecast the number of customers by six major customer categories. The primary economic drivers in the customer forecast models are state population estimates, service area households and Hillsborough County employment growth.

1. <u>Residential Customer Model</u>: Customer projections are a function of Florida's population. Since a strong mathematical relationship (correlation) exists between historical changes in service area customers and historical changes in Florida's population, Florida population estimates for 2002-2022 were used to forecast the future growth patterns in residential customers.

   <u>Commercial Customer Model</u>: Total commercial customers include commercial customers plus temporary service customers (temporary poles on construction sites); therefore, two models are used to forecast total commercial customers.

2. Commercial customers are a function of residential customers and a time trend variable. An increase in the number of households provides the need for additional services, restaurants, and retail establishments. The amount of residential activity also plays a part in the attractiveness of the Tampa Bay area as a place to relocate or start a new business. Therefore, the residential customer forecast is a driver in the commercial model along with a time trend variable that captures non-residential driven growth and/or structural changes in the commercial sector.

3. Projections of employment in the construction sector are a good indicator of expected increases and decreases in local construction activity. Therefore, the Temporary Service model projects the number of customers as a function of construction employment.

4. Non-Phosphate Industrial Customer Model: Customer projections are a function of commercial and industrial employment. Since the structure of our local industrial sector has been shifting from an energy-intense manufacturing sector to a non-energy intense manufacturing sector, the type of customers in this sector have qualities of both large scaled commercial customers and smaller scaled industrial customers. Therefore, the best predictor of this sector's customer growth is the combination of commercial and industrial employment projections for Hillsborough County.

5. Public Authority Customer Model: Customer projections are a function of Florida's population. The need for public services will depend on the number of people in the region; therefore, consistent with the residential customer model, Florida's population projections are used to determine future growth in the public authorities sector.

6. Street & Highway Lighting Customer Model: As the residential population increases so does the need for infrastructure expansion, of which street and highway lighting is a part of. Therefore, the residential customer forecast is the basis for the Street & Highway Lighting customer model.

3. Energy Multiregression Model

There are a total of six energy models. The residential and commercial models represent average usage per customer (kWh/customer), while the temporary services, industrial, public authorities, and street lighting models represent total kWh sales for the class. The residential and commercial energy models interact with the residential and commercial customer models to arrive at total sales for each class.

The energy models are based on an approach known as Statistically Adjusted Engineering (SAE). SAE entails specifying end-use variables, such as heating, cooling and base use appliance/equipment, and incorporating these variables into regression models. This approach allows the models to capture long-term structural changes that end-use models are known for, while also performing well in the short-term time frame, as do econometric regression models.

1. Residential Energy Model: The residential forecast model is made up of three major components: (1) The end-use equipment index variables, which capture the long-term net effect of equipment saturation and equipment efficiency improvements; (2) The second component serves to capture changes in the economy such as household income, household size, and the price of electricity; and, (3) The third component is made up of weather variables, which serve to allocate the seasonal impacts of weather throughout the year.

   The SAE model framework begins by defining energy use for an average customer in year (y) and month (m) as the sum of energy used by heating equipment (XHeat y,m), cooling equipment (XCool y,m), and other equipment (XOther y,m). The XHeat, XCool, and XOther variables are defined as a product of **an annual equipment index** and **a monthly usage multiplier**.

   $$\textbf{Average Usage}_{y,m} = (\textbf{XHeat}_{y,m} + \textbf{XCool}_{y,m} + \textbf{XOther}_{y,m})$$

   Where:

   $$\textbf{XHeat}_{y,m} = \text{HeatEquipIndex}_{y} \times \text{HeatUse}_{y,m}$$

   $$\textbf{XCool}_{y,m} = \text{CoolEquipIndex}_{y} \times \text{CoolUse}_{y,m}$$

   $$\textbf{XOtherUse}_{y,m} = \text{OtherEquipIndex}_{y} \times \text{OtherUse}_{y,m}$$

The **annual equipment variables** (*HeatEquipIndex, CoolEquipIndex, OtherEquipIndex*) are defined as a weighted average across equipment types multiplied by equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations and operating efficiencies. The weights are defined by the estimated energy use per household for each equipment type in the base year.

Where:

$$\textbf{HeatEquipIndex} = \sum_{Tech.} \text{Weight x} \left(\frac{\text{Saturation}_{y} \ / \ \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \ / \ \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{CoolEquipIndex} = \sum_{Tech.} \text{Weight x} \left(\frac{\text{Saturation}_{y} \ / \ \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \ / \ \text{Efficiency}_{\text{base y}}} \right)$$

$$\textbf{OtherEquipIndex} = \sum_{Tech.} \text{Weight x} \left(\frac{\text{Saturation}_{y} \ / \ \text{Efficiency}_{y}}{\text{Saturation}_{\text{base y}} \ / \ \text{Efficiency}_{\text{base y}}} \right)$$

Next, the **monthly usage multiplier or utilization variable** (*HeatUse, CoolUse, OtherUse*) are defined using economic and weather variables. A customer's monthly usage level is impacted by several factors, including weather, household size, income levels, electricity prices and the number of days in the billing cycle. The degree day variables serve to allocate the seasonal impacts of weather throughout the year, while the remaining variables serve to capture changes in the economy.

