ORIGINAL

AUSLEY & McMULLEN

ATTORNEYS AND COUNSELORS AT LAW

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TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

040000-PU

April 1, 2004

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

RECEIVED-FPSC
04 APR -1 PM 4:07
COMMISSION CLERK

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 2004 to December 2013 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

AUS ___
CAF ___ JDB/pp
CMP ___ Enclosures
COM ___
CTR ___
ECR Haff cc: Michael Haff (w/enc.)
GCL ___
OPC ___
MMS ___
SEC 1
OTH Kim + 1 copy

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FPSC-BUREAU OF RECORDS

DOCUMENT NUMBER-DATE
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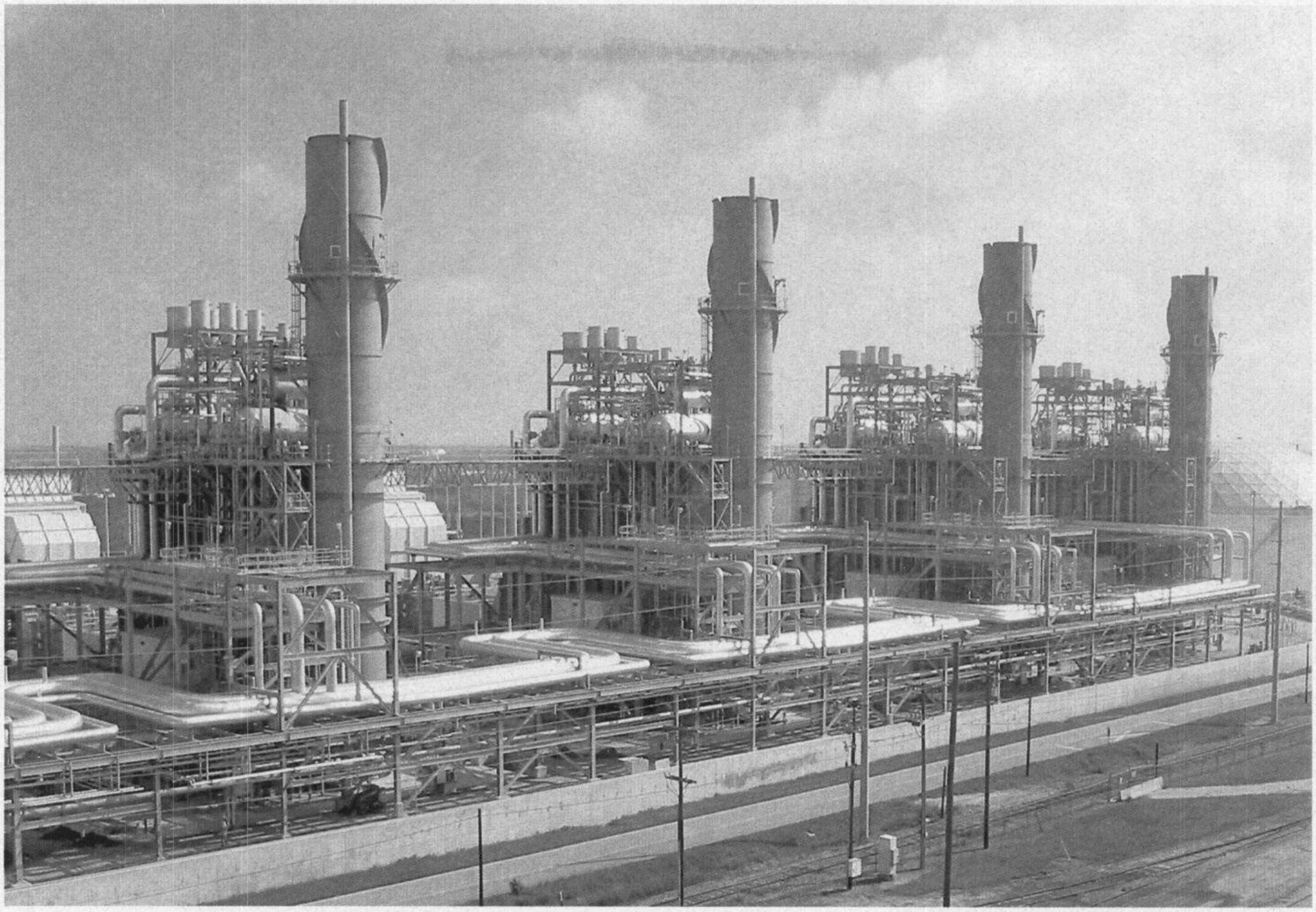

H.L. Culbreath Bayside Power Station

TECO

TAMPA ELECTRIC

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

JANUARY 2004 TO DECEMBER 2013

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

January 2004 to December 2013

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2004

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LIST OF SCHEDULES

LIST OF SCHEDULES

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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

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CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric started the shutdown of Gannon station in 2003. Gannon Unit 5 was removed from coal operations in January 2003 and the steam turbine was repowered as H. L. Culbreath Bayside Unit 1. Gannon Unit 5 was retired on January 1, 2004. Gannon Units 1 and 2 were removed from coal operations in April 2003 and retired on January 1, 2004. Gannon Unit 6 was removed from coal operations in September 2003 and the steam turbine was repowered as H. L. Culbreath Bayside Unit 2. Gannon Unit 6 was retired on January 1, 2004. Gannon Units 3 and 4 were placed on long term reserve standby in October 2003 and retired from coal operations on January 1, 2004. Gannon Units 3 and 4 may be repowered at some future date.

This leaves Tampa Electric with five generating stations consisting of fossil steam units, combined cycle units, combustion turbine peaking units, an integrated coal gasification combined cycle unit, and internal combustion diesel units.

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

Bayside: The station contains two natural gas fired combined cycle units. Bayside Unit 1 utilizes three combustion turbines, three heat recovery steam generators (HRSGs) and one steam turbine (formerly Gannon 5 steam turbine). Bayside Unit 2 utilizes four combustion turbines, four HRSGs and one steam turbine (formerly Gannon 6 steam turbine).

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 feedstock 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, 2003

(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 Capability Summer MW	(14) Net Capability Winter MW
Big Bend		Hillsborough											
		Co. 14/31S/19E									1,998,000	1,852	1,924
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	421	428
	2		FS	C	N	WA	N	0	04/73	"	445,500	411	433
	3		FS	C	N	WA	N	0	05/76	"	445,500	428	438
	4		FS	C	N	WA	N	0	02/85	"	486,000	452	460
	CT 1		CT	LO	N	WA	TK	0	02/69	"	18,000	14	15
	CT 2 (a)		CT	LO	N	WA	TK	0	11/74	"	78,750	66	80
	CT 3		CT	LO	N	WA	TK	0	11/74	"	78,750	60	70
Gannon		Hillsborough											
		Co. 4/30S/19E									1,301,880	1,083	1,107
	1 (b)		FS	C	N	WA	N	0	09/57	01/04	125,000	94	94
	2 (b)		FS	C	N	WA	N	0	11/58	01/04	125,000	100	100
	3 (c)		FS	C	N	WA	N	0	10/60	01/04	179,520	150	155
	4 (c)		FS	C	N	WA	N	0	11/63	01/04	187,500	164	164
	5 (d)		FS	C	N	WA	N	0	11/65	01/04	239,360	222	222
	6 (e)		FS	C	N	WA	N	0	10/67	01/04	445,500	353	372
Bayside		Hillsborough											
		Co. 4/30S/19E									809,060	690	779
	1		CC	NG	N	PL	N	0	5/03	Unknown	809,060	690	779
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 (f)		HRSG	WH	N	N	N	0	06/83	Unknown	3,600	3	3
Polk		Polk Co.											
		2,3/32S/23E									677,839	580	620
	1		IGCC	C	LO	WA/TK	TK	0	09/96	Unknown	326,299	255	260
	2 (g)		CT	NG	LO	PL	TK	0	07/00	Unknown	175,770	160	180
	3 (g)		CT	NG	LO	PL	TK	0	5/02	Unknown	175,770	165	180
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	4,248	4,473