Where:

HeatUse $_{y,m}$ =

$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y,m}}} \right)^{-.20} \text{x} \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y,m}}} \right)^{.20} \text{x} \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y,m}}} \right)^{.30} \text{x} \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

CoolUse $_{y,m}$ =

$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y,m}}} \right)^{-.20} \text{x} \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y,m}}} \right)^{.20} \text{x} \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y,m}}} \right)^{.30} \text{x} \left(\frac{\text{HDD}_{y,m}}{\text{Normal HDD}} \right)$$

OtherUse $_{y,m}$ =

$$\left(\frac{\text{Price}_{y,m}}{\text{Price}_{\text{base y,m}}} \right)^{-.20} \text{x} \left(\frac{\text{HH Income}_{y,m}}{\text{HH Income}_{\text{base y,m}}} \right)^{.20} \text{x} \left(\frac{\text{HH Size}_{y,m}}{\text{HH Size}_{\text{base y,m}}} \right)^{.25} \text{x} \left(\frac{\text{Billing Days}_{y,m}}{\text{Billing Days}_{\text{base y,m}}} \right)$$

The SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels and gives estimates of weather sensitivity that varies over time as well as estimate trend adjustments.

Commercial Energy Models: Total Commercial energy sales include commercial sales plus temporary service sales (temporary poles on construction sites); therefore, two models are used to forecast total commercial energy sales.

2. Commercial Sector Model: The model framework for the commercial sector is the same as the residential model; it also has three major components and utilizes the SAE model framework. The differences lie in the type of end-use equipment and in the economic variables used. The end-use equipment variables are based on commercial appliance/equipment saturation and efficiency assumptions. The economic drivers in the commercial model are commercial productivity measured in terms of dollar output and the price of electricity for the commercial sector. The third component, weather variables, is the same as in the residential model.

3. Temporary Service Model: The model is a subset of the total commercial sector and is a rather small percentage of the total commercial sector. Although small in nature, it is still a component that needs to be included. A simple regression model is used with the primary drivers being the construction sector's productivity and heating and cooling degree-days.

4. Industrial Sector Model (Non-Phosphate): While the residential and commercial models estimate average energy usage for a single customer, the industrial model estimates total energy usage for all customers in the sector. Another difference is that this model has only two major components. Utilizing the SAE model framework, the first component, economic index variables, includes estimates for manufacturing output and the price of electricity in the industrial sector. The second component is a cooling degree-day variable. Unlike the previous models discussed, heating load does not impact the industrial sector.

5. Public Authority Sector Model: The public authority sector model has characteristics of both the commercial and industrial sector models. The equipment index is based on the same commercial equipment saturation and efficiency assumptions used in the commercial model, and the economic component is based on government sector productivity and the price of electricity in this sector. Similar to the industrial model, heating load does not have a significant impact on this sector's sales; therefore, heating degree-days are not included in the weather component of this model.

6. Street & Highway Lighting Sector Model: The street and highway lighting sector is not impacted by weather; therefore; it is a rather simple model and the SAE modeling approach does not apply. The model is a linear regression model where street & highway lighting energy consumption is a function of residential customers, number of billing days in the cycle, and the number of daylight hours in a day for each month.

The six energy models described above plus a phosphate forecast are added together to arrive at the total retail energy sales forecast.

In summary, the SAE approach to modeling provides a powerful framework for developing short-term and long-term energy forecasts. This approach reflects changes in equipment saturation and efficiency levels, gives estimates of weather sensitivity that varies over time, as well as estimates trend adjustments.

4. Demand Multiregression Model

After the total retail energy sales forecast is complete, it is integrated into the peak demand model as an independent trend variable along with weather variables. The energy forecast acts as a trend variable to increase the peak demands according to the projected increases in customers and energy usage.

The weather variables provide the monthly seasonality to the peaks. The weather variables used are heating and cooling degree-days for both the peak day and the day prior to the peak day. By incorporating temperatures for both the day prior to and the day of the peak, the model is accounting for the fact that cold/heat buildup contributes to determining the peak day.

5. Phosphate Demand and Energy Analysis

Because Tampa Electric's phosphate customers are relatively few in number, the company's Commercial/Industrial Customer Service 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.

6. Conservation, Load Management and Cogeneration Programs

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

1. Defer expansion, particularly production plant construction.
2. Reduce marginal fuel cost by managing energy usage during higher fuel cost periods
3. Provide customers with some ability to control energy usage and decrease energy costs.
4. Pursue the cost-effective accomplishment of the Florida Public Service Commission (FPSC) ten-year demand and energy goals for the residential and commercial/industrial sectors.
5. Achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act.

The company's current Demand Side Management (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 residential heating and cooling equipment.

2. Load Management - Reduces weather-sensitive heating, cooling, water heating and pool pump loads through a radio signal control mechanism. Residential, commercial and industrial programs are offered.

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 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. The 2000 through 2002 demand and energy savings achieved by conservation and load management programs are listed in Table III-1.

Tampa Electric developed a 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.

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 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, Progress Energy Florida, the City of St. Cloud, and Reedy Creek Improvement District. Since Tampa Electric's sales to Wauchula and Fort Meade will vary over time based on the strength of the 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. For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric.

TABLE III-1

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%
2001	24.7	32.2	76.7%	9.2	11.1	82.9%	26.0	20.0	130.0%
2002	38.2	46.3	82.5%	15.3	16.1	95.0%	40.8	29.0	140.7%

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%
2001	3.7	3.0	123.3%	9.1	6.9	131.9%	27.3	25.7	106.2%
2002	6.3	4.5	140.0%	13.3	10.4	127.9%	38.2	38.6	99.0%

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	131.9%
2001	28.4	35.2	80.7%	18.3	18.0	101.7%	53.3	45.7	116.6%
2002	44.5	50.8	87.6%	28.6	26.5	107.9%	79.0	67.6	116.9%

Base Case Forecast Assumptions

Retail Load

Numerous assumptions are inputs to the MetrixND models of which the more significant ones are listed below.

1. Population and Households;
2. Commercial, Industrial and Governmental Employment;
3. Commercial, Industrial and Governmental Output;
4. Per Capita Income;
5. Price of Electricity;
6. Appliance Efficiency Standards; and
7. Weather.

1. Population and Households

The population forecast is the starting point from which the customer and energy projections are developed. The University of Florida's Bureau of Economic and Business Research supply the population projections for Hillsborough County and Florida. Over the next ten years the average annual growth rate in Hillsborough County's population is expected to be 1.5% and in Florida, 1.6%. Additionally, Economy.com provides Hillsborough County's and Florida's population and household data, used as means of comparison.

2. Commercial, Industrial and Governmental Employment

Commercial and industrial employment assumptions are utilized in computing the number of customers in their respective sectors. It is imperative that employment growth be consistent with the expected population expansion and unemployment levels. Over the next ten years (2003 – 2012), employment is assumed to rise at a 2.1% average annual rate. Economy.com supplies employment projections for the models.

3. Commercial, Industrial and Governmental Output

In addition to employment, output in terms of real gross domestic product by employment sector is utilized in computing energy in their respective sectors. Over the next ten years, output for the entire employment sector is assumed to rise at a 3.8% average annual rate. Economy.com supplies output projections for the models.

4. **Per Capita Income**
   Economy.com supplies the assumptions for Hillsborough County's per capita income growth. During 2003 - 2012, personal income per capita for Hillsborough County is expected to increase at a 5.4% average annual rate.

5. **Price of Electricity**
   Forecasts for the price of electricity by customer class are supplied by Tampa Electric's Regulatory Department.

6. **Appliance Efficiency Standards**
   Another factor influencing 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.

   Also influencing energy consumption is the saturation levels of appliances. The saturation trend for heating appliances is increasing through time, however overall electricity consumption actually declines over time as less efficient heating technologies (room heating and furnaces) are replaced with more efficient technologies (heat pumps). Similarly, cooling equipment saturation will continue to increase, but be offset by heat pump and central air conditioning efficiency gains.

   Improvements in the efficiency of other non weather related appliances also helps to lower electricity growth, however any efficiency gains are offset by the increasing saturation trend of electronic equipment and appliances in households throughout the forecast period.

7. **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 twenty 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 twenty years plus the temperatures on peak days for the past twenty years.

In summary, despite the high saturation of electric appliances, increased appliance and equipment efficiencies will slow residential usage making them less sensitive to changes in temperature through time. However, economic conditions such as the decreasing real price of electricity and the increasing household income will mitigate any decline in consumption and actually increase overall energy consumption.

High and Low Scenario Forecast Assumptions

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. The high scenario represents more optimistic economic conditions in the areas of customers, employment, and income. The low band represents a less optimistic scenario in the same areas. Compared to the base case, the expected customer and economic growth rates are 0.5% higher in the high scenario and 0.5% lower in the low scenario.

History and Forecast of Energy Use

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3.

Retail Energy

For 2003-2012, retail energy sales are projected to rise at a 3.1% annual rate. The major contributors to growth are the residential, commercial, and industrial (not including phosphate) categories. These three sectors all are increasing at an annual rate of over 3.0% (3.3%, 3.6% and 3.7% respectively).

Wholesale Energy

Wholesale energy sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 500 GWh are expected in 2003, and are projected to decline at a -7.7% annual rate through 2012. Sales are expected to remain in the 450 - 478 GWh range for 2004-2010, declining during 2011 – 2012 (263 GWh and 243 GWh, respectively).

History and Forecast of Peak Loads

Historical and base scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the 2003-2012 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 3.0% and 3.1%, respectively.

CHAPTER IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Schedule 8 integrate DSM programs and alternative generation technologies with traditional generating resources to provide economical, reliable service to Tampa Electric's customers. To achieve this objective, various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective DSM 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's integrated resource planning process is included in Chapter V.