Notes:
(a) Big Bend CT2 was placed on long term reserve standby in the fall of 2002 and is scheduled to resume operations in May 2006.
(b) Gannon units 1 and 2 were removed from coal operations in April 2003, and retired on January 1, 2004
(c) Gannon units 3 and 4 were placed on long term reserve standby in October 2003, and retired from coal operations on January 1, 2004. Gannon units 3 and 4 may be repowered on natural gas at some future date.
(d) Gannon unit 5 was removed from coal operations in January 2003 and repowered as Bayside unit 1 in April 2003. Gannon unit 5 was retired on January 1, 2004.
(e) Gannon unit 6 was removed from coal operations in September 2003, and repowered as Bayside unit 2 in January 2004. Gannon unit 6 was retired on January 1, 2004.
(f) Phillips unit 3 was placed on long term reserve standby in February 1991.
(g) Polk units 2 & 3 turbine name plate rating is based on 59 deg. F. The net capacity of these units may vary with ambient air temperature.

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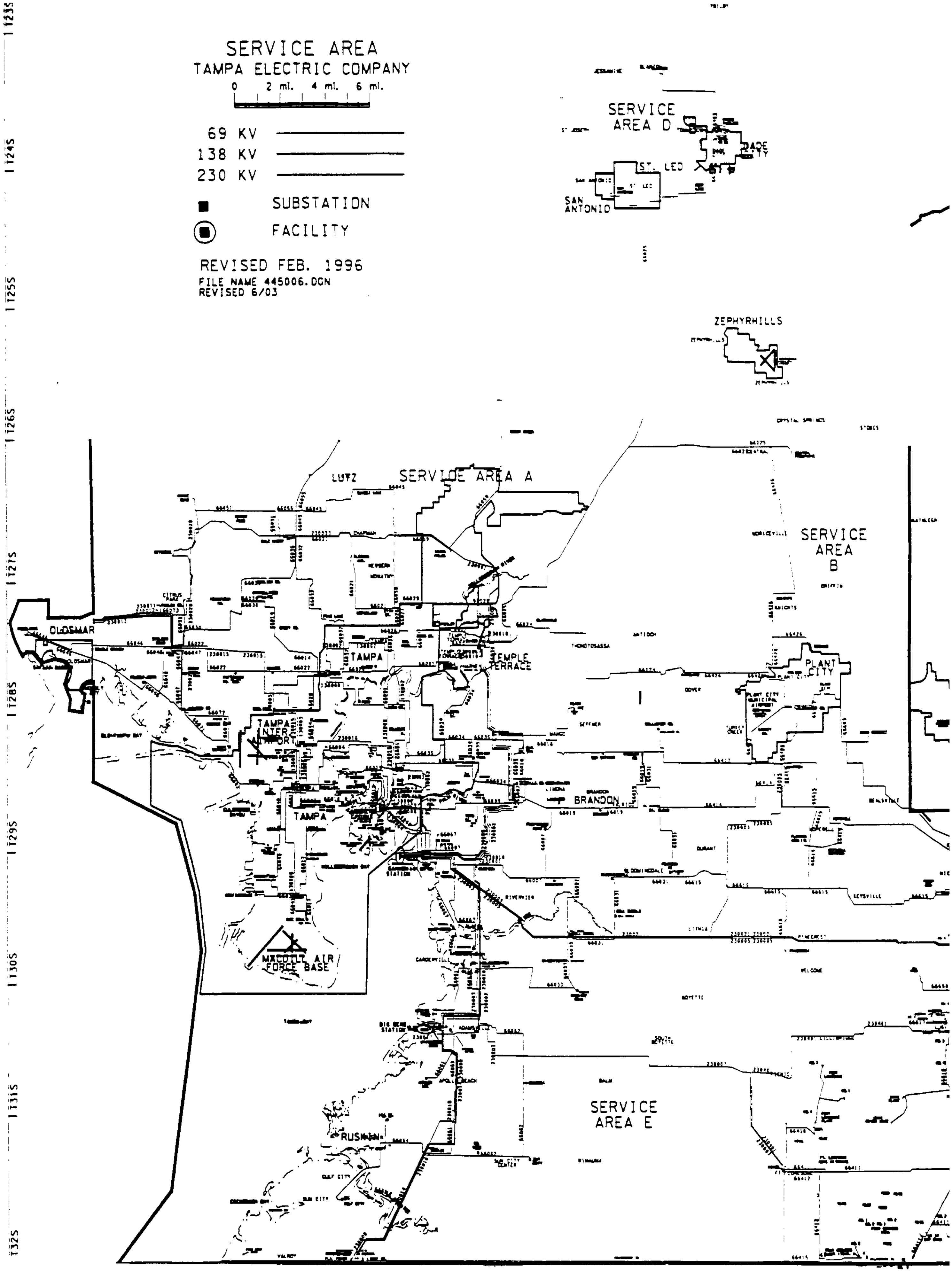

SERVICE AREA
TAMPA ELECTRIC COMPANY
0 2 mi. 4 mi. 6 mi.
69 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1996
FILE NAME 445006.DGN
REVISED 6/03
SERVICE AREA D
DADE CITY
ST. LEO
SAN ANTONIO
ZEPHYRHILLS
SERVICE AREA A
LUTZ
SERVICE AREA B
OLDSMAR
TAMPA
TEMPLE TERRACE
PLANT CITY
TAMPA INTER. AIRPORT
BRANDON
TAMPA
MACDILL AIR FORCE BASE
SERVICE AREA E
RUSKIN
T23S
T24S
T25S
T26S
T27S
T28S
T29S
T30S
T31S
T32S