The results of the analysis provide Tampa Electric 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 Schedule 8. To meet the expected long term system demand and energy requirements over the next ten years, combustion turbine additions are planned for service in 2005, 2006, 2007, 2008, 2009, 2010 and 2012. Tampa Electric will, in the short term, increase its generating capacity while diversifying 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. The units are scheduled to come on-line in May 2003 and January 2004. In addition, Gannon units 1 and 2 will be placed on long term reserve standby in April 2003 and Gannon units 3 and 4 in September 2003. Gannon units 1 and 2 will be retired on December 31, 2004. Gannon units 3 and 4 will be retired from coal operations on December 31, 2004, after which the assets may be utilized for natural gas operations. 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 plans for 447 MW of cogeneration capacity operating in its service area in 2003. Self-service capacity of 228 MW (net) is used by cogenerators to serve internal load requirements, 62 MW are purchased by Tampa Electric on a firm contract basis, and 5 MW are purchased on a non-firm, as-available basis. The remaining 152 MW of cogeneration capacity is contracted to other utilities and is exported out of Tampa Electric's system.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2, respectively. Tampa Electric currently uses coal as the primary fuel for most of its generating requirements. Starting in the spring of 2003, Tampa Electric will increase the diversity of its fuel supply with the repowering of the coal fired Gannon unit 5 to a combined cycle unit burning natural gas and renaming the unit to Bayside 1. In January of 2004 Gannon unit 6 will be repowered to a combined cycle unit burning natural gas, and renamed to Bayside 2. Tampa Electric has entered into a firm transportation contract with the Florida Gas Transmission Company (FGT) for delivery of natural gas to the new Bayside units. The implementation of repowering these units will reduce Tampa Electric's coal generation from 69% in 2002 to 66% in 2003 and 53% in 2004.

Environmental Considerations

Emissions reductions made since 2000 are largely the result of a cooperative effort between the Florida Department of Environmental Protection (DEP) and Tampa Electric. The effort resulted in a comprehensive emissions reduction plan, which was finalized with the DEP on December 6, 1999. Approximately one year later, on December 29, 2000, Tampa Electric reached a similar agreement with the U.S. Environmental Protection Agency (EPA). The efforts to reduce emissions from the company's facilities began long before its recent settlement with the EPA. Since 1998, Tampa Electric has reduced annual sulfur dioxides (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) emissions from our facilities by 105,418 tons, 11,206 tons, and 1,113 tons, respectively.

Reductions in SO_2 emissions were primarily accomplished through the installation of flue gas desulfurization (scrubber) systems on Big Bend units 1 and 2 in 1999. Big Bend unit 3 was integrated with Big Bend unit 4's scrubber in 1995. Big Bend unit 4 was originally constructed with a scrubber. Currently, the scrubbers at Big Bend station remove more than 95% of the SO_2 emissions from the flue gas streams. In addition, reductions in NO_x have been accomplished through combustion tuning and optimization projects at Big Bend and Gannon Stations.

Particulate matter is controlled at Big Bend and Gannon stations through the use of electrostatic precipitators, which remove more than 99.9% of the PM generated during the combustion process.

Significant reductions in emissions outlined in the Consent Decree and Consent Final Judgment will result from the ongoing repowering of Gannon station and, should Tampa Electric decide to continue to combust coal at Big Bend station, the installation of additional NO_x emissions controls is required on all Big Bend units. By 2010, these projects will result in the estimated additional phased reduction of SO_2 by 47,467 tons per year, NO_x by 50,488 tons per year, and PM by 1,981 tons per year. In total, Tampa

Electric's emission reduction initiatives will result in the reduction of SO_2, NO_x, and PM emissions by 87 percent, 89 percent, and 60 percent, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in our community.

Interchange Sales and Purchases

Tampa Electric's long-term interchange sales include Schedule D, Partial Requirements service agreements with Progress Energy Florida, Reedy Creek Improvement District, as well as the cities of St. Cloud, and Wauchula.

Tampa Electric has a long-term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation) from January 1, 1993 through December 31, 2012. The contract involves a shared-capacity agreement with Seminole Electric Cooperative (SEC), whereby Tampa Electric plans for the full net capability (359 MW winter and 296 MW summer) of the Hardee Power Station during those times when SEC plans for the Seminole units 1 and 2 and the SEC Crystal River unit 3 allocation to be available for operation, 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 winter and 72 MW summer of firm non-shared capacity. The contract began in May 2000 and expires on December 31, 2012.

Tampa Electric had a firm system power call option from Progress Energy Florida for 150 MW from January 1, 2002 running through April 30, 2003. In addition, Tampa Electric had purchase power agreements with the following:

1) Ringhaver Equipment Co. Power Division for firm capacity of 50 MW from January 1, 2003 through March 31, 2003.
2) Okeelanta for firm capacity of 30 MW from January 1, 2003 through March 31, 2003.
3) A unit contingent call option on capacity and energy from Tallahassee's Purdom unit 8 for 52 MW in January 1, 2003.
4) Okeelanta for firm capacity of 55 MW from April 1, 2003 through April 30, 2003.

Wholesale power sales and purchases are included in Schedules 3.1, 3.2, 3.3, 4, 5, 6.1, 7.1, and 7.2.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2003	3,763	368	0	62	4,193	3,594	599	17%	0	599	17%
2004	4,004	368	0	62	4,434	3,681	753	20%	0	753	20%
2005	4,164	368	0	62	4,594	3,802	792	21%	0	792	21%
2006	4,324	368	0	62	4,754	3,920	834	21%	0	834	21%
2007	4,484	368	0	62	4,914	4,040	873	22%	0	873	22%
2008	4,644	368	0	62	5,074	4,159	914	22%	0	914	22%
2009	4,804	368	0	62	5,234	4,279	954	22%	0	954	22%
2010	4,964	368	0	47	5,379	4,407	971	22%	0	971	22%
2011	4,964	368	0	21	5,353	4,465	887	20%	0	887	20%
2012	5,124	368	0	21	5,513	4,604	908	20%	0	908	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 for 2003 through 2012 includes firm purchase power agreement with Hardee Power Partners of 368 MW.
3. The QF column accounts for cogeneration that will be purchased under firm contracts.
4. Gannon units 1 and 2 will be placed in long term reserve standby in April 2003 and units 3 and 4 will be placed in long term reserve standby in September 2003.