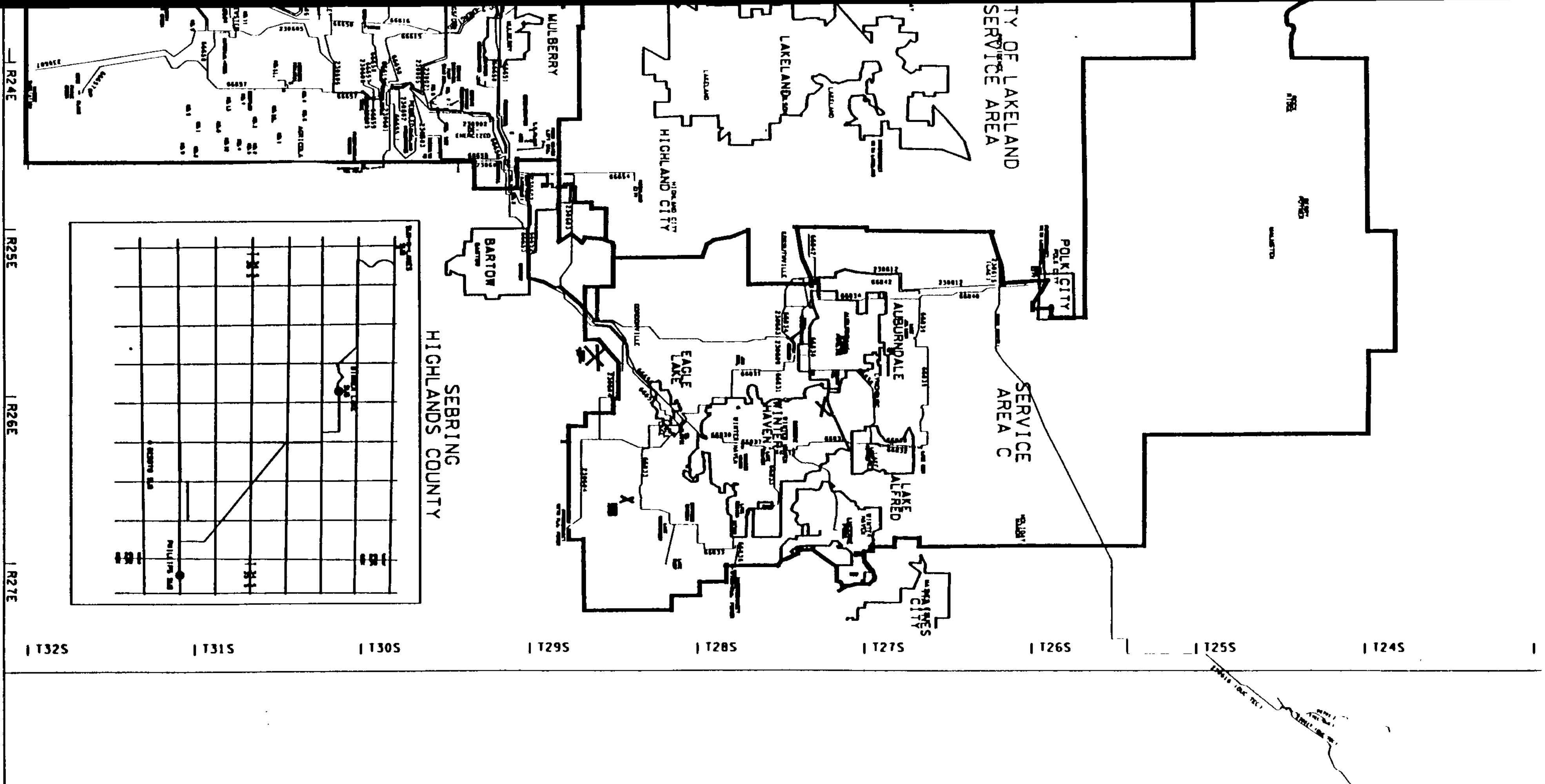

FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

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

FILE NAME 445006.DG
REVISED 6/0

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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
Schedule 2.2:	History and Forecast of Energy Consumption and Number of Customers by Customer Class
Schedule 2.3:	History and Forecast of Energy Consumption and Number of Customers by Customer Class
Schedule 3.1:	History and Forecast of Summer Peak Demand
Schedule 3.2:	History and Forecast of Winter Peak Demand
Schedule 3.3:	History and Forecast of Annual Net Energy for Load
Schedule 4:	Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
Schedule 5:	History and Forecast of Fuel Requirements
Schedule 6.1:	History and Forecast of Net Energy for Load by Fuel Source in GWH
Schedule 6.2:	History and Forecast of Net Energy for Load by Fuel Source as a Percentage

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
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	1,075,609	2.6	8,265	531,257	15,557	5,843	66,041	88,475
2004	1,092,430	2.5	8,462	543,346	15,574	6,006	67,253	89,305
2005	1,109,650	2.5	8,781	555,668	15,803	6,161	68,499	89,943
2006	1,127,529	2.5	9,178	569,088	16,128	6,326	70,030	90,333
2007	1,145,719	2.5	9,492	581,684	16,318	6,475	71,440	90,635
2008	1,164,202	2.5	9,791	593,988	16,483	6,632	72,672	91,259
2009	1,182,983	2.5	10,119	606,527	16,684	6,798	73,867	92,030
2010	1,201,563	2.5	10,440	618,915	16,868	6,966	75,250	92,571
2011	1,218,992	2.5	10,767	630,423	17,079	7,130	76,580	93,105
2012	1,236,588	2.5	11,100	642,047	17,288	7,293	77,927	93,588
2013	1,255,185	2.5	11,447	653,850	17,507	7,465	79,304	94,131

December 31, 2003 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
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	2,580	1203	2,144,638	0	57	1,481	18,226
2004	2,736	1,336	2,047,904	0	64	1,581	18,849
2005	2,788	1,394	2,000,000	0	66	1,631	19,427
2006	2,635	1,458	1,807,270	0	68	1,708	19,915
2007	2,679	1,516	1,767,150	0	70	1,750	20,466
2008	2,734	1,574	1,736,976	0	71	1,792	21,020
2009	2,727	1,632	1,670,956	0	73	1,836	21,553
2010	2,784	1,690	1,647,337	0	75	1,879	22,144
2011	2,736	1,743	1,569,707	0	77	1,920	22,630
2012	2,788	1,798	1,550,612	0	79	1,961	23,221
2013	2,854	1,852	1,541,037	0	80	2,007	23,853

December 31, 2003 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) Year	(2) Sales for * Resale GWH	(3) Utility Use ** & Losses GWH	(4) Net Energy *** for Load GWH	(5) Other **** Customers	(6) Total **** Customers
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	587	985	19,798	6,399	604,900
2004	524	974	20,347	6,541	618,476
2005	544	1,004	20,975	6,720	632,281
2006	546	1,029	21,490	6,893	647,469
2007	547	1,057	22,070	7,057	661,697
2008	552	1,086	22,658	7,219	675,453
2009	549	1,113	23,215	7,385	689,411
2010	552	1,145	23,841	7,547	703,402
2011	300	1,169	24,099	7,698	716,444
2012	260	1,200	24,681	7,851	729,623
2013	191	1,232	25,276	8,005	743,011

December 31, 2003 Status

* Includes sales to Progress Energy Florida, 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	
1994	2,869	69	2,800	200	97	30	8	14	2,451	☑
1995	3,038	81	2,957	170	105	32	10	16	2,624	
1996	3,144	92	3,052	234	104	35	13	19	2,647	
1997	3,187	106	3,081	225	95	39	21	24	2,677	☑
1998	3,458	111	3,347	204	107	43	21	27	2,945	
1999	3,648	190	3,458	193	98	48	19	31	3,069	
2000	3,568	171	3,397	182	78	52	21	36	3,028	
2001	3,730	178	3,552	181	90	55	21	40	3,165	
2002	3,869	122	3,747	206	99	60	21	43	3,318	☑
2003	3,854	122	3,732	188	63	65	21	44	3,351	
2004	4,138	175	3,963	218	97	69	21	47	3,511	
2005	4,271	185	4,086	222	99	72	21	48	3,624	
2006	4,379	186	4,193	192	100	75	22	50	3,754	
2007	4,493	186	4,307	192	100	78	22	52	3,863	
2008	4,617	186	4,431	194	100	81	23	53	3,980	
2009	4,734	186	4,548	187	101	84	23	54	4,099	
2010	4,865	186	4,679	187	101	87	24	55	4,225	
2011	4,911	115	4,796	187	101	89	24	56	4,339	
2012	5,036	115	4,921	187	101	92	24	56	4,461	
2013	5,153	100	5,053	187	101	94	24	57	4,590	