• Values may be affected due to rounding.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export		Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	QF MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2002-03	3,611	731	0	62	4,404	3,810	594	16%	0	594	16%
2003-04	4,305	449	0	62	4,816	3,905	911	23%	0	911	23%
2004-05	4,305	449	0	62	4,816	4,017	799	20%	0	799	20%
2005-06	4,485	449	0	62	4,996	4,129	867	21%	0	867	21%
2006-07	4,665	449	0	62	5,176	4,258	918	22%	0	918	22%
2007-08	4,845	449	0	62	5,356	4,386	970	22%	0	970	22%
2008-09	5,025	449	0	62	5,536	4,508	1,028	23%	0	1,028	23%
2009-10	5,205	449	0	47	5,701	4,643	1,058	23%	0	1,058	23%
2010-11	5,385	449	0	21	5,855	4,777	1,078	23%	0	1,078	23%
2011-12	5,385	449	0	21	5,855	4,853	1,002	21%	0	1,002	21%

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 for 2003 through 2012 includes firm purchase power agreement with Hardee Power Partners of 449 MW. Capacity imports for 2003 also include Florida Power Corp. (150 MW), Ringhaver Equipment Co. (50 MW), Okeelanta (30 MW) and Tallahassee (52 MW)
3. The QF column accounts for cogeneration that will be purchased under firm contracts.
4. Gannon units 1 and 2 will be placed in long term reserve standby in April 2003 and units 3 and 4 will be placed in long term reserve standby in September 2003.

* Values may be affected due to rounding.

Schedule 8

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Bayside	1	Hills. Co.	CC	NG	N	PL	N	4/01	5/03	unknown	unknown	690	779	UC
Bayside	2	Hills. Co.	CC	NG	N	PL	N	4/02	1/04	unknown	unknown	908	1022	UC
Bayside	3A	Hills. Co.	CT	NG	LO	PL	U	1/04	5/05	unknown	unknown	160	180	P
Bayside	3B	Hills. Co.	CT	NG	LO	PL	U	1/05	5/06	unknown	unknown	160	180	P
Polk	4	Polk Co.	CT	NG	LO	PL	TK	9/05	5/07	unknown	unknown	160	180	P
Polk	5	Polk Co.	CT	NG	LO	PL	TK	9/06	5/08	unknown	unknown	160	180	P
Polk	6	Polk Co.	CT	NG	LO	PL	TK	9/07	5/09	unknown	unknown	160	180	P
Future Unit	1	unknown	CT	NG	LO	PL	TK	12/07	5/10	unknown	unknown	160	180	P
Future Unit	2	unknown	CT	NG	LO	PL	TK	12/09	5/12	unknown	unknown	160	180	P

Note: Gannon unit 5 steam turbine is being repowered in the spring of 2003 with three combustion turbines and will be renamed Bayside unit 1.
Gannon unit 6 steam turbines will be repowered in the fall of 2003 with four combustion turbins and renamed Bayside unit 2.

SCHEDULE 9

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	690
	B. WINTER	779
(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 [1]	APPROXIMATELY 213 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)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2003)	55%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	7,034 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	486.04
	DIRECT CONSTRUCTION COST ($/kW)	449.01
	AFUDC AMOUNT ($/kW)	37.03
	ESCALATION ($/kW)	0.00
	FIXED O&M ($/kW – Yr)	4.23
	VARIABLE O&M ($/MWH)	2.89
	K FACTOR	1.7586

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

SCHEDULE 9

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	908
	B. WINTER	1022
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	APR 2002
	B. COMMERCIAL IN-SERVICE DATE	JAN 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 [1]	APPROXIMATELY 213 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)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2004)	40%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	7,130 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	354.56
	DIRECT CONSTRUCTION COST ($/kW)	305.34
	AFUDC AMOUNT ($/kW)	42.19
	ESCALATION ($/kW)	7.02
	FIXED O&M ($/kW – Yr)	2.60
	VARIABLE O&M ($/MWH)	2.95
	K FACTOR	1.7586

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

SCHEDULE 9

(Page 3 of 9)

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

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 3A
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JAN 2004
	B. COMMERCIAL IN-SERVICE DATE	MAY 2005
(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 [1]	APPROXIMATELY 213 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 (2005)	2.7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	248.20
	DIRECT CONSTRUCTION COST ($/kW)	227.07
	AFUDC AMOUNT ($/kW)	10.57
	ESCALATION ($/kW)	10.57
	FIXED O&M ($/kW – Yr)	2.68
	VARIABLE O&M ($/MWH)	8.56
	K FACTOR	1.6815

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

SCHEDULE 9

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

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNITS 3B
(2)	CAPACITY	
	A. SUMMER	160
	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	DRY LOW NO_X BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [1]	APPROXIMATELY 213 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)	3.1%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	253.91
	DIRECT CONSTRUCTION COST ($/kW)	227.07
	AFUDC AMOUNT ($/kW)	10.81
	ESCALATION ($/kW)	16.03
	FIXED O&M ($/kW – Yr)	2.74
	VARIABLE O&M ($/MWH)	8.76
	K FACTOR	1.6815