December 31, 2003 Status

* Includes residential and commercial/industrial conservation.
** Includes sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud and Reedy Creek.
*** Historical data in columns (6) through (9) has been updated.
☑ 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
1993/94	3,064	69	2,995	181	177	294	7	33	2,303
1994/95	3,613	74	3,539	240	245	314	10	35	2,695
1995/96	3,833	98	3,735	152	260	331	10	36	2,946
1996/97	3,632	109	3,523	228	164	353	21	38	2,719
1997/98	3,231	99	3,132	210	160	370	21	39	2,332
1998/99	3,986	131	3,855	152	266	388	18	40	2,990
1999/00	4,019	125	3,894	212	209	402	19	43	3,009
2000/01	4,405	136	4,269	191	196	410	21	44	3,407
2001/02	4,217	127	4,090	168	176	419	22	46	3,259
2002/03	4,484	129	4,355	195	210	428	21	46	3,455
2003/04	4,844	179	4,665	199	221	459	19	47	3,720
2004/05	4,998	190	4,808	203	226	488	20	49	3,822
2005/06	5,130	191	4,939	177	227	517	23	50	3,945
2006/07	5,283	191	5,092	177	227	545	23	51	4,069
2007/08	5,434	192	5,242	178	228	572	23	52	4,189
2008/09	5,578	192	5,386	173	229	600	24	52	4,308
2009/10	5,737	193	5,544	173	229	627	24	53	4,438
2010/11	5,893	194	5,699	173	230	654	24	54	4,564
2011/12	5,968	123	5,845	173	230	680	24	55	4,683
2012/13	6,110	108	6,002	173	230	706	24	55	4,814

December 31, 2003 Status

- Includes cumulative conservation.

** Includes sales to Progress Energy Florida, Wauchula, Fort Meade, St. Cloud and Reedy Creek.

*** Historical data in columns (6) through (9) has been updated.

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 %
1994	14,185	235	18	13,932	163	636	14,731	59.5
1995	14,871	245	26	14,600	212	870	15,682	54.8
1996	15,232	262	41	14,929	399	760	16,088	52.8
1997	15,430	279	61	15,090	507	731	16,328	57.5
1998	16,401	297	76	16,028	431	783	17,242	58.1
1999	16,212	315	92	15,805	533	900	17,238	55.3
2000	17,083	333	112	16,638	763	972	18,373	58.5
2001	17,444	346	122	16,976	684	794	18,455	53.3
2002	18,423	361	137	17,925	502	935	19,362	58.7
2003	18,756	378	152	18,226	587	985	19,798	56.4
2004	19,408	399	160	18,849	524	974	20,347	53.4
2005	20,014	419	168	19,427	544	1004	20,975	53.7
2006	20,527	437	175	19,915	546	1029	21,490	53.8
2007	21,101	454	181	20,466	547	1057	22,070	53.8
2008	21,677	470	187	21,020	552	1086	22,658	53.6
2009	22,230	486	191	21,553	549	1113	23,215	53.8
2010	22,841	502	195	22,144	552	1145	23,841	53.8
2011	23,346	517	199	22,630	300	1169	24,099	53.1
2012	23,954	532	201	23,221	260	1200	24,681	53.7
2013	24,603	547	203	23,853	191	1232	25,276	53.9

December 31, 2003 Status

* Historical conservation has been updated.
** Includes sales to Progress Energy Florida, 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)
	2003 Actual		2004 Forecast		2005 Forecast	
	Peak Demand *	NEL **	Peak Demand *	NEL **	Peak Demand *	NEL **
Month	MW	GWH	MW	GWH	MW	GWH
January	4,010	1,649	4,338	1,527	4,461	1,571
February	2,764	1,278	3,574	1,386	3,679	1,422
March	3,128	1,496	3,357	1,507	3,462	1,552
April	3,215	1,494	3,289	1,475	3,398	1,518
May	3,599	1,872	3,724	1,781	3,850	1,835
June	3,596	1,793	3,892	1,883	4,021	1,942
July	3,745	1,927	4,007	1,992	4,140	2,055
August	3,600	1,864	4,022	2,034	4,151	2,100
September	3,552	1,793	3,881	1,887	4,006	1,950
October	3,416	1,650	3,636	1,748	3,759	1,802
November	3,230	1,468	3,336	1,512	3,450	1,562
December	3,237	1,511	3,578	1,613	3,699	1,667
TOTAL		19,798		20,347		20,975

December 31, 2003 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	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	6,556	5,378	4,431	4,344	4,248	4,407	4,383	4,349	4,364	4,364	4,350	4,451
(3)	Residual	Total	1000 BBL	138	160	122	83	142	172	80	76	354	360	363	236
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	138	160	122	83	142	172	80	76	354	360	363	236
(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	319	179	292	297	305	318	346	394	499	376	560	619
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	214	131	238	246	244	249	249	233	249	249	245	249
(11)		CT	1000 BBL	105	48	54	51	61	70	97	161	250	127	315	371
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	5,151	27,084	58,336	59,071	64,701	64,032	67,266	71,070	70,404	66,777	80,043	95,802
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	22,337	57,371	58,139	63,584	62,757	65,556	68,285	66,086	64,540	74,604	89,431
(16)		CT	1000 MCF	5,151	4,747	965	932	1,117	1,275	1,709	2,785	4,318	2,237	5,439	6,371
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	545	359	591	567	559	574	573	550	572	572	565	576

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 2002	Actual 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Firm Interchange		GWH	359	699	374	458	513	525	363	473	407	339	503	78
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	13,353	11,454	9,791	9,726	9,523	9,857	9,814	9,731	9,779	9,764	9,741	9,965
(4)	Residual	Total	GWH	86	103	79	54	92	111	52	49	228	232	233	152
(5)		Steam	GWH	(2)	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	89	103	79	54	92	111	52	49	228	232	233	152
(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	191	103	150	152	156	163	175	197	247	187	275	303
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	149	85	125	129	128	130	130	122	130	130	128	130
(12)		CT	GWH	43	18	25	24	29	33	45	75	116	57	147	172
(13)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	474	3,561	7,876	7,974	8,735	8,653	9,072	9,535	9,366	8,980	10,627	12,740
(15)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWH	0	3,128	7,795	7,895	8,640	8,545	8,929	9,303	9,008	8,800	10,176	12,213
(17)		CT	GWH	474	433	81	79	95	108	143	232	358	181	452	527
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWH	1,522	867	1,428	1,371	1,353	1,388	1,386	1,329	1,384	1,383	1,368	1,394
(20)	Net Interchange		GWH	2,902	2,494	193	774	655	908	1,334	1,436	2,073	2,918	1,670	380
(21)	Purchased Energy from														
(22)	Non-Utility Generators		GWH	477	516	456	465	465	465	465	465	356	297	265	265
(23)	Net Energy for Load*		GWH	19,363	19,798	20,346	20,974	21,491	22,070	22,660	23,214	23,840	24,100	24,682	25,276

* 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 2002	Actual 2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Annual Firm Interchange		%	2	4	2	2	2	2	2	2	2	1	2	0
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		%	69	58	48	46	44	45	43	42	41	41	39	39
(4)	Residual	Total	%	0	1	0	0	0	1	0	0	1	1	1	1
(5)		Steam	%	(0)	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	%	0	1	0	0	0	1	0	0	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	1	1	1
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	1	0	1	1	1	1	1	1	1	1	1	1
(12)		CT	%	0	0	0	0	0	0	0	0	0	0	1	1
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	2	18	39	38	41	39	40	41	39	37	43	50
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	16	38	38	40	39	39	40	38	37	41	48
(17)		CT	%	2	2	0	0	0	0	1	1	2	1	2	2
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	8	4	7	7	6	6	6	6	6	6	6	6
(20)	Net Interchange		%	15	13	1	4	3	4	6	6	9	12	7	2
(21)	Purchased Energy from														
(22)	Non-Utility Generators		%	2	3	2	2	2	2	2	2	1	1	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.

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CHAPTER III

FORECAST OF ELECTRIC POWER DEMAND

Tampa Electric Company Forecasting Methodology

The Customer, Demand and Energy Forecast is the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric 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 2004-2013 forecast. The data tables in Chapter II outline the expected customer, demand, and energy values for the 2004-2013 time period.

Retail Load

MetrixND was used to develop the 2004-2013 Customer, Demand and Energy forecasts. MetrixND, designed by Regional Economic Research (RER), is an advanced statistics program for analysis and forecasting. This software allows a platform for the development of more dynamic and fully integrated models. During 2002, Itron, Inc. completed the acquisition of RER. Itron provides solutions for the energy and water industries.

In addition, Tampa Electric 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. Residential Customer Model: 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 2003-2023 were used to forecast the future growth patterns in residential customers.

   Commercial Customer Model: 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, such as street and highway lighting. 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:

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

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

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

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 $_{y,m}$ =

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

CoolUse $_{y,m}$ =

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

OtherUse $_{y,m}$ =

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

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. <u>Heating and Cooling</u> - 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 2003 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 Cities of Wauchula, Fort Meade, and St. Cloud, Progress Energy Florida 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%
2003	50.9	59.2	86.0%	21.7	20.7	104.8%	56.9	37.5	151.7%

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[(1)]	6.3	4.5	140.0%	13.2	10.4	126.9%	38.6	38.6	100.0%
2003	7.1	5.9	120.3%	15.1	13.5	111.9%	51.2	50.3	101.8%

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[(1)]	44.5	50.8	87.6%	28.5	26.5	107.5%	79.4	67.6	117.5%
2003	58.0	65.1	89.1%	36.8	34.2	107.6%	108.1	87.8	123.1%

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 (2004-2013) the average annual growth rate in Hillsborough County's population is expected to be 1.6% 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, employment is assumed to rise at a 2.6% average annual rate. Economy.com supplies employment projections.

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 4.3% average annual rate. Economy.com supplies output projections.

4. Per Capita Income

Economy.com supplies the assumptions for Hillsborough County's per capita income growth. During 2004 - 2013, personal income per capita for Hillsborough County is expected to increase at a 6.5% 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 2004-2013, retail energy sales are projected to rise at a 2.7% annual rate. The major contributor to growth is the residential category. This sector is increasing at an annual rate of 3.4%.

Wholesale Energy

Wholesale energy sales to Progress Energy Florida, Wauchula, Ft. Meade, St. Cloud, and Reedy Creek of 524 GWh are expected in 2004. Sales are projected to increase at a 0.9% annual rate through 2010. In 2011, sales drop substantially to 300 GWh and continue to decline to 260 GWh in 2012 and 191 GWh in 2013.

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 2004-2013 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 2.9% and 3.0%, respectively.

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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 created. 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. 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 2008, 2009, 2010, 2011, and 2013 and a combined cycle unit in 2013. Tampa Electric increased its generating capacity while diversifying its present generation mix with the repowering of Gannon Station. The station was repowered with natural gas and renamed Bayside Power Station. The repowering consists of the addition of three CTs and three HRSGs to supply steam to Gannon Unit 5 steam turbine and four CTs and four HRSGs to supply steam to Gannon Unit 6 steam turbine. The repowered units are named Bayside Units 1 and 2. Bayside Unit 1 in service date was April 24, 2003 and Bayside Unit 2 in service date was January 15, 2004. In addition, Gannon Units 1 and 2 were removed from coal operations in April 2003 and retired January 1, 2004. Gannon Units 3 and 4 were placed in long term reserve standby in October 2003 and retired from coal operations on January 1, 2004, Gannon Units 3 and 4 may be repowered at some future date. Gannon Unit 5 was removed from coal operations in January 2003 and retired on January 1, 2004. Gannon Unit 6 was removed from coal operations in September 2003 and retired on January 1, 2004. Tampa Electric also plans on reactivating Big Bend CT 2 and adding chillers to each of the Bayside CTs before 2008. This will provide 227 MW summer and 80 MW winter of increased system capacity. 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 436 MW of cogeneration capacity operating in its service area in 2004. Self-service capacity of 229 MW (net) is used by cogenerators to serve internal load requirements, 60 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 142 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. Tampa Electric currently uses a balanced generation portfolio of coal and natural gas for its generating requirements. Tampa Electric increased 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 Unit 1 in April 2003. In January of 2004 Gannon Unit 6 was repowered to a combined cycle unit burning natural gas, and renamed to Bayside Unit 2. Tampa Electric has a firm transportation contract with the Florida Gas Transmission Company (FGT) for delivery of natural gas to the new Bayside Units. As shown in Schedule 6.2, in 2004 coal and pet coke will fuel 55% of net energy for load and natural gas will fuel 39%. One percent of net energy for load will be fueled by distillate oil at the Phillips plant and other combustion turbines. The remaining net energy for load is served by non-utility generators and net interchange.

Environmental Considerations

Emissions reductions made since 2000 are largely the result of an agreement reached between the Florida Department of Environmental Protection (DEP) and Tampa Electric. The effort resulted in a comprehensive emissions reduction plan called the Consent Final Judgment (CFJ), 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) called the Consent Decree (CD). Collectively, the CFJ and CD are referred to as the "Agreements". 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 129,430 tons, 27,630 tons, and 2,865 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 between 93% and 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 Station and the repowering of Gannon Station to Bayside Power Station.

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

Significant reductions in emissions outlined in the Agreements will result from the 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 required on all Big Bend Units. By 2010, these projects will result in the estimated additional phased reduction of SO_2 by 27,071 tons per year, NO_x by 33,919 tons per year, and PM by 761 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 89 percent, 90 percent, and 70 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 Ft. Meade, St. Cloud, and Wauchula.

Tampa Electric has a long-term purchase power contract for capacity and energy with Invenergy who purchased the Hardee Power Station from Hardee Power Partners Limited in September 2003. The contract term is 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.

In evaluating its 2005 capacity and energy requirements, Tampa Electric determined that it had a need for peaking capacity beginning May 2005. To determine how best to meet this requirement, the company issued a Request for Proposal (RFP) in July 2003. The overriding objective of this RFP is to solicit bids for competitive resources that provide Tampa Electric with the most cost-effective peaking capacity alternative to satisfy its projected capacity requirements. This RFP sought proposals for up to two hundred and twenty-five megawatts (225 MW) of firm peaking capacity to be available for delivery by May 1, 2005. Tampa Electric is evaluating the purchase of up to 200 MW through this RFP process, which is currently in the negotiation stage.