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

SCHEDULE 9

(Page 5 of 9)

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	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	SEP 2005
	B. COMMERCIAL IN-SERVICE DATE	MAY 2007
(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 [1]	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 (2008)	3.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	261.16
	DIRECT CONSTRUCTION COST ($/kW)	226.56
	AFUDC AMOUNT ($/kW)	13.02
	ESCALATION ($/kW)	21.57
	FIXED O&M ($/kW – Yr)	2.80
	VARIABLE O&M ($/MWH)	8.96
	K FACTOR	1.6815

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

SCHEDULE 9

(Page 6 of 9)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK 5
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2006
	B. COMMERCIAL IN-SERVICE DATE	MAY 2008
(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 [1]	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)	3.8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	267.17
	DIRECT CONSTRUCTION COST ($/kW)	226.56
	AFUDC AMOUNT ($/kW)	13.32
	ESCALATION ($/kW)	27.28
	FIXED O&M ($/kW – Yr)	2.87
	VARIABLE O&M ($/MWH)	9.17
	K FACTOR	1.6815

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

SCHEDULE 9

(Page 7 of 9)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK 6
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	SEP 2007
	B. COMMERCIAL IN-SERVICE DATE	MAY 2009
(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 [1]	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 (2010)	4%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [2]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	273.31
	DIRECT CONSTRUCTION COST ($/kW)	226.56
	AFUDC AMOUNT ($/kW)	13.63
	ESCALATION ($/kW)	33.12
	FIXED O&M ($/kW – Yr)	2.93
	VARIABLE O&M ($/MWH)	9.38
	K FACTOR	1.6815

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

SCHEDULE 9

(Page 8 of 9)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE UNIT 1
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	DEC 2007
	B. COMMERCIAL IN-SERVICE DATE	MAY 2010
(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	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(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 (2011)	4.5%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	282.62
	DIRECT CONSTRUCTION COST ($/kW)	225.55
	AFUDC AMOUNT ($/kW)	18.14
	ESCALATION ($/kW)	38.92
	FIXED O&M ($/kW – Yr)	3.00
	VARIABLE O&M ($/MWH)	9.60
	K FACTOR	1.6815

[1] BASED ON IN-SERVICE YEAR.

SCHEDULE 9

(Page 9 of 9)

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

(1)	PLANT NAME AND UNIT NUMBER	FUTURE UNIT 2
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	DEC 2009
	B. COMMERCIAL IN-SERVICE DATE	MAY 2012
(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	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(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 (2011)	6.1%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	295.77
	DIRECT CONSTRUCTION COST ($/kW)	225.55
	AFUDC AMOUNT ($/kW)	18.99
	ESCALATION ($/kW)	51.22
	FIXED O&M ($/kW – Yr)	3.14
	VARIABLE O&M ($/MWH)	10.04
	K FACTOR	1.6815

[1] BASED ON IN-SERVICE YEAR.

Schedule 10

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
Gannon/Juneau Conversion	1	No new right of way required	14.5 mi	230 kV	Summer 2003	$13.0 million	2 - 230/69 kV autos at Juneau	None
Juneau/ Ohio/Sheldon Loop	1	Possible road ROW required	5.2 mi	230 kV	Fall 2003	$4.4 million	No new substations	None
Recker to So. Eloise	3	Road ROW required	16.7	230 kV	Fall 2003	$14.5 million	230 kV ring-bus at So. Eloise	Progress Energy Florida
River - Chapman	1	No new right of way required	8.3 mi	230 kV	Summer 2007	$9.0 million	230 kV ring-bus at River	None
FishHawk – Wheeler	1	No new right of way required	11.0 mi	230 kV	Summer 2008	$8.5 million	Wheeler 230/69 kV Substation	None
FishHawk - Davis	1	No new right of way required	14.4 mi	230 kV	Summer 2009	$9.0 million	No new substations	None
Davis - Dale Mabry	1	No new right of way required	13.3 mi	230 kV	Summer 2010	$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 2002 Florida Reliability Coordinating Council (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.

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 the qualitative and quantitative considerations 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 Daily, Energy Ventures Analysis, Inc., and coal, oil, natural gas, and propane pricing publications and periodicals which include: Inside FERC, Natural Gas Week, Platt's Oilgram. Additionally, NYMEX forward pricing curves are utilized in conjunction with the forecasted data to derive our forecast pricing.

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 35% above or below the base case. The high and low case price projections variation from the base case forecast represents the implied volatility of oil and gas prices used in the base forecast.

Only base case forecasts are prepared for coal fuels because of the fuels relatively low price volatility. 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 models generating unit performance in the Generation and Fuel (GAF) module of STRATEGIST, 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. 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'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.

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. Initially, 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 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 FPSC'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 evaluates DSM measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., and the FPSC'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 service area.

The technologies that 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 units, firm power purchases from other entities, joint ownership of generating capacity, and modifications of the transmission system to increase import capability are included in the analysis.

Tampa Electric uses the PROVIEW module of STRATEGIST to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the timing 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 that have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements and 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 STRATEGIST. 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.