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
2004	4,038	368	0	60	4,466	3,685	781	21%	0	781	21%
2005	4,038	568	0	61	4,667	3,810	857	22%	0	857	22%
2006	4,104	568	0	61	4,734	3,940	794	20%	0	794	20%
2007	4,265	568	0	61	4,894	4,049	845	21%	0	845	21%
2008	4,425	568	0	61	5,054	4,166	888	21%	0	888	21%
2009	4,585	568	0	61	5,214	4,285	929	22%	0	929	22%
2010	4,745	568	0	38	5,351	4,411	940	21%	0	940	21%
2011	4,905	568	0	30	5,503	4,454	1,049	24%	0	1,049	24%
2012	4,905	568	0	21	5,494	4,576	918	20%	0	918	20%
2013	5,509	200	0	21	5,730	4,690	1,040	22%	0	1,040	22%

NOTE:
1. Per FPSC ruling (Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, Issued December 22,1999) 15% Reserve Margin increased to 20% starting summer 2004.
2. Capacity import for 2004 through 2012 includes firm purchase power agreement with Hardee Power Partners of 368 MW. Capacity imports for 2005 through 2013 include an Undetermined supplier for up to 200 MW. (RFP issued July 2003)
3. The QF column accounts for cogeneration that will be purchased under firm contracts.
4. Gannon units 1 and 2 were removed from coal operations in April 2003 and retired on January 1, 2004.
5. Gannon units 3 and 4 were placed in long term reserve standby in October 2003 and retired from coal operations on January 1, 2004. Gannon 3 and 4 may be repowered on natural gas at some future date.
6. Chiller additions to Bayside units 1 and 2 in May 2007 will provide 23 MW per CT (161MW Total) of additional summer capacity.
7. Bayside unit 1 received a capacity increase in February 2004 to 702 MW summer.

* 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	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2003-04	4,323	449	0	60	4,832	3,899	933	24%	0	933	24%
2004-05	4,331	449	0	61	4,841	4,012	829	21%	0	829	21%
2005-06	4,331	649	0	61	5,041	4,136	905	22%	0	905	22%
2006-07	4,411	649	0	61	5,121	4,260	861	20%	0	861	20%
2007-08	4,591	649	0	61	5,301	4,381	920	21%	0	920	21%
2008-09	4,771	649	0	61	5,481	4,500	981	22%	0	981	22%
2009-10	4,951	649	0	47	5,647	4,631	1,016	22%	0	1,016	22%
2010-11	5,131	649	0	30	5,810	4,758	1,052	22%	0	1,052	22%
2011-12	5,131	649	0	21	5,801	4,806	995	21%	0	995	21%
2012-13	5,813	200	0	21	6,034	4,922	1,112	23%	0	1,112	23%

NOTE:

1. Per FPSC ruling (Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, Issued December 22,1999) 15% Reserve Margin increased to 20% starting summer 2004.
2. Capacity import for 2004 through 2012 includes firm purchase power agreement with Hardee Power Partners of 449 MW. Capacity imports for 2005 through 2013 include an Undetermined supplier for up to 200 MW. (RFP issued July 2003)
3. The QF column accounts for cogeneration that will be purchased under firm contracts.
4. Gannon units 1 and 2 were removed from coal operations in April 2003 and retired on January 1, 2004.
5. Gannon units 3 and 4 were placed in long term reserve standby in October 2003 and retired from coal operations on January 1, 2004. Gannon 3 and 4 may be repowered at some future date.
6. Bayside unit 1 received a capacity increase in February 2004 to 787 MW winter.

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. Start	Commercial In-Service	Expected Retirement	Gen. Max. Nameplate	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Mo/Yr	Mo/Yr	Mo/Yr	kW	Summer MW	Winter MW	Status
Bayside	2	Hills. Co.	CC	NG	N	PL	N	4/02	1/04	unknown	unknown	930	1040	UC
Bayside	3A	Hills. Co.	CT	NG	LO	PL	U	7/06	1/08	unknown	unknown	160	180	P
Bayside	3B	Hills. Co.	CT	NG	LO	PL	U	7/07	1/09	unknown	unknown	160	180	P
Polk	4	Polk	CT	NG	LO	PL	TK	5/08	1/10	unknown	unknown	160	180	P
Polk	5	Polk	CT	NG	LO	PL	TK	5/09	1/11	unknown	unknown	160	180	P
Polk	6	Polk	CT	NG	LO	PL	TK	5/11	1/13	unknown	unknown	160	180	P
Future Unit	1	unknown	CC	NG	LO	PL	TK	7/09	1/13	unknown	unknown	444	502	P

SCHEDULE 9

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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	930
	B. WINTER	1040
(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 [3]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	CONSTRUCTION PERMITS OBTAINEI
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.8
	FORCED OUTAGE RATE (FOR)	4.1
	EQUIVALENT AVAILABILITY FACTOR (EAF)	92
	RESULTING CAPACITY FACTOR (2004)	59%
	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.
[3] CERTIFICATION NOT REQUIRED.

SCHEDULE 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	JUL 2006
	B. COMMERCIAL IN-SERVICE DATE	JAN 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 213 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS [3]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2008)	5.5%
	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 $/kW)	247.77
	DIRECT CONSTRUCTION COST ($/kW)	225.00
	AFUDC AMOUNT ($/kW)	3.28
	ESCALATION ($/kW)	19.48
	FIXED O&M ($/kW – Yr)	2.74
	VARIABLE O&M ($/MWH)	8.76
	K FACTOR	1.6926

1 REPRESENTS TOTAL GANNON OR BAYSIDE SITE.
2 BASED ON IN-SERVICE YEAR.
3 CERTIFICATION NOT REQUIRED.

SCHEDULE 9

(Page 3 of 7)

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	JUL 2007
	B. COMMERCIAL IN-SERVICE DATE	JAN 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 213 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS [3]	N/A
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2009)	7.0%
	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 $/kW)	253.47
	DIRECT CONSTRUCTION COST ($/kW)	225.00
	AFUDC AMOUNT ($/kW)	3.36
	ESCALATION ($/kW)	25.11
	FIXED O&M ($/kW – Yr)	2.80
	VARIABLE O&M ($/MWH)	8.96
	K FACTOR	1.6926

[1] REPRESENTS TOTAL GANNON OR BAYSIDE SITE.
[2] BASED ON IN-SERVICE YEAR.
[3] CERTIFICATION NOT REQUIRED.

SCHEDULE 9

(Page 4 of 7)

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

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 4
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	MAY 2008
	B. COMMERCIAL IN-SERVICE DATE	JAN 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 [1]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS [3]	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2010)	7.0%
	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 $/kW)	259.30
	DIRECT CONSTRUCTION COST ($/kW)	225.00
	AFUDC AMOUNT ($/kW)	3.44
	ESCALATION ($/kW)	30.86
	FIXED O&M ($/kW – Yr)	2.87
	VARIABLE O&M ($/MWH)	9.17
	K FACTOR	1.6926

[1] REPRESENTS TOTAL POLK SITE.
[2] BASED ON IN-SERVICE YEAR.
[3] CERTIFIED REFERS TO ENVIRONMENTALY PERMITED SITE.

SCHEDULE 9

(Page 5 of 7)

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	MAY 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2011
(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 [3]	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2011)	2.0%
	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 $/kW)	265.26
	DIRECT CONSTRUCTION COST ($/kW)	225.00
	AFUDC AMOUNT ($/kW)	3.52
	ESCALATION ($/kW)	36.74
	FIXED O&M ($/kW – Yr)	2.93
	VARIABLE O&M ($/MWH)	9.38
	K FACTOR	1.6926

[1] REPRESENTS TOTAL POLK SITE.
[2] BASED ON IN-SERVICE YEAR.
[3] CERTIFIED REFERS TO ENVIRONMENTALY PERMITED SITE.

SCHEDULE 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	MAY 2011
	B. COMMERCIAL IN-SERVICE DATE	JAN 2013
(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 [3]	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	4.8
	EQUIVALENT AVAILABILITY FACTOR (EAF)	93
	RESULTING CAPACITY FACTOR (2013)	6.0%
	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 $/kW)	277.61
	DIRECT CONSTRUCTION COST ($/kW)	225.00
	AFUDC AMOUNT ($/kW)	3.68
	ESCALATION ($/kW)	48.93
	FIXED O&M ($/kW – Yr)	3.07
	VARIABLE O&M ($/MWH)	9.82
	K FACTOR	1.6926

[1] REPRESENTS TOTAL POLK SITE.
[2] BASED ON IN-SERVICE YEAR.
[3] CERTIFIED REFERS TO ENVIRONMENTALY PERMITED SITE.

SCHEDULE 9

(Page 7 of 7)

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	444
	B. WINTER	502
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	JUL 2009
	B. COMMERCIAL IN-SERVICE DATE	JAN 2013
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS [3]	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.8
	FORCED OUTAGE RATE (FOR)	4.0
	EQUIVALENT AVAILABILITY FACTOR (EAF)	92
	RESULTING CAPACITY FACTOR (2013)	62.9%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,130 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	26
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	733.92
	DIRECT CONSTRUCTION COST ($/kW)	565.74
	AFUDC AMOUNT ($/kW)	65.82
	ESCALATION ($/kW)	102.36
	FIXED O&M ($/kW – Yr)	23.47
	VARIABLE O&M ($/MWH)	0.38
	K FACTOR	1.6926

[1] BASED ON IN-SERVICE YEAR.

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
FishHawk/ Pebbledale/ Gannon/ Hampton	3	No new right of way required	0.1 mi	230 kV	Summer 2004	$2.2 million	FishHawk – New 230 kV Switching Station and 230/13 kV Substation	None
Pebbledale/ Twilight	1	Possible road ROW required	12.0 mi	230 kV	Summer 2005	$13.0 million	Twilight – New 230/69 kV Substation	None
Twilight/Hamp ton	1	Possible road ROW required	8.0 mi	230 kV	Summer 2006	$8.2 million	Hampton – New 230 kV Ring Bus	None
Hampton/ Wheeler	1	Possible road ROW required	10.2 mi	230 kV	Summer 2007	$11.0 million	Wheeler – New 230 kV Ring Bus and 230/69 kV Transformer	None
Davis/ Chapman	2	No new right of way required	8.4 mi	230 kV	Summer 2007	$15.0 million	Davis - New 230 kV Switching Station/ Chapman – Complete 230 kV Ring Bus	None
Davis/ Wilderness	1	Possible road ROW required	12.6 mi	230 kV	Summer 2008	$8.0 million	Wilderness – New 230/69 kV Substation	None
Wheeler/Davis	1	No new right of way required	13.0 mi	230 kV	Summer 2008	$13.0million	No new substations	None

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CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Based on an assessment of the Tampa Electric transmission system using year 2003 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 in this study.

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 and discussed later in this 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 the 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 are considered within the Integrated Resource Planning process 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 resulting expansion plan may include self-build generation, market purchase options or other viable supply and demand-side alternatives.

The results of the Integrated Resource Planning process provide Tampa Electric Company with an expansion plan that meets the needs of both the company and its customers in a cost-effective manner. To meet the expected system demand and energy requirements beyond 2005 and to cost-effectively maintain system reliability, Tampa Electric Company conducted an RFP process through which it is evaluating up to 200 MW of peaking capacity beginning May 2005. Tampa Electric also plans on reactivating Big Bend CT 2 and adding chillers to each of the Bayside CTs before 2008. This will provide 227 MW summer and 80 MW winter of increased system capacity. New capacity additions shown in Schedule 8 are combustion turbine additions planned for service in January 2008, 2009, 2010, 2011, and 2013 and a combined cycle in 2013. The repowering of Gannon Unit 5 to Bayside Unit 1 was on April 24, 2003 and Gannon Unit 6 to Bayside Unit 2 was January 15, 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.

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

Generation Dispatch Modeled

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

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

Transmission System Planning 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 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 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 Company complies with the FRCC ATC calculation methodology as well as the principles contained in the NERC ATC Definitions and Determinations document.

Transmission Planning Assessment Practices

Base Case Operating Conditions

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

Single Contingency Planning Criteria

The Tampa Electric Company transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service 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 peak load level. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of FRCC criteria.

First Contingency Total Transfer Capability Considerations

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

Tie Line Corridor	FCTTC
Lake Tarpon - Sheldon Rd. 230 kV (FPC)	1,100 MVA
Big Bend - Manatee 230 kV (FPL)	1,700 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.

DSM Energy Savings Durability

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

(1) periodic system load reduction analyses 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) periodic DOE2 modeling of various program participants to evaluate savings achieved in residential programs involving building components;

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

(5) in commercial programs such as Standby Generator and Commercial Load Management, the reductions are verified through metering of 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, DX commercial cooling units) have program standards that require the new equipment to be installed in a permanent manner thus insuring their durability.