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 the 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 Schedule 8. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, combustion turbine additions are planned for service in May 2005, 2006, 2007, 2008, 2009, 2010 and 2012. The Gannon repowering of Gannon 5 to Bayside 1 is planned for May 2003 and Gannon 6 to Bayside 2 is January 2004.

Generation and Transmission Reliability Criteria

Generation

As part of the stipulation reached in FPSC 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 are 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.

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 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 Loading Limits 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 Loading Limits	
Transmission System Conditions	**Maximum Acceptable Loading Limit for Transformers and Transmission Lines**
All elements in service	100%
Single Contingency (pre-switching)	115%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	115%
Bus Outages (post-switching)	100%

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 criterion 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 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Single Contingency (post-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Bus Outages	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric 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 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 transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service up to the forecasted peak load level without any violations of 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 forecasted peak load level. The Tampa Electric 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's multiple-circuit corridors must be observed:

Tie Line Corridor	FCTTC
Lake Tarpon – Sheldon Rd. 230 kV (FPC)	1,100 MVA
Big Bend - Manatee 230 kV (FPL)	1,550 MVA

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, due to the timing of this document in relationship to our internal planning schedule, this plan may change in the near future.

Supply Side Resources Procurement Process

Tampa Electric 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.

DSM Energy Savings Durability

Tampa Electric 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 validates the energy savings. These include:

(1) periodic notch tests for residential load management (Prime Time) to confirm the accuracy of Tampa Electric's load reduction estimation formulas;

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

(3) end-use sampling of building segments to validate savings achieved in Conservation Value and Commercial Indoor Lighting programs; and

(4) in commercial programs such as Standby Generator and Commercial Load Management, the reductions are verified through submetering of those loads under control to determine the demand and energy savings.

Second, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Specifically, those programs that promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs) have program standards that require the new equipment to be installed in a permanent manner. This eliminates the participant from installing the less efficient, old style equipment at some future point in time.

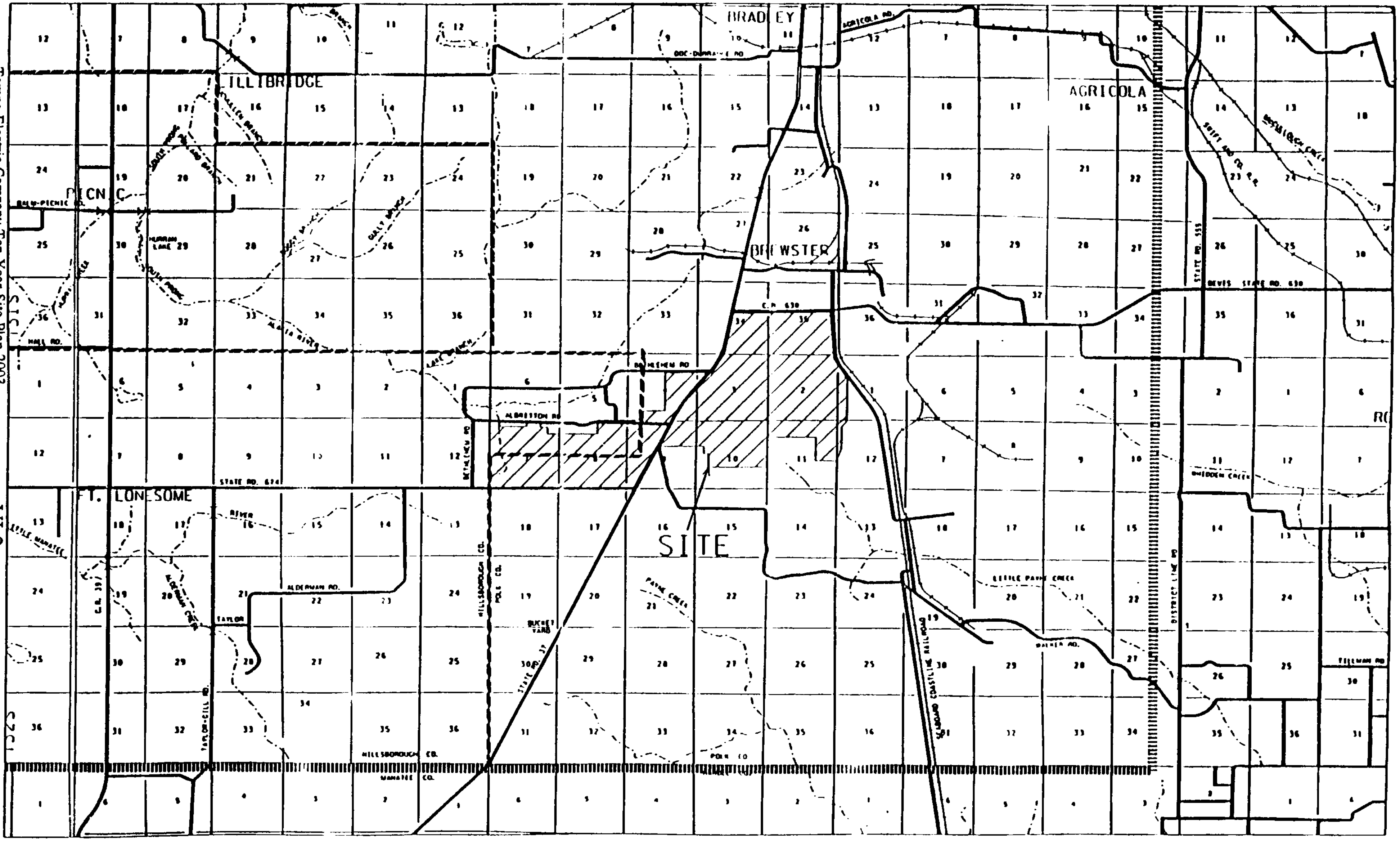
Smart Source – Tampa Electric's Green / Renewable Energy Program