Tampa Electric's Renewable Energy Program

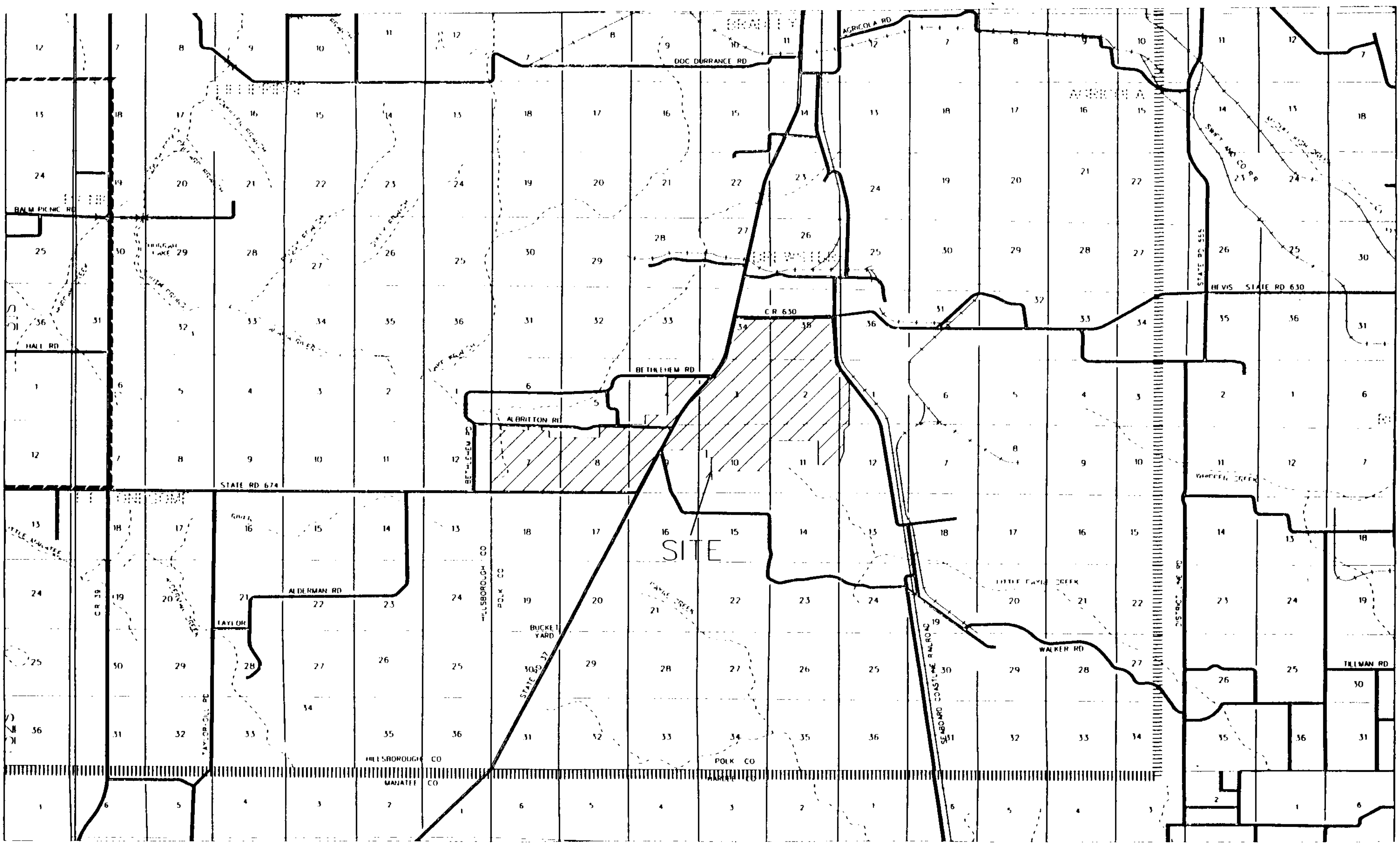
The renewable generation mix consists of an 18kW photovoltaic array installed at the Museum of Science and Industry (MOSI) and a 30 kW Capstone micro turbine that operates on methane at a Hillsborough County landfill. In April 2004, a 4kW photovoltaic system will be installed at a local middle school in a partnership with the Hillsborough County School District. Tampa Electric will also be conducting test burn at its Polk Power Station to determine the feasibility of gasifying biomass at that facility. 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 Bayside Power station and the Polk Power Station. The Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-2) and the Polk Power station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-1). Both facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.

FIGURE VI-1



SITE LOCATION OF POLK POWER STATION

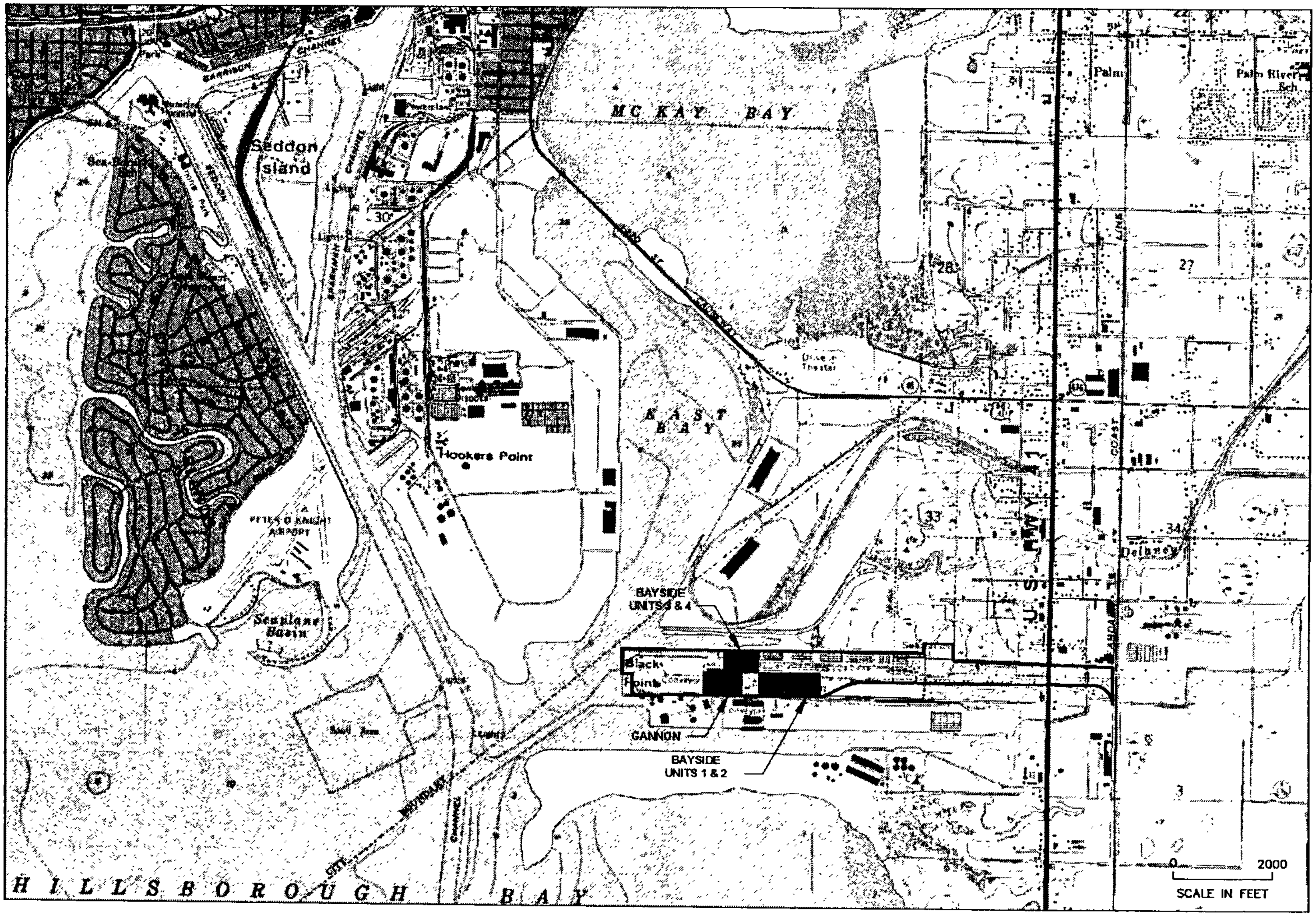
SOURCES: FDOT MAP, FLA, FCT

TAMPA ELECTRIC COMPANY

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

FILE NAME 403020.DG
REVISION 3/9/2000 MM

FIGURE VI-2



F.J. GANNON / BAYSIDE LOCATION MAP

SOURCE: USGS QUAD, TAMPA, FL 1981

TECO