Smart Source generation mix consists of an 18kW photovoltaic array installed at the Museum of Science and Industry (MOSI), biomass (wood derived fuels) co-fired with coal in Gannon's cyclone units and biomass that has been gasified at Polk Power station. A 30 kW Capstone microturbine, operating from a Hillsborough County landfill, will begin commercial operation in March 2003. The level of generation from biomass is contingent on the number of program subscribers and system operational needs.

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.



SITE LOCATION OF POLK POWER STATION

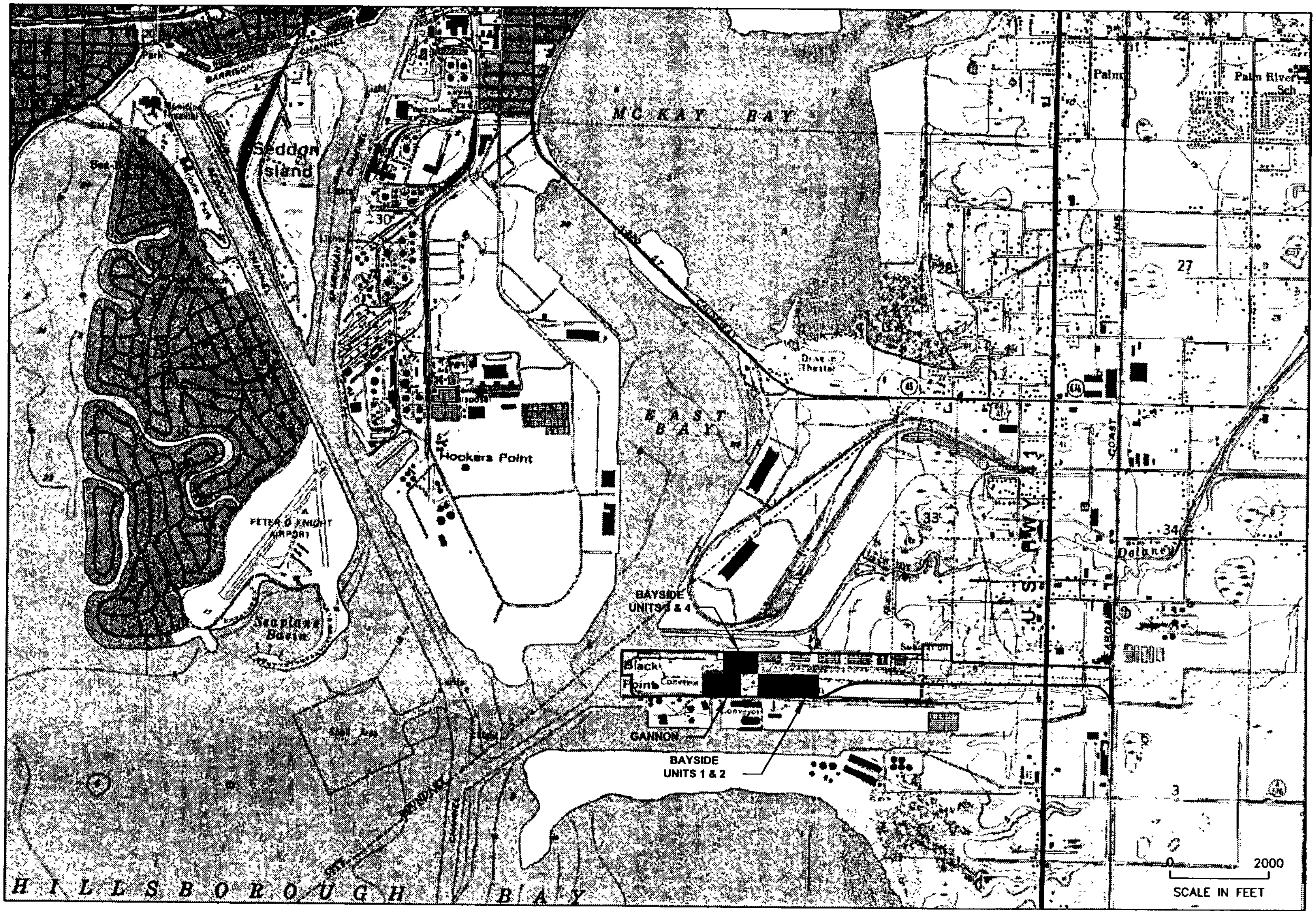
SOURCES: FDOT MAP, FLA, ECT

TAMPA ELECTRIC COMPANY

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

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

FIGURE VI-2



F.J. GANNON / BAYSIDE LOCATION MAP

SOURCE: USGS QUAD, TAMPA, FL 1